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DOCKET NO. UE-130617
2013 PSE PCORC
WITNESS: TOM A. DEBOER

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PUGET SOUND ENERGY, INC.,** **Respondent.**	**Docket No. UE-130617**

FIRST EXHIBIT (NONCONFIDENTIAL) TO THE
PREFILED SUPPLEMENTAL DIRECT TESTIMONY OF TOM A. DEBOER
ON BEHALF OF PUGET SOUND ENERGY, INC.

JULY 29, 2013

2013 Integrated Resource Plan

CHAPTERS 1-7

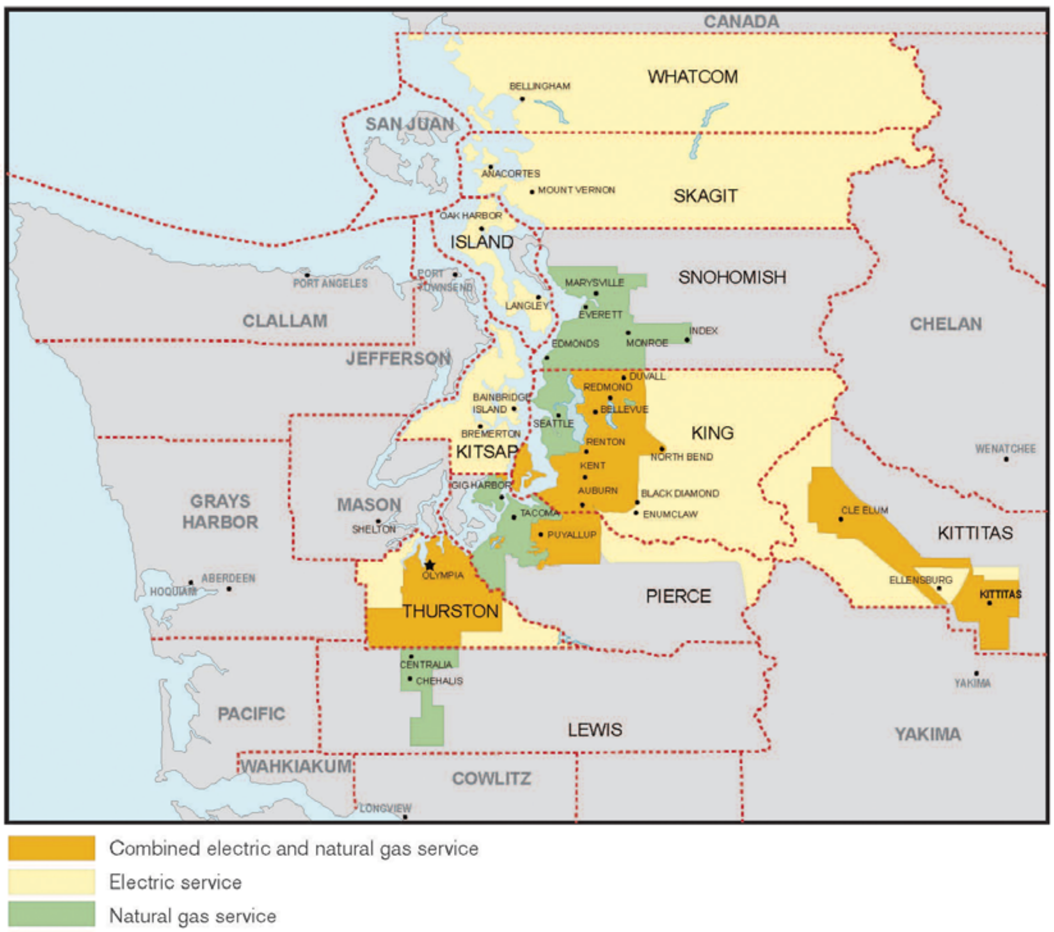
May 30, 2013

PSE.com

PUGET SOUND ENERGY

About PSE

Puget Sound Energy is Washington state's oldest local energy company, providing electric and natural gas service to customers primarily in the vibrant Puget Sound area. With a more than 6,000-square-mile service area, stretching from south Puget Sound north to the Canadian border, and from Central Washington's Kittitas Valley west to the Kitsap Peninsula, we serve more than 1 million electric customers and more than 750,000 natural gas customers in 10 counties.



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2013 Integrated Resource Plan

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CHAPTER 1

Executive Summary

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This Integrated Resource Plan (IRP or plan) presents a long-term forecast of the lowest reasonable cost combination of resources necessary to meet the needs of Puget Sound Energy's customers over the next 20 years. The plan presented here will change as circumstances change, and actual resource acquisitions will take place in the real – rather than the hypothetical – marketplace. But, examining the long-term implications of our customer's energy needs every two years makes it possible to identify many challenges as they appear on the horizon, study them as they approach, and better prepare to meet them. Among the insights from this planning cycle are the following.

The Northwest energy marketplace is changing.

For more than a decade, the Pacific Northwest has been capable of generating more electric energy than the region's utilities required for meeting customer demand. Now, however, the Regional Resource Adequacy Forum's 5-year forecast indicates the region will soon reach load-resource balance. Looking out to 2020, a recent analysis by the Northwest Power and Conservation Council found the planned retirement of as much as 2,000 MW of electric generation in Washington and Oregon may lead to a significant degradation in reliability of the electrical system, unless the retiring generation is replaced. In addition, planned retirements in the Southwest energy market, plus more intermittent renewable resources and stricter environmental regulations may impact winter imports that the Northwest has relied on for decades. Utilities across the region will probably need to either construct new resources or support their development financially with long-term purchased power agreements.

Market purchases remain a least cost choice for the present, but this strategy will need to change in the future.

The region's electric "surplus" has kept market prices low and made transmission contracts plus short-term power purchases a more cost effective alternative for filling peak capacity need than building new generation. This has been true not just for PSE, but for other regional utilities as well. The strategy remains sound for now, but as regional resource adequacy reaches load-resource balance and moves toward capacity deficits, physical reliability risks will grow and costs will increase. The action plan for this IRP makes a number of recommendations directed at developing a strategy for reducing reliance on market.

There is long-term uncertainty for coal generation in general, but Colstrip reduces cost and market risk in most likely scenarios.

A number of factors may impact the future operations of coal-fired generation throughout the United States; this IRP investigates their potential impact on the economic operation of PSE's Colstrip facility. For this analysis, PSE developed four environmental compliance cost cases to test the economic viability of Colstrip under a variety of potential regulatory requirements. Overall, the analysis found that Colstrip reduces cost and market risk for our customers. Three key risk factors have the greatest effect on Colstrip's performance as an economic, least-cost resource: very high CO_2 costs, very high disposal costs for coal combustion residuals, and very low natural gas prices for a very long time. At this time, the analysis indicates that continuing current operations at Colstrip saves PSE customers about $131 million per year. Put a different way, replacing Colstrip with another resource would result in approximately a 5 percent annual rate increase, apart from any other rate pressures. Conditions may change in the future, but for this planning cycle, it does not appear PSE should begin developing resources to replace Colstrip.

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As natural gas usage expands, prices will increase and infrastructure issues will become more pressing.

Production from North American shale bed deposits has increased natural gas supplies and lowered prices, but it is not realistic to expect natural gas prices to remain this low over the long term. The very affordability of this fuel means that usage is also increasing, especially in the transportation and utility sectors. Along with the possibility of exports of gas from North America, increased usage will create upward pressure on prices over time. Of greater concern, perhaps, is that as greater volumes of gas move through the system, physical reliability risks will increase as capacity of existing infrastructure strains to keep up.

The electric plan presented here is similar to past plans since resource alternatives remain limited. The plan relies on continued acquisition of demand-side resources; it adds renewable resources as needed to meet statutory requirements; and it recommends adding peaking resources. Renewing transmission capacity contracts to support additional generating units or to facilitate market power purchases makes sense in the near term, but long-term reliance on short-term markets clearly requires further study and action given the expected retirements of coal plants in our region and concerns about the availability of resources from Southwestern markets.

It is important to recognize that the IRP does not make purchasing or investment decisions for the next two decades. The IRP process enables us to construct a portfolio that meets future challenges as we understand them today. Actual resource acquisitions and investment decisions are informed by the foresight developed in the IRP, but those acquisitions must respond to the market conditions that exist at the time when the decision is made.

1. Electric Resource Plan

Electric resource need

PSE must meet the physical needs of our customers reliably. For resource planning purposes, those physical needs are simplified and expressed in terms of peak hour capacity and energy. Operating reserves are included in physical needs; these are required by contract with the Northwest Power Pool and by the North American Electric Reliability Corporation (NERC), to ensure total system reliability. In addition to meeting customers' physical needs, Washington state law (RCW 19.285) also requires utilities to acquire specified amounts of renewable resources or equivalent renewable energy credits (RECs). There are details in the law such that complying with RCW 19.285 may not directly correspond to meeting physical needs, so this is expressed as a separate category of resource need.

Electric peak hour capacity need

Figure 1-1 compares the existing resources available to meet peak-hour capacity[1] with the projected need over the planning horizon. The company's electric resource outlook indicates the need for an additional 12 MW of peak hour capacity by 2017, assuming that approximately 1,600 MW of PSE's capacity need is met by short-term purchases over firm transmission. The need grows to 100 MW by 2020 after acquisition of all cost-effective demand-side resources identified in the analysis – again, assuming 1,600 MW of short-term purchases on firm transmission. This includes the resources required to meet peak hour customer demand events, and the planning margin and operating reserves that must be maintained to achieve acceptable reliability.[2] Figure 1-1 illustrates the important role demand-side resources play in moderating the need to add supply-side resources in the future.

[1] *Resource capacities illustrated here reflect the contribution to peak, not nameplate capacity, so PSE's approximate 780 MW of owned and contracted wind appear very small on this chart. Refer to Chapter 5 for how peak capacity contributions were assessed.*
[2] *Refer to Appendix K for a description of electric planning standards.*

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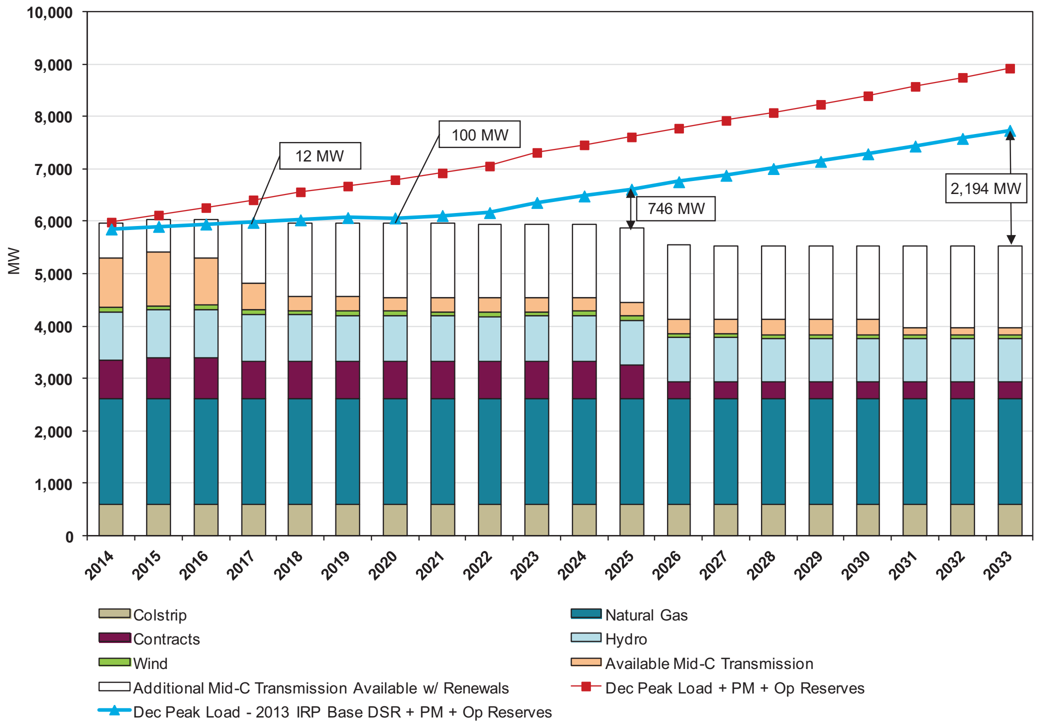
Figure 1-1
Electric Peak Hour Capacity Resource Need
Projected peak hour need and effective capacity of existing resources



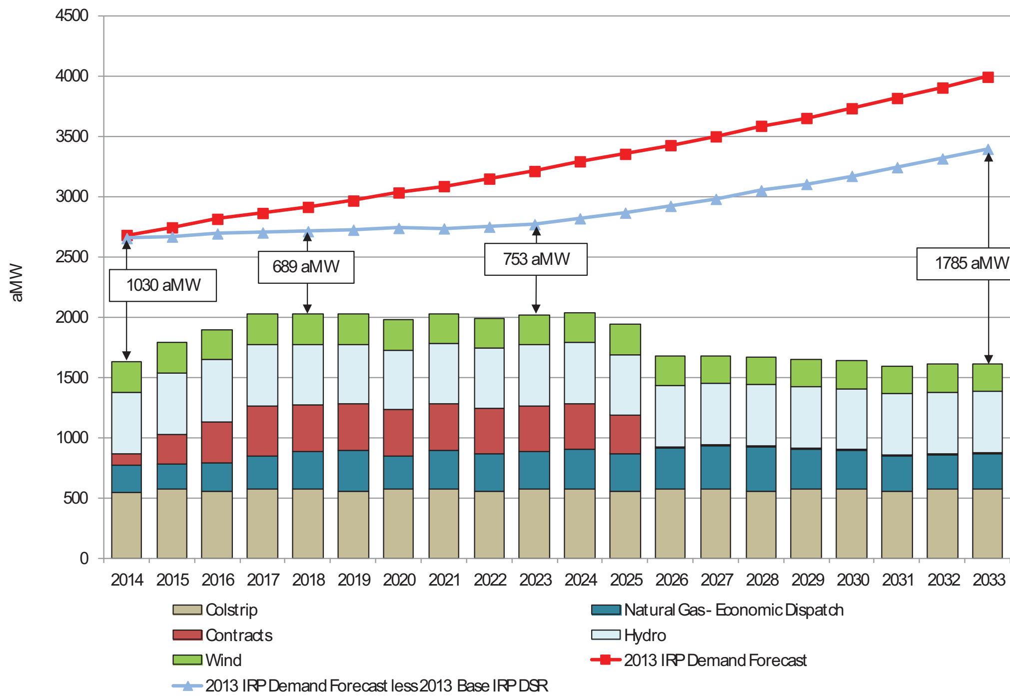
Electric energy need

Peak hour capacity is an important aspect of PSE's ability to adequately meet the physical needs of our customers. However, our customers require electric service in more than just one hour each year – they expect reliable, economic electric service during all hours. Figure 1-2 compares the company's annual forecast of energy sales to retail electric customers with expected generation for the year by resource type.[3] This "Energy Position" reflects the most economical dispatch of our electric resource portfolio based on expected market conditions, it is not a physical need. PSE's resources are physically capable of generating significantly more energy, but from a cost perspective, it

[3] *Wind in this chart shows more prominently than in the capacity need chart, because this reflects the expected annual generation of wind, not just what can be relied upon to meet peak capacity needs.*

makes sense to dispatch plants based on specific market conditions. Load forecasts in this chart are aggregated to an annual basis.

Figure 1-2
Annual Energy Position for 2013 IRP Base Scenario



Renewable resources

In addition to reliably meeting the physical needs of our customers, RCW 19.285 – Washington State's Energy Independence Act (EIA) – establishes three specific targets for qualifying renewable energy. These are commonly referred to as the state's renewable portfolio standard (RPS). Sufficient "qualifying renewable energy" must equal at least 3 percent of retail sales in 2012, 9 percent in 2016, and 15 percent in 2020. Figure 1-3 compares existing qualifying renewable resources with this annual target, and shows that PSE has acquired enough eligible renewable resources and RECs to meet the requirements of the law through 2022. The need in 2022 amounts to 693,550 RECs, assuming a 30 percent capacity factor and the 1.2 multiplier allowed for certain construction practices; this translates to 2,011 MW of wind resources.

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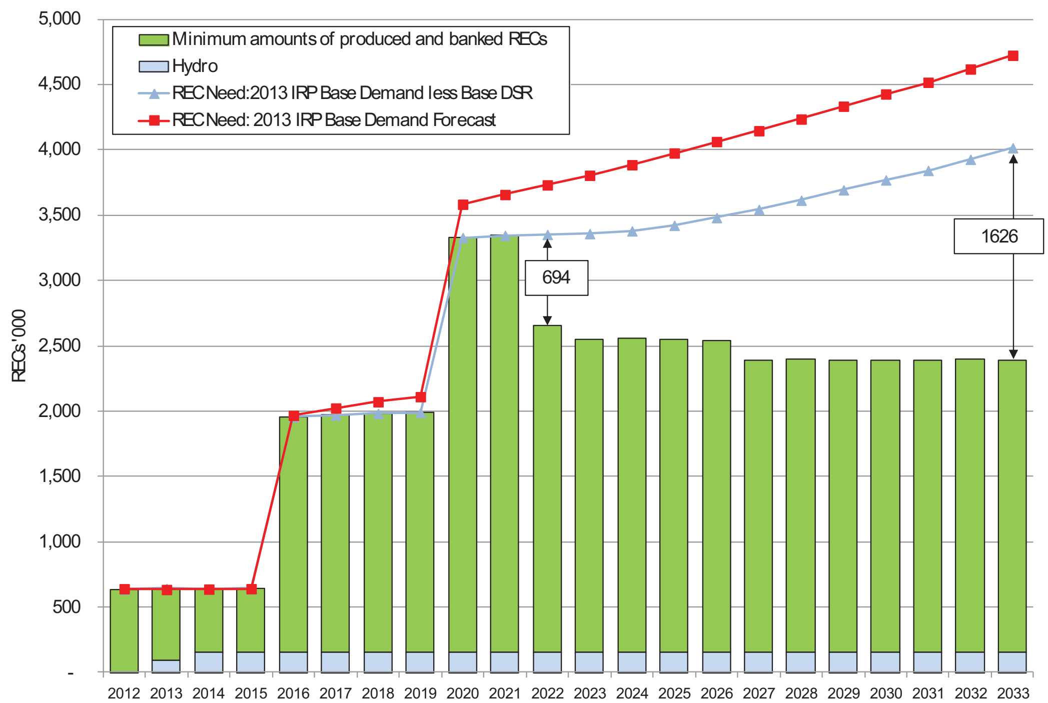
Qualifying renewable energy is expressed in annual qualifying renewable energy credits (RECs) rather than Megawatt hours, because the state law incorporates multipliers that apply in some cases. For example, PSE's Lower Snake River project receives a 1.2 REC multiplier, because qualifying apprentice labor was used in construction. Thus the project is expected to generate approximately 900,000 MWh per year of electricity, but would contribute about 1,080,000 equivalent RECs toward meeting the renewable energy target. Note this is a long-term compliance view. PSE has sold surplus RECs to various counterparties in excess of those needed for compliance and will continue to do so as appropriate to minimize costs to customers.

Figure 1-3
Renewable Resource/REC Need



Electric plan resource additions

Figure 1-4 summarizes changes to the electric resource portfolio in terms of peak hour capacity. This plan is the "integrated resource planning solution."[4] It reflects the lowest reasonable cost portfolio of resources that meets the projected capacity, energy, and renewable resource needs described above. Except for demand-side resources, which significantly reduce risk, most of the other resources show the same risk profile. The resource plan reflects the expectation that Colstrip will continue to be a least-cost resource in the portfolio. In this IRP, we have chosen to reflect gas storage for generation fuel as part of the electric resource plan. While gas storage is not a "supply-side resource" for generation (and therefore not required to be addressed by the IRP rule), it is important to highlight this aspect of the company's resource plan.

Figure 1-4
Electric Resource Plan, Cumulative Nameplate Capacity of Resource Additions

	2017	2023	2027	2033
Demand-Side Resources (MW)	327	800	887	1,007
Wind (MW)	0	300	500	600
Peakers (CT in MW)	221	442	1,327	2,212
Transmission Renewals (MW)	1,141	1,407	1,407	1,567
Gas Storage (MDth/day Gas)	100	100	100	150

Demand-side resources (DSR)

This plan – like prior plans – includes acquiring conservation to levels such that much of what is available will be acquired. That is, significant changes in avoided cost had little impact on how much could be acquired cost effectively. PSE's analysis indicates that although current market power prices are low, accelerating acquisition of DSR continues to be a least-cost strategy.

[4] *Chapter 2 includes a detailed explanation of the reasoning that supports each individual element of the resource plan.*

Renewable resources

Timing of renewable resource additions is driven by requirements of RCW 19.285. PSE's analysis shows that while additional wind is not a least-cost resource, we anticipate remaining comfortably below the revenue requirement compliance mechanism included in the law. PSE has acquired enough eligible renewable resources and RECs to meet the requirements of the law through 2022.

Peakers appear more cost effective than combined-cycle plants.

This finding holds as long as the peakers are equipped with oil back-up and a sufficient amount of interruptible natural gas pipeline capacity is available for fuel delivery. This should certainly be the case for the first few additions, but adding several hundred MW of new peakers may over-tax the natural gas infrastructure. Should peakers require firm pipeline capacity, some level of combined-cycle combustion turbine (CCCT) plants may be found to be cost effective.

Transmission contract renewals backed by market purchases appear cost effective.

In the short to intermediate term, transmission contract renewals do appear least cost. These contracts only need to be renewed for 5-year terms to preserve PSE's unilateral roll-over rights in the future. If and when Unit 1 of TransAlta's Centralia coal plant retires in 2020, regional resource adequacy is expected to decline abruptly. Unless replacement generation is developed, it is unlikely that heavy reliance on short-term markets over firm transmission will continue to be a viable resource strategy. There also may be concerns about longer-term generation plant closures in the California market; this could reduce the Northwest region's ability to import power from that region, as has been done traditionally for decades. The action plan below states PSE will file an update to the 2013 IRP later this year to focus specifically on this issue.

Colstrip is expected to continue to be a least-cost resource.

In the near term, Colstrip owners do not anticipate making multiple-year payback capital investments. Such decisions will not be required until the 2016 time frame, after the requirements for new regional haze regulations have been clarified. Longer term, high carbon costs, high costs for disposal of coal combustion residuals, and very low gas prices for a very long time are key risks for Colstrip. As policies and market conditions change, the owners group of the Colstrip facility will factor those conditions into their decision-making process.

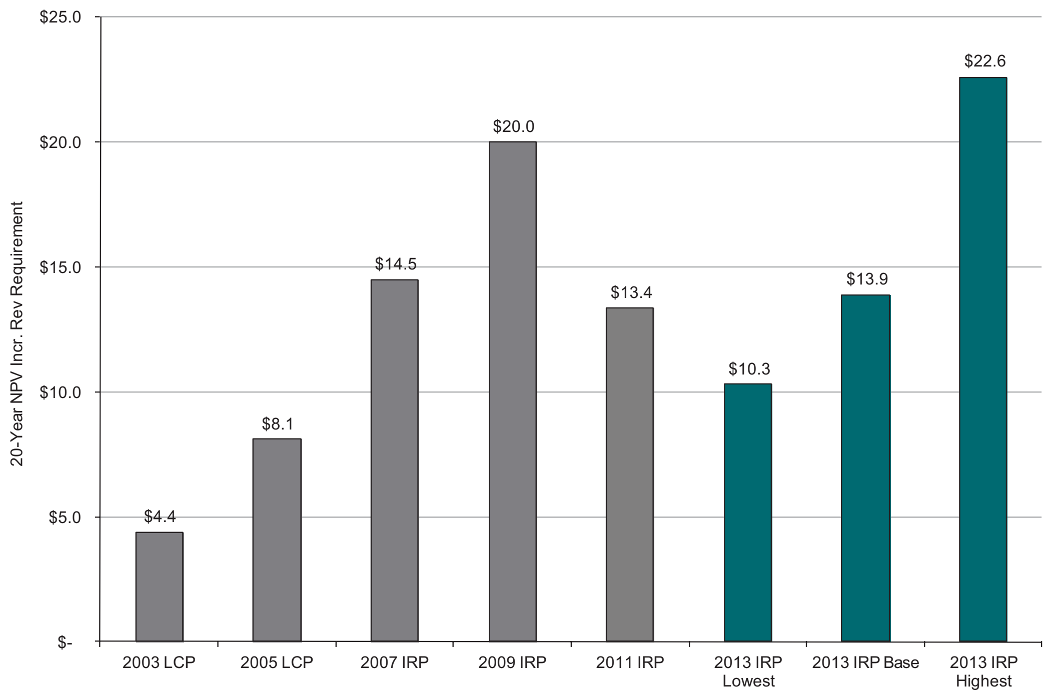
Portfolio costs and carbon emissions

Portfolio costs

The long-term outlook for incremental portfolio costs has been dynamic across IRP planning cycles since 2003, driven by changing expectations about natural gas prices and costs associated with carbon regulation. Conservation, gas-fired generation and wind have been the primary resource alternatives since 2005. Figure 1-5 illustrates how incremental portfolio costs have changed over time, along with the context for the range of costs examined in this IRP.

Figure 1-5

Incremental Portfolio Costs Over Time.



Carbon emissions associated with electric service

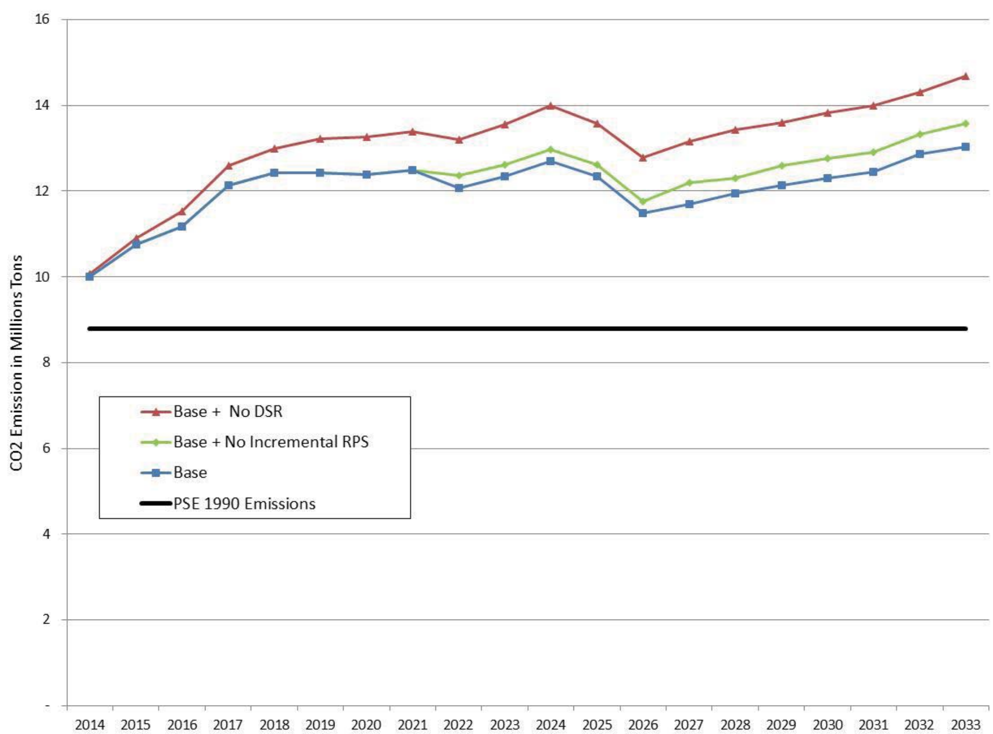
A number of Washington state laws address carbon emissions. RCW 70.235 adopts a state goal for reducing emissions. RCW 80.80 sets an emissions performance standard (EPS) that prevents utilities from entering into long-term financial commitments for base-load electric generation unless the generation source complies with the greenhouse gas emissions performance standard set by the state, effectively banning purchases from additional coal plants or older gas CCCT plants. In 2011, the legislature amended the EPS to achieve permanent reduction of certain CO_2 emissions by retiring the TransAlta coal plant in Centralia, Wash. Utilities are allowed to enter into long-term contracts for “coal transition power” from TransAlta, and TransAlta will shut down one generating boiler at the Centralia coal plant by the end of 2020 and the other by the end of 2025. TransAlta also will provide financial assistance for local economic development and clean energy. RCW 19.285, the Energy Independence Act, requires electric utilities to reach certain targets for renewable resources and acquire all cost-effective achievable conservation. Meanwhile, according to WAC 480-100-238, “Each electric utility regulated

CHAPTER 1 – EXECUTIVE SUMMARY

by the commission has the responsibility to meet its system demand with a least cost mix of energy supply resources and conservation."

The combined impact of these laws, rules and policies on PSE's CO_2 emissions from electric operations is shown in Figure 1-6. The initial ramp-up in CO_2 emissions followed by a reduction is due to PSE's coal transition power agreement with TransAlta; ultimately, this contributes to the retirement of the nearly 1,400 MW plant and a permanent reduction of emissions. The chart also shows a significant reduction in emissions from acquisition of all cost-effective conservation. By 2033, the cumulative CO_2 savings from conservation is approximately 20.82 million tons. Finally, additional wind required by the state's RPS in 2020 also reduces CO_2 emissions somewhat (approximately 4.59 million tons in total by 2033). The wind addition has much more limited impact because adding wind to a region rich in hydro power has a more limited impact than it would in other regions.

Figure 1-6
Projected Annual CO_2 Emissions and Savings from Cost-effective Demand-side Resources and the 2020 Requirement for Renewable Resources from RCW 19.285



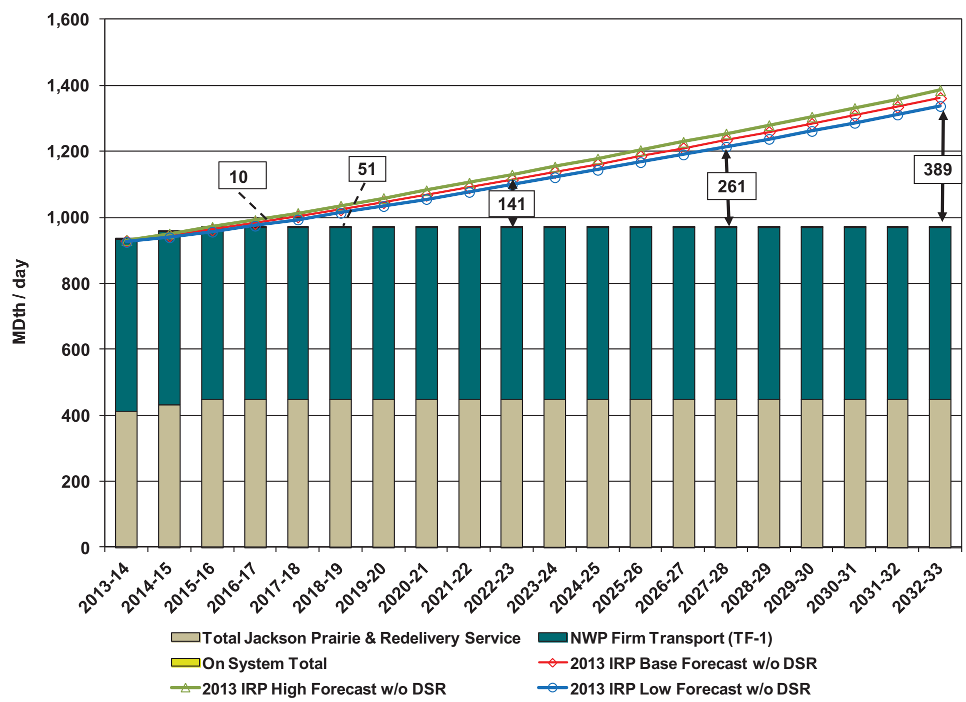
2. Gas Sales Resource Plan

PSE develops a separate integrated resource plan to address the needs of more than 770,000 retail gas sales customers. The resource needs of gas sales customers are relatively more straightforward than those of the electric utility, because delivery of electric service involves so many types of generation. This plan is developed in accordance with WAC 480-90-238, the IRP rule for gas utilities. (See Chapter 6 for PSE's analysis of gas for power need.)

Gas sales resource need

Gas sales resource need is driven by design peak day demand. The current design standard ensures that supply is planned to meet firm loads on a 13-degree design peak day, which corresponds to a 52 Heating Degree Day (HDD). Like electric service, gas service must be reliable every day, but design peak drives the need to acquire resources. Figure 1-7 illustrates the load-resource balance for gas sales portfolio. The chart demonstrates a need for resources beginning in the winter of 2016-17.

Figure 1-7
Gas Sales Design Peak Day Resource Need



Gas plan resource additions

Figure 1-8 summarizes the gas resource plan additions in terms of peak day capacity in MDth per day. As with the electric resource plan, this is the "integrated resource planning solution." It combines the amount of demand-side resources that are cost effective with supply-side resources in order to minimize the cost of meeting projected need.

Figure 1-8
Gas Resource Plan, Cumulative Additions in MDth/Day of Capacity

	2018-19	2022-23	2027-28	2032-33
Demand-Side Resources	15	28	33	37
PSE LNG Peaking Project	50	50	50	50
Swarr Upgrade	30	30	30	30
Mist Storage Expansion	50	50	50	50
NWP/Westcoast Expansion	0	54	150	150
NWP/KORP Expansion	0	0	0	78

Demand-side resources (DSR)

Analysis in the 2013 IRP supports continuation of the accelerated 10-year ramp rate for acquiring demand-side resources. We also examined a 20-year ramp rate and a 10-year rate that delayed acquisition of "discretionary"[5] gas DSR measures for two years, given that gas prices are so low early in the planning period. The 10-year ramp rate proved most cost effective.

[5] Discretionary resources *are retrofit opportunities in existing facilities that, theoretically, remain available at any point over the course of the study period.* Lost opportunity resources *are those with pre-determined availability, such as replacements after equipment failure and opportunities in new construction.*

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PSE LNG Peaking Project

PSE is considering development of a liquefied natural gas (LNG) project to provide peak day supply as part of a larger LNG project that would support the needs of emerging transportation markets. Converting local maritime traffic and truck transport to natural gas fuel will significantly improve local air quality and reduce greenhouse gas emissions. If such a multi-purpose project is constructed, this IRP finds the project's capacity to provide peaking supplies would be cost effective for our gas customers.

Swarr Upgrade

This IRP finds that restoring the Swarr LP-Air facility to its original 30 MDth per day capability may be a cost effective resource. Swarr is a propane-air injection facility on PSE's gas distribution system that operates as a needle-peaking facility. Propane and air are combined in a prescribed ratio to ensure the mixture injected into the distribution system maintains the same heat content as natural gas. Based on this IRP analysis, PSE needs to refine assumptions and perform additional analysis to ensure Swarr could be upgraded to perform safely, efficiently, and cost effectively.

Mist storage and Northwest Pipeline capacity

Storage capacity at Northwest Natural's Mist storage project, along with firm pipeline capacity on Northwest Pipeline from the Portland area, also appeared to be part of the least-cost solution. The timing of this resource addition may hinge on updated cost assumptions and whether or not the PSE LNG Peaking Project and/or Swarr Upgrade move forward. If either resource is unavailable, additional Mist storage with transport would be desirable earlier.

Northwest Pipeline/Westcoast Expansion

Additional transportation capacity from the producing regions in British Columbia (BC) at Station 2 south to PSE's system are also in the plan, but a bit further out in the 2022-23 heating season. Similar to Mist, if the PSE LNG Peaking Project and/or Swarr Upgrade do not move forward, additional Northwest Pipeline capacity from the Canadian border and capacity on Westcoast Pipeline south from Station 2 would be needed sooner.

Northwest Pipeline/KORP expansion

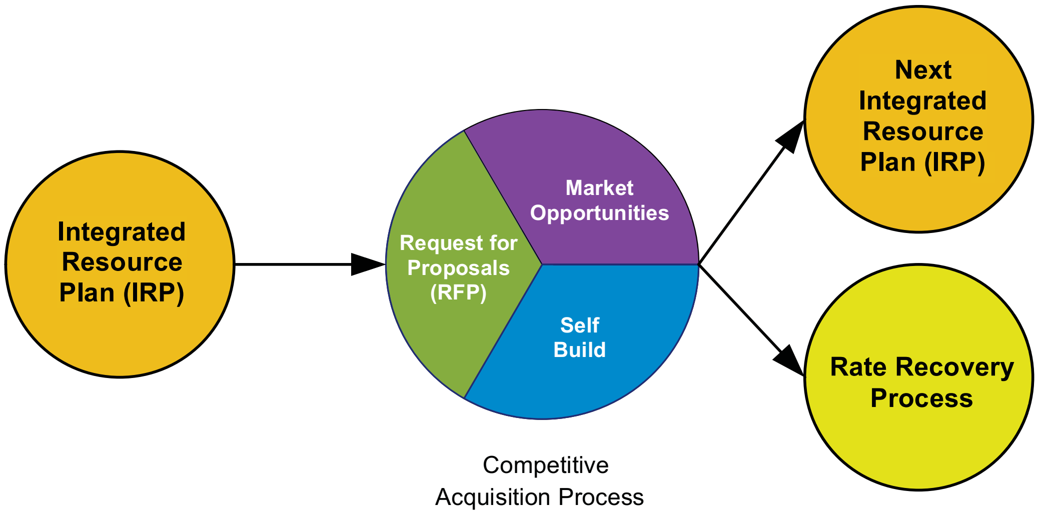
This is an expansion of Northwest Pipeline south from the Canadian border, along with an upstream expansion west across southern BC on a line built by Fortis to bring additional Alberta supplies to the I-5 corridor. Analysis in this IRP found that late in the planning horizon, such a resource may look cost effective; however, this issue will be revisited in several future IRPs before any decision needs to be made.

3. Action Plans

The IRP is not a substitute for the resource-specific analysis done to support specific acquisitions; the IRP's primary purpose is to inform the acquisition process. The action plans presented here focus on identifying key decision-points PSE may face during the 20-year planning horizon, so that PSE can meet needs in a timely fashion.

Figure 1-9 illustrates the relationship between the IRP and activities related to resource acquisitions. Specifically, the chart shows how the IRP directly informs the formal RFP process. In Washington, the formal RFP process for demand-side and supply-side resources are just one source of information for making acquisition decisions. Market opportunities outside the RFP and self-build (or PSE demand-side resource programs) must also be considered when making prudent resource acquisition decisions. Figure 1-9 also illustrates how the resource acquisition process itself informs subsequent IRPs. While Figure 1-9 is focused on supply-side resources, the same diagram applies to demand-side resources. The energy efficiency program design process can include both RFP and market opportunities, though most are PSE programs – similar to "self-build" generation.

Figure 1-9
Relationship between the IRP and the Acquisition Process



Electric Resource Action Plan

- Pursue cost-effective demand-side resources based on IRP guidance. Work with external stakeholders in the CRAG process to establish targets and tariff filings, using this IRP as a starting point. Issue RFPs as appropriate to assist with efficient acquisition of demand-side resources.
- Develop a strategy to reduce reliance on market in the intermediate to long-term, including coordination with others in the region as appropriate. File an update or addendum to the 2013 IRP early in the fourth quarter of 2013 to address concerns about relying on market to meet capacity needs.
- Ensure that the timeline for resource acquisitions is long enough to accommodate the type of infrastructure development that may be required due to anticipated changes in regional resource adequacy.
- Pursue the prudent acquisition of gas storage for generation.
- Develop a robust work plan for the 2015 IRP to clarify the roles and expectations of the public participation process and to provide greater transparency regarding PSE's analytical processes.

Gas Sales Resource Action Plan

- Pursue cost-effective demand-side resources based on IRP guidance. Work with external stakeholders in the CRAG process to establish goals, targets and tariff filings, using this IRP as a starting point. Issue RFPs as appropriate to assist with efficient acquisition of demand-side resources.
- Continue working toward developing the potential PSE LNG Project to support gas utility peaking and transportation sector needs. Update and refine cost/resource estimates on expanding the facility's potential to provide peaking capabilities for the gas utility portfolio as the project proceeds.
- Further analyze the costs and resource issues associated with investing in Swarr to restore its original 30 MDth per day capability. Decide whether such investments will provide a safe, cost effective resource for meeting the needs of customers.
- Continue working with Northwest Natural Gas and Northwest Pipeline on the possibility of participating in an expansion of the Mist storage facility and transportation to PSE's service territory.
- Remain active in the market to ensure PSE can acquire existing surplus firm pipeline capacity in case the PSE LNG Peaking Project or Swarr opportunities do not move forward.
- Complete analysis of whether the gas planning standard should include additional aspects, such as sustained peaking or cold snap metrics.
- Develop a robust work plan for the 2015 IRP to clarify the roles and expectations of the public participation process and to provide greater transparency regarding PSE's analytical processes.

CHAPTER 2

Developing the Resource Plan

Contents

The resource plan in this IRP represents "…the mix of energy supply and conservation that will meet current and future needs at the lowest reasonable cost to the utility and its ratepayers."[1] It is the culmination of comprehensive quantitative and qualitative analyses, including extensive risk analysis, reported throughout the document.

It is important to recognize that the IRP does not make purchasing decisions for the next two decades. For example, the decision to include Colstrip in the plan does not mean that the company has decided to continue to operate the plant for the next 20 years; instead, it means that at this point in time, continuing to operate the plant appears to be cost effective for our customers based on the potential futures considered in the analysis. The IRP process enables us to construct a portfolio that meets future challenges *as we understand them today*. Resource decisions can be informed by the foresight developed in the IRP, but ultimately these decisions will be made when it best serves the interest of our customers, and they will depend upon actual market opportunities and updated assessments of market conditions.

The following discussion assumes the reader is familiar with the key assumptions described in Chapter 4.

[1] *WAC 480-100-238 (2) (a) Definitions, Integrated Resource Plan.*

CHAPTER 2 – DEVELOPING THE RESOURCE PLAN

1. Electric Resource Plan

Figure 2-1 summarizes the resource additions to the company's electric portfolio that resulted from the IRP analysis. The least cost set of resource additions is very similar across the scenarios and sensitivities examined in this IRP:

- In a reasonable range of gas prices, possible carbon costs, and future environmental costs, the extensive analysis conducted for this IRP indicates that Colstrip will remain a cost-effective resource, though that could change in the future, especially for Units 1 & 2. At this time, it does not appear PSE should take near-term actions to begin planning to replace Colstrip in its portfolio.
- Demand-side resource additions across scenarios are very similar. For example, under Colstrip Environmental Cost Case 2, most scenarios show 1,007 MW as cost effective, though that drops to 957 MW for the Low Load and Low Gas Price scenario, and 706 MW for the Very Low Gas Price scenario—neither of which are likely to occur.
- Wind is added to meet requirements of RCW 19.285 in all but one of the 10 scenarios. Only in the Base + Very High CO_2 scenario would additional wind be cost effective, which is an extreme scenario.
- Transmission renewals are cost effective under all scenarios, as long as the market behind that transmission is reliable. This will be investigated more closely in an IRP update planned for release early in the fourth quarter of 2013.
- Peakers meet capacity needs in 9 out of 10 market scenarios. The Base + Very High CO_2 scenario shows combined-cycle combustion turbines (CCCTs) are cost effective, but the CO_2 costs in that scenario are so high that the likelihood they will be realized is quite small. Gas storage for generation fuel also appears to be a cost effective resource.
- The load forecast, which represents customer demand, has the most significant impact on the quantity of resources added across scenarios over the long-term, but it does not change the mix of resources. A higher load forecast increases the number of peakers and wind plants needed, and low load forecasts decrease the total number of both. PSE chose to use the 2013 IRP Base Demand Forecast[2] to determine the quantity of resources in the resource plan, since that forecast represents the most likely expected change in loads.

[2] *For more information on demand forecasts, see Chapter 4, Key Assumptions, and Appendix H, Load Forecasting Models.*

Figure 2-1
The Electric Resource Plan
(Cumulative Nameplate Capacity of Resource Additions)

	2017	2023	2027	2033
Demand-side Resources (MW)	327	800	887	1,007
Wind (MW)	0	300	500	600
Peakers (CT in MW)	221	442	1,327	2,212
Transmission Renewals (Tx in MW)	1,141	1,407	1,407	1,567
Gas Storage (MDth/Day)	100	100	100	100

Electric results across scenarios

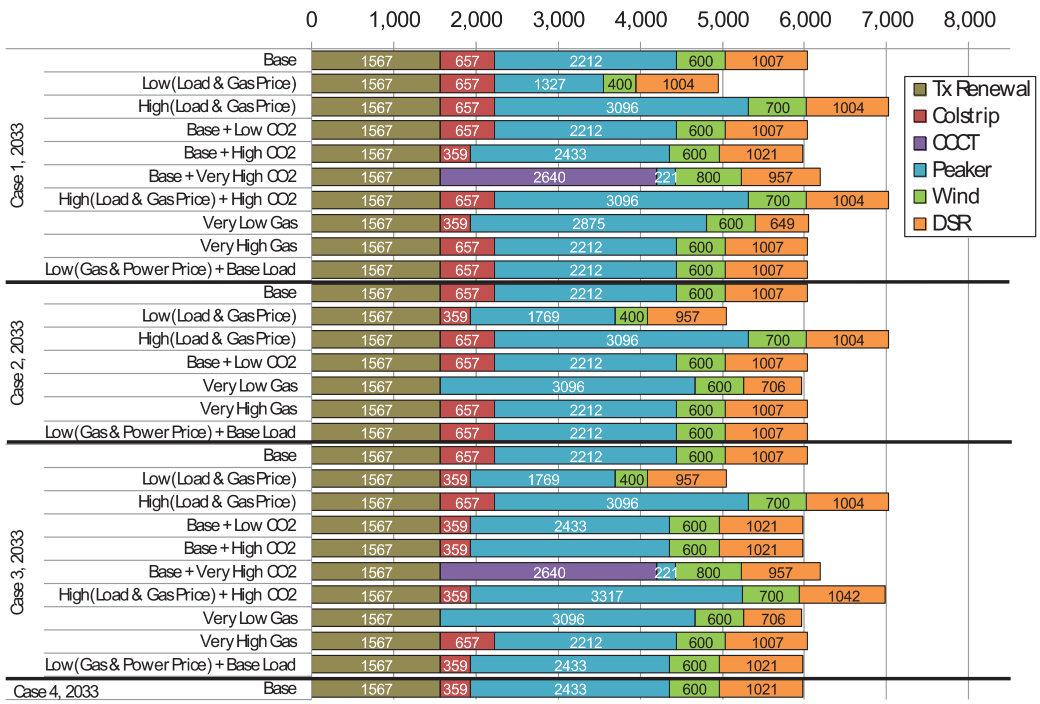
Figure 2-2 summarizes the demand- and supply-side resource additions to PSE's existing resource portfolio across all the scenarios, sensitivities, and Colstrip environmental compliance cost cases analyzed in this IRP.[3] This allows a relatively easy comparison of the differences between them. To read across the 2033 Colstrip Environmental Cost Case 1 Base Scenario, for example, the least cost portfolio includes 1,567 MW of transmission contract extensions, continued operation of all four Colstrip units, 2,212 MW of additional peakers, 600 MW of additional wind, and 1,007 MW of demand-side resources.

Each portfolio analysis considered supply- and demand-side resources on an equal footing. All were required to meet three objectives: physical capacity need (peak demand), energy need (customer demand across all hours), and renewable energy need (to meet RCW 19.285 targets). Under the market conditions and resource costs assumed for each scenario and each Environmental Cost case, the selected portfolio minimizes long-term revenue requirements (costs as customers will experience them in rates).

[3] *See Chapter 4 for a description of scenarios, sensitivities and cases.*

CHAPTER 2 – DEVELOPING THE RESOURCE PLAN

Figure 2-2
Resource Builds by Scenario
Cummulative additions by nameplate (MW)



A high degree of consistency

Least-cost portfolio builds are similar across most scenarios, sensitivities and cases. This consistency is a powerful finding. It means that the wide variety of external market factors modeled in these scenarios will have little impact on the mix of lowest reasonable cost resources. We may adjust the number of peaking plants, transmission renewals, or amount of wind should the conditions modeled in the High or Low scenarios prevail, but the types of resources selected remains consistent. Similarly, should Colstrip be rendered uneconomic for customers by environmental regulations or market conditions, additional peakers are selected as the least-cost replacement across all but one scenario.

A detailed discussion of each element of the resource plan follows.

CHAPTER 2 – DEVELOPING THE RESOURCE PLAN

Colstrip analysis

This IRP examined the effect that existing and proposed environmental regulations may have on the economic operation of Colstrip under a variety of market and policy conditions. The purpose of the analysis was essentially to determine if – in the near term – PSE should begin planning to replace Colstrip. Specifically, since the IRP helps to establish the resource need for the next RFP/acquisition cycle, the question is whether resource needs for that process should reflect removal of Colstrip from the portfolio and the need to replace it with other resources. The answer to that question is no. At this time, it does not appear that PSE should begin committing significant resources to replacing Colstrip. The following discussion summarizes the analysis that was performed and the results that support this conclusion.

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Overview of Colstrip analysis. To test Colstrip's economic performance under a wide range of potential environmental regulations, PSE developed four Colstrip environmental compliance cost cases ("Cases" or "Case"). Below are brief descriptions of the four cases modeled. They are described in detail in Appendix J, Colstrip.

Four Colstrip Environmental Compliance Cost Cases

Case 1 – Low Cost Estimated additional costs are based on achieving compliance using existing, installed equipment with a minimum of modifications or additions to meet the MATS Rule and the BART requirements of EPA's Regional Haze FIP. This case and Case 2 assume that coal combustion residuals continue to be classified as non-hazardous.	***Case 2 – Mid Cost*** This case includes all the costs from Case 1, plus costs for adding additional equipment that may be needed to assure compliance. It is largely based on EPA estimates for equipment intended to bring Units 1 & 2 into compliance with the BART requirements of EPA's Regional Haze FIP.
Case 3 – High Cost Case 3 assumes the Case 2 costs, plus additional costs for equipment needed to meet potential new requirements. It reflects a scenario in which (1) coal combustion residuals are defined as hazardous waste and therefore are more costly to dispose of, and (2) the Reasonable Progress requirements of the Regional Haze program require the addition of Selective Catalytic Reduction (SCR) technology on all units by 2027.	***Case 4 – Very High Cost*** Case 4 assumes all Case 2 costs, plus it accelerates the effective date for installation of SCR technology to 2022. It also increases the estimated cost of SCR technology on Units 1 & 2, and it triples the cost of hazardous waste disposal for CCR included in Case 3. Case 4 was examined only in the Base Scenario, as it was developed late in the IRP process.

The different sets of assumptions in these cases allowed us to analyze Colstrip's continued operation along side new supply- and demand-side resources in order to determine the least-cost combination of resources for PSE's portfolio. Key aspects of the approach are summarized below. (See Chapter 5 for further detail on the Colstrip analysis.)

- ***Units analyzed independently***. Colstrip Units 1 & 2 were analyzed independently of Units 3 & 4.
- ***Ongoing investments included.*** Projected investments needed to maintain safe and efficient operations were included as a cost in every case for each set of units. Those costs are not disclosed in the IRP, but the analysis does reflect them.
- ***Transmission costs reflected.*** Three transmission segments move Colstrip power from Montana to PSE. The cost of this transmission was included based on the timing of the transmission contracts.
- ***Portfolio analysis.*** Colstrip Units 1 & 2 and 3 & 4 were treated as independent resource alternatives so that we could determine whether either or both sets would be part of the least-cost portfolio. The two sets of resources (Units 1 & 2 and Units 3 & 4) were analyzed using three sets of assumptions (Cases 1, 2, and 3), in each of 10 scenarios. Case 4 was examined in the Base Scenario only. Finally, a replacement power portfolio was developed for each scenario as a benchmark to estimate the savings from (or cost of) continuing to operate Colstrip.
- ***Timing for replacing Colstrip***. The analysis asked whether Colstrip should be replaced in 2017, or should it continue to operate through the planning horizon. The year 2017 was selected in order to capture the first round of investment decisions necessary to comply with regional haze requirements reflected in Case 1 and Case 2.
- ***Not included.*** Early retirement of Colstrip would result in increasing depreciation/amortization expenses for the unrecovered plant balances. The IRP did not address this impact, because it is not possible to know exactly what time period the Commission would adopt for recovery of these costs. Remediation costs are also not reflected, since Montana has not yet detailed remediation requirements. Were it possible to reflect these costs in the analysis, both of these factors would result in higher rate impacts than reported in this IRP.

Summary of Colstrip results. Colstrip was clearly a least-cost resource early in the planning horizon, however, this may change in the future depending on a number of factors identified in the analysis. Units 3 & 4, built in the 1980s, were found cost effective across nearly every scenario considered; most of the likely scenarios also showed continued operation of Units 1 & 2 would be least cost for customers. These two units were built in the 1970s. Three risk factors rendered Units 1 & 2 uneconomic in some scenarios. These are summarized below.

Gas prices. Colstrip Units 1 & 2 would no longer be a least-cost resource if gas prices remain significantly below expected levels for the next 20 years; however, this seems unlikely. The increasing demand for natural gas, potential upward pressure on shale gas production costs from additional regulation, and upward pressure from normalization of natural gas liquids markets make it far more likely that prices will rise over time.

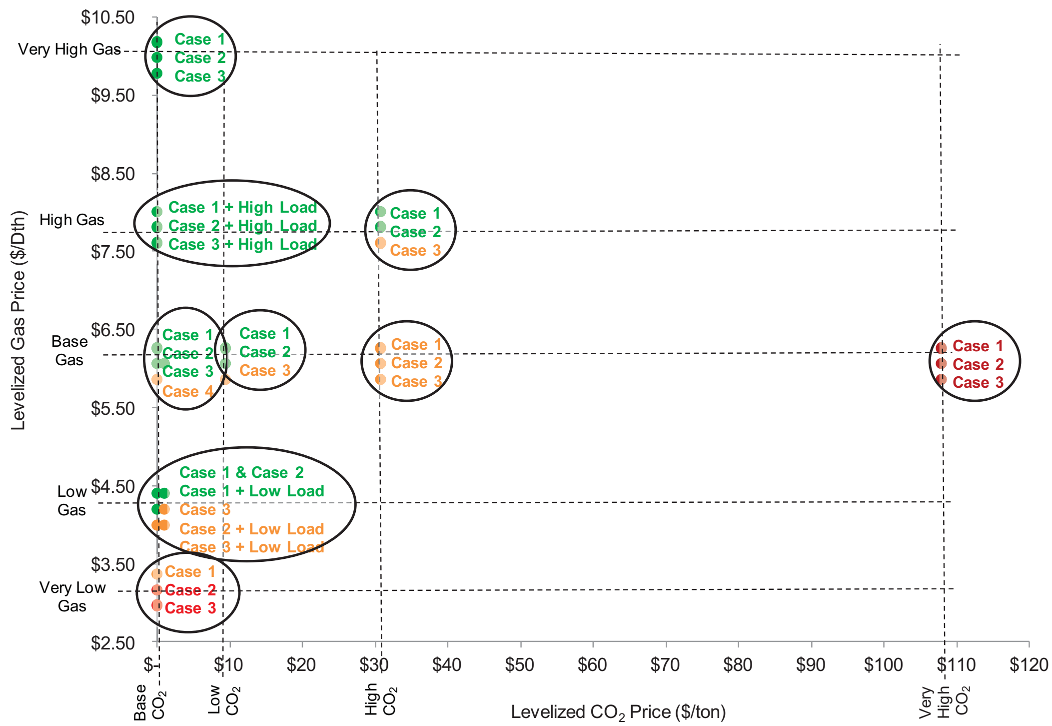
Coal combustion residuals (CCR). The cost effectiveness of Units 1 & 2 would be compromised if new EPA regulations designate CCR a hazardous waste that requires off-site disposal. Units 3 & 4 could be rendered uneconomic as well if disposal costs were extremely high (as in Colstrip Case 4). Two considerations significantly temper this risk. First, it is unlikely the EPA will make such a finding since CCR, in general, does not meet existing definitions of hazardous waste. Second, off-site disposal is a significant cost driver for Colstrip Cases 3 and 4, but depending on how regulations develop, the facility may be allowed to store even CCR waste on-site given the quality of Colstrip's current containment methods.

Very high carbon costs. Carbon costs starting at $25 per ton in 2017 and increasing to $80 per ton by the end of the study period could render Colstrip Units 1 & 2 uneconomic. Should carbon costs reach $75 rising to $180 per ton (as in the Base + Very High CO_2 Cost Scenario), Colstrip Units 3 & 4 would also be uneconomic. The risk of such high CO_2 costs seems low at this time. Even when the economy was booming, policies that imposed carbon costs in these ranges were not politically feasible; therefore, it seems unlikely that such costs would be adopted while the economic recovery is uncertain.

Figure 2-3 summarizes the findings of the analyses in relation to the scenarios' levelized CO_2 prices (which appear on the horizontal axis), and levelized gas prices (which appear on the vertical axis). The dots on the chart represent the four environmental compliance cost cases. Their color indicates which units were cost effective in the particular scenario and case: green dots mean all four units are cost effective, orange means only Units 3 & 4 are cost-effective, and red means none of the units would be cost effective to continue to operate.

Figure 2-3

Summary of Four Colstrip Environmental Compliance Cost Cases



Legend

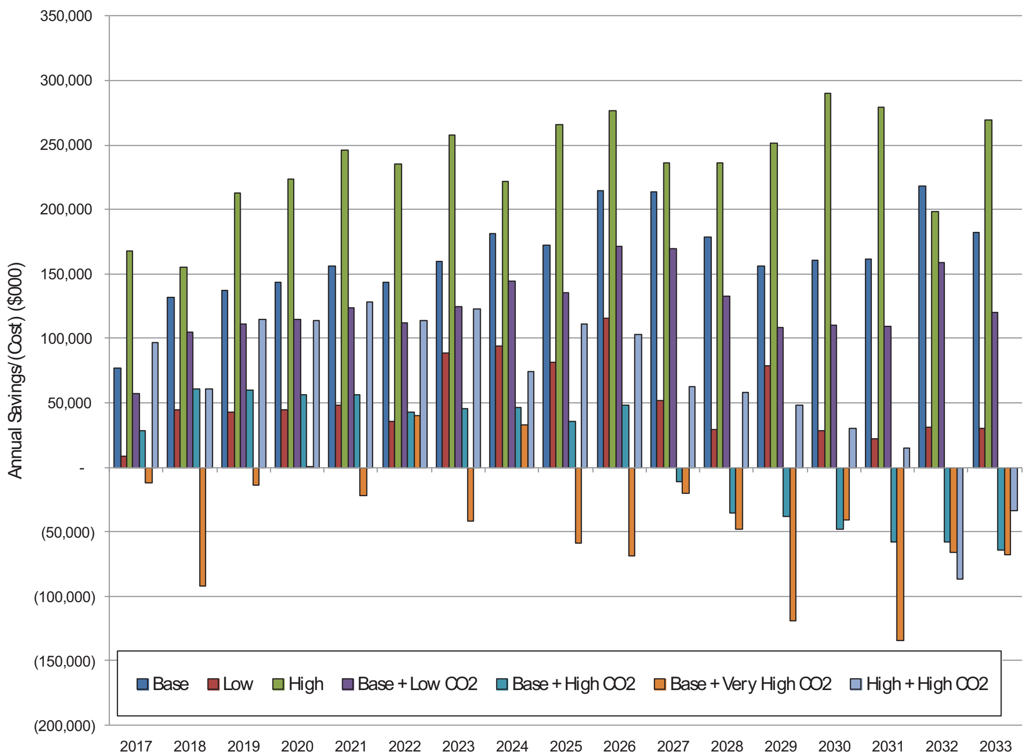
Green indicates where all four units are cost effective.

Orange indicates where only Colstrip 3&4 are cost effective.

Red indicates scenarios where replacement power was more cost effective.

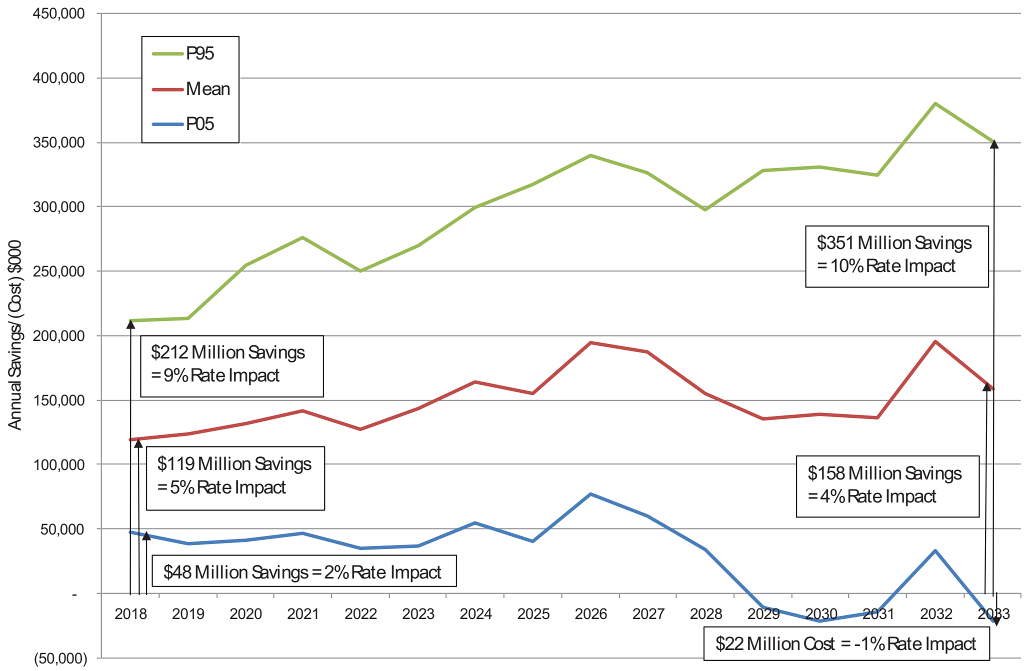
Annual savings from Colstrip operations. Given the number of variables that can affect the relative value of Colstrip in the portfolio (power prices, gas prices, CCR policies, etc.), it is helpful to simplify the picture by holding many of the variables constant. Figure 2-4, below, illustrates the estimated annual savings of continuing to operate Colstrip through 2033 in the Base Scenario under Colstrip Case 2. The savings are significant; customers will save an estimated $130 million per year by Colstrip's continued operation. To calculate these savings, we first developed a least-cost portfolio in which Colstrip was replaced in 2017. Then we compared the cost of that portfolio with the cost of portfolios in which Colstrip continued to operate under the compliance conditions and costs described in the four cases. The cost of continuing to operate under Case 2 is the focus of this figure. Note, PSE's analysis minimizes the long-term net present value (20+ years with end-effects) of revenue requirements; annual costs are shown here because it better illustrates how customers will experience those costs.

Figure 2-4
Annual Savings from Colstrip Operations in Base Scenario, Case 2



Range of Colstrip savings over time. While Figure 2-4, above, illustrates significant savings from continuing to operate Colstrip under a snapshot of expected conditions, savings over time are less certain. Key market variables may influence the relative value to customers of continuing operations. These include possible fluctuations in gas prices (from very high to very low), market electric prices, temperature impacts on loads, and variations in hydro and wind generation. Figure 2-5, below, uses Case 2 as a reference point to illustrate the range of potential savings. The savings are significant, though the lower end of the interval shows no savings in later years.

Figure 2-5
Percentile Range of Savings in Annual Revenue Requirement between Colstrip Case 2 and Replacement Power – Base Case without CO_2 Policy Risk



CCR disposal and regional haze reduction. Colstrip Cases 1 and 2 primarily deal with requirements to reduce regional haze; Cases 3 and 4 primarily deal with the potential costs should coal combustion residuals (CCR) be designated hazardous waste that requires off-site disposal. Figure 2-6, below, shows the annual savings in the Base Scenario under all four cases. It shows that the risks posed by regional haze compliance in Cases 1 and 2 are less significant than the potential impact of having to haul coal combustion residuals off-site for disposal as hazardous waste, as modeled in Cases 3 and 4. Note that in Case 4, Colstrip Units 1 & 2 were replaced with peakers plus market purchases and Units 3 & 4 show only a slim benefit. If coal combustion residuals are considered hazardous waste that requires off-site storage, Colstrip may not continue to be economic. Resolution of this issue is still several years off, so it would be premature to take actions to replace Colstrip today based on this risk.

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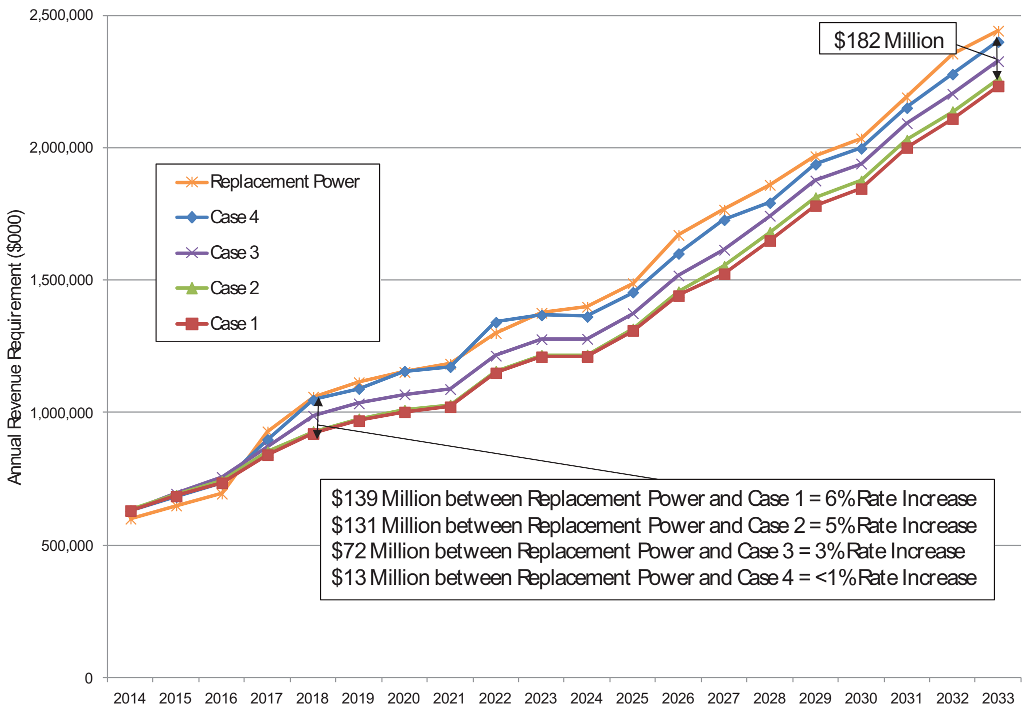
Figure 2-6

Annual Revenue Requirement Savings in Base Scenario for Four Colstrip Cases

CCR as hazardous waste poses a bigger risk than regional haze reduction regulations.



Carbon costs and gas prices. Future carbon regulation and gas prices could significantly impact the economic viability of Colstrip operations. Figure 2-3 illustrates a number of complexities.

- Using Base Scenario gas prices, internalizing carbon costs at the Low CO_2 Cost assumption used in this IRP ($6 per ton in 2014 rising to $20 per ton in 2033) would render operation of Colstrip Units 1 & 2 uneconomic in Colstrip Compliance Case 3.
- If a CO_2 price consistent with the High CO_2 Cost assumption was imposed (approximately $30 per ton levelized), replacing Units 1 & 2 would cost less than continuing to operate them under any of the cases.
- Higher gas prices, however, would restore the economic viability of Units 1 & 2.
- Colstrip Units 3 & 4 appeared economic under all scenarios and cases, except for the one that included the Very High CO_2 Cost assumption.

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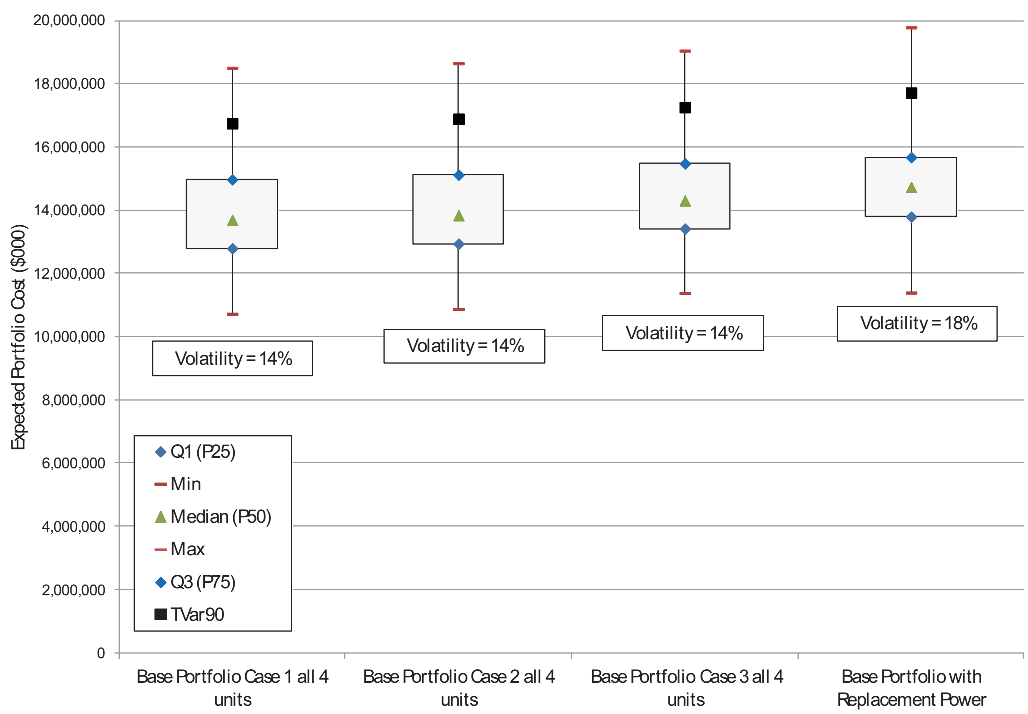
Given the uncertainty around future carbon regulation, this IRP included a stochastic analysis that internalized carbon costs rather than simulating a cap-and-trade scheme as in prior IRPs. We performed a simulation that assigned a 1/3 chance that there will be no additional carbon regulation during the planning horizon, a 1/3 chance that the Low CO_2 Cost would be internalized, and a 1/3 chance that the High CO_2 Cost would be internalized. Figure 2-7, below, illustrates the range of costs across Cases 1, 2, and 3 in the Base Scenario. This diagram represents the 20-year net present value (NPV) showing the full range from high to low, with the 25th – 75th percentile highlighted by the box, along with expected cost and TailVar90 risk metric[4]. Figure 2-7 illustrates that replacing Colstrip would increase cost and risk, relative to all three Colstrip cases.

Figure 2-7

Range of Portfolio Costs across 1000 Simulations – with CO_2 Policy Risk



In conclusion, it does not appear that PSE needs to plan on committing considerable resources toward actions to replace Colstrip in its portfolio at this time. This does not mean PSE strongly believes Colstrip will be part of the least-cost energy supply portfolio for the foreseeable future. Analysis presented here demonstrates that there are combinations of low gas prices, high carbon costs, and high CCR disposal costs that

[4] *TailVar90 risk is the mean of the cost distribution above the 90th percentile.*

could lead to a finding that replacing Colstrip, especially Units 1 & 2, would be least cost for customers.

Electric demand-side resources

The level of demand-side resources in the electric resource plan, including demand-response, reflects the Base Scenario results. The amount of demand-side resources found to be cost effective varied little across a wide range of avoided cost values in the scenarios. Only 85 MW separated highest and lowest results after 20 years.

While the amount of cost-effective DSR is nearly the same across scenarios, the range of market prices considered in this IRP resulted in a huge spread in avoided costs. By 2033, these ranged from approximately $30/MWh (nominal) on the low end to approximately $150/MWh (nominal) on the high end.[5] PSE's analysis in this IRP, as in past IRPs, illustrates that market power prices, gas prices, carbon prices, and other policies have little impact on the cost effectiveness of conservation.

Electric renewable resources

The resource plan includes wind sufficient to meet requirements of RCW 19.285; the Base Scenario adds 300 MW by 2022 and 600 MW by the end of the study period. Acquiring wind resources beyond requirements was found to be cost effective only in the scenario that modeled very high carbon costs. Otherwise, differences in the amount of wind additions were driven by the long-term load growth assumptions modeled in the scenarios.

This IRP focused on Northwest wind as the primary renewable resource.[6] Biomass and geothermal technologies were not modeled, because although they have been theoretically cost effective in past IRPs, PSE has been unable to find these resources through the RFP process on terms that that would be least cost for customers. Should they become competitive with wind resource costs and be commercially available, we will adjust future integrated resource plans accordingly.

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[5] *The full value of conservation includes the value of avoided capacity, in addition to energy. The range of energy prices is used here to demonstrate the wide range of values examined, not as an estimate of the value of energy efficiency.*

[6] *This IRP also examined the cost implications of using wind from Montana to replace the energy output of Colstrip. See Chapter 5 for more detail.*

This IRP also examined the cost effectiveness of battery storage. Findings indicated that costs will need to fall before this technology can become cost effective in the Northwest. The analysis showed that batteries contributed only 57 percent as much as CT peakers toward meeting reliability needs, but at a significantly higher cost. Batteries may be able to provide ancillary services or local distribution system benefits in specific applications, especially as technology and markets evolve. PSE is participating in a pilot battery storage project described in Appendix D, Electric Resource Alternatives.

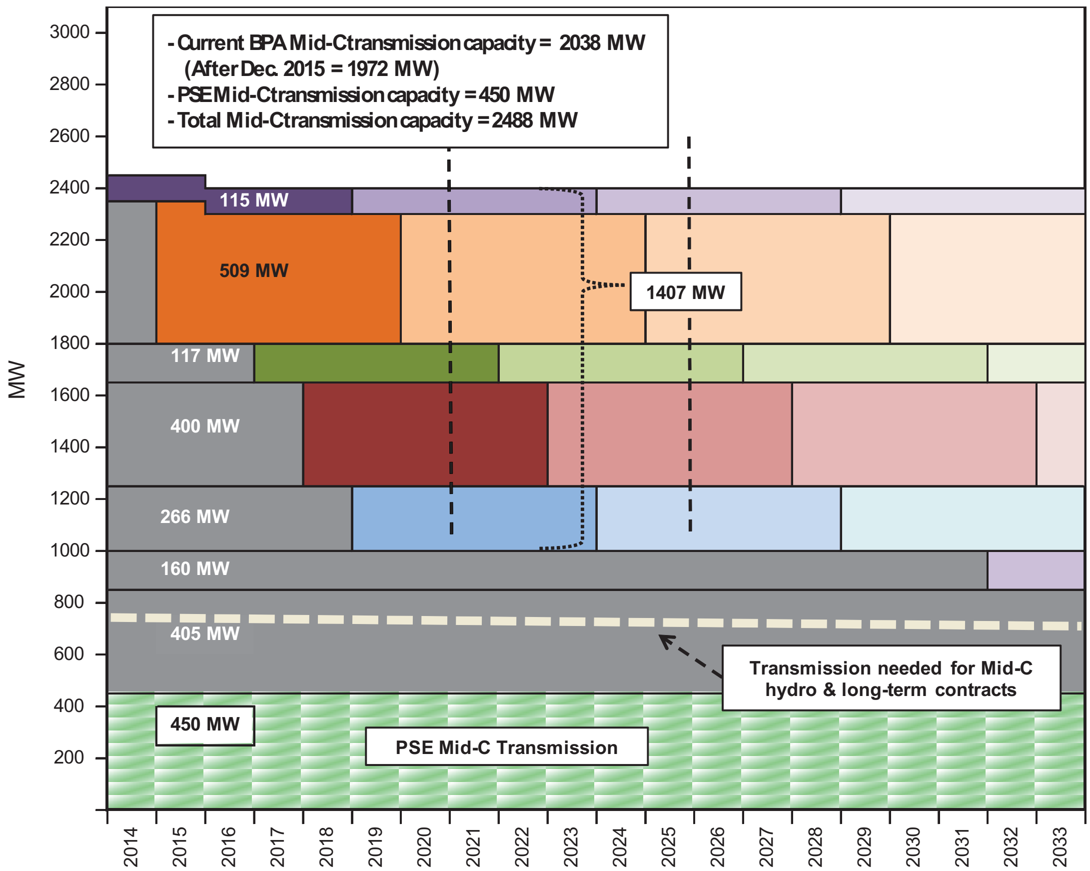
Transmission contract extensions

The resource plan selects renewal of transmission contracts in all scenarios. While the "surplus" capacity persists in the Northwest energy market, this is clearly a least-cost alternative for customers. However, the TransAlta coal plant in Centralia is expected to retire 720 MW of merchant generation in 2020, and another 720 MW in 2025. In addition, expected changes in the California energy market, from which the Northwest region imports energy during the winter, may also reduce available capacity in the future. PSE is concerned that long-term reliance on transmission access to the market without firm, long-term resources behind that transmission may not be a reasonable long-term strategy.

Fortunately, these transmission contracts do not require long-term commitments. PSE has both the unilateral right to extend the contracts and control of the duration of the extension. Extending the contracts for five years preserves the unilateral roll-over rights; therefore, in the early years of the planning horizon, five-year renewals would be reasonable to preserve flexibility for decision-making in the future. This resource strategy may need to be modified as we approach 2020, depending on how the region's energy market unfolds. Figure 2-8, below, compares the timeline for transmission contract expirations with expected changes in the region's energy capacity at 2020 and 2025. The gray shaded areas show the current BPA contracts and when they expire. Each contract is shown as a box with the related capacity. Every five years the shade changes. This helps to illustrate how the 5-year renewal terms line up with periods when regional adequacy may change abruptly in 2020 and 2025.

Figure 2-8

Transmission Renewals and Major Resource Retirements (MW)



Gas-fired resources

The balance of physical capacity need in the electric resource plan is met with gas-fired resources. Consistent with past IRPs, gas-fired single-cycle combustion turbines with oil back-up (peakers) were found more cost effective than combined-cycle combustion generation (CCCT). The Base + Very High CO_2 Cost Scenario was the only exception; there, CCCT plants were found more cost effective than peakers. The following discussion steps through details of the decision, including quantity, location, the importance of oil back-up, and how reliability of interruptible gas transportation impacts the finding.

MW of peakers in the plan. The gas-fired MW additions in the plan reflect the Base Scenario and demand forecast. Demand forecasts significantly influenced the amount of peakers added across scenarios. As Figure 2-2 shows, under Colstrip Case 1, the Base Scenario added 2,212 MW of peakers; the Low (load and gas price) scenario added 1,327 MW, and the High (load and gas price) scenario added 3,096 MW. The high and low demand forecasts reflected in these scenarios represent the extremes of future macroeconomic conditions analyzed. When the time comes to make actual acquisitions, PSE will adjust the amount to reflect prevailing conditions. Figure 2-2 also shows how Colstrip's presence or absence impacts the amount of peakers included in the portfolio; however, since Colstrip is expected to remain a cost-effective resource, load forecast variability is the focus here.

Significance of oil back-up. The new gas-fired peakers included in the resource plan are assumed to be equipped with oil back-up. These plants would turn first to interruptible pipeline capacity for natural gas fuel, but if gas supply was unavailable, up to two days of fuel oil stored onsite could be used to run the plant. Major barriers to siting back-up oil supplies do not appear to be a problem at this time, but if this did become an issue, peakers without back-up fuel may not remain cost effective compared to CCCT plants.

Figure 2-9 shows the results of the net cost per kW market risk analysis from a 250-draw Monte Carlo simulation, as described more fully in Chapter 5. The chart illustrates a probability density function of the net cost/MW for a CT with oil back-up, a CCCT, and a CT without oil back-up, where the horizontal axis is the net cost [7] and the vertical axis is the probability of that net cost occurring from the Monte Carlo simulation. Figure 2-9 demonstrates that gas-fired peakers without back-up oil supply would be significantly more expensive on a net dollars per MW basis than a CCCT plant. This net cost analysis is helpful to understand the relative importance of the cost distributions of the three different plants, but is not a substitute for portfolio analysis. PSE's full portfolio analysis also takes into consideration the timing and size of capacity needs—CCCT plants are lumpier than CTs, so the smaller CT without oil back-up could still lead to a lower overall portfolio cost than a CCCT.

[7] *Net Cost = Fixed Costs – (Market Price-Variable Cost)*MWh of dispatch.*

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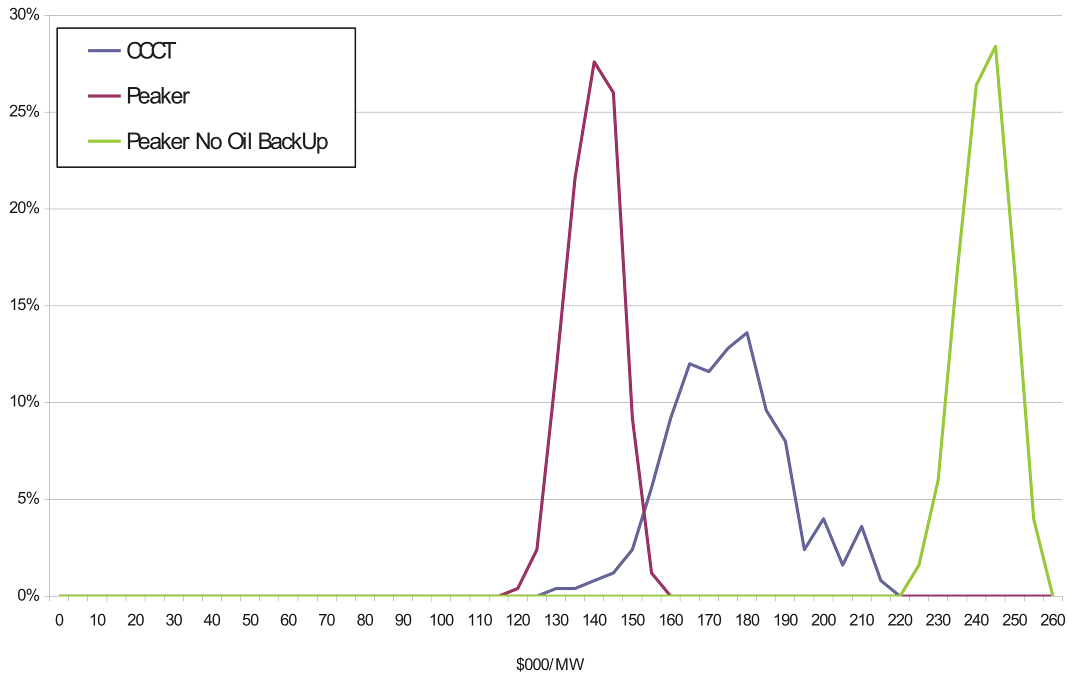
Figure 2-9

Comparison of Net Cost Distribution: CCCT and Peakers



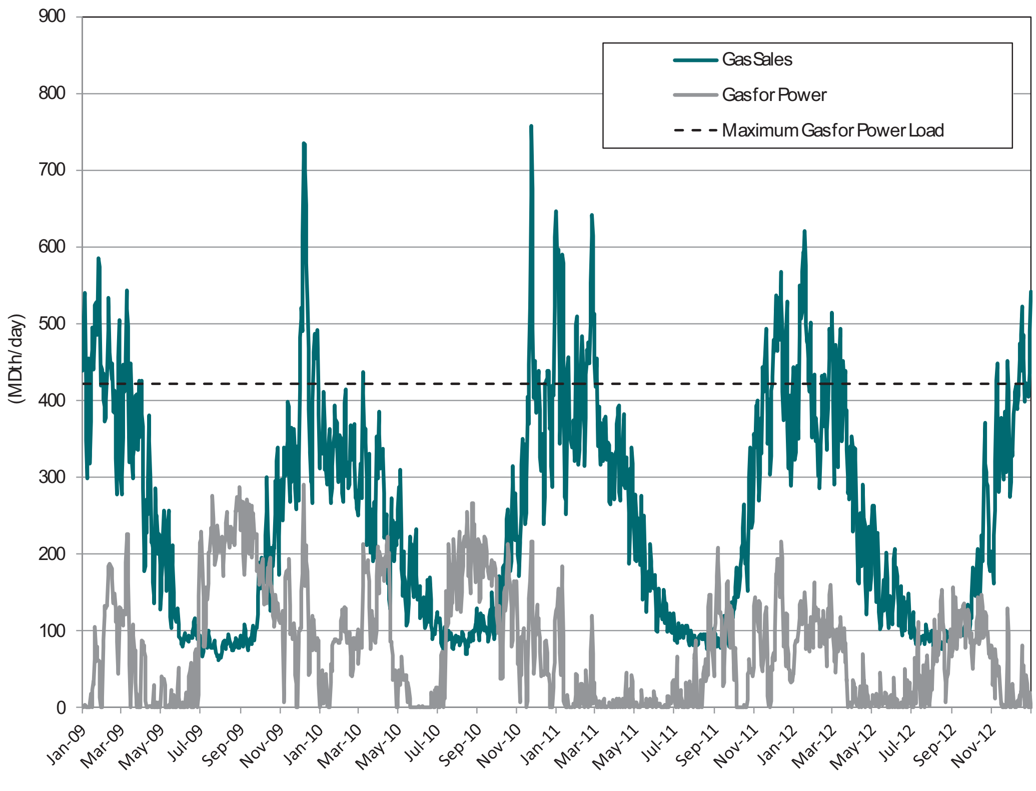
Reliance on interruptible pipeline capacity. Interruptible pipeline capacity is a key factor in the economic advantage that peakers with oil back-up have over CCCT plants. Firm pipeline capacity guarantees the right to transport a given quantity of gas; it requires a fixed payment whether or not the capacity is used. Cheaper, intermittent service can be purchased through the market for interruptible pipeline capacity. This makes it a good fit for peaking plants, which run only when needed. If sufficient interruptible gas supplies are not available, or if two days of oil back-up is not available (or sufficient to meet reliability needs), it may be necessary to turn to firm pipeline capacity. Should this happen, the added cost of equipping peakers with oil back-up would not make sense, and CCCT plants may become more economic to operate than peakers.

Gas storage for generation. In this IRP, PSE is including the need to acquire gas storage for generation fuel in its resource additions for the electric resource plan. PSE's analysis of gas storage for electric fuel supply is presented in Chapter 6 – Gas Resources. That analysis demonstrates that acquiring natural gas storage – based on Northwest Natural Gas Company's Mist storage service – would be cost effective for the electric generation's fuel supply portfolio.

The increasing reliance on natural gas for generation is currently attracting significant attention in the U.S., as discussed in more detail in Chapter 3. Concerns include short-term issues, such as mismatched transaction periods (daily for gas markets and hourly/sub-hourly for electric markets) and long-term planning issues such as gas resource adequacy. With respect to long-term planning concerns, it is important to recognize that firm capacity on an interstate pipeline, alone, cannot fuel a generator – there must be gas supply to ship on that pipeline capacity.

Day-to-day variability of gas for generation fuel can be significantly greater than daily swings for meeting PSE's gas utility sales needs. Figure 2-10, below, illustrates the daily gas consumption by PSE's gas customers and gas for generation fuel. The black dashed line represents the peak-day capacity if all of PSE's gas-fired generators all ran for one-day. While that did not happen in 2012, if those units were needed for reliability, it would create the same order of magnitude as PSE's entire gas utility load on a winter day. It is not reasonable for PSE to expect the spot market can provide those kinds of swings in gas supply. Thus, in addition to the gas storage being cost effective for fuel supply, it also will be an important resource to ensure reliable fuel supply for generation.

Figure 2-10
Daily Gas Sales and Gas for Power Loads, 2009 – 2012
Comparing demand curves and volatility



2. Gas Sales Resource Plan

This section describes the gas sales resource plan. The plan is summarized in Figure 2-11, followed by a discussion of the reasoning that led to the plan. (Information on the analysis of gas for generation fuel can be found in Chapter 6.)

Figure 2-11
Gas Sales Resource Plan – Cumulative Capacity Additions (MDth/day)

	2018-19	2022-23	2027-28	2032-33
Demand-side Resources	15	28	33	37
PSE LNG Peaking Project	50	50	50	50
Swarr Upgrade	30	30	30	30
Mist Storage Expansion	50	50	50	50
NWP/Westcoast Expansion	0	54	150	150
NWP/KORP Expansion	0	0	0	78

The gas sales resource plan integrates demand-side and supply-side resources to arrive at the lowest reasonable cost portfolio capable of meeting customer needs over the 20-year planning period. The additions identified above are very similar to the optimal portfolio additions produced for the Base Scenario by the SENDOUT® analysis tool. SENDOUT results are theoretical portfolios based on specified inputs and must be reviewed based on judgment and market conditions.

We made two changes to the optimal SENDOUT results reported in Chapter 6. We removed the small increment of the Palomar/Blue Bridge project (13 MDth per day) beginning in 2022-23, and replaced it with the same amount of NWP/Westcoast capacity. It is doubtful that PSE would participate in the project to acquire such a limited amount of capacity.

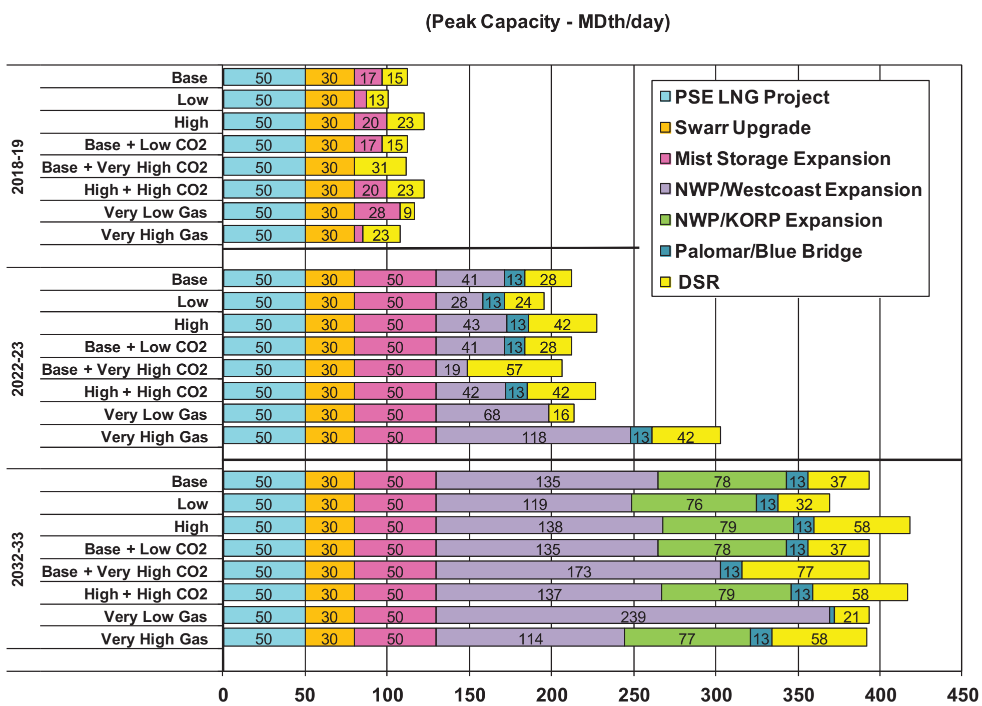
We also included the full expansion capacity of the Mist storage expansion project (50 MDth per day) from the beginning, rather than SENDOUT's recommendation to acquire 13 MDth per day by 2018-19 with an additional 37 MDth per day added later. Should we participate in the expansion, more than likely all 50 MDth per day would have to be acquired at once.

Decisions about whether and when to proceed with the Mist storage expansion, the PSE LNG Peaking Project, Swarr Upgrade, and all other resource acquisitions will be adjusted as the feasibility studies are completed and project development moves forward.

Gas sales results across scenarios

As with the electric analysis, the gas sales analysis examined the lowest reasonable cost mix of resources across the range of eight scenarios. Figure 2-12 illustrates the lowest reasonable cost portfolio of resources across those potential future conditions.

Figure 2-12
Gas Sales Portfolios by Scenario



As shown in Figure 2-12, the amount of DSR varies among the scenarios. As was the case in the 2011 IRP, we found that DSR is somewhat sensitive to underlying gas prices. Three resource alternatives were consistently selected early in the analysis period in all scenarios: the PSE LNG Peaking Project, the Swarr Upgrade project and Mist storage expansion. The other primary addition selected in all scenarios is increased capacity on Northwest Pipeline (NWP) to Sumas,combined with expansion of Westcoast pipeline to northern British Columbia (BC). Later in the time period the KORP project across southern BC is selected also in conjunction with expanded NWP capacity.

Gas sales demand-side resource additions

DSR additions are based on the levels found cost effective in the Base Scenario. Although cost-effective DSR levels vary somewhat across scenarios, by the 2018-19 heating season, the difference between the High scenario (at 23 MDth per day) and the Low scenario (at 13 MDth per day) is only 10 MDth per day. Given the small range, it is reasonable to adopt the level of conservation from the Base Scenario for the resource plan. There will be two more IRP cycles (the 2015 IRP and the 2017 IRP) before the 2018-19 heating season.

Gas sales DSR ramp rates

Retaining PSE's current 10-year acceleration of gas conservation was found to be cost effective and is reflected in the resource plan. This IRP investigated three ramp rates for acquiring discretionary DSR measures: a 10-year ramp rate, a 20-year ramp rate, and a 10-year ramp rate with a 2-year delay. Figure 2-13, below, summarizes results of this analysis for the Base Scenario. The lowest net present value portfolio cost was achieved with the 10-year ramp rate without the two-year delay. This ramp rate resulted in the lowest NPV in all scenarios. (See Chapter 6 for more detail on the analysis.)

Figure 2-13

Comparison of NPV Portfolio Costs of Different DSR Ramps Tested (in Billions)

Scenario	10-year Ramp	2-Year Delay + 10-year Ramp	20-year Ramp
Base	$8.078	$8.125	$8.163

PSE LNG Peaking Project and Swarr Upgrade

All the scenarios evaluated selected both the PSE LNG Peaking Project and the Swarr Upgrade project early in the study period (by 2018). It is important to keep in mind that these projects are in the evaluation stages and may not move forward. The PSE LNG Peaking Project depends upon final cost-effectiveness and will require agreements with transportation customers for the sales and purchase of liquefied natural gas (LNG). Completion of the Swarr Upgrade project also will depend upon final cost-effectiveness and a comprehensive risk assessment.

To consider the possibility that these resources may not be available, additional SENDOUT evaluations assumed that one or both or these projects was absent. Under these circumstances, the analyses identified adding more NWP and Westcoast pipeline capacity to Sumas and Station 2, respectively, earlier than currently planned. Based on discussions with NWP, we are confident that sufficient NWP and Westcoast capacity can be developed to meet our needs if these projects do not move forward.

Mist storage expansion

The Northwest Natural Gas Company (NW Natural), the owner and operator of the Mist underground storage facility near Portland, Ore., is investigating a potential expansion project to be completed in 2016. PSE is assessing the cost-effectiveness of this project and may participate in the expansion. As with the PSE LNG Peaking Project and the Swarr Upgrade project, this project is not firm at this point, but it is cost effective based on the current costs and project description.

NWP and Westcoast pipeline/Northern BC gas supply

The gas sales plan calls for a 41 MDth per day expansion of NWP/Westcoast pipeline capacity by the winter of 2022-23 and further expansions over the planning horizon. The inclusion of the NWP/Northwest pipeline expansion alternative was expected since it is a low-cost alternative, and it provides access to an ample, relatively low-cost gas supply in northern BC. The combination of NWP/Westcoast pipeline capacity expansion is a robust decision among the various planning scenarios.

NWP and KORP pipeline/Alberta gas supply

The gas sales plan calls for the inclusion of 78 MDth per day of NWP/Kingsgate Oliver Reinforcement Project (KORP) pipeline capacity near the end of the study period. This project is proposed by Fortis BC and Spectra, but no firm decisions have been made about proceeding. This is not an immediate concern since the project is not included in the resource plan for several years.

CHAPTER 3

Planning Environment

Contents

Here we present the factors and conditions that defined the planning context for the 2013 IRP.

1. Regional resource adequacy

Regional resource adequacy is changing. For more than a decade, the Northwest region has had the capability to generate more electric energy than the region's utilities required to meet customer demand. This "surplus" has kept market power purchase prices low, and made these existing resources a lower cost alternative to filling PSE's peak capacity need than building new generation.

However, according to the Pacific Northwest Resource Adequacy Forum's[1] November 2012 forecast, the region will turn capacity deficit by 2017; to bring the system back into load-resource balance, the forecast indicates that approximately 350 MW of firm, dispatchable generation will need to be developed by that date. Given actions by other

[1] *The Resource Adequacy Forum was created in 2005 by the Northwest Power and Conservation Council (NPCC) and BPA to develop "a framework to provide a means of assessing whether the region has sufficient deliverable resources to meet its electricity demands reliably." PSE is an active participant in the Forum's work, and we find their detailed examination of the sufficiency of market resources extremely useful to the resource planning process.*

utilities in the region, it appears this amount of new generation will be achieved in time. Longer-term, however, there is reason for concern. In the Northwest, nearly 2,000 MW of coal-fired generation will be eliminated with the retirement of the Boardman and Centralia plants. In the Southwest, our regular source for imported power in the winter, California is expected to retire more than 11,000 MW of thermal generation as regulations that prohibit once-through cooling (OTC) take effect.[2] Analysis presented to the Northwest Power and Conservation Council in January of 2013 estimates regional resource reliability will erode to a 15% loss of load probability by 2020 unless additional generation is built in the region. (This is in addition to the 350 MW expected to be added by 2017). The Resource Adequacy Forum's November 2012 report and January 2013 presentation to the Council are both included in Appendix I, Regional Resource Adequacy.

Boardman retirement. The transition plan for Boardman's 650 MW of generation will probably not have a significant impact on resource adequacy. The plant retires in 2020, but Portland General is planning to replace that capacity.

Centralia retirement. The retirement of TransAlta's coal plant in Centralia, on the other hand, will have a significant impact. Assuming the policy to retire Centralia remains effective, the approximately 670 MW Centralia Unit 1 will shut down in 2020, and the 670 MW Unit 2 will shut down in 2025. This will create a 1,300+ MW deficit; regional utilities, PSE among them, will need to add new generation (and associated transmission) to the grid to ensure reliable energy supplies.

At present, PSE and many area utilities rely heavily on purchases in the "surplus" market to meet peak needs at lowest cost. More than 25 percent of PSE's peak need is met in this way (1,600 MW relative to a 6,000 MW peak). This remains a sound strategy for the near term, but as the region's surplus diminishes, relying on market purchases will grow costlier and the risks to physical reliability will grow greater. PSE will be filing an update to this IRP to specifically analyze long-term reliance on market.

As resource strategies change to accommodate new circumstances, utilities will probably need to lengthen their acquisition planning windows. While short-term market purchases are typically managed within a three-year timeframe, building gas-fired generating plants

[2] These regulations require power plants to either re-use cooling water or shut down. More information on the California OTC can be found on slides 31-33 of the September 6, 2012, IRP Advisory Group Meeting at http://pse.com/aboutpse/EnergySupply/Documents/IRPAG_2013-09-06.pdf

typically requires four to five years, and transmission construction, if required, can take 10 or more years.

2. The future of coal

The long-term future of coal is uncertain for many reasons. Continued low natural gas prices, potential future environmental regulations, and potential future greenhouse gas regulations are among the circumstances that could significantly affect the future of all coal-fired generation throughout the United States.

Among U.S. coal plants, PSE's Colstrip generating facility is relatively "young." It was equipped with modern technology from the start, and the plant has continually invested in upgrades to increase both efficiency and environmental performance. As a result, Colstrip is less susceptible to competition from natural gas because it operates so economically, and it already meets many of the requirements in environmental regulations that are expected to apply to the plant.

Nevertheless, several recently enacted regulations, changes in existing regulations and proposed rules governing coal combustion materials will impact Colstrip's operation. To assess their possible effects, this IRP tests Colstrip's economic viability under four environmental compliance cost cases. The analysis indicates that the plant remained a least-cost resource in most of the scenarios modeled; three key risk factors significantly affected economic performance: high carbon costs, high disposal costs for coal combustion residuals, and very low gas prices for a very long time.

Results of the analysis are discussed in Chapter 2, Developing the Plan, and Chapter 5, Electric Analysis. For detailed descriptions of the plant, its ownership structure and operations, the new and proposed regulations, and the four environmental compliance cost cases, see Appendix J, Colstrip.

Washington state laws and regulations that impact coal-fired generation include restrictions on emissions that preclude development of new coal resources in the state (RCW 80.80) and a commitment to reduce greenhouse gas emissions to 1990 levels by 2020 (RCW 70.235.020).

3. Natural gas

Reliance on natural gas for electric generation will continue to increase for the foreseeable future. Aside from market power purchases plus transmission capacity – and after adding demand-side and wind resources – economics and public policy make natural gas-fueled generation (in the form of peaking plants that furnish back-up reliability or CCCT plants that run for energy purposes) the only other viable option for filling resource and ancillary needs.

4. Gas supplies and pricing

Earlier concerns about supply diversity have been allayed by a dramatic increase in production that has taken place with the abundance of shale gas deposits. The application of horizontal drilling and hydraulic fracturing technologies has made it feasible to recover gas from shale-gas deposits that are widely dispersed across North America. The producing areas that supply this region with natural gas – the U.S. Rockies (mostly Wyoming, Colorado, Utah), Northeast British Columbia (BC) and Alberta – all have significant gas reserves. Canadian supplies are growing due to increased production from the world-class Montney and Horn River production areas in BC. These supplies are being developed at relatively low costs (between $4 to $5 per MMBtu).

Gas prices have declined significantly as supplies have increased. For example, according to the U.S. Energy Information Administration the average spot price for natural gas (the price paid for gas to be delivered the next day) was $8.86 per MMBtu in 2008. The average spot price in 2012 was $2.75.

The low natural gas prices seen recently are the result of an oversupply or surplus of natural gas in the market and commodity prices will increase as that surplus is worked off. It is important to note, however, that natural gas prices in general appear to be operating in a new, lower price-paradigm than even five years ago.

A number of market dynamics could influence natural gas prices one way or the other in the future. Among them:

- The effect of new or improved production techniques and technologies.
- Potential regulations involving hydraulic fracturing.

- World demand and supply for natural gas liquids (NGLs) from the petrochemical industry.
- Shifting investment away from dry gas production to more profitable oil and other liquid hydrocarbons.
- Coal plant retirements caused by more stringent regulation of SO_2 and mercury emissions.
- The pace of economic growth across North America and the Pacific Northwest.
- Accelerated adoption of natural gas as a transportation fuel.
- The switch from oil to gas by energy-intensive industries if gas prices remain lower than crude oil on a heat-content basis.
- Benefits and costs of exporting North American natural gas to premium overseas markets via LNG.

5. Gas transportation and storage

Natural gas supplies are abundant now, and the existing natural gas transportation system is sufficient to meet current demand. However, that system is likely to come under increasing stress as more and more of the region's electric generation requires natural gas for fuel and as sectors like transportation begin to adopt it as an attractive fuel option. Significant additions of gas-fired resources – as with the 2,212 MW of peaking plants added over the 20-year planning period in this IRP – could create large swings in gas loads on the interstate pipeline system and strain the entire supply chain. Increasing reliance on natural gas is likely to increase the need for gas storage in the future and possibly new or expanded pipeline capacity also. In addition to traditional gas storage resources, this IRP examines the potential for using a liquefied natural gas (LNG) facility as a resource alternative.

6. Gas for the transportation sector

The relatively low cost of natural gas has made it an increasingly attractive alternative for transportation fuel, where it would replace higher-priced, higher-polluting petroleum-based fuels. PSE is considering development of an LNG facility that would make it feasible for a portion of Puget Sound's marine traffic to have reliable access to lower cost, less polluting LNG fuel. The facility would also be able to serve land-based vehicles. The facility could also support the reliability of natural gas service for PSE customers by serving as a back-up supply source during winter peaks in demand or during temporary disruption in gas supply or transmission. This resource alternative is explored in the gas analysis in this IRP.

Transportation is the largest contributor of carbon dioxide emissions in the state, causing about 55 percent of the total. Transportation also accounts for nearly 45 percent of all end-use energy consumption in the state. Sixty percent of Washington's $20 billion in annual energy expenditures are devoted to moving people and goods, with the average household spending almost two-thirds of its yearly energy budget on vehicle fuel.

It appears that substantial public- and private-sector savings on energy, along with significant environmental benefits, could be gained from increased use of alternative-fueled transportation, including electric-powered vehicles and vehicles fueled by compressed natural gas (CNG) and liquefied natural gas (LNG). Carbon dioxide emissions from CNG / LNG vehicles are lower than from gas- or diesel-power vehicles. Other pollutants, such as sulfur oxide, nitrogen oxide and particulate matter, are also lower with natural gas.

While the market share for alternative-fueled vehicles currently is small, PSE has seen a marked increase during the past few years in the number natural gas vehicles (NGVs) within the utility's service territory. At the end of 2012, there were 789 CNG vehicles registered in the 11 counties PSE serves; more than 57 percent of those vehicles were newly registered in 2012. PSE natural-gas deliveries to NGVs in 2012 totaled more than 7.1 million therms – equivalent to the natural gas consumption of nearly 9,000 homes.

NGVs are available in many forms today, including heavy-duty trucks, transit buses, school buses, and light-duty cars and trucks. The relative lack of refueling stations, however, is likely inhibiting more widespread NGV adoption in Washington. Similarly, the absence of an LNG marine terminal along Puget Sound may be hindering ship and ferry conversion from high-cost, high-polluting petroleum fuels to natural gas. The facility PSE is considering would help to address these needs.

7. Demand-side resources

Low natural gas prices, slow economic recovery, the elimination of federal tax incentives and the introduction of new water heater federal standards may impact PSE's ability to acquire demand-side resources. Lower growth and lower use per customer means less demand-side potential, and continued economic uncertainty may reduce the willingness of customers to invest in energy efficiency resources. Also, as a result of energy efficiency tax credits and grants, PSE experienced increases in customer demand for certain energy efficiency equipment. Now that most federal stimulus funds have been allocated and the recently extended energy efficiency federal tax credits end on December 31, 2013, the demand for these measures may diminish. This could mean that PSE may have to increase incentives, customer education, and promotional efforts to achieve energy efficiency goals. While energy savings may reduce costs over time, customers will continue to face rate pressure from program costs in the short run.

The acquisition of demand-side resources is dependent on the decisions of many individual customers to undertake a wide array of actions. These actions can range from installing a compact fluorescent light (CFL) bulb to overhauling a large industrial facility. For example, in 2012 PSE achieved 86,600 MWh of savings from the purchase of 4.4 million CFL bulbs and fixtures by residential customers. In the same time frame, PSE also achieved 70,000 MWh of savings from 833 custom commercial/industrial customer efficiency projects.

Customers may be driven by a variety of motivations: cost savings, comfort, productivity, environmental responsibility, or legal compliance. Barriers to widespread customer adoption of demand-side measures include high first costs, access to information about benefits and costs, convenience, decision timing, unfamiliar technologies, and capacity of the supply-chain infrastructure. Customer decisions are further affected by more “global” factors, such as employment, income, or general industry conditions.

Projecting energy savings available from a specific market or measure in a particular time period is a less than perfect science due to this complexity. Assumptions are made that are simplifications of the real world, particularly around the level and timing of customer adoption of demand-side measures. Actual customer behavior will likely follow a different path than predicted by a planning model.

In addition to general market complexity, PSE, like any utility, must determine how much of the total available demand-side resource potential is within its control to achieve. Generally speaking, demand-side resource potential may be achieved through utility-funded programs, tax incentives, mandated codes and standards, or independently by customers with no utility or government encouragement. The total “achievable” potential may therefore require further screening to determine what can realistically be acquired by utility programs.

Finally, PSE must balance positive and negative customer impacts, regulatory requirements, and financial performance, including lost revenues from reduced sales, in setting its program mix and targets.

8. CO_2 emissions costs

While Congressional action to limit greenhouse gas emissions is uncertain at this time, it is entirely possible that future policy decisions could increase CO_2 emissions costs within the 20-year planning horizon. President Obama announced that addressing climate change will be a priority for the Executive branch during his second term, though what form such actions may take is not clear at this time. State initiatives on carbon taxes are also uncertain at this time. The analysis models potential CO_2 costs that range from $0 to $179 per ton to capture this uncertainty.

In past IRPs, PSE has modeled CO_2 emissions costs as penalties, taxes, or prices placed on carbon that increases the cost of fossil fuel-burning power plants and changes market power prices. These costs are "internalized" in the analysis such that they can reduce the dispatch of resources with high emission rates.

In response to input from stakeholders, PSE has also "internalized" the social costs associated with CO_2 emissions in this IRP analysis. The lowest and highest costs cited in the federal study titled *Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis under Executive Order 12866* are included in the Low CO_2 Cost and High CO_2 Cost assumptions that serve as inputs to the scenarios.

In this way, the IRP included both the estimated societal costs of carbon as well as policy attempts to reduce carbon emissions through pricing in the analysis; however, there is significant uncertainty as to whether either of these CO_2 policies will be adopted by state or federal authorities in the future.

More detail on the carbon cost assumptions included in the analysis can be found in Chapter 4, Key Assumptions.

9. Operational flexibility

Variations in load and wind drive the company's need to carry balancing reserves and other ancillary services for wind. As customer demand fluctuates daily, hourly, and seasonally, and as intermittent resources like wind also fluctuate quickly, PSE must have enough resources standing by to "balance the load." The more wind generation and load variability is added to the system, the greater the need for operations that are flexible enough to handle these swings.

Currently, balancing reserves are provided primarily by the company's mid-Columbia hydroelectric assets. However, unless these contracts are renewed as they expire, we anticipate using natural gas turbines more frequently to provide reliable balancing reserves. The shift to using thermal resources instead of hydroelectric resources to meet balancing needs will impact both portfolio costs and operations.

Appendix G, Operational Flexibility, discusses the portfolio's ability to effectively balance load and wind fluctuations and describes the related economic analysis.

10. Renewable portfolio standards (RPS)

The state of Washington's RPS (under RCW 19.285) continues to require renewable resource additions to PSE's portfolio; PSE must meet 3 percent of load with renewable resources by 2012, 9 percent by 2016, and 15 percent by 2020.

The company's RPS need is expressed in units called renewable energy credits (RECs). To model RPS need for this IRP, PSE tested how different load levels affected our need for RECs. Additionally, the RPS allows for REC banking. This analysis assumes a REC banking strategy, which pushes the need for RECs later into the planning period relative to not banking. The REC banking strategy used here is a representative strategy, not an official strategy of the company.

The statute that governs RPS requirements also includes a revenue requirement cost cap. According to RCW 19.285, all electric utilities in Washington must meet 15 percent of their electric load with eligible renewable resources by 2020. However, if the incremental cost of those renewable resources compared to an equivalent non-renewable is greater than 4 percent of its revenue requirement, then a utility shall be considered in compliance with the annual target. Appendix K, Electric Analysis, includes an analysis that demonstrates PSE will probably remain under the incremental cost cap.

11. Convergence of gas and electric markets

The increasing use of natural gas for electric generation has also increased awareness of the need to coordinate operation and planning between the two industries. Both sectors and several government agencies are working to address the growing interdependence and avoid a crisis. A FERC staff report titled "Gas Electric Coordination Technical Conferences," dated November 13, 2012, delivers a comprehensive overview of federal and regional efforts; it is included in Appendix M, Gas/Electric Coordination. PSE is participating actively in the Federal, Western, and Northwestern efforts described in the report.

Generally, two aspects of the convergence are attracting attention, operational issues and long-term planning.

A major operational challenge is that gas markets operate on a nation-wide, standard trading day while regional electric markets operate on a calendar-day absis, which effectively creates different starting times from one time zone to another, and operate hourly or sub-hourly. Having different trading days and hours creates challenges for electric generation operators trying to line up supply. Another operational challenge is the potential need for these industries to coordinate communication and actions in an emergency situation. PSE has led the effort to address such communications through development of the Northwest Mutual Assistance Agreement, which is also included in Appendix M.

Long-term planning challenges involve resource adequacy issues. No standard guidelines require gas-fired generators to have firm fuel supply to sell firm power in centralized markets. The risk that a supplier will fail to deliver on a power contract is generally addressed through a liquidated damages clause in the purchased power agreement; should the supplier fail to deliver, the buyer must acquire the replacement energy and the defaulting supplier pays the difference. While this approach fosters a liquid market for financial transactions, it does not ensure that the lights will stay on.

Adequate pipeline capacity is necessary, but electric generators run on fuel – having the capacity to deliver that fuel does little good if there's no natural gas available to put into the pipeline in a timely manner. As gas-fired electric generation continues to expand – especially the use of peaking plants designed to ramp up and down hourly to balance fluctuations in load and renewable resources like wind – this concern will grow. Interstate pipeline infrastructure will come under increasing strain as higher and higher volumes of gas move through it. The State-Provincial Steering Committee (SPSC) formed the Western Gas-Electric Regional Assessment Task Force to examine this issue across the WECC[3], and the Pacific Northwest Utilities Coordinating Committee (PNUCC) and the Northwest Gas Association (NWGA) have also developed a Power and Natural Gas Planning Task Force. The Task Force files periodic reports to FERC; the March 5, 2013, report is also included in Appendix M.[4]

Gas/electric convergence issues are addressed in considerable detail in this IRP. Firm pipeline capacity was included in the costs of gas-fired CCCT generation and gas-fired peakers without oil back-up. Peakers with two days of oil back-up were not burdened with firm pipeline capacity costs, but we are continuing to analyze whether a two-day supply is sufficient to avoid firm pipeline capacity. In the electric portfolio analysis, all gas-fired generation assumed some costs for gas storage. The detailed analysis of gas for generation fuel found additional gas storage would be cost effective. Further results of the gas for generation analysis can be found in Chapter 6, Gas Resources.

[3] Additional materials from the SPSC's Task Force is available at http://www.westgov.org/ngei/index.htm
[4] Additional information on the PNUCC/NWGA Power and Gas Task Force is available at http://www.pnucc.org/system-planning/power-natural-gas-taskforce

CHAPTER 4

Key Assumptions

Contents

This chapter describes the forecasts, estimates, and assumptions that were developed as key inputs to the quantitative analysis conducted for this IRP. We combine these into scenarios and sensitivities to test resource portfolios in different possible futures and to measure the effects of an isolated variable.

PSE develops ranges of forecasts, estimates, and assumptions for the following key areas.

- Demand
- Power prices
- Gas prices
- CO_2 costs

We then combine these in different ways to create scenarios. Scenarios are “pictures” of the future that reflect a set of integrated assumptions that could occur together. This enables us to test how portfolio costs and risks respond to changes in economic conditions, environmental regulation, natural gas prices, and energy policy. In addition, we develop sensitivities that allow us to isolate the effect of a single variable; sensitivities start with the Base Scenario and change only one input. In this IRP, we also developed a series of cases to test the economic viability of an existing resource, Colstrip, under a variety of regulatory conditions.

CHAPTER 4 – KEY ASSUMPTIONS

The scenarios, sensitivities and cases developed for this IRP are listed below.

Scenarios

Base Scenario

Low (load & gas price)

High (load & gas price)

Very Low Gas Prices

Very High Gas Prices

Base + Low CO_2 Cost

Base + High CO_2 Cost

Base + Very High CO_2 Cost

High (load & gas price) + High CO_2 Cost

Low Gas & Power Price + Base Load

Sensitivities

Peaker Type-Combustion Turbines and Reciprocating Engines for Flexibility

Firm Gas Transport for Peakers

Thermal Plant Location: East and West of Cascades

DSR Ramp Rates

Replacing Colstrip Energy with Energy from Montana Wind

Additional 300 MW of Wind Beyond RPS Requirements

Colstrip Environmental Compliance Cost Cases

Case 1 – Low Cost

Case 2 – Mid Cost

Case 3 – High Cost

Case 4 – Very High Cost

1. Key Inputs

Demand forecasts

Customer load is the single most important input assumption to the IRP analysis. The demand forecast PSE develops for the IRP is an estimate of energy sales, customer counts, and peak demand over a 20-year period. Significant inputs include information about regional and national economic growth, demographic changes, weather, prices, seasonality, and other customer usage and behavior factors. Known large load additions or deletions are also included. Currently, job growth remains below pre-recession levels, but continued improvement is expected as the national and regional economies slowly grow out of the recession. Long-term job growth in PSE's service area is forecast to continue at a moderate pace in the Base Scenario.

Three demand forecasts were used for portfolio analysis in this IRP.

The 2013 IRP Base Scenario uses the **2013 IRP Base Demand Forecast**. This forecast is based on 2011 macroeconomic conditions such as population growth and unemployment. Details on how the demand forecast was developed can be found in Appendix H.

The 2013 IRP Low scenario uses the **2013 IRP Low Demand Forecast**. This forecast represents a pessimistic view of the macroeconomic variables identified in the base forecast. The pessimistic view creates a lower demand that PSE needs to meet.

The 2013 IRP High scenario uses the **2013 IRP High Demand Forecast,** which is a more optimistic view of the base forecast.

Why don't they match?

The load forecasts that appear in the IRP often do not match the load forecasts presented in rate cases or during acquisition discussions.
Why is this?

The IRP analysis takes 12 to 18 months to complete. Load forecasts are so central to the analysis that they are one of the first inputs we need to develop.

By the time the IRP is completed, the company will have updated the load forecast. The range of possibilities in the IRP forecast is sufficient for long-term planning purposes, but PSE will always present the most current forecast for rate cases or when making acquisition decisions.

CHAPTER 4 – KEY ASSUMPTIONS

The graphs below show the peak load and annual energy load forecasts for Gas Sales and Electric. See Appendix H, Load Forecasting Models, for a full discussion of how the IRP forecasts were developed.

Figure 4-1: PSE Electric Peak Load Forecast

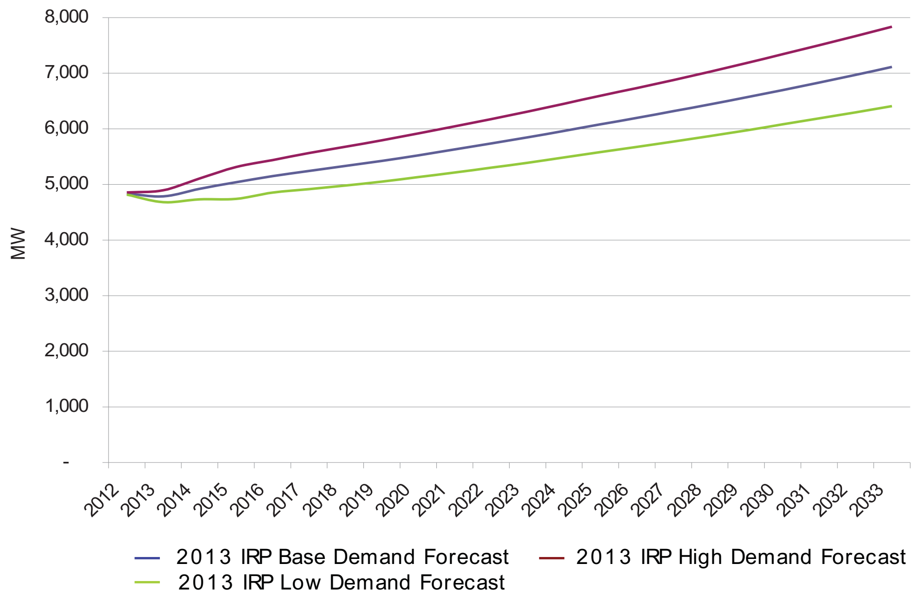
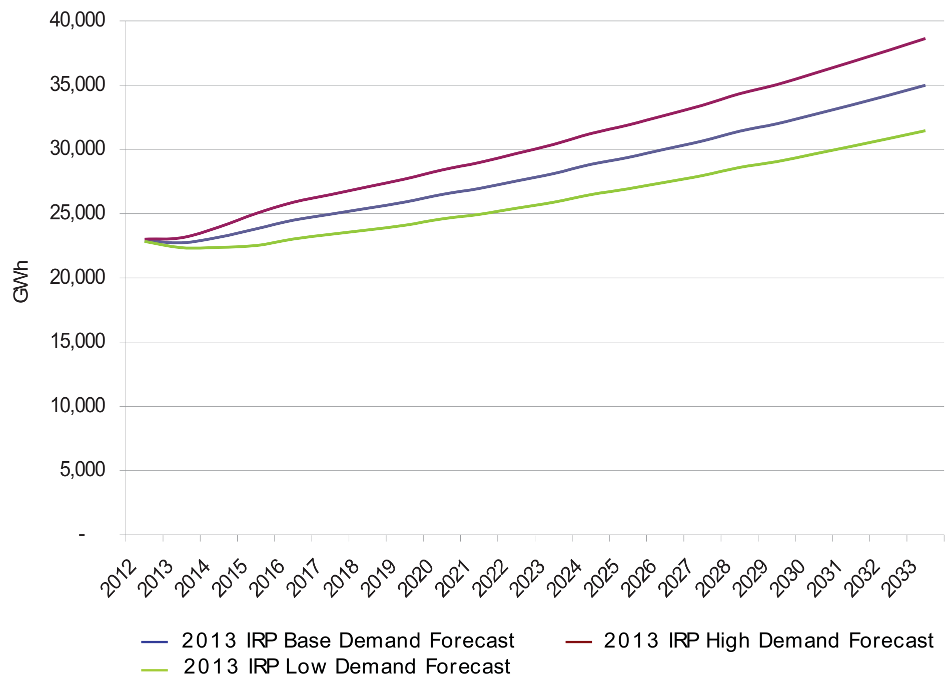


Figure 4-2: PSE Annual Electric Energy Load Forecasts 2012-2033



CHAPTER 4 – KEY ASSUMPTIONS

Figure 4-3: PSE Peak Day Gas Sales Load Forecast

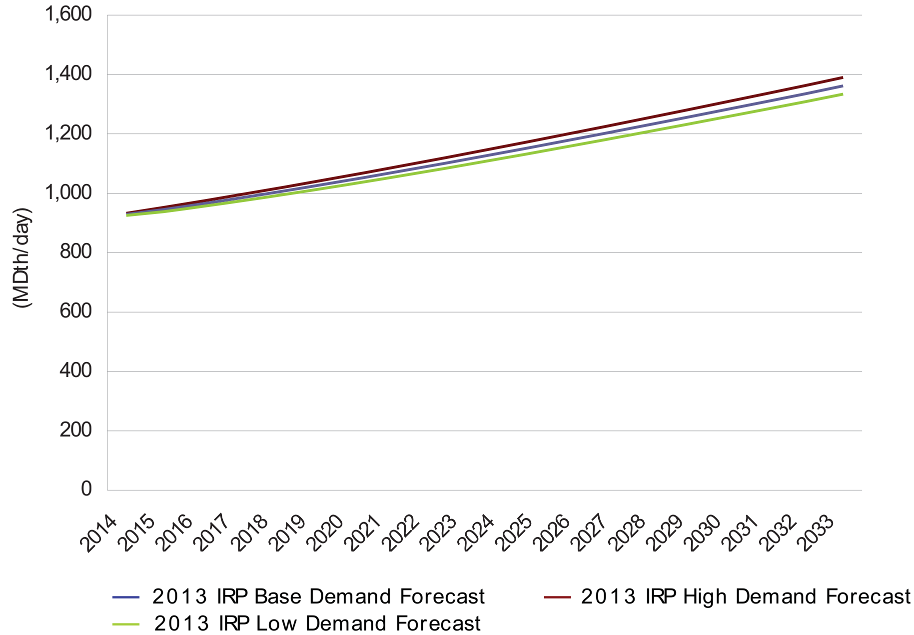
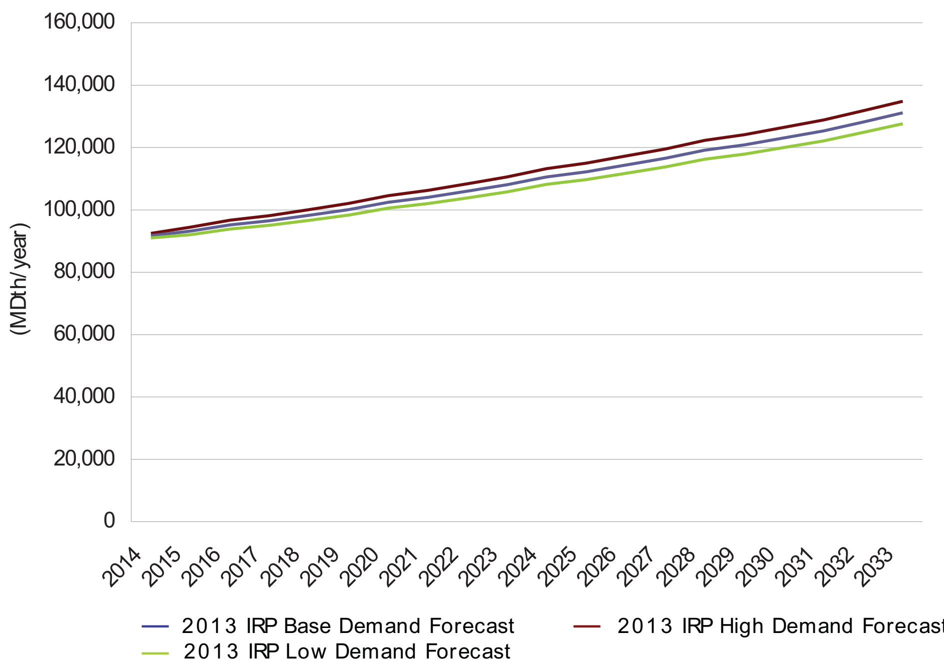


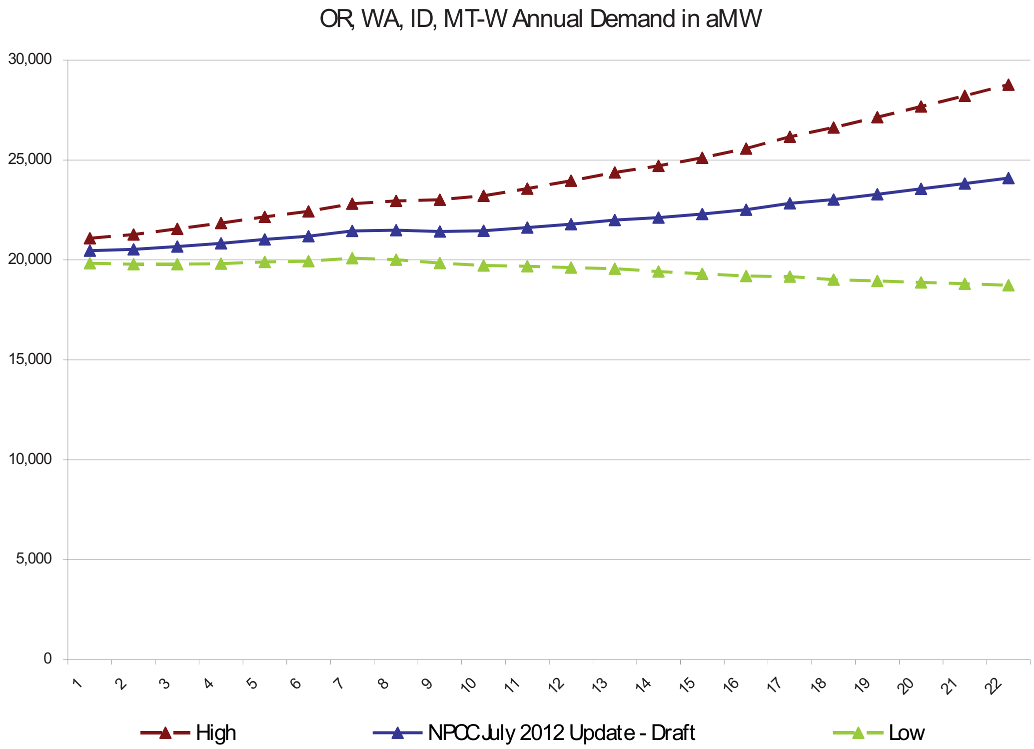
Figure 4-4: PSE Annual Gas Sales Load Forecast



Regional load

To develop power prices, PSE must use a forecast of regional demand. This IRP uses the Northwest Power and Conservation Council's preliminary regional forecast from the 6th Power Plan Mid-term Assessment. Figure 4-5 below shows the regional forecast, as well as high and low variations.

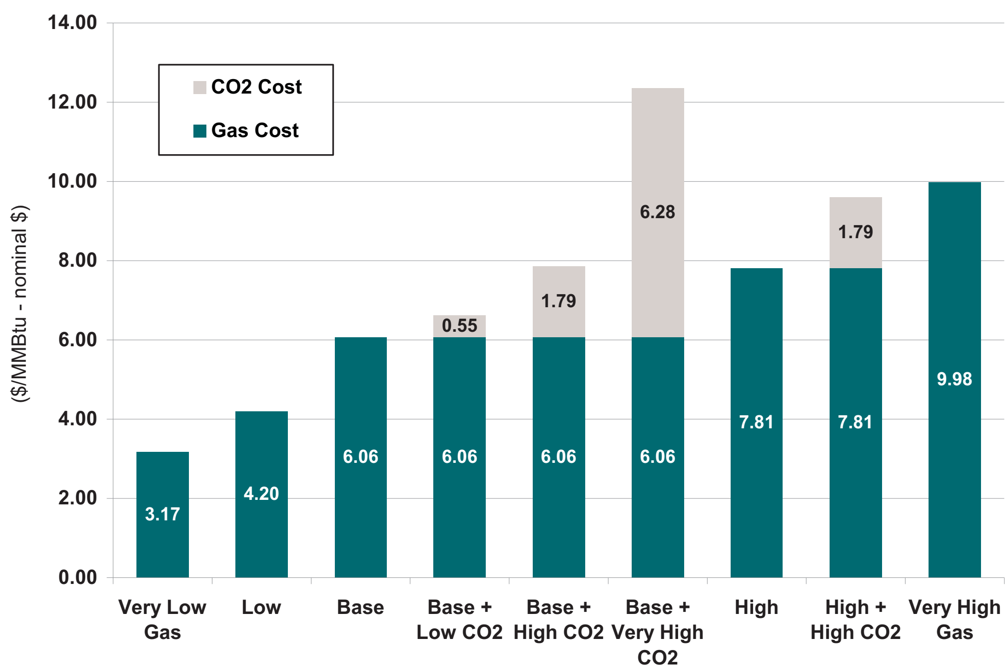
Figure 4-5
NPCC Regional Demand Forecast



Gas prices

Gas price assumptions for the Base Scenario are a combination of forward market prices and fundamental forecasts acquired in July 2012 from Wood Mackenzie, a well known macroeconomic and energy forecasting consultancy. Wood Mackenzie's gas market analysis includes regional, North American, and international factors, as well as Canadian markets and LNG exports. The full range of gas price assumptions was derived by calculating the relative difference between the Base Scenario gas prices and the very low, low, high, and very high forecasts in the 2011 IRP, and applying those ratios to the 2012 Wood Mackenzie fundamental forecast. Figure 4-6, below, illustrates the range of 20-year levelized gas prices and associated CO_2 costs used in these IRP analyses.

Figure 4-6
Levelized Gas Prices by Scenario
(Sumas Hub, 20-year levelized – 2014 to 2033 – nominal $)



CO_2 prices

To capture a range of uncertainty around CO_2 costs, PSE developed the following estimates as inputs.

Base CO_2 Cost. $0 per ton. This estimate is based on existing Washington law RCW 80.70, which applies to new fossil fuel-fired thermal generation built within the state. The law's cost can be reflected on a per ton basis or as a one-time expense included in the facility's construction cost. The 2011 IRP tracked the cost at $0.32 per ton; to simplify modeling, this IRP incorporates the cost as a one-time expense. Base CO_2 cost was modeled in all scenarios except the four that specify Low, High, or Very High CO_2 Cost in their names.

Low CO_2 Cost. $6 per ton in 2014 to $20 per ton in 2033. This estimate is based on the lowest cost estimate in the *Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis under Executive Order 12866*.[1] This cost was used as an internal CO_2 penalty that affects fossil fuel costs and dispatch. Low CO_2 cost was modeled in the Base + Low CO_2 Cost scenario.

High CO_2 Cost. $25 per ton in 2017 to $80 per ton in 2033. This estimate was developed using the CO_2 prices modeled and published by the Environmental Protection Agency (EPA) in their analysis of the Kerry-Lieberman "American Power Act" cap-and-trade scheme. In this environment, CO_2 costs are reflected in gas prices and power prices. High CO_2 Cost was included in the Base + High CO_2 Cost and High (load & gas price) + High CO_2 Cost scenarios.

Very High CO_2 Cost. $75 per ton in 2014 to $179 per ton in 2033. This estimate is based on the highest cost estimate in the *Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis under Executive Order 12866*.[2] This cost was used as an internal CO_2 penalty that affects fossil fuel costs and dispatch. Very High CO_2 Cost was modeled in the Base + Very High CO_2 Cost scenario.

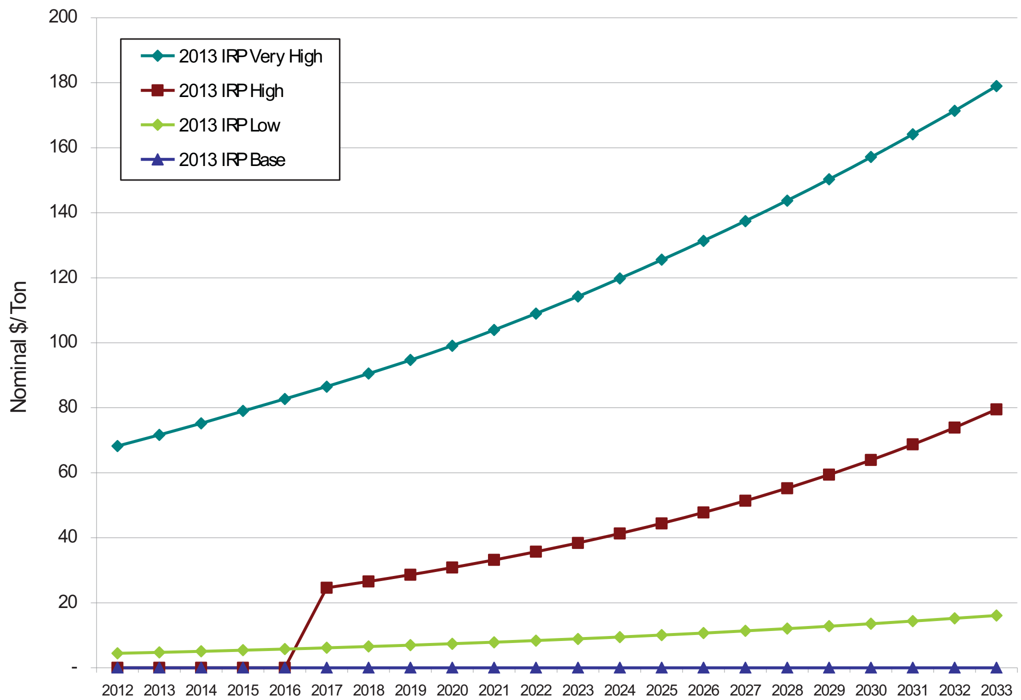
[1] *The study can be found on the Environmental Protection Agency's website.*
[2] *Ibid*

CHAPTER 4 – KEY ASSUMPTIONS

The range of CO_2 costs used in the IRP is illustrated below in Figure 4-7.

Figure 4-7

CO_2 Costs Used in the Analysis



2. Scenarios, Sensitivities and Cases

The scenarios developed for this IRP enable us to test portfolio costs and risks in a wide variety of possible future conditions. Sensitivities enable us to isolate the effects of an individual variable. Cases enable us to test how an existing resource responds economically to varying conditions.

The full range of scenarios is described first, followed by a detailed description of the Base Scenario against which others are defined by reference. Descriptions of the sensitivities follow, then the cases. Finally, a summary table including all of these assumptions appears at the end of this chapter.

Scenarios

PSE developed ten scenarios for this IRP. NOTE: Subjective probabilities are not assigned to the likelihood of any particular scenario occurring; in other words, it is important to remember that no scenario is judged to be more likely to occur than any other.

The Base Scenario

This scenario provides a starting set of assumptions; other scenarios are described by how they differ from it. A full description of the Base Scenario follows these summaries.

Low (load & gas price)

This scenario models weaker long-term economic growth than the Base Scenario.

- Demand for energy is lower in the region and in PSE's service territory.
- Natural gas prices are lower due to lower energy demand.

A low growth rate has been applied for the WECC region, and the 2013 IRP Low Demand Forecast has been applied for PSE. The long-run low forecast is applied to natural gas prices.

High (load & gas price)

This scenario models more robust long-term economic growth than the Base Scenario.

- Demand for energy is higher in the region and in PSE's service territory.
- Natural gas prices are higher as a result of increased demand.

The High growth rate has been applied in the WECC region, and the 2013 IRP High Demand Forecast has been applied for PSE. The long-run high forecast is applied to gas prices.

Very Low Gas Price

This scenario models the impact of very weak long-term gas prices

- Gas prices remain constant in nominal terms throughout the study period.

Prices remain at 2012 levels ($3.17 per MMBTu) throughout the 20-year period, which translates to a levelized price of approximately $1.03 per MMBTu lower than the low gas price forecast.

Very High Gas Price

This scenario models a future in which gas prices are extremely high.

- Gas prices are substantially higher than other forecasts.

The levelized price is $2.17 per MMBtu higher than the high gas price forecast ($9.98 compared to $7.81 for the high price forecast).

Base + Low CO_2 Cost

This scenario tests portfolio decisions in a world with Low CO_2 costs.

- Power and gas prices reflect higher CO_2 costs than the Base Scenario, but lower than other CO_2 scenarios.

Low CO_2 prices are based on the lowest forecast from the EPA Technical Support Document, and modeled as a CO_2 cost/price.

Base + High CO_2 Cost

This scenario tests portfolio decisions in a world with high CO_2 costs.

- Power and gas prices reflect higher CO_2 costs than the Base + Low CO_2 Case.

High CO_2 prices based on the American Power Act are used, and are modeled as a CO_2 cost/price.

Base + Very High CO_2 Cost

This scenario tests portfolio decisions in a world with very high CO_2 costs.

- Power and gas prices reflect the highest CO_2 costs modeled.

Very high CO_2 prices, based on the highest forecast from the EPA Technical Support Document, are modeled as a CO_2 cost/price.

High (load & gas price) + High CO_2 Cost

This scenario tests portfolio decisions in a high growth, high demand world, with high CO_2 costs.

- Demand for electricity is higher, reflecting the robust economic conditions that would be required to make material CO_2 costs politically viable.
- Gas prices are much higher.
- CO_2 emission costs are much higher.

A high growth rate applies for the WECC region, and the 2013 IRP High Demand Forecast applies for PSE. CO_2 emission costs rise from $25 per ton in 2017 to $80 per ton in 2033 – per the High CO_2 cost estimates developed from the American Power Act. Demand for natural gas increases and prices move higher as developers of new generating resources switch from coal to gas to satisfy legal and environmental requirements. Gas-fired generation also increases as more intermittent, renewable energy generation comes online (wind and solar).

Low Gas & Power Price + Base Load

This scenario models lower gas prices with the same demand forecast as the Base Scenario.

- Natural gas prices are lower due to lower energy demand.
- Power prices are the same as in the Low (load and gas price) scenario.

Base Scenario description

Modifications made in the other scenarios and sensitivities are deviations from the reference points established in the Base Scenario assumptions described below.

Resource costs. The estimated cost of generic resources is based on a study conducted by Black and Veach (December 2012) on behalf of PSE and on information derived from offers received in response to PSE's formal 2012 Requests for Proposals (RFPs). Offer prices received were not firm and were occasionally revised. The cost of each resource is escalated at 2.5% over the 20-year time horizon to reflect an annual inflation rate.

In general, cost assumptions represent the "all-in" cost to deliver a resource to customers, which includes plant, siting, and financing costs. PSE's activity in the resource acquisition market during the past five years informs the company's cost assumptions, and our extensive discussions with developers, vendors of key project components, and firms that provide engineering, procurement, and construction services lead us to believe the estimates used here are appropriate and reasonable.

Heat rates. PSE applies the improvements in new plant heat rates as estimated by the Energy Information Administration (EIA) in the Annual Energy Outlook (AEO) Base Case scenario. New equipment heat rates are expected to improve slightly over time, as they have in the past.

Regional demand growth. PSE based regional demand growth on a preliminary forecast provided by the Northwest Power and Conservation Council as part of their 6th Power Plan Mid-term Assessment.

PSE demand growth. PSE-specific demand growth incorporates assumptions about regional demand growth, but also includes many factors specific to the service territory. Development of PSE demand forecasts is discussed in detail in Appendix H. For this reference scenario, we assume the 2013 IRP Base Demand Forecast.

Natural gas prices. Gas price forecasts are a combination of forward marks in the near term and Wood Mackenzie forecasts for the longer term.

- From 2014 through 2016, PSE used the three month average of forward marks for the period ending July 09, 2012. Forward marks reflect the price of gas being purchased at a given point in time for future delivery.
- Beyond 2016, PSE based gas prices on the fundamental forecasts acquired In July 2012 from Wood Mackenzie. Wood Mackenzie's modeling assumptions and resulting forecasts are first compared with other forecasts for reasonableness.

CO_2 costs. The Base Scenario assumes CO_2 costs in current state law (RCW 80.70); this is effectively a charge of $0 per ton starting in 2012 which remains constant over the study period.[3]

Federal subsidies. Three federal subsidies have reduced renewable resource costs in the U.S. during the most recent expansion of the renewable resource industry. While these subsidies are set to expire, it is important to note that in the past they have expired, only to be renewed and expanded later. Currently there is no momentum for long-term renewals and PSE does not have a near-term need for more renewable resources. Therefore, the 2013 IRP does not include any renewable resources that meet the current eligibility criteria for the current federal subsidies. A description of each of the major federal subsidies follows.

Production Tax Credits. The Production Tax Credit (PTC) is a subsidy identified in the American Recovery and Reinvestment Act of 2009 (ARRA) for production of renewable energy. In January 2013, the American Taxpayer Relief Act of 2012 (H.R. 6, Sec. 407) removed the "placed in service dates" for eligibility and replaced this language with "begins construction in 2013." Currently, the PTC amounts to approximately $22 (in 2012 dollars) per MWh for 10 years of production after a project is placed into service. The PTC is indexed for inflation. The Base Scenario assumes no further PTCs are available for new resource development as of 2014.

Investment Tax Credits. The Investment Tax Credit (ITC) currently amounts to 30% of the eligible capital cost for renewable resources; it expires at the end of 2013. These scenarios assume no extension of ITCs.

[3] RCW 80.70 applies to new fossil fuel-fired thermal generation built in the state. It allows this cost to be reflected on a per ton basis or as a one-time expense included in the facility's construction cost. The 2011 IRP tracked the cost at $0.32 per ton; to simplify modeling, this IRP incorporates the cost as a one-time expense.

Treasury Grants. The Treasury Grant (Grant) is subsidy that amounts to 30% of the eligible capital cost for renewable resources; it also expires at the end of 2013. For projects placed in service in 2013, construction must have started in 2009, 2010, or 2011 and the project must meet eligibility criteria. This subsidy differs from the previous two in that it is a cash payment from the federal government, versus a tax credit. No extension of the Treasury Grant is assumed.

Renewable portfolio standards. Renewable portfolio standards (RPS) currently exist in 29 states and the District of Columbia, including most of the states in the WECC and British Columbia. They affect PSE because they increase competition for development of renewable resources. Each state and territory defines renewable energy sources differently, sets different timetables for implementation, and establishes different requirements for the percentage of load that must be supplied by renewable resources.

To model these varying laws, PSE first identifies the applicable load for each state in the model and the renewable benchmarks of each state's RPS (e.g. 3 percent in 2015, then 15 percent in 2020, etc.). Then we apply those requirements to each state's load. No retirement of existing WECC renewable resources is assumed, which perhaps underestimates the number of new resources that need to be constructed. After existing and "proposed" renewable energy resources are accounted for, "new" renewable energy resources are matched to the load to meet the applicable RPS. Following an internal and external review for reasonableness, these resources are created in the AURORA database. Technologies included wind, solar, biomass, and geothermal. Creation of RPS resources was guided by estimates of potential production by states that appear in the "Renewable Energy Atlas of the West," which can be found at www.dsireusa.gov. These vary considerably depending on local conditions; Arizona, for example, has little wind potential but great solar potential. Appendix K, Electric Analysis, includes a table that identifies renewable portfolio standards by jurisdiction.

Build constraints. PSE added constraints on coal technologies to the AURORA model in order to reflect current political and regulatory trends. Specifically, no new coal builds were allowed in any state in the WECC. In addition, all the coal plants in the WECC must meet the National Ambient Air Quality Standards (NAAQS) and the Mercury and Air Toxics Standards (MATS). Any plant that did not meet these standards and had no plans to retrofit was assumed to retire. Washington state law RCW 80.80 (Greenhouse Gases Emissions-Baseload Electric Generation Performance Standard) clearly prohibits construction of new coal-fired generation within the state without carbon capture and sequestration. Absent constraints, the AURORA model would have identified coal as a least-cost resource and built some coal units in the WECC. PSE also reflected the retirement of California power plants that would be shuttered by the state's Once-through Cooling regulations. Renewable resources were added to the database to meet all current state RPS laws or goals in the WECC. Further discussion of the RPS by state is located in Appendix K, Electric Analysis.

Sensitivities

Sensitivities change only one variable in the Base Scenario, so that we can isolate the effect that variable has on the portfolio. In this IRP we tested four sensitivities.

- Firm Gas Transport Cost for Peakers
- Peaker Type
- Thermal Plant Location
- DSR Ramp Rates
- Replacing Colstrip Energy with Montana Wind
- Additional 300 MW of Wind Beyond RPS Requirements

Firm Gas Transport for Peakers

This sensitivity adds higher-priced, firm pipeline capacity costs to the peakers. This sensitivity also assumes that peakers are unable to use oil as a back-up fuel when natural gas is unavailable; the Base Scenario assumes that they can.

Peaker Type

This sensitivity explores how the portfolio's operational flexibility would change depending on what type of peaker technology was employed. This sensitivity tests the difference between two peaker types: frame and reciprocating engines.

Thermal Location

This sensitivity tests whether the economics of thermal generation are affected by the location of the resource. Thermal generating plants located west of the Cascades within PSE's service territory are assumed to have certain advantages because they operate within PSE's transmission system, but their fuel cost is higher and they may be subject to constraints on siting. Thermals located east of the Cascades must rely on the regional transmission network to deliver power to the service territory but benefit from lower cost fuel supply and fewer siting constraints. This sensitivity imposes the type of locational build constraints that could result from local air permitting limits, lack of available development sites, or lack of transmission resources.

DSR Ramp Rates

For the gas sales analysis, we created sensitivities that tested 10- and 20-year ramp rates for DSR measures, and a 2-year delay on a 10-year ramp rate. For the electric analysis, the IRP tested both 10- and 20-year DSR ramp rates.

Replacing Colstrip Energy with Montana Wind

This sensitivity tested the cost impact of replacing the energy from PSE's Colstrip plant with wind power from Montana. PSE's share of Colstrip output is approximately 5 million MWh per year. Given the uncertainty characteristic of wind generation, two sensitivities were performed. One assumed the Montana wind would have a 40 percent annual capacity factor, which would translate to approximately 1,400 MW of wind. The other assumed a 31% annual capacity factor, which would translate to approximately 1,800 MW of wind.

Additional 300 MW of Wind Beyond RPS Requirements

This sensitivity included an additional 300 MW of southeastern Washington wind added in 2017 on top of the renewable resources needed to comply with the state's RPS. This analysis was used to estimate the fundamental cost of generating Renewable Energy Credits (RECs) from wind and to estimate the cost of CO_2 abatement using Northwest wind resources.

Colstrip Environmental Compliance Cost Cases

Several proposed or recently enacted rules will affect the operation of the Colstrip plant in eastern Montana in coming years. This IRP developed four compliance cost cases to analyze the continued economic viability of this resource under varying regulatory conditions. Operations at Colstrip Units 1 & 2 are analyzed separately from operations at Units 3 & 4 because the older units are subject to different requirements than the newer units. Below are brief descriptions of the four compliance cases modeled. The four cases are described in detail in Appendix J, Colstrip.

Case 1 – Low Cost

In this case, compliance is achieved using existing, installed equipment with a minimum of modifications or additions.

Case 2 – Mid Cost

This case includes additional equipment that may be needed to assure compliance. It is largely based on the need for equipment to bring the older Units 1 & 2 into compliance with the EPA's Regional Haze FIP.

Case 3 – High Cost

Case 3 assumes all of the Case 2 costs, plus additional costs for new equipment to meet future requirements. It also reflects a scenario in which coal combustion residuals are determined to require off-site hazardous waste disposal.

Case 4 – Very High Cost

Case 4 assumes all Case 2 costs plus it triples the hazardous waste disposal costs included in Case 3 and it accelerates the schedule for meeting other requirements.

NOTE: The assumption that coal combustion residuals will need to be disposed of off-site as hazardous waste is a significant cost driver for Cases 3 and 4; however, depending on how potential regulations develop in the future, Colstrip may be able to store CCR waste on-site, given the quality of its current containment methods. If so, compliance costs for both cases would be substantially lower.

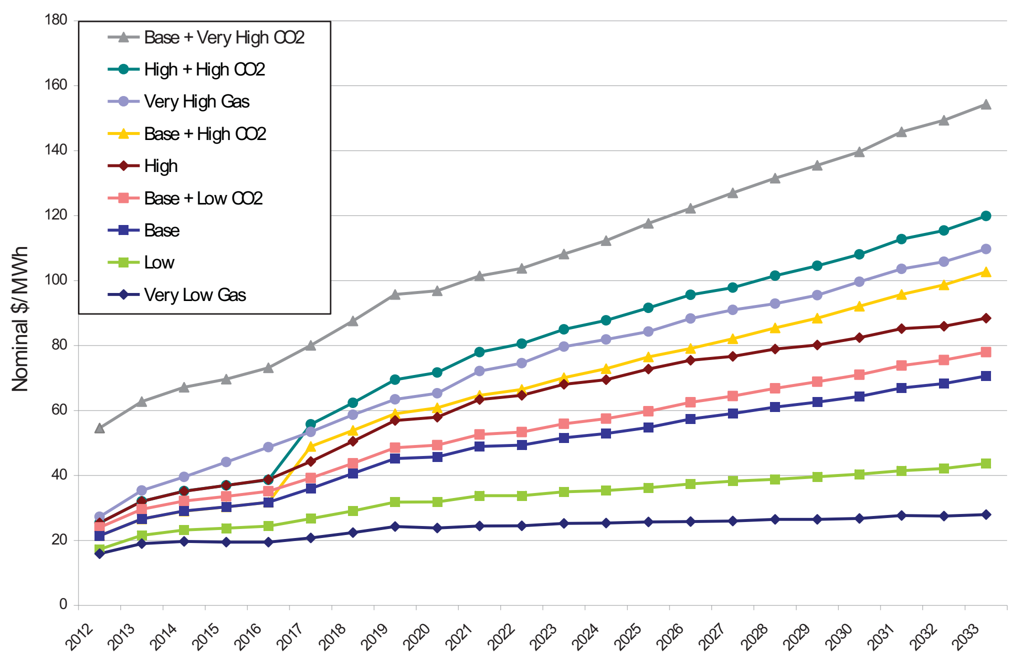
3. Input Matrices

Power prices

One of the primary reasons for conducting scenario analysis is to develop the power prices used in the optimization model. PSE used a deterministic method to develop power prices. For each scenario, we ran AURORA using the different sets input variables described in section two of this chapter to calculate power prices. For example, The Base Scenario uses the 2013 IRP Base Demand Forecast and the 2012 fundamental gas price forecast from Woods Mackenzie, while the High (load & gas price) scenario uses the 2013 IRP High Demand Forecast and long-run high gas price forecast. The sensitivities do not require AURORA runs since they rely on the Base Scenario assumptions; they are simply manipulations of the constraints and assumptions in the optimization model. See Appendix K for a discussion of how power prices and the stochastic model were used.

The following table shows the power prices used in each of the core scenarios.

Figure 4-8
Input Power Prices by Scenario
Annual Average Mid-C Power Price (Nominal $/MWh)



Resource assumptions

PSE also uses the resource assumptions shown in Figure 4-9 in the analysis. The generic CCCT is an F type, 1x1 engine with wet cooling tower. The peaker is also an F type, wet cooled turbine. The reciprocating engine is a 3-engine design with wet cooling. In addition to these supply-side resources, PSE also uses the demand-side resource assumptions identified in Appendix K, Electric Analysis.

Figure 4-9
Electric Supply-side Resources

2012 $	Units	CCCT	Frame Peaker w/ Oil	Frame Peaker w/o Oil	Recip Engine	Wind
Capacity	MW	377	221	221	18	100
Capital Cost	$/KW	$1,540	$915	$879	$2,186	$2,019
O&M Fixed	$/KW-yr	$22.06	$19.91	$10.99	$40.57	$23.16
O&M Variable	$/MWh	$0.42	$0.44	$0.44	$1.80	$3.00
Forced Outage Rate	%	3%	3%	3%	3%	
Wind Capacity Factor	%					30%
Capacity Credit	%	100%	100%	100%	100%	4%
Operating Reserves	%	7%	7%	7%	7%	5%
Heat Rate – GT	Btu/KWh	6,822	10,231	10,231	8,370	
Heat Rate – DF	Btu/KWh	8,972				
Westside	Location	West of Cascades	West of Cascades	West of Cascades	West of Cascades	
Fixed Gas Transport	$/KW-yr	$43.23	$0.00	$66.94	$54.77	
Variable Gas Transport	$/MWh	$0.04	$0.24	$0.04	$0.04	
Fixed Transmission	$/KW-yr	$0.00	$0.00	$0.00	$0.00	
Variable Transmission	$/MWh	$0.00	$0.00	$0.00	$0.00	
Eastside	Location	East of Cascades	East of Cascades	East of Cascades	East of Cascades	East of Cascades
Fixed Gas Transport	$/KW-yr	$27.86	$0.00	$43.13	$35.29	
Variable Gas Transport	$/MWh	$0.01	$0.05	$0.01	$0.01	
Fixed Transmission	$/KW-yr	$17.47	$17.47	$17.47	$17.47	$31.79
Variable Transmission	$/MWh	$0.00	$0.00	$0.00	$0.00	$1.99
Emissions:						
SO_2	lbs/MMBtu	0.010	0.010	0.010	0.010	
NO_x	lbs/MMBtu	0.007	0.009	0.009	0.009	
CO_2	lbs/MMBtu	115.9	115.9	115.9	115.9	
First Year Available		2018	2016	2016	2016	2016

4. Summary Table of Scenario, Sensitivity and Case Assumptions

	Reference	Base	High	Low	High + High CO2	Base + Very High CO2	Base + High CO2	Base + Low CO2	Very High Gas	Very Low Gas	Low + Base Demand
Theme		Best estimate of current resource costs and characteristics, fuel prices, state and federal laws	Higher Regional and PSE demand load growth based on higher long-term economic growth	Lower Regional and PSE demand load growth based on lower long-term economic growth	Support for stronger environmental legislation at the federal level.	Best estimates of current costs with High CO2 Societal Costs.	Best estimates of current costs with CO2 price	Best estimates of current costs with Low CO2 Societal Costs.	Impact of Very High Gas	Impact of Very Low Gas	Lower Natural Gas Prices
Aurora Power Price		Base	High	Low	High + High CO2	Base + Very High CO2	Base + High CO2	Base + Low CO2	Very High Gas Price	Very Low Gas Price	Low
WECC Demand (Aurora)	NPCC 6th Power Plan Preliminary midterm update (Aug 2012)	Reference	High	Low	High	Reference	Reference	Reference	Reference	Reference	Low
PSE Demand	F2012 IRP Demand Forecast	Reference	High	Low	High	Reference	Reference	Reference	Reference	Reference	Reference
Gas Price	Forward Marks 2014-2016 (July 9, 2012), and Wood Mac April 2012 Long-run fundamental forecast	Reference	High	Low	High	Reference	Reference	Reference	Very High Gas Price	Very Low Gas Price	Low
Coal Price	EPIS Default DB 2012.01 (EIA AEO 2011)	Reference	Reference	Reference	Reference	Reference	Reference	Reference	Reference	Reference	Reference
Generic Resource Costs	PSE Market Based Estimates	Reference	Reference	Reference	Reference	Reference	Reference	Reference	Reference	Reference	Reference
Emissions – CO2	RCW 80.70 Carbon Mitigation Plan	Reference	Reference	Reference	EPA Analysis adjusted to start in 2017 at $25/Ton (Nominal) and escalate to $80 by 2033	Technical Support Document (TSD) Societal 95th Percentile starts in 2014 at $75/Ton (Nominal) and escalates to $179 by 2033	EPA Analysis adjusted to start in 2017 at $25/Ton (Nominal) and escalate to $80 by 2033	TSD Societal low average starts in 2014 at $6/Ton (Nominal) and escalates to $20 by 2033	Reference	Reference	Reference
Emissions – SO2, Nox	National Ambient Air Quality Standards	Reference	Reference	Reference	Reference	Reference	Reference	Reference	Reference	Reference	Reference
Emissions – Hg	Mercury and Air Toxics Standards (MATS)	Reference	Reference	Reference	Reference	Reference	Reference	Reference	Reference	Reference	Reference
Financial Incentive; Treasury Grant	Current Federal law, no renewal after 2012	Reference	Reference	Reference	Reference	Reference	Reference	Reference	Reference	Reference	Reference
RPS	Meet Current State RPS through 2033.	Reference	Reference	Reference	Reference	Reference	Reference	Reference	Reference	Reference	Reference
WECC Build Constraints	No new coal or nuclear. RPS builds consistent with DSIRE and the Renewable Energy Atlas of the West	Reference	Reference	Reference	Existing Coal Retired (2025). Existing Nuclear retire at end of license	Reference	Reference	Reference	Reference	Reference	Reference
PSE Build Constraints	All Existing generating plants operate through 2033	Test Colstrip Environmental Cases, Expiration of Transmission Contracts, and DSR ramp rates	Test Colstrip Environmental Cases and Expiration of Transmission Contracts	Test Colstrip Environmental Cases and Expiration of Transmission Contracts	Test Colstrip Environmental Cases and Expiration of Transmission Contracts	Test Colstrip Environmental Cases and Expiration of Transmission Contracts	Test Colstrip Environmental Cases and Expiration of Transmission Contracts	Test Colstrip Environmental Cases and Expiration of Transmission Contracts	Test Colstrip Environmental Cases and Expiration of Transmission Contracts	Test Colstrip Environmental Cases and Expiration of Transmission Contracts	Test Colstrip Environmental Cases and Expiration of Transmission Contracts
Renewable Energy Credit	2012: $3.00/REC increasing at …	Reference	Reference	Reference	Reference	Reference	Reference	Reference	Reference	Reference	Reference

CHAPTER 5

Electric Analysis

Contents

More than a million customers in Washington state depend on PSE for safe, reliable, and affordable electric services. The IRP analysis described in this chapter enables PSE to develop valuable foresight about how resource decisions may unfold over the next 20 years in conditions that depict a wide range of possible futures.

1. Resource Need

For PSE, resource need has three dimensions. The first is physical: Can we provide reliable service to our customers at peak demand hours and at all hours? The second is economic: Can we meet the needs of customers across all hours cost effectively? The third is policy-driven: Are there enough renewable resources in the portfolio to fulfill the state's renewable portfolio standard requirements? Each dimension is described below.

Physical reliability need

Physical reliability need refers to the resources required to ensure reliable operation of the system. This operational requirement has three components: customer demand, planning margins, and operational reserves. The word "load" – as in "PSE must meet load obligations" – specifically refers to the total of generated demand plus planning margins and operating reserve obligations. The planning margin and reserves must be maintained in order to minimize interruption of service due to extreme weather or the unlikely event of equipment failure or transmission interruption.

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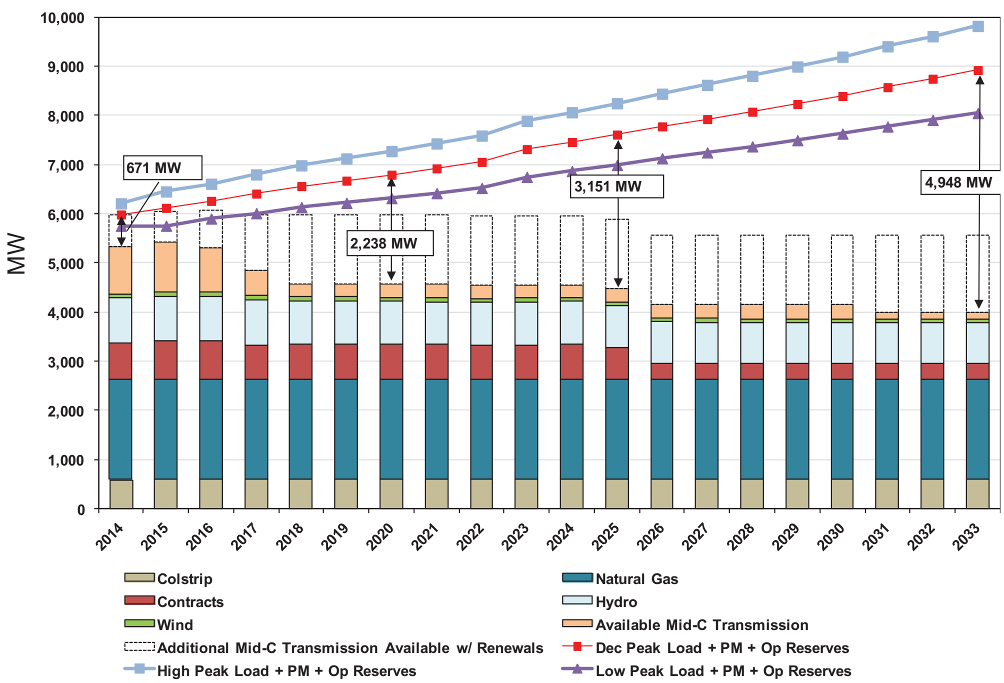
Physical characteristics of the electric grid are very complex, so for planning purposes PSE simplifies physical resource need into a peak hour capacity metric through a loss of load probability analysis. That is, if PSE has sufficient resources modeled in the IRP to meet its normal peak hour demand plus a planning margin and the operating reserves required to dispatch those resources, the company will be able to maintain an adequate level of reliability across all hours. We can simplify physical resource need in this way because PSE is much less hydro-dependent than other utilities in the region, and because resources in the IRP are assumed to be available year-round. If we were more hydro-dependent, issues like the sustained peaking capability of hydro and annual energy constraints could be important; likewise, if seasonal resources or contracts were contemplated, supplemental capacity metrics may be appropriate to ensure adequate reliability in all seasons.

Figure 5-1 shows physical reliability need for the three demand scenarios modeled in this IRP. The components of this "peak need" are described more fully following the chart.

Figure 5-1
Electric Peak Need (Physical Reliability Need)
Comparison of projected peak hour need with existing resources



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Customer demand

PSE uses national, regional, and local economic and population data to develop a range of demand forecasts for the 20-year IRP planning horizon.[1] These forecasts are incorporated into the scenarios modeled in the electric analysis. (See Chapter 4 for summary descriptions, and Appendix H for a detailed discussion of the methodologies and inputs used to develop the forecasts.)

PSE is a winter-peaking utility, meaning that we experience the highest end-use demand for electricity when the weather is coldest, so projecting peak energy demand begins with a forecast of how much power will be used at a temperature of 23 degrees Fahrenheit at SeaTac (a normal winter peak for PSE, see Appendix H, Demand Forecasts). We also experience sustained strong demand during the summer air-conditioning season, although these highs do not reach winter peaks.

Planning margin

PSE incorporates a planning margin in its description of resource need in order to achieve a 5 percent loss of load probability (LOLP). The 5 percent LOLP is an industry standard resource adequacy metric used to evaluate the ability of a utility to serve its load, and one that is used by the Pacific Northwest Resource Adequacy Forum.[2] The process has two steps. First, we perform an analysis on the likelihood that load will exceed resources on an hourly basis over the course of a full year with focus on the winter period since PSE has a winter peaking load. Included are uncertainties around temperature impacts on loads and conservation savings, hydro conditions, wind, and forced outage rates (both their likelihood and duration). This analysis allows us to identify the amount of resources needed to achieve a 5 percent LOLP in the winter period. In step two, the 5 percent LOLP is translated into the planning margin for the winter period. (For the calculations used to determine the planning margin, see the discussion of PSE's Loss of Load Probability Model in Appendix K, Electric Analysis.) Figure 5-2 shows the updated targets for winter period planning margins that are estimated to result in an adequate level of reliability. Given that PSE has a winter peaking load, any capacity brought in to meet the planning margin in the winter is also available to meet capacity in other seasons.

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[1] *The demand forecasts developed for the IRP are a snapshot in time, since the full IRP analysis takes more than a year to complete and this input is required at the outset. Forecasts are updated continually during the business year, which is why those used in acquisitions planning or rate cases may differ from the IRP.*
[2] *See http://www.nwcouncil.org/library/2008/2008-07.htm*

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Figure 5-2
(2013 IRP Winter Period Planning Margin)

	Planning Margins Net of Operating Reserves @ 5% LOLP		
	Winter 2014-2015	Winter 2018-2019	Winter 2023-2024
IRP2013-Winter Season	13.5%	14.0%	16.0%

In addition to the planning margin, the LOLP model also allows PSE to calculate the incremental capacity equivalent (ICE) of different types of new resources. The incremental capacity equivalent is defined as the change in capacity of a generic natural gas peaking plant that results from adding a new type of resource with any given energy production characteristics to the system while keeping the LOLP target constant at 5 percent. The new resource could be wind, battery, coal plant, or even a power purchase agreement (PPA). This allows us to assign the capacity contribution of certain projects relative to a gas peaker, and it is especially useful for variable energy resources such as wind. Fixed PPAs have an ICE of more than 100 percent, since they are available all hours without the forced outage rate peakers must account for. (For a more detailed explanation of ICE, see Appendix K, Electric Analysis.) Figure 5-3 below shows the estimated incremental capacity equivalent of certain projects.

Although a generic wind project could be located in many parts of the Northwest,[3] a southeast Washington wind location was chosen as the generic wind for this IRP. Good historical wind data exists for the area, PSE already owns development rights at the Lower Snake River site, and transmission to the grid already exists in this location. Comparison of improvements in the incremental capacity equivalents for other wind sites must account for the incremental transmission costs required to connect the site to the regional grid.

[3] *PSE examined the incremental capacity equivalent of a central Washington wind project in the 2011 IRP.*

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Figure 5-3
ICE Comparisons

Incremental Capacity Equivalent @5% LOLP	
Resource Type	Winter 2018-2019
**** Natural Gas Peaker**	**100%**
1) Existing Wind (Cumulative = 822MW)	10%
2) New Wind (SE Washington = 100MW)	4%
3) Battery (100MW, 400 MWhs Energy, Charge/Discharge Time=4Hrs)	57%
4) Colstrip (All Units =657MW[4])	90%
5) Fixed PPA (200MW, 8760Hours)	106%

Operating reserves

North American Electric Reliability Council (NERC) standards require that utilities maintain a "reserve" in excess of end-use demand as a contingency in order to ensure continuous, reliable operation of the regional electric grid. PSE's operating agreements with the Northwest Power Pool, therefore, require the company to maintain two kinds of operating reserves: contingency reserves and balancing reserves.

Contingency reserves. Contingency reserves are intended to bolster short-term reliability in the event of forced outages. Under the Northwest Power Pool's contingency reserve sharing agreement, generators must reserve an additional 5 percent of hydro or wind resources and 7 percent of thermal resources, when such units are dispatched to meet firm sales obligations. This capacity must be available within 10 minutes, and 50 percent of it must be spinning. For example, if a 100 MW thermal generator is dispatched to meet firm sales, the utility must have an additional 7 MW of resources available to meet the contingency reserve sharing obligation. Each member of the power pool maintains such reserves. If any member's generator experiences a forced outage, the contingency reserve sharing agreement is activated. Reserves from other members come online to make up for the lost generation. This is a very short-term arrangement. Contingency reserve sharing covers such forced outages for up to one hour. After that, the utility must balance its load (firm sales plus operating reserves) by either purchasing resources on the market or, if necessary, shedding load.

[4] *Colstrip capacity of 657 MW reflects the 677 MW of Net Maximum Capacity described in the Existing Resources section below, minus transmission line losses on BPA's transmission system.*

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The Federal Energy Regulatory Commission (FERC) is likely to approve a new ruling that will affect the amount of reserves we carry. Instead of 5 percent of hydro and wind and 7 percent of thermal, Bal-002-WECC-1 would require us to carry 3 percent of generating resources (hydro, wind and thermal) and 3 percent of load. Primarily, this affects daily operations in hours when we are relying more on market power purchases than PSE-owned generation. The rule will increase peak hour capacity need in 2014 by approximately 35 MW. NERC approved the standard on Nov 7, 2012; next, NERC will file for final approval from FERC.[5]

Balancing reserves. Utilities must also have sufficient reserves available to maintain system reliability within the operating hour; this includes frequency support, managing load and variable resource forecast error, and actual load and generation deviations. Balancing reserves do not provide the same kind of short-term, forced-outage reliability benefit as contingency reserves, which are triggered only when certain criteria are met; balancing reserves must be able to ramp up and down as loads and resources fluctuate instantaneously each hour. For a more detailed explanation, see Appendix G, Operational Flexibility.

For PSE, the amount of balancing reserves is 123 MW. This amount is based on a 95 percent confidence interval, or the amount of reserves that would capture 95 percent of the within-hour load and resource deviations. This confidence interval is derived from historical data during the months of December and January, coinciding with the period used for PSE's winter-peak planning. 123 MW reflects an increase from the 35 MW used in prior IRPs, which was also termed "regulating reserves." This was the amount historically needed for PSE to meet its Control Performance Standard 2, a NERC reliability metric that measures a utility's Area Control Error every 10 minutes. While this amount is adequate for balancing the system over 10 minute periods, it is inadequate for balancing the system over the entire operating hour. For more information, see Appendix G, Operational Flexibility.

[5] *For more information, go to http://www.wecc.biz/Standards/Development/WECC-0083/default.aspx.*

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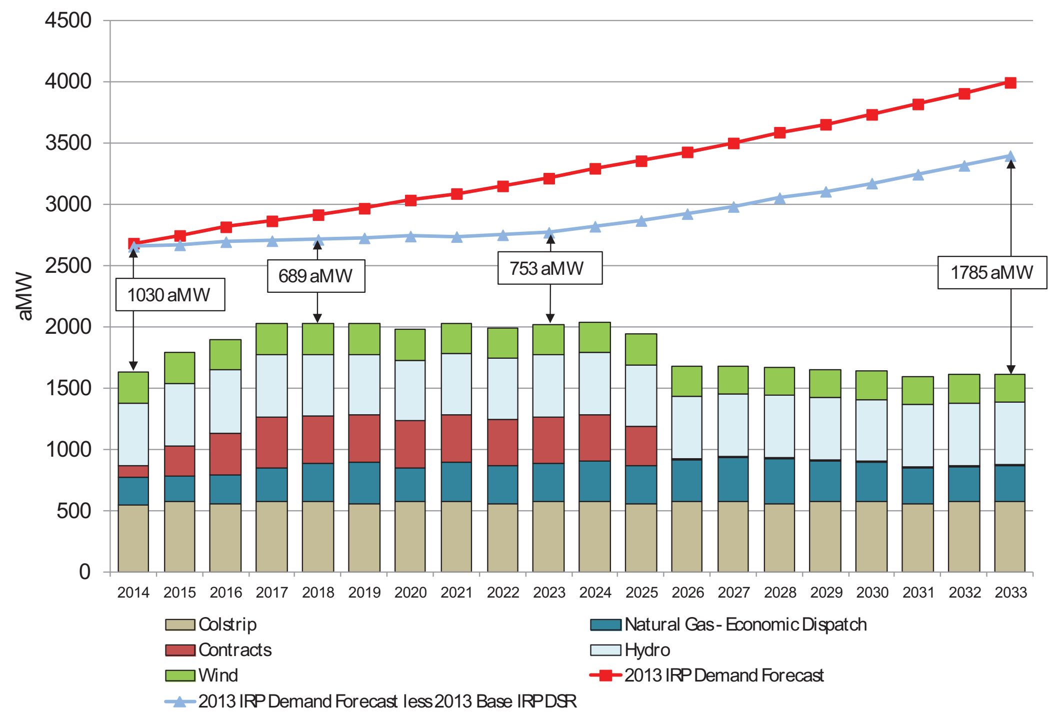
Energy need

Meeting customers' "energy need" is more of a financial concept that involves minimizing cost rather than a physical planning constraint for PSE. Portfolios are required to cover the amount of energy needed to meet physical loads, but our models also examine how to do this most economically. We do not have to constrain (or force) the model to dispatch resources that are not economical; if it is cheaper to buy power than dispatch a generator, PSE will choose to buy. Similarly, if a zero (or negative) marginal cost resource like wind is available, PSE will displace higher-cost market purchases and use the wind to meet the "energy need." Figure 5-4, below, illustrates the company's energy position into the future, based on the energy load forecasts and economic dispatched of the Base Scenario presented in Chapter 4, Key Assumptions.

Figure 5-4
Annual Energy Position for 2013 IRP Base Scenario



Renewable resources

Washington state's renewable portfolio standard (RPS) requires PSE to meet specific percentages of our load with renewable resources or renewable energy credits (RECs) by specific dates. The main provisions of the statute (RCW 19.285) are summarized below.

For all practical purposes, wind remains the main resource available to fulfill RPS requirements for PSE. Existing hydroelectric resources may not be counted towards RPS goals except under certain circumstances for new run of river and efficiency upgrades, and other renewable technologies are not yet capable of producing power on a large enough scale to make substantial contributions to meeting the targets.

Washington State RPS Targets

3% of supply-side resources by 2012
9% of supply-side resources by 2016
15% of supply-side resources by 2020

Renewable resources influence supply-side resource decisions.

Adding wind to the portfolio increases the need for stand-by back-up generation that can be turned on and off or adjusted up or down quickly. The amount of electricity supplied to the system by wind drops off when the wind stops, but customer need does not. As the amount of wind in the portfolio increases, so does the need for reliable back-up generation. Appendix G, Operational Flexibility, discusses PSE wind integration challenges in more detail.

Demand-side achievements affect renewable amounts.

Washington's renewable portfolio standard calculates the required amount of renewable resources as a percentage of kWh sales; therefore, if the kWh decreases, so does the amount of renewables we need to plan for. Achieving demand-side resources (DSR) has precisely this effect: DSR decreases sales volumes, and therefore the amount of renewables needed.

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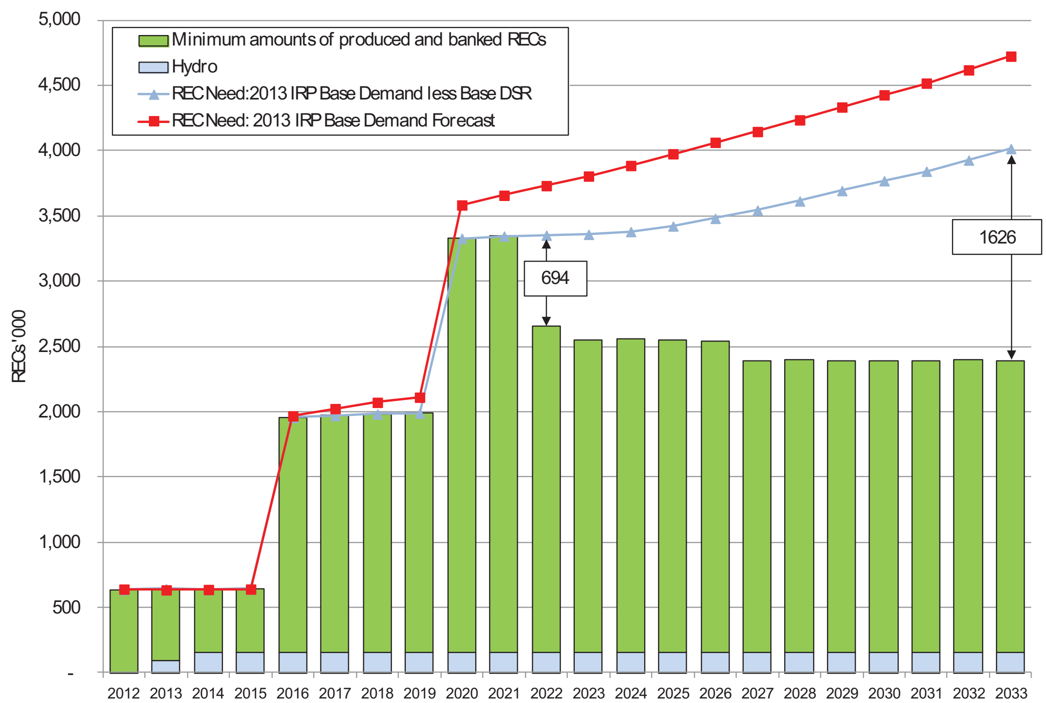
REC banking provision

Washington's renewable portfolio standard allows for REC banking. Unused RECs can be banked forward one year or can be borrowed from one year in the future. In this IRP, PSE assumes that the company would employ a REC banking strategy that would push the need for additional RECs further into the future.

Figure 5-5 illustrates the need for renewable energy after accounting for REC banking and the savings from demand-side resources that were found cost effective for the 2013 IRP.

Figure 5-5
RPS Need Based on Achievement of All Cost-effective DSR



2. Existing Resources

Resources are divided into two categories, depending on where they originate. Supply-side resources generally originate on the company side of the meter, while demand-side resources (DSR) generally originate on the customer side of the meter.

With supply-side resources, power is generated by means of water, natural gas, coal, wind, etc., and then transmitted (or "supplied") to customers.

Demand-side resources include energy efficiency measures, demand-response, and other techniques that reduce the amount of power customers need (or "demand") in order to operate their homes and businesses.

Existing supply-side resources

To build the portfolios for the IRP analysis, we begin with a snapshot of PSE's existing resources. The map and tables that follow summarize PSE's existing resources and their expiration dates as of March 2013. The location of PSE's existing supply-side generation resources is pictured in Figure 5-6.

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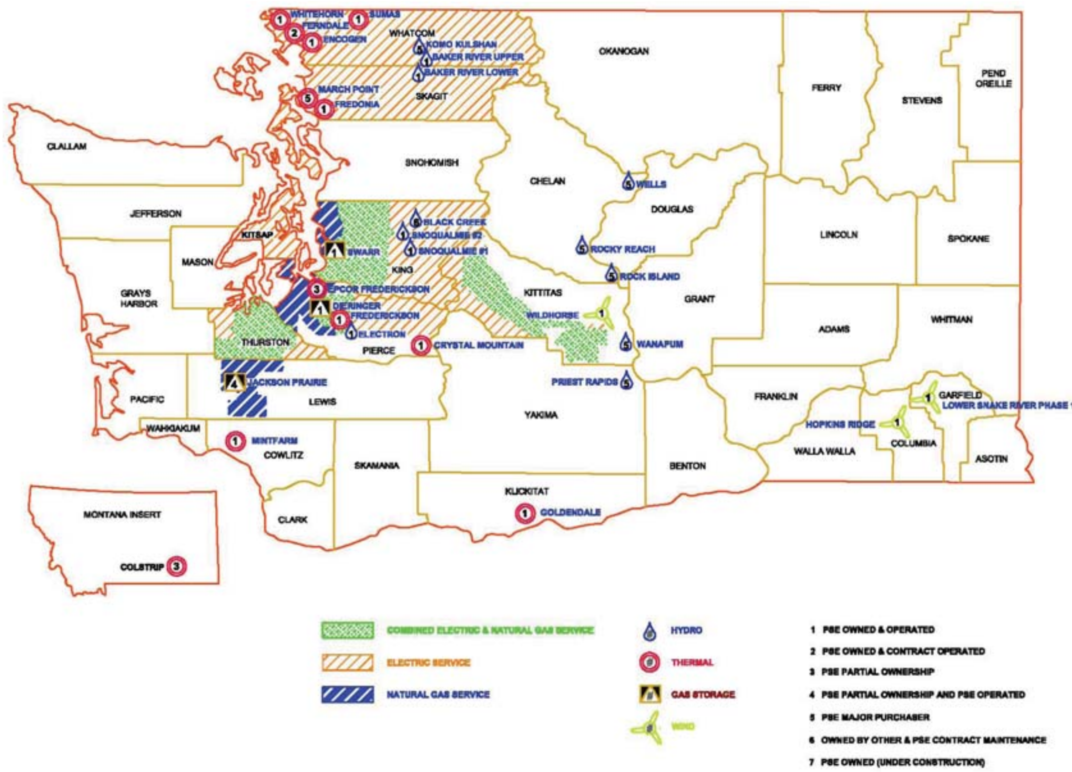
Figure 5-6
Location of Supply-side Resources



PSE's supply-side resources are diversified geographically and by fuel type. Most of the company's gas-fueled resources are in western Washington. The major hydroelectric contracted resources are in central Washington, outside PSE's service area. Wind facilities are located in central and eastern Washington. Coal-fired generation is located in eastern Montana.

Resource capacity note. The following tables represent the capacity value of resources in terms of Net Maximum Capacity in megawatts. The Net Maximum Capacity is different than the winter peak capacity used for the IRP peak capacity need. This is consistent with the descriptions contained in the company's10K (which is filed with the U.S. Securities and Exchange Commission) and FERC Form 1. Net Maximum Capacity is the capacity a unit can sustain over a specified period of time – in this case 60 minutes – when not restricted by ambient conditions or deratings, less the losses associated with auxiliary loads.

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You may notice that PSE sometimes references different capacity values in different publications for the same plant. This is because plant output can vary for many reasons, among them ambient temperature, fuel supply, whether a natural gas plant is using duct firing, whether a combined-cycle facility is delivering steam to a steam host, outages, upgrades and expansions, just to name a few. When talking about the relative size of resources, it is often necessary to select a single reference point based on a consistent set of assumptions. Depending on the nature and timing of the discussion, these assumptions – and thus the capacity – may vary.

Hydroelectric resources

Figure 5-7
Hydroelectric Resources

PLANT	OWNER	PSE SHARE %	NET MAXIMUM CAPACITY (MW)[1]	CONTRACT EXPIRATION DATE
Upper Baker River	PSE	100	91	None
Lower Baker River	PSE	100	79	None
Snoqualmie Falls	PSE	100	54[2]	None
Electron	PSE	100	22[3]	None
Total PSE-Owned			**246**	
Wells	Douglas Co. PUD	29.9	251	3/31/18
Rocky Reach	Chelan Co. PUD	25.0	325	10/31/31
Rock Island I & II	Chelan Co. PUD	25.0	156	10/31/31
Wanapum	Grant Co. PUD	0.8[4]	9	04/04/52
Priest Rapids	Grant Co. PUD	0.8[4]	9	04/04/52
Mid-Columbia Total			**719**	
Total Hydro			**996[5]**	

NOTES

1 Net maximum capacity reflects PSE's share only.
2 Snoqualmie Falls is running at partial capacity while powerhouse 1 is offline for redevelopment. The plant is expected to be fully operational and provide a net maximum capacity of approximately 54 MW upon completion of powerhouse 1, which expected in the second quarter of 2013.
3 As of December 31, 2012, Electron project output is limited to approximately 7 MW due to the condition of the flume that conveys water to the plant. This limitation is expected into 2013.
4 Based on Grant Co. PUD current load forecast for 2012; our share will be reduced to this level in 2013.
5 Individual resource and Mid-Columbia totals are rounded to the nearest megawatt.

Coal, natural gas, and wind resources

Figure 5-8
Coal, Combined-cycle Combustion Turbines, Simple-cycle Combustion Turbines, and Wind Resources

POWER TYPE	UNITS	PSE OWNERSHIP	NET MAXIMUM CAPACITY (MW)[1]
Coal	Colstrip 1 & 2	50%	307
Coal	Colstrip 3 & 4	25%	370
Total Coal			**677**
CCCT	Encogen	100%	165
CCCT	Ferndale	100%	253
CCCT	Frederickson 1[2]	49.85%	136
CCCT	Goldendale	100%	278
CCCT	Mint Farm	100%	297
CCCT	Sumas	100%	127
Total CCCT			**1,256**
SCCT	Fredonia 1 & 2	100%	207
SCCT	Fredonia 3 & 4	100%	107
SCCT	Whitehorn 2 & 3	100%	149
SCCT	Frederickson 1 & 2	100%	149
Total SCCT			**612**
Wind	Hopkins Ridge	100%	157
Wind	Lower Snake River, Phase 1	100%	343
Wind	Wild Horse	100%	273
Total Wind			**773**

NOTES

1 Net maximum capacity reflects PSE's share only.
2 Frederickson 1 CCCT unit is co-owned with Atlantic Power Corporation - USA.

Long-term contracts

Long-term contracts consist of agreements with independent producers and other utilities to supply electricity to PSE. Fuel sources include hydro, gas, waste products, and system deliveries without a designated supply resource. These contracts are summarized below. Short-term contracts negotiated by PSE's energy trading group are not included in this listing.

Figure 5-9
Long-term Contracts for Electric Power Generation

NAME	POWER TYPE	CONTRACT EXPIRATION	CAPACITY (MW)[1]
BPA- WNP-3 Exchange	System	6/30/2017	82
Powerex/Pt.Roberts	System	Ongoing	8
BPA Baker Replacement	Hydro	9/5/2029	7
PG&E Seasonal Exchange-PSE	Thermal	Ongoing	300
Canadian EA	Hydro	09/15/2024	- 40.5
Barclays Bank	System	02/28/2015	75
Centralia Transition Coal	Transition Coal	12/31/2025	180[2]
Klamath Toll	Natural Gas	2/29/2016	100
Klondike III	Wind	11/31/2026	50
Twin Falls	Hydro-QF	3/8/2025	20
Koma Kulshan	Hydro-QF	3/31/2037	10.9
Weeks Falls	Hydro-QF	12/31/2022	4.6
Hutchison Creek	Hydro-QF	9/30/2016	1.0
Cascade Clean Energy- Sygitowicz	Hydro-QF	2/21/2014	<1
Qualco Dairy	Biogas	12/11/2013	<1
Farm Power Lynden	Schedule 91 - Biogas	12/31/2019	<1
Farm Power Rexville	Schedule 91 - Biogas	12/31/2019	<1
Rainier Biogas	Schedule 91 – Biogas	12/31/2020	1.0
Vanderhaak Dairy	Schedule 91 – Biogas	12/31/2019	<1
Van Dyk	Schedule 91 – Biogas	12/31/2020	<1
Bio Energy	Schedule 91 - Biogas	12/31/2021	4.88
Edaleen Dairy	Schedule 91 – Biogas	12/31/2021	<1
Bio fuels, WA	Schedule 91 – Biogas	12/31/2021	4.5

NAME	POWER TYPE	CONTRACT EXPIRATION	CAPACITY (MW)[1]
Skookumchuck	Schedule 91 – Hydro	12/31/2020	1
Smith Creek	Schedule 91 – Hydro	12/31/2020	<1
Black Creek	Schedule 91 – Hydro	3/24/2021	4.2
Nooksack Hydro	Schedule 91 – Hydro	12/31/2021	3.5
Island Solar	Schedule 91 – Solar	12/31/2021	<1
Finn Hill Solar (Lake Wash SD)	Schedule 91 – Solar	12/31/2021	<1
Knudson Wind	Schedule 91 – Wind	12/31/2019	<1
3 Bar-G Wind	Schedule 91 – Wind	12/31/2019	1.395
Swauk Wind	Schedule 91 – Wind	12/31/2021	4.25
Total			**828**

Notes

1 Capacity reflects PSE share only.

2 The capacity of the TransAlta Centralia PPA is designed to ramp up over time to help meet PSE's resource needs. According to the contract, PSE will receive 180 MW from 12/1/2014 to 11/30/2015, 280 MW from 12/1/2015 to 11/30/2016, 380 MW from 12/1/2016 to 12/31/2024, and 300 MW from 1/1/2025 to 12/31/2025.

Existing transmission resources

Transmission capacity to the Mid-Columbia (Mid-C) market hub gives PSE access to the most liquid principal market hub in the Northwest and one of the major trading hubs in the WECC. It is the central market for northwest hydroelectric generation. As shown earlier in Figure 5-1, Mid-C transmission access to market is a significant portion of PSE's peak supply portfolio. The majority of this transmission is contracted from BPA on a long-term basis. PSE owns 450 MW of capacity to Mid-C. PSE's transmission contracts with BPA and owned capacity are shown in Figure 5-10 below.

Figure 5-10
Transmission Resources as of 12/31/12

NAME	EFFECTIVE DATE	TERMINATION DATE	TRANSMISSION DEMAND
BPA Mid-C Transmission			
Midway	11/1/2012	11/1/2017	100
Midway	10/1/2008	10/1/2013	115
Midway	3/1/2009	3/1/2014	35
Midway	4/1/2008	11/1/2035	5
Rock Island	7/1/2007	7/1/2037	400
Rocky Reach	11/1/2012	11/1/2017	100
Rocky Reach	11/1/2012	11/1/2017	100
Rocky Reach	11/1/2009	11/1/2014	40
Rocky Reach	11/1/2009	11/1/2014	40
Rocky Reach	11/1/2009	11/1/2014	40
Rocky Reach	11/1/2009	11/1/2014	5
Rocky Reach	11/1/2009	11/1/2014	55
Rocky Reach	11/1/2011	11/1/2031	160
Vantage	11/1/2012	11/1/2017	100
Vantage	12/1/2010	12/1/2014	235[1]
Vantage	11/1/2009	11/1/2014	27
Vantage	11/1/2009	11/1/2014	27
Vantage	11/1/2009	11/1/2014	27
Vantage	11/1/2009	11/1/2014	3
Vantage	11/1/2009	11/1/2014	36
Vantage	11/1/2009	11/1/2014	5
Wells	1/24/1966	8/31/2018	266
NWE Purchase IR Conversion	10/1/2011	10/1/2016	94
Spokane Municipal Waste	3/1/2011	3/1/2016	23
Total BPA Mid-C Transmission			**2038**
PSE Owned Mid-C Transmission			
McKenzie to Beverly	-	-	50
Rocky Reach to White River	-	-	400
Total PSE Mid-C Transmission	**-**	**-**	**450**
Total Mid-C Transmission			**2488**

Notes:

1. *The capacity of this contract decreases from 235 to 209 MW upon expiration of the existing contract as of 12/1/2014.*

As shown, PSE has 2,038 MW of BPA transmission capacity and owns 450 MW of capacity for a total of 2,488 MW. The capacities and contract periods for the various BPA contracts are also shown in Figure 5-11.

PSE's Mid-C peak transmission capacities are included in Figure 5-1, Electric Peak Need. The specific allocation of that capacity as of December 2014 is listed in Figure 5-11.

Figure 5-11
PSE Mid-C Transmission Capacity as of December 2014

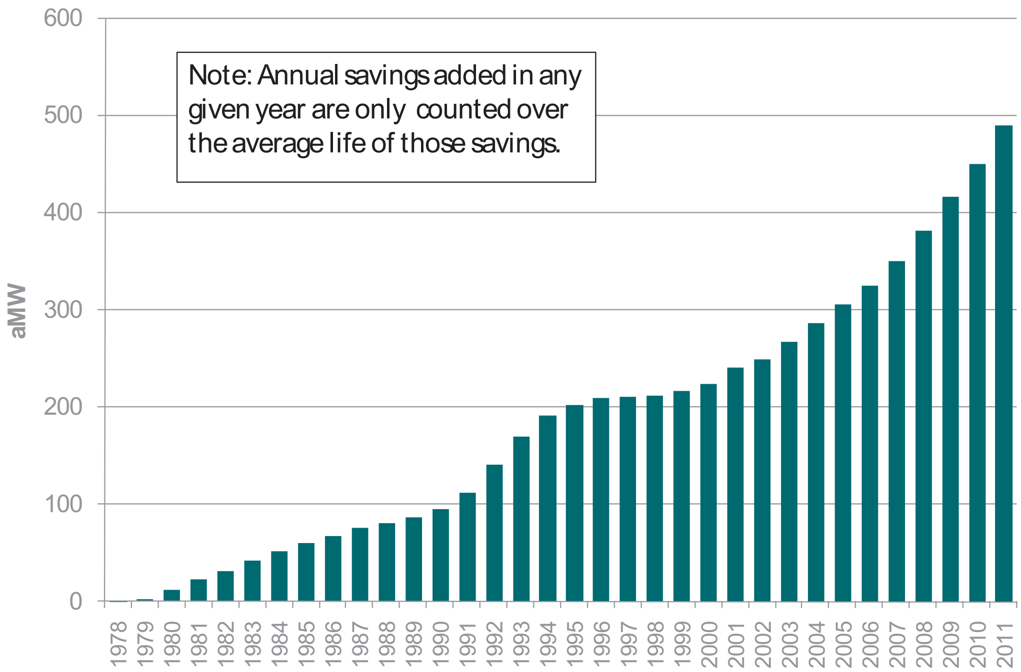
Total Mid-C Transmission	2462
Allocated to Long-term Resources & Contracts	(844)
Available for hedging and short-term market purchases	1618

As of December 2014, PSE will have 2,462 MW of Mid-C transmission. A portion of the capacity, 844 MW, is allocated to long-term contracts and existing resources such as PSE's portion of the Mid-C hydro projects. This leaves 1,618 MW of capacity available for short-term market purchases.

Existing demand-side resources

While DSR includes demand-response, fuel conversion, distributed generation, distribution efficiency, and generation efficiency, energy efficiency measures are by far the most substantial contributor to meeting resource need. During the 2010-2011 tariff period, the 72.7 aMW contributed by these programs amounted to enough energy to power approximately 55,000 homes. Since 1978, annual first-year savings (as reported at the customer meter) have increased more than 300 percent, from 9 aMW in 1978 to 39.1 aMW in 2011. The cumulative investment and savings from 1978 through 2011 are over $800 million and 490 aMW respectively. Figure 5-12 shows the cumulative savings from 1978 through 2011. This represents more than the annual output from PSE's share of Colstrip 1 & 2, and is equivalent to the electricity used by about 372,000 homes for a year. As with supply-side resources, PSE evaluates energy efficiency programs for cost-effectiveness and suitability within a lowest reasonable cost strategy.

Figure 5-12
Cumulative Electric Energy Savings from DSR, 1978 to 2011



Our energy efficiency programs serve all types of customers – residential, low-income, commercial, and industrial. Energy savings targets and the programs to achieve those targets are established every two years. The 2010-2011 biennial program period concluded at the end of 2011; current programs operate January 1, 2012 through December 31, 2013. The majority of electric energy efficiency programs are funded using electric "rider" funds collected from all customers.[6]

For the 2012-2013 period, a two-year target of approximately 76 aMW in energy savings was adopted. This goal was based on extensive analysis of savings potentials and developed in collaboration with key external stakeholders represented by the Conservation Resource Advisory Group (CRAG) and Integrated Resource Plan Advisory Group (IRPAG).

[6] *See Electric Rate Schedule 120 for more information.*

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Current electric energy efficiency programs

The two largest programs offered by PSE to customers are the Commercial and Industrial Retrofit Program and the residential Energy Efficient Lighting Programs.

The Commercial and Industrial Retrofit Program offers expert assistance and grants to help existing commercial and industrial customers use electricity and natural gas more efficiently via cost-effective and energy efficient equipment, designs, and operations. This program gave out grants totaling more than $13.6 million to over 830 business customers in 2012 to achieve a savings of over 70,000 MWh.

The Energy Efficient Lighting Programs offer instant rebates for residential customers and builders who purchase Energy Star fixtures and compact fluorescent light bulbs. This program provided incentives totaling more than $6 million, which resulted in the installation of over 3.5 million CFL lamps and fixtures in 2011 to achieve savings of over 86,000 MWh.

Figure 5-13
Annual Energy Efficiency Program Summary, 2010-2013
(Dollars in millions, except MWh)

Program	2010 - 20011 Actual	'10-'11 2-Year Budget./Goal	'10/'11 Actual vs. Budget % Total	2012 Actual	'12-'13 2-Year Budget./Goal	'12 Actual vs. '12-13 % Total
Electric Program Costs	$ 153	$ 167	92.0%	$ 92	$ 193	48%
Megawatt Hour Savings	636,000	622,000	102%	339,500	666,000	51%

Figure 5-13 shows program performance compared to two-year budget and savings goals for the biennial 2010-2011 electric energy efficiency programs, and records 2012 progress against 2012-2013 budget and savings goals.

During 2010-2011, electric energy efficiency programs saved a total of 77 aMW of electricity at a cost of $153 million. The company surpassed two-year savings goals while operating at a cost that was under budget. In 2012, these programs saved 39 aMW of electricity at a cost of $92 million. The average cost for acquiring energy efficiency in 2010-2011 was approximately $240 per MWh, compared to a budgeted cost of approximately $290 per MWh in the 2012-2013 program cycle.

Distribution efficiency

This energy efficiency measure consists of conservation voltage reduction (CVR) accompanied by load phase balancing. In 2012, PSE began preparing to implement distribution efficiency on three substations. Load flow modeling tools were set up, and field inspections of equipment were conducted. Also, we updated the energy savings expected from DE measures using system data and a Northwest Energy Efficiency Alliance study. The final step requires improving the measurement and verification capabilities of residential metering infrastructure, and we developed company policies and procedures for that equipment installation. Implementation at the three initial substations is scheduled for 2013, and the 20-year rollout of distribution efficiency measures is captured in DE bundle used in the IRP analysis.

Generation efficiency

PSE assessed potential energy conservation measures at its owned and operated generation facilities within Washington state to identify opportunities to increase energy efficiency. Measures identified included lighting, compressor, cooling tower, pump, and motor upgrades. PSE has focused first on implementing the lighting upgrades; so far full or partial upgrades have been implemented at nine generation facilities. The table below summarizes the potential savings from these upgrades based on the original assessment. None of these savings have been claimed toward PSE's conservation targets yet, as these projects still require documentation and verification to meet the standard required of claimed savings.

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Figure 5-14
Energy Savings from Completed Generation Facility Efficiency Upgrades

Generation Facility	Measure	Annual Energy Savings	
Upper Baker	Lighting Upgrade	24,601	kWh
Lower Baker	Lighting Upgrade	59,300	kWh
Encogen	Lighting Upgrade	37,692	kWh
	VFD Air Compressor	127,000	kWh
Fredrickson	Lighting Upgrade	15,000	kWh
Fredonia	Lighting Upgrade	9,800	kWh
Mint Farm	Lighting Upgrade	54,000	kWh
Goldendale	Lighting Upgrade	25,600	kWh
Sumas	Lighting Upgrade	30,000	kWh
Whitehorn	Lighting Upgrade	15,000	kWh
Total		**397,993**	**kWh**
		0.045	**aMW**

3. Resource Alternatives

In addition to supply- and demand-side resource alternatives, this IRP also models transmission combined with short-term market power purchases as a resource in order to test if current conditions make it economical.

This IRP also considered how locating gas-fired resources east or west of the Cascades affected their performance in the portfolio. The analysis is preliminary in nature and discussed in the Results and Key Findings section of this chapter. It sheds light on the trade-offs that need to be considered, but the results were too close to produce a definitive answer. This resource plan assumes all new thermal resources are located on the west side of the mountains.

More detail on supply-side resource alternatives is included in Appendix D-Electric Resources. Demand-side resource alternatives are discussed at length in Appendix N.

Power Purchase Agreements (PPAs)

PPAs are contracts of varying lengths for purchasing electricity in the market. The IRP did not evaluate PPAs as a resource alternative because costs and commitment terms are market-driven and known only at the time of the offer, so they are not possible to model over a 20-year period. However, when actual acquisitions are made and terms and conditions *can* be known, they will certainly be considered and evaluated as alternatives.

Supply-side resource alternatives

Thermal resource alternatives

Coal. The coal resources that are part of PSE's existing portfolio provide a low-cost, stable fuel source and resource diversity. New coal resources were not modeled because of the emissions restrictions set forth in Washington state law RCW 80.80. This IRP considers the effect that current and proposed rules and regulations may have on the operation of the company's existing coal resource, the Colstrip generating plant located in Montana. Four environmental compliance cost cases were developed to test the economic viability of this resource under a variety of possible regulatory scenarios.[7]

Natural gas. Additional long-term coal-fired generation is not a resource alternative, because RCW 80.80 precludes utilities in Washington from entering into new long-term agreements for coal. New large-scale hydro projects are not practical to develop today. Therefore, natural gas generation is extensively modeled in this IRP analysis due to the following characteristics.

- Proximity. Gas-fired generators can often be located within or adjacent to PSE's service area, thereby avoiding costly transmission investments required for long-distance resources like coal or wind.
- Timeliness. Gas-fired resources are dispatchable, meaning they can be turned on when needed to meet loads, unlike "intermittent" resources that generate power sporadically such as wind and run-of-the-river hydropower.
- Versatility. Gas-fired generators have varying degrees of ability to ramp up and down quickly in response to variations in load and/or wind generation.
- Environmental burden. Natural gas resources produce significantly lower emissions than coal resources (approximately half the CO_2).

Gas storage and fuel supply become increasingly important considerations as reliance on natural gas grows, so the analysis includes gas storage for some of the resources included. Three types of gas-fired generators are modeled in this analysis, because each brings particular strengths into the overall portfolio (for details, see Chapter 4, Key Assumptions).

[7] *For a complete description of these cases, see Appendix J, Colstrip.*

Combined-cycle combustion turbines (CCCTs). In CCCTs, the heat that a simple-cycle combustion turbine produces when it generates power is captured and used to create additional energy. This makes it a more efficient means of generating power than simple-cycle turbines. CCCT plants currently entering service can convert about 50 percent of the chemical energy of natural gas into electricity. Because of their high thermal efficiency and reliability, relatively low initial cost, and low emissions, CCCTs have been the resource of choice for power generation for well over a decade. This analysis assumes a certain amount of gas storage is available to the CCCT plants modeled.

Simple-cycle combustion turbines (peaker). Simple-cycle combustion turbines are better at serving peak need than CCCTs because they can be brought online more quickly. They also have lower capital costs. However, simple-cycles are less efficient and have higher heat rates, which make them more expensive to run. This analysis models peakers with and without oil back-up. The peakers modeled without oil back-up were required to have firm gas supplies and storage to ensure they would be able to run when needed.

"Peaker" is a term used to describe generators that can ramp up and down quickly in order to meet spikes in need.

Reciprocating engines (peaker). Like simple-cycle combustion turbines, these can be brought online quickly to serve peak loads. Unlike gas turbines, reciprocating engines demonstrate consistent heat rate and output during all temperature conditions. Generally these units are small and constructed in power blocks with multiple units. Reciprocating engines are more efficient than simple-cycle combustion turbines, but have a higher capital cost. Their small size allows a better match with peak loads thus increasing operating flexibility relative to simple-cycle combustion turbines.

Thermal resources not modeled: nuclear. Development and construction costs for nuclear power plants are so much higher than the next highest baseload option as to be prohibitive for all but a handful of the largest capitalized utilities. In addition, permitting, public perception, and waste disposal pose substantial risks.

Transmission resource alternatives

In this IRP, PSE modeled the renewal of transmission capacity contracts plus market power purchases. We wanted to test whether continuing this “transmission-to-market” strategy to meet peak need would result in lower portfolio costs than adding other resources. PSE currently relies on approximately 1,500 MW of transmission to acquire electric energy and capacity from the market; during the planning period, this increases to almost 1,700 MW.

PSE evaluates the renewal of Mid-C transmission similar to a resource acquisition. We compare its costs and benefits to other alternatives. Generally, Mid-C transmission is the lowest cost resource alternative. Due to the multitude of Mid-C transmission contracts and termination dates (see Figure 5-11), in any given year PSE has the option to renew a portion of Mid-C capacity and reevaluate Mid-C transmission need. Renewing these contracts for the minimum 5-year term preserves the company’s roll-over rights and allows the most flexibility for responding to future conditions. The total capacity available for renewal ranges from 664 MW in 2014 to 1,567 MW in 2033.

Renewable resource alternatives

Renewable resources modeled

Hydroelectric. Hydroelectric resources are valuable because of their ability to follow load, and because they cost less relative to other resources. Although water is a renewable resource, existing hydroelectric may not be counted toward fulfilling Washington’s RPS requirement unless it is an efficiency upgrade to an existing project; this IRP does reflect upgrades in Snoqualmie and Lower Baker that qualify under RPS rules. For new hydroelectric to qualify, it must be a low-impact, run-of-the-river project.

Wind. Wind energy is the primary renewable resource that qualifies to meet RPS requirements in our region due to wind’s technical maturity, reasonable lifecycle cost, acceptance in various regulatory jurisdictions, and large “utility” scale compared to other technologies. However, it also poses challenges. Because of its variability, wind’s daily and hourly power generation patterns don’t necessarily correlate with customer demand;

therefore, more flexible thermal and hydroelectric resources must be standing by to fill the gaps. This variability also makes it challenging to integrate into transmission systems. Finally, because wind projects are often located in remote areas, they frequently require long-haul transmission on a system that is already crowded and strained.

Renewable technologies not modeled

For this IRP, biomass, batteries, pumped storage hydro, solar, geothermal, tidal, long-haul wind, and unbundled REC contracts were not modeled. At this time, these technologies are not capable of producing power on a scale and at a cost that would make sense for PSE customers.

Biomass. PSE has tried to acquire biomass resources through the RFP process for more than 8 years, but without success.

Batteries. Based on PSE's experience with bids submitted in the 2011 RFP, utility-scale battery storage costs remain above $2,000 per kW for systems with up to four hours of discharge capacity compared to a peaker that has a capital cost of $915 per kw, making them substantially more expensive than natural gas turbines for both capacity and energy. Energy storage technologies are improving rapidly and PSE is conducting a detailed study with BPA, Pacific Northwest National Laboratories, and an emerging battery storage company to more fully assess the multiple values that storage systems may provide. The ICE (incremental capacity equivalent) for a battery (with capacity of 100 MW peak and 400 MWh energy, and charge time of 4 hours) is about 57 percent compared to a peaker (see Appendix K, Electric Analysis).

Pumped storage hydro. PSE has examined the cost effectiveness of adding pumped storage between the Mt. Baker hydroelectric project's upper and lower reservoirs in the past, but such a retrofit was too costly. Costs and commercial viability of developing new pumped storage facilities in the region are very uncertain. While PSE did not model this resource in the IRP, it is possible that commercially viable projects could be offered in future RFPs.

Solar. New utility-scale solar has not been found to be cost competitive with wind technology nor more beneficial from a capacity perspective. We completed the Wild Horse Solar Facility in 2008, a demonstration project that uses photovoltaic technology to produce electricity, and we continue to collect data from the facility to evaluate equipment, performance, and fit with our resource portfolio. The ability for solar power in the Pacific Northwest to help meet PSE's peak demand is limited by the season and timing of PSE's system peaks—we are not a summer peaking utility. PSE's system peaks in the winter. Loads pick up in the morning, mostly before the sun has risen, then loads pick up again in the afternoon, after the sun has set.

Geothermal. We continue to monitor technology developments in geothermal as well, and entertain proposals for geothermal power projects.

Tidal and wave. PSE has made financial contributions in support of two Northwest ocean energy studies.

A tidal power feasibility study led by the Electric Power Research Institute (EPRI) that assessed and demonstrated in-stream tidal technology at seven sites in the United States and Canada. One site reviewed was the Tacoma Narrows, 0.1 miles east of Pt. Evans, Washington. Environmental and biological effects were considered in addition to technological and economic factors. Tidal in-stream energy is harnessed by converting the kinetic energy of tidal flows to electricity. PSE became involved in 2004, and was considered a sponsor of this assessment. A report documenting the study is available on EPRI's web site at http://oceanenergy.epri.com/streamenergy.html#reports.

Development of an offshore 1 MW pilot project in Makah Bay, Clallam County, Washington. The plant was intended to convert kinetic wave energy to electrical energy. The FERC granted a license to this project in December 2007; however, the developer filed an application to surrender the license in February 2010.[8]

Long-haul wind. PSE modeled long-haul wind only for comparison purposes in the Colstrip replacement portfolio analysis; otherwise, long-haul wind outside the Pacific Northwest was not modeled in this IRP. Analysis in the 2009 IRP demonstrated that the added transmission cost required to bring such resources to load made them far more expensive than wind resources located in Pacific Northwest; analysis on actual resource/contract bids in the 2010 RFP process confirmed these findings. Current market fundamentals make long-haul wind difficult to consider. Power prices have fallen by more than 50 percent since the 2009 IRP, but the capital cost of wind has fallen only 25 percent; meanwhile, transmission costs rose at an annual average rate of more than 3 percent.

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[8] *For more information, search project number 12751-006 in FERC's e-library at http://elibrary.ferc.gov/IDMWS/search/fercadvsearch.asp.*

Unbundled RECs. Unbundled RECs are a form of a contract similar to PPAs. Just like other alternatives, if the acquisition process found unbundled REC contracts to be more cost effective and lower risk than self-building resources to comply with RCW 19.285, the company would pursue those alternatives. Our experience in the 2011 RFP process found very limited quantities of unbundled RECs available, but PSE will continue to consider such offers in the future.

Demand-side resource alternatives

Energy efficiency measures. This label is used for a wide variety of measures that result in a smaller amount of energy doing the same work as a larger amount of energy. Among them are codes and standards that make new construction more energy efficient, retrofitting programs, appliance upgrades, and HVAC and lighting changes.

Demand-response. Demand-response resources are comprised of flexible, price-responsive loads, which may be curtailed or interrupted during system emergencies or when wholesale market prices exceed the utility's supply cost.

Distributed generation. Distributed generation refers to small-scale electricity generators located close to the source of the customer's load.

Distribution efficiency. This involves voltage reduction and phase balancing. Voltage reduction is the practice of reducing the voltage on distribution circuits to reduce energy consumption, as many appliances and motors can perform properly while consuming less energy. Phase balancing eliminates total current flow losses that can reduce energy loss.

Generation efficiency. This involves energy efficiency improvements at the facilities that house PSE generating plant equipment. Typical measures target HVAC, lighting, plug loads, and building envelope end-uses.

4. Analytic Methodology

This section describes the quantitative analysis of electric demand- and supply-side alternatives. It explains how portfolios were created in response to a variety of key economic assumptions expressed as scenarios, and how these portfolios were evaluated for cost and risk. The resulting analysis allowed the company to quantify how sensitive portfolios were to the planning assumptions, and provided insight into how adding different types of generation would affect PSE ratepayers' costs. Among the critical questions posed were the following.

- How might economic conditions and load growth affect resource decisions?
- What is the cost-effective level of energy efficiency?
- How sensitive are the demand-side portfolios to different levels of avoided costs?
- What are the key decision points and most important uncertainties in the long-term planning horizon, and when should we make those decisions?
- What impact might very different levels of natural gas prices have on resource decisions?
- How might future carbon regulation affect the relative value of resource alternatives?
- What carbon emissions are produced by portfolios under different scenarios?
- How do cost compliance cases impact operations at Colstrip?
- How does the location of resources affect resource decisions?
- How do operational flexibility needs affect resource decisions?

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Electric analytic methodology followed the four basic steps illustrated in Figure 5-15. (For a detailed technical discussion of models and methods, see Appendix K, Electric Analysis).

Figure 5-15
Methodology Used to Create and Evaluate Portfolios

Step 1. Identify needs and resources.

1. Forecast resource needs
   Capacity, energy, and renewable needs
2. Gather assumptions and screen supply side resources
   Ensure supply side resource to be modeled are commercially available
3. Gather assumptions and screen demand side resources (DSR)
   Screen for technical and achievable potential
   Develop bundles and ramp rates

Step 2. Create optimal, integrated portfolios for each scenario.

1. Gather input data for each scenario
   Develop power prices for each scenario
   Generate dispatch of resources for each scenario
2. Evaluate portfolio costs based on inputs
   Develop lowest cost portfolio for each scenario ensuring that each portfolio:
   - Meets resource need (customer demand + operating reserves + planning margin)
   - Meets renewable resources/RECS need
   - Includes optimal DSR bundle

Step 3. Evaluate costs and risks.

1. Use input variable distributions to develop 1000 risk trials
2. Calculate cost and risk metrics using the results of the 1000 risk trials

CHAPTER 5 – ELECTRICAL ANALYSIS

Step 1: Identify needs and resources.

The analysis begins by using the most recently available forecast of customer demand. We use this information to develop resource need assumptions.
Next, all resources that are available to fill unmet need are identified.

Supply-side resources included natural gas-fired generation, wind, and biomass.

Demand-side resource selection followed the three-step process illustrated in Figure 5-15 and detailed in Figure 5-16.

- First, each demand-side measure was screened for technical potential.
- Second, market constraints are applied to estimate the achievable potential.
- Finally, the remaining measures were combined into bundles based on levelized cost for inclusion in the optimization analysis. This analysis identifies the economic potential (cost-effective level) of DSR.

Screening for technical potential assumed that all opportunities could be captured regardless of cost or market barriers, so the full spectrum of technologies, load impacts, and markets could be surveyed.

To gauge achievability, we relied on customer response to past PSE energy programs, the experience of other utilities offering similar programs, and the Northwest Power and Conservation Council's most recent energy efficiency potential assessment. For this IRP, PSE assumed achievable electric energy efficiency potentials of 85 percent in existing buildings and 65 percent in new construction.

This methodology is consistent with the methodology used by the Northwest Power and Conservation Council. A comparison of the two can be found in Appendix B.

For a more detailed discussion of demand-side resource evaluation and the development of DSR bundles, see Appendix N, Demand-side Resource Analysis.

Figure 5-16
General Methodology for Assessing Demand-side Resource Potential

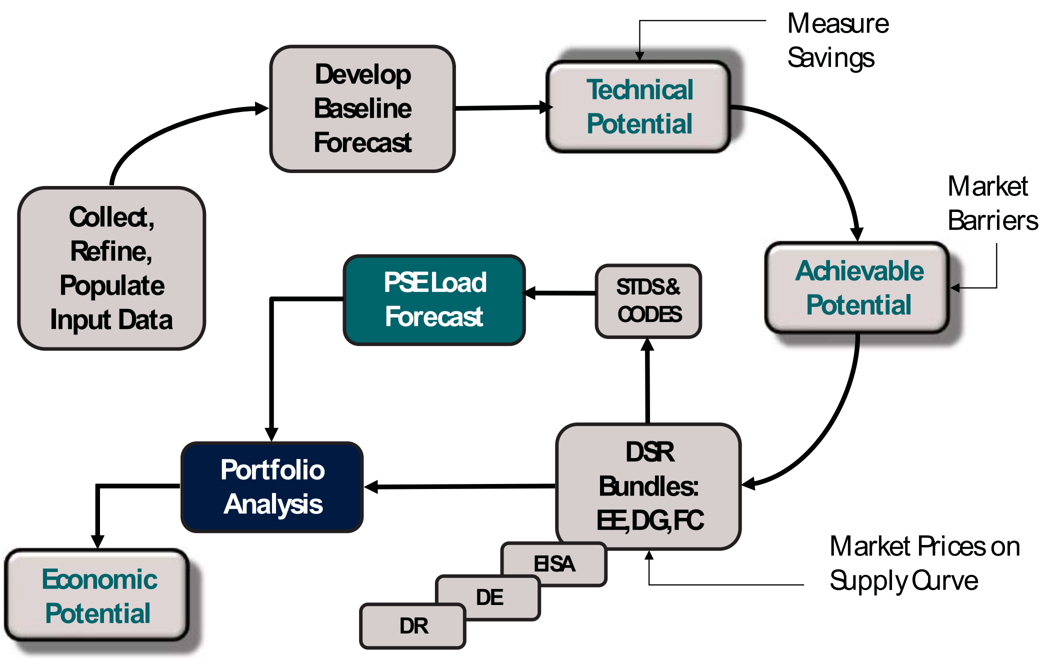

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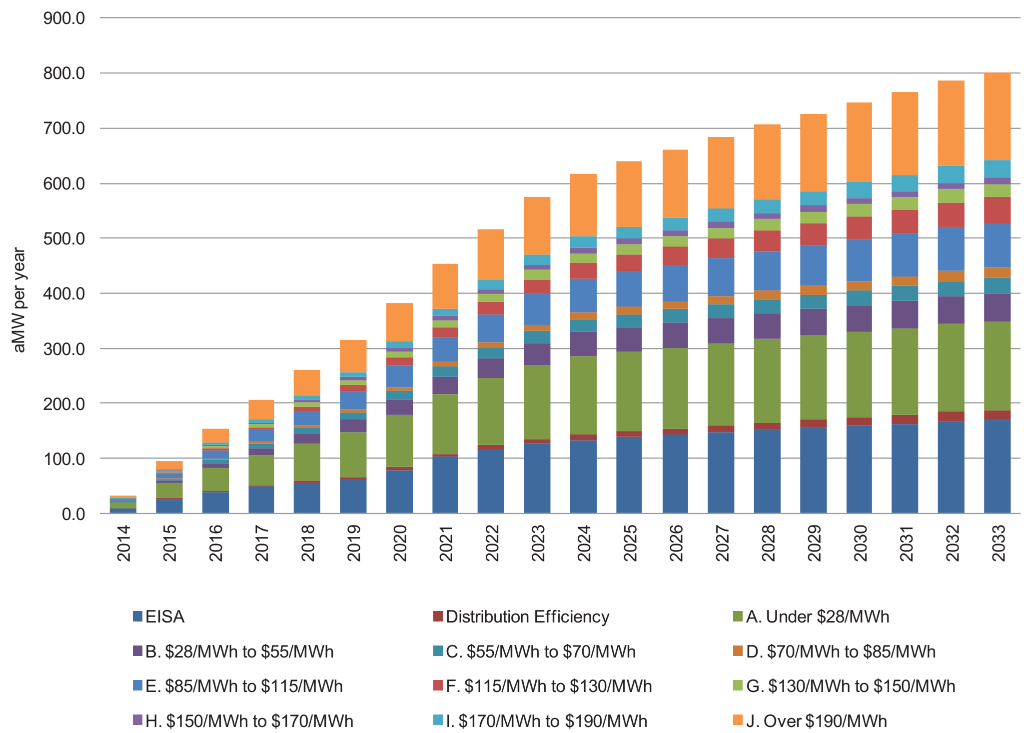
Figure 5-17 shows the achievable potential of all DSR bundles tested in the IRP. The effect of these bundles is to reduce load, so the costs of achieving the savings are added to the cost of the electric portfolios.

Figure 5-17
Achievable Technical Potential by Demand-side Cost Bundles (aMW)



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The achievable potential from generation efficiency (energy efficiency at PSE generating facilities) was not included in the above bundles since the total value of these savings is relatively small (3.1 aMW) and development of the measure costs was still under way. Figure 5-18 shows the measures identified by facility. Once this is completed, the measures will be incorporated in the supply curve of the bundles to be tested in the next IRP.

Figure 5-18
Achievable Technical Potential by Generation Facility

Generation Facility	Measure	Annual Energy Savings	
Upper Baker	Pumping Station Motors	45,000	kWh
	Pumping Station Transformers	51,000	kWh
	Pumping Station Controls	150,000	kWh
Electron[1]	Lighting Upgrade	20,061	kWh
Mint Farm	Supply Gas Pressure Increase	19,000,000	kWh
	Air Compressor Upgrade	77,709	kWh
	Exterior Sensors	6,900	kWh
	Cooling Tower	2,500,000	kWh
	Feedwater Pump	2,349,900	kWh
Goldendale	Cooling Tower	2,520,000	kWh
	Compressed Air	35,000	kWh
Sumas	Compressed Air	70,000	kWh
Tenaska	VFD Air Compressor	276,890	kWh
Total		**27,102,460**	**kWh**
		3.1	**aMW**

Note:

1. At present PSE is investigating the sale of this facility. Given that a sale has not been finalized, its potential is still included.

Distribution efficiency consists of two primary measures: phase balancing and conservation voltage reduction (CVR).

Step 2: Create optimal, integrated portfolios for each scenario.

An optimal, integrated portfolio for each scenario and sensitivity was created using the portfolio optimization model PSM III to combine supply-side resources with the demand-side bundles. The optimization model used the inputs provided to identify the lowest cost portfolio that:

- Meets capacity need
- Meets renewable resources/RECS need
- Includes as much conservation as is cost effective

PSE models lowest cost from the customer perspective, so it is measured as the lowest net present value (NPV) revenue requirement of a portfolio. To arrive at this calculation the company aligns three analytical efforts:

- An economic dispatch model that can provide a reasonable forecast of variable costs and wholesale market revenue from operating plants, given market assumptions. For this process, PSE uses Aurora.
- A revenue requirement model, to incorporate the costs of capital investments and other fixed costs the way customers will experience them in rates; the IRP uses the same financial model the general rate case uses for calculating revenue requirements.
- An optimization model, to develop and test different portfolios to find the lowest cost combination of resources; PSM III uses an LP (linear programming)/Quadratic optimization model.

Step 3: Evaluate costs and risks.

Once the optimal portfolio for each of the deterministic scenarios was identified, PSE conducted risk analysis on select portfolios. The PSM III process used to calculate risk measures for each portfolio is briefly discussed below.

A Stochastic model was used to create 250 draws of stochastic input variables for the Base Scenario, first without explicitly modeling CO_2 risks and then including the range of CO_2 policy risks described in Chapter 4, Key Assumptions. Two scenarios internalize societal costs. For a full analysis of the risks associated with potential CO_2 policies, see Appendix K, Electric Analysis.

Each set of input draws imply a set of resource outputs, costs and revenues obtained from the economic dispatch and unit commitment capabilities of Aurora. These Aurora outputs are then fed into PSM III and used in the simulation tool of Risk Solver Platform to draw 1,000 trials of revenue requirements for any given portfolio. These trials allowed us to fully understand the risks in portfolio costs or revenue requirements associated with differing gas prices, power prices, load variations, hydropower, and wind generation levels. Risk metrics such as Tail Var 90 and volatility were also calculated for each of the tested portfolios first without any CO_2 policy risk, and then with the risk of a CO_2 policy being implemented in the future. (A full discussion of PSE's stochastic modeling approach appears in the "Stochastic Model" section of Appendix K, Electric Analysis).

5. Results and Key Findings

The quantitative results produced by this extensive analytical and statistical evaluation led to several key findings that guided the long-term resource strategy presented in this IRP. These are summarized below and discussed in more detail in the following pages

1. **Least-Cost portfolio builds are similar across most scenarios.**
2. **Colstrip reduces cost and market risk in most scenarios.**
3. **Peakers are lower cost than CCCT plants.**
4. **The location of resources (east vs. west of the Cascades) involves trade-offs.**
5. **RPS requirements drive renewable builds.**
6. **Emissions results vary across portfolios.**
7. **DSR reduces cost and market risk.**
8. **Transmission renewals look cost effective, but questions remain.**

1. Portfolio builds are similar across most scenarios.

Resource alternatives are so limited that the portfolio builds for all scenarios look very similar. For all but one scenario in Figure 5-19, transmission renewals, nearly the same conservation, gas-fired peaking plants, and wind to meet the RPS would be the least cost set of resource additions. Small variations occur due to load variations from the high/low load forecasts, but the similarities are striking.

Base + Very High CO_2 is the only exception. In this scenario, very high CO_2 and market power costs create a situation where wind power is cheaper than market power. Left unconstrained, Base + Very High CO_2 would have include an unlimited amount of wind. Because it is unrealistic for a load-serving utility to take such a speculative position, we constrained the amount of wind allowed to be developed in this scenario to 800 MW. The lesson learned from this planning exercise is clear: if wind becomes cheaper than market, PSE will have to develop a reasoned basis to limit the amount it builds, like the "B2 Energy Standard" developed in the 2003 resource plan.

Figure 5-19
Relative Optimal Portfolio Builds and Costs by Scenario by 2033
Energy in total MW, dollars in billions, Colstrip Case 2

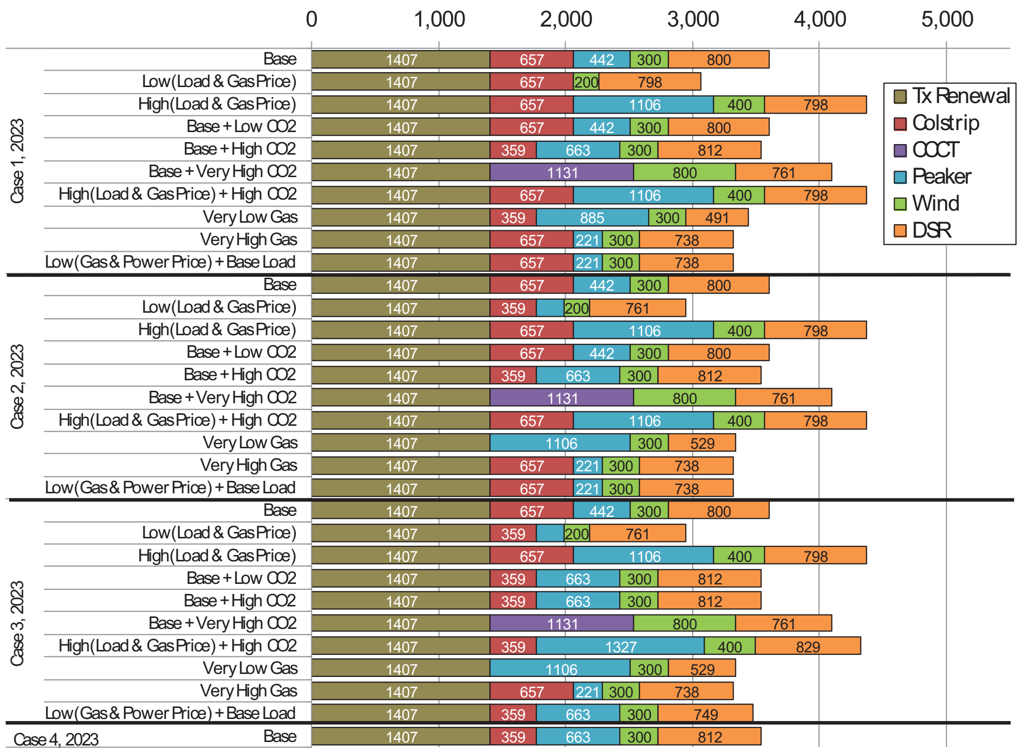
	Cost	DSR	Wind	CCCT	Peaker	Tx Renewal	Colstrip
Base	**$13.93**	1,007	600	0	2,212	1567	657
Low	**$10.52**	957	400	0	1,769	1567	359
High	**$18.02**	1,004	700	0	3,096	1567	657
Base + Low CO2	**$15.10**	1,007	600	0	2,212	1567	657
Base + High CO2	**$17.63**	1,021	600	0	2,433	1567	359
Base + Very High CO2	**$22.60**	957	800	2,640	221	1567	0
High + High CO2	**$22.13**	1,004	700	0	3,096	1567	657
Very Low Gas	**$11.52**	706	600	0	3,096	1567	0
Very High Gas	**$16.32**	1,007	600	0	2,212	1567	657
Low + Base Load	**$11.97**	1,007	600	0	2,212	1567	657

Summary of least-cost portfolio analysis

Figure 5-20 displays the MW additions for the optimal portfolios for all Colstrip cases in all scenarios by 2023. See Appendix K, Electric Analysis, for more detailed information. Note that with the exception of Base + Very High $CO_{2,}$ the portfolios look very similar.

Note: Three of the four Colstrip environmental compliance cost cases were run in every IRP scenario. To make the presentation of results less cumbersome, we chose to display Colstrip Compliance Case 2, the Mid-cost Case, in this summary section. Results for all four cases are discussed in the next section of this chapter. Complete results for the Colstrip analyses are available in Appendix K, Electric Analysis.

Figure 5-20
Resource Builds by Scenario
Cumulative additions by nameplate (MW)



Range of expected portfolio costs

Figure 5-21 shows the 20-year net present value costs for each of the portfolios.

Figure 5-21
Net Present Value Expected Portfolio Cost

Scenarios	Expected Portfolio Cost (Incremental Rev Req $Billions)			
	Case 1	Case 2	Case 3	Case 4
Base	$13.78	$13.93	$14.47	$15.12
Low	$10.38	$10.52	$10.76	
High	$17.87	$18.02	$18.56	
Base + Low CO2	$14.95	$15.10	$15.60	
Base + High CO2	$17.55	$17.63	$17.74	
Base + Very High CO2	$22.60	$22.60	$22.60	
High + High CO2	$21.98	$22.13	$22.43	
Very Low Gas	$11.45	$11.52	$11.52	
Very High Gas	$16.18	$16.32	$16.86	
Low + Base Load	$11.83	$11.97	$12.27	

The NPV of the costs shown in Figure 5-21, above, represents the expected value of the least cost portfolios identified in Figure 5-20 based on the deterministic scenario assumptions.

2. Colstrip reduces cost and market risk in most scenarios.

Overview of Colstrip analysis

To test Colstrip's economic performance under a wide range of potential environmental regulations, PSE developed four Colstrip environmental compliance cost cases. The continuing operations at Colstrip Units 1 & 2 are analyzed separately from operations at Units 3 & 4 because the older units are subject to slightly different requirements than the newer units. Below are brief descriptions of the four compliance cases. They are described in detail in Appendix J, Colstrip.

Four Colstrip environmental compliance cost cases

Case 1 – Low Cost Estimated additional costs are based on achieving compliance using existing, installed equipment with a minimum of modifications or additions to meet the MATS Rule and the BART requirements of EPA's Regional Haze FIP. This case and Case 2 assume that coal combustion residuals continue to be classified as non-hazardous.	***Case 2 – Mid Cost*** This case includes all the costs from Case 1, plus costs for adding additional equipment that may be needed to assure compliance. It is largely based on EPA estimates for equipment intended to bring Units 1 & 2 into compliance with the BART requirements of EPA's Regional Haze FIP.
Case 3 – High Cost Case 3 assumes the Case 2 costs, plus additional costs for equipment needed to meet potential new requirements. It reflects a scenario in which (1) coal combustion residuals are defined as hazardous waste and therefore are more costly to dispose of, and (2) the Reasonable Progress requirements of the Regional Haze program require the addition of Selective Catalytic Reduction (SCR) technology on all units by 2027.	***Case 4 – Very High Cost*** Case 4 assumes all Case 2 costs, plus it accelerates the effective date for installation of SCR technology to 2022. It also increases the estimated cost of SCR technology on Units 1 & 2, and it triples the cost of hazardous waste disposal for CCR included in Case 3. Case 4 was examined only in the Base scenario, as it was developed late in the IRP process.

Cost assumptions

Each case incorporated the basic investment costs of maintaining safe and efficient plant operations (though such costs cannot be publicly disclosed), plus the cost of complying with the specific set of requirements. Coal costs were assumed to increase at the rate of inflation.

The analysis included the impact on transmission costs should Colstrip be retired. Three transmission segments would be affected.

- Garrison, Mont. to PSE on BPA transmission. This segment operates under 5-year contracts. The cost of this transmission ($13.3 million per year for all four units) was treated as an incremental cost of continuing to operate Colstrip, and was included as a cost starting in 2017.
- Townsend, Mont. to Garrison, Mont., on the BPA system. This contract expires in 2027 at approximately $3.8 million. Until 2027 it is treated as a sunk cost, after that it is treated as a continuing operations cost.
- Colstrip to Townsend, Mont. This segment is jointly owned by Colstrip owners and was treated as a sunk cost.[9]

Two categories of costs were not included in the Colstrip analysis: recovery of undepreciated costs and remediation costs. Both would increase costs to customers beyond those reflected in this analysis. In this IRP, undepreciated costs were assumed to be recovered over the current depreciation period (to 2036 for Units 1 & 2 and to 2046 for Units 3 & 4), which means they did not impact the results of the analysis. However, should Colstrip retire early, recovery would probably proceed on an accelerated schedule, and compressing the time period for recovery would increase costs to customers. Undepreciated costs are recovered through the ratemaking process, and the Commission is ultimately responsible for determining the schedule. Potential remediation costs are not included in the analysis either, because conditions that may be imposed by the state of Montana have not yet been defined. If remediation costs are significant, retiring Colstrip early would increase costs to customers on a net present value basis by incurring these costs earlier.

[9] *Note, the costs shown for transmission are in 2013 dollars. The analysis escalates those costs at an annual inflation rate of 2.5% per year.*

How the portfolio analysis was performed

To learn how the cost effectiveness of Colstrip faired under the different cases, each was analyzed under a broad range of economic and market conditions. Three of the four cases were analyzed in each of the ten market scenarios, the fourth was analyzed in the Base Scenario only. In total, 31 separate scenario/case combinations were analyzed.

Using Case 2 as an example is helpful. PSE analyzed Colstrip Units 1 & 2 under Case 2 as if it were a new resource alternative; that is, given the costs of the Colstrip units and the cost of alternative resources, would Colstrip be part of the least-cost portfolio under a variety of different gas price/carbon cost scenarios? Incremental Colstrip costs included:

- projected capital investments to keep the plant operating safely and efficiently, plus
- additional capital costs of $69.7 million
- additional fixed O&M costs of $1.6 million per year
- an additional variable cost of $1.6 per MWh to comply with Regional Haze Rule, explained in Appendix J
- half the of the transmission costs mentioned above.

The same process was applied to Colstrip Units 3 & 4.

Colstrip Units 1 & 2 and Units 3 & 4 were treated like every other supply-side resource in the portfolio analysis. In each scenario, the portfolio optimization analysis was used to identify the least-cost combination of demand-side and supply-side resources in each of 10 different scenarios. All four Colstrip Units were part of the least-cost mix in the Base Scenario, but Colstrip Units 1 & 2 under Case 2 were not part of the least-cost portfolio in the Base + High CO_2 case.

We also performed a “replacement power” portfolio analysis that took Colstrip out of PSE’s portfolio across the scenarios so we could compare the cost of continuing to operate Colstrip under the different cases with the cost of replacing Colstrip. This provided the basis for comparing the cost of replacing Colstrip with the cost of continuing to operate the plant.

Timing assumptions

Addressing the timing of a potential Colstrip retirement involves a complex set of questions and analyses. This is PSE's first comprehensive analysis of Colstrip in an IRP filing. Given the complexity of developing input assumptions and the need to develop new analytical frameworks, and considering the IRP is not a Colstrip-specific study, it was necessary to simplify the issue of timing for this analysis. This IRP focuses on 2017 as the single time to hypothetically decide the future of Colstrip.

2017 was chosen because it was the "deadline" by which new investments to comply with the Regional Haze Rule would need to be in place. This rule has the greatest impact on Units 1 & 2, and it is the focus of Cases 1 and 2. As a first-time analysis, it seemed reasonable to focus on whether these early investments would be cost effective. This date is also early enough in the planning horizon that it allows for a fuller examine of cost impacts.

PSE proposed a 2025 date early in the IRP process. However, stakeholders suggested looking at an earlier date, so that the analysis would better capture the question of whether or not to make the Case 1 or Case 2 investments (rather than using a later date that assumed those investments would be made). PSE agreed and moved the date to 2017.

Reflecting more complicated timing scenarios, such as exploring an optimal retirement date, or modeling alternative dates to support different kinds of negotiated conditions was also considered. However, as a compliance filing, the IRP must examine a wide range important issues. The analysis in this IRP provides very useful information on the specific kinds of policy and market factors that could impact the future economic viability of Colstrip and provides a reasonable range of estimates on the annual savings to customers and rate impacts if Colstrip was replaced, but it does not achieve the level of detail of a resource-specific investment decision.

Timing and ownership structure

Two qualitative factors are important to keep in mind with regard to Colstrip. The first relates to timing. Colstrip already complies with many of the impending EPA regulations that put other U.S. coal plants at risk, so major, multi-year payback investment decisions will not need to be made until approximately 2016. These will specifically involve compliance with EPA regional haze requirements. The second factor is the plant's ownership structure. Units 1 & 2 are owned equally by PSE and PPL; Units 3 & 4 are shared by five owners. Multiple ownership makes decisions to modify operations more complex than if the facility were controlled by a single entity.

Colstrip analysis results

Continuing the operation of Colstrip lowered the cost and market risk of the portfolio. Figure 5-22 shows the cumulative resource additions for all four cases under the various scenarios by 2033. Detailed descriptions of the cases can be found in Appendix J, Colstrip. Complete results for all four cases are available in Appendix K, Electric Analysis.

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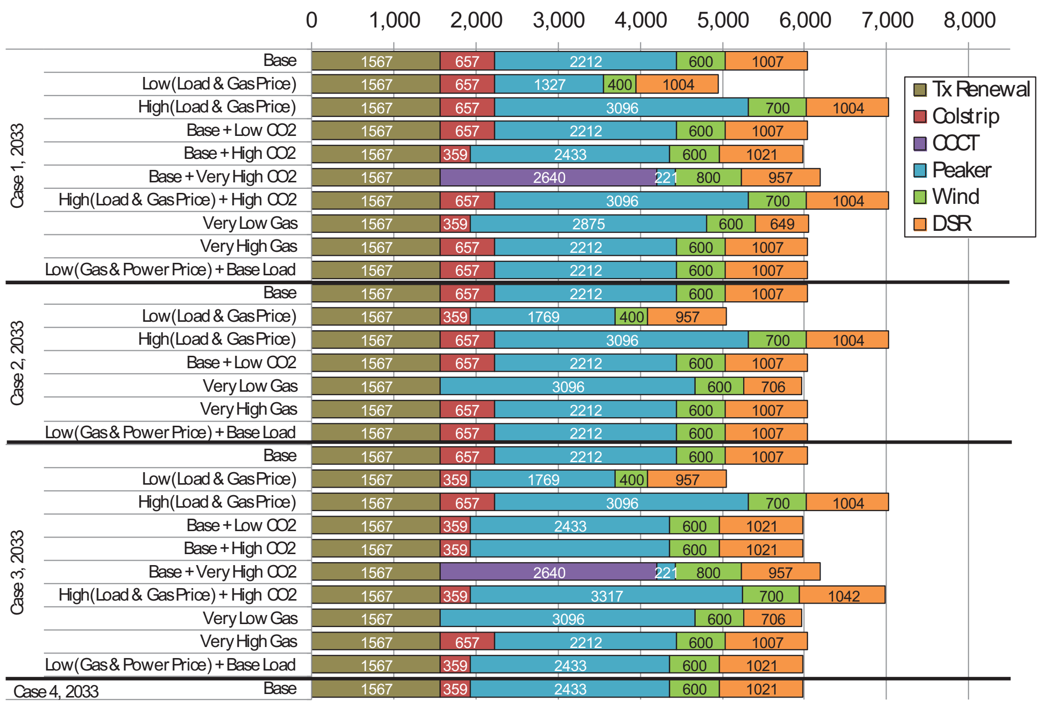
Figure 5-22
Resource builds by Scenario and Colstrip Compliance Cases
Cumulative additions by 2033 in MW



Under Case 1 conditions, all four Colstrip units continue to run in seven of the ten scenarios. Units 3 & 4 continue to run in two of the remaining three scenarios. Only one scenario replaces all four units. In this scenario, Base + Very High CO_2, CO_2 prices are so high that the plant does not even dispatch.

Under Case 2 conditions, all four Colstrip units continue to be economic for customers in six of the ten scenarios. Units 3 & 4 continue to run in two of the remaining four scenarios. Again, the Base + Very High CO_2 scenario replaces all four units with alternative resources; in this scenario CO_2 prices are so high that the plant does not even dispatch, and in the Very Low Gas Scenario, all 4 units are replaced since gas prices are so low.

Under Case 3 conditions, in which coal combustion residuals must be disposed of off-site as hazardous waste, all four units continue to run in three of the ten scenarios. Units 3 & 4 continue to run in five of the remaining seven scenarios. Again, only in the Base + Very High CO_2 and Very Low Gas scenarios are all four units replaced.

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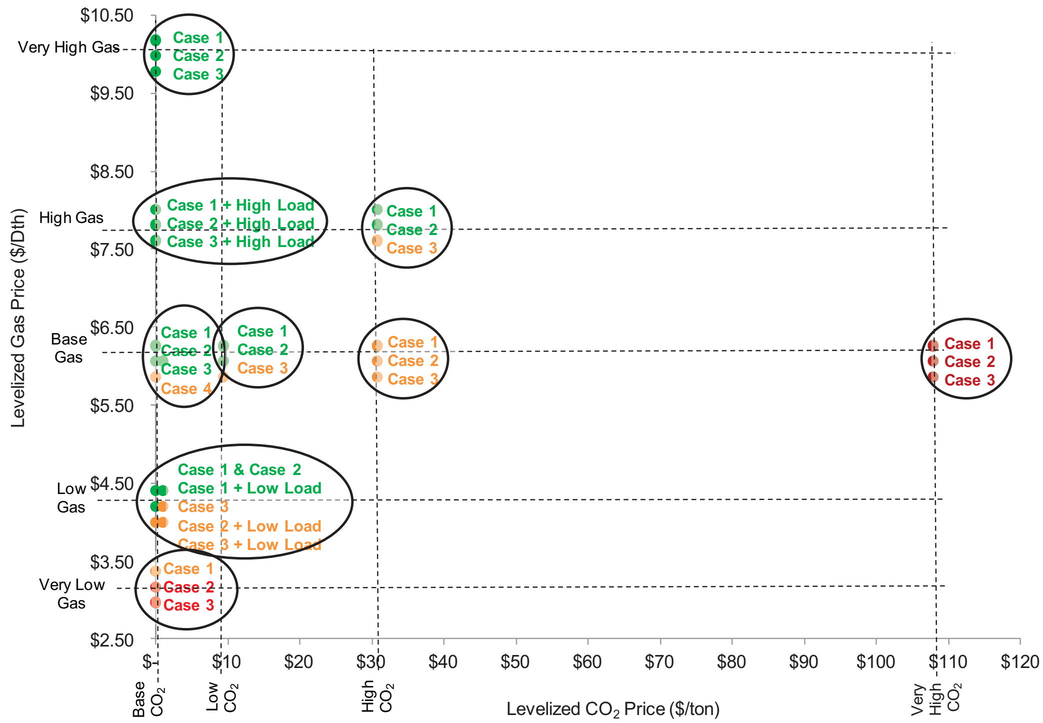
Under Case 4, in which the cost for off-site hazardous waste disposal of coal combustion residuals triples and other requirements are accelerated, Units 3 & 4 continued to run in the Base Scenario.

Three factors had the most influence on Colstrip's cost-effectiveness as a portfolio resource: sustained low gas prices, high CO_2 costs, and the potential for offsite disposal of coal combustion residuals as hazardous waste. Figure 5-23 shows how gas price and CO_2 price interact around the plant's cost effectiveness.

Figure 5-23
Gas Price and CO_2 Price interaction for Colstrip cost-effectiveness



Legend
Green indicates where all four units are cost effective.
Orange indicates where only Colstrip 3&4 are cost effective.
Red indicates scenarios where replacement power was more cost effective.

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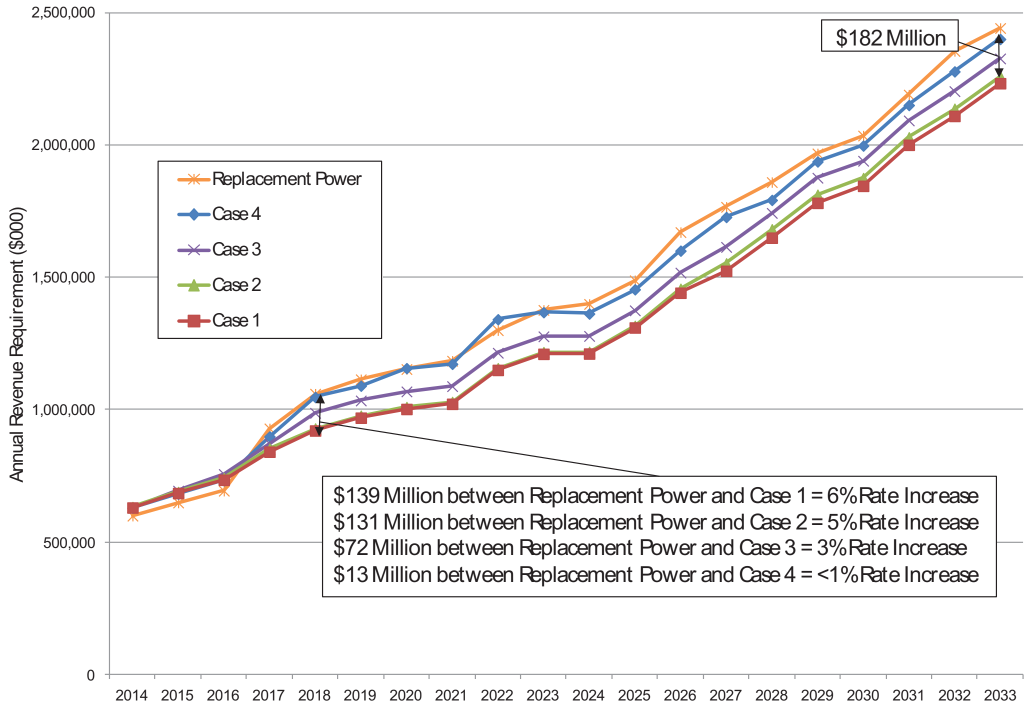
Figure 5-24 compares the four Colstrip compliance cases with the cost of replacing Colstrip power under the Base Scenario. While PSE's analysis minimizes long-run NPV of revenue requirements (20+ years including end-effects) presenting annual results can be helpful to illustrate how customers will experience those long-term costs in rates. When creating the replacement power portfolio, the option to replace Colstrip with a combination of peakers and market purchases or CCCT plants is analyzed for the lowest portfolio cost. In this portfolio, the option to replace Colstrip with peakers for capacity and market purchases for energy was lower cost than a CCCT. The results indicate that continuing operations at Colstrip would save customers $131 million per year in 2018, increasing to $182 million a year in 2033. The revenue requirement of replacement power is slightly lower than continuing Colstrip operation before 2017, because if Colstrip is replaced, it does not make sense to invest in maintaining the plant before that.

NOTE: The assumption that coal combustion residuals will need to be disposed of off-site as hazardous waste is a significant cost driver for Cases 3 and 4; however, depending on how potential regulations develop in the future, Colstrip may be able to store CCR waste on-site, given the quality of its current containment methods. If so, compliance costs for both cases would be substantially lower.

Figure 5-24
Annual Cost for continued operations of Colstrip and Replacement Power



Given the costs considered in this IRP, replacement power is expected to have higher annual revenue requirements than Colstrip; the higher revenue requirements are estimated to increase average rates by about 1 percent to 6 percent in 2018, depending on the environmental case. The analysis assumes Colstrip is replaced in 2017 in the replacement power scenario.

Figure 5-25 below compares the cost savings from Base Scenario Case 2 compliance costs with replacement power. In this view, the $131 million in the chart above is expressed as cost savings between continuing operations of all 4 units under Case 2 and replacing all 4 units in PSE’s portfolio.

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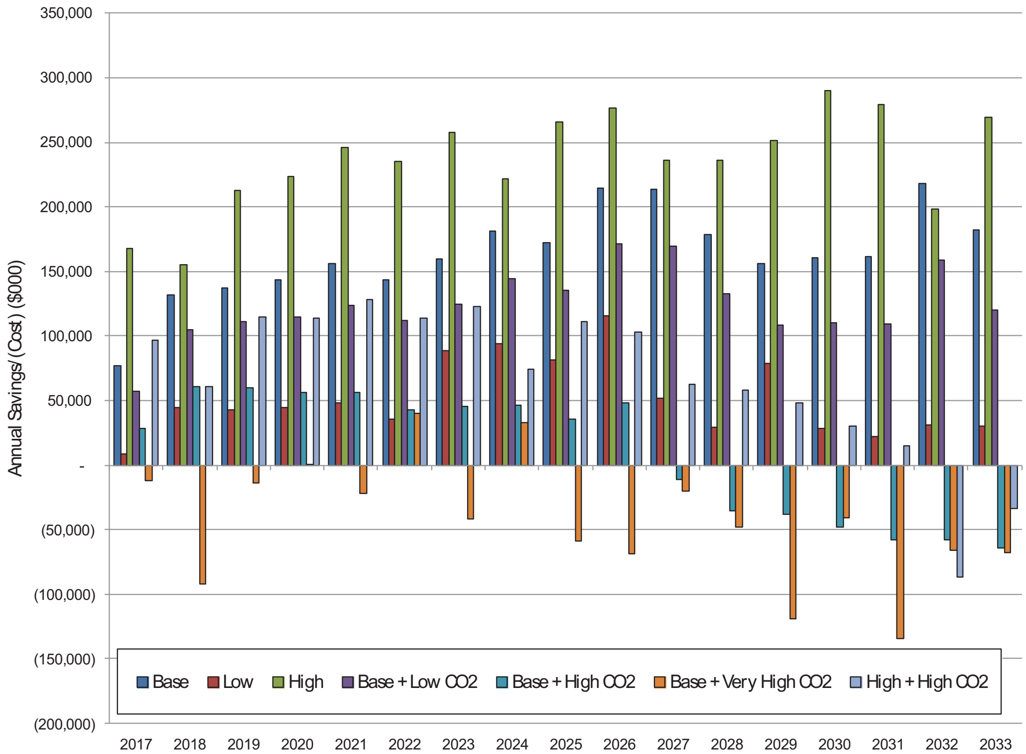
Figure 5-25
Annual Savings/(Cost) of Continuing Operations of Colstrip for Compliance Case 2 under All Scenarios



Potential rate impacts of replacing Colstrip may provide a useful context. The most direct way to estimate this is to compare the annual savings shown in Figure 5-25, with the annual electric retail revenue requirement from PSE's last approved general rate case (Docket UE-111048). That revenue requirement was $2,039,909,367. Dollars shown in Figure 5-25 are nominal, so they should be adjusted to 2012 dollars. Performing this calculation for the Base Scenario in Case 2 for 2018 shows an estimated rate impact of approximately 5 percent. Data for all scenarios is presented in Appendix K, Electric Analysis. Note the annual revenue requirement impacts are only a subset of the long-term net present value calculation. For Colstrip, a comparison of annual revenue requirements is useful, as it approximates how the costs would be experienced by customers.

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This estimate potentially **understates** the rate impacts of replacing Colstrip for two reasons:

- Potential changes in depreciation of existing Colstrip ratebase are not reflected. If Colstrip were replaced in 2017 as this analysis assumed, it would most likely result in an increase in rates to recover the return of and on that outstanding balance. The current net book value of the plant is more than $300 million. The analysis does not reflect this potential impact because the specific depreciation terms would be determined by the Commission and an unknown ending value of the plant.

- Potential impacts of remediation costs are not reflected. Replacing Colstrip in 2017 would bring any potential remediation costs closer to the present. This would impact long-term NPV, but also rates. These costs were not included for two reasons. First, the State of Montana has not yet specified what remediation activities will be required. Not knowing what will be required, it is not possible to develop reasonable cost estimates. Second, these could be fixed but highly unknown costs, rather than a function of how long the plant operates into the future, though some aspects would actually be slightly declining over time as water in exsiting holding ponds continues to be removed. Reflecting these costs and moving them closer to the present would make continued operation of Colstrip appear more cost effective. That is, retiring Colstrip earlier would mean those remediation costs would increase customers' rates sooner.

Figure 5-26 below shows results of the net cost per kW market risk analysis. Net cost per kW reflects the market value of the energy produced less the variable cost of generation, netted against the capital costs as the NPV of revenue requirements; basically it reflects Fixed Costs – Price per MWh + Variable Cost per MWh + End Effects. On a plant-by-plant basis, a comparison of the net cost per KW can be made to determine the relative contribution of each plant to revenue requirements. Figure 5-26 demonstrates that Colstrip provides revenue for the portfolio instead of cost in 2 of the 7 scenarios. This lowers the overall portfolio revenue requirement.

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Figure 5-26
Net Cost Comparison

	Peaker w/ Oil		Colstrip Case 2		CCCT	
	Net Cost	$/KW	Net Cost	$/KW	Net Cost	$/KW
Base	$384,636	$1,870	($523,370)	($951)	$931,458	$2,656
Low	$380,269	$1,849	$717,054	$1,303	$991,478	$2,827
High	$381,688	$1,856	($1,155,822)	($2,101)	$951,071	$2,712
Base + Low CO2	$385,666	$1,875	$103,483	$188	$922,576	$2,631
Base + High CO2	$387,277	$1,883	$1,062,858	$1,932	$879,234	$2,507
Base + Very High CO2	$409,430	$1,991	$1,034,727	$1,881	$546,556	$1,559
High + High CO2	$381,571	$1,855	$463,415	$842	$934,098	$2,664

Figure 5-27 below compares the probability distribution of net cost for Colstrip against a generic peaker and combined-cycle gas plant, based on 250 draws of the risk variables. It shows that Colstrip, for the most part, produces a net benefit to PSE customers compared to the generic gas plants which are a net cost to the customers. For a complete discussion of the peaker and CCCT net costs, see section 3 “Peakers are lower cost than CCCT plants” below.

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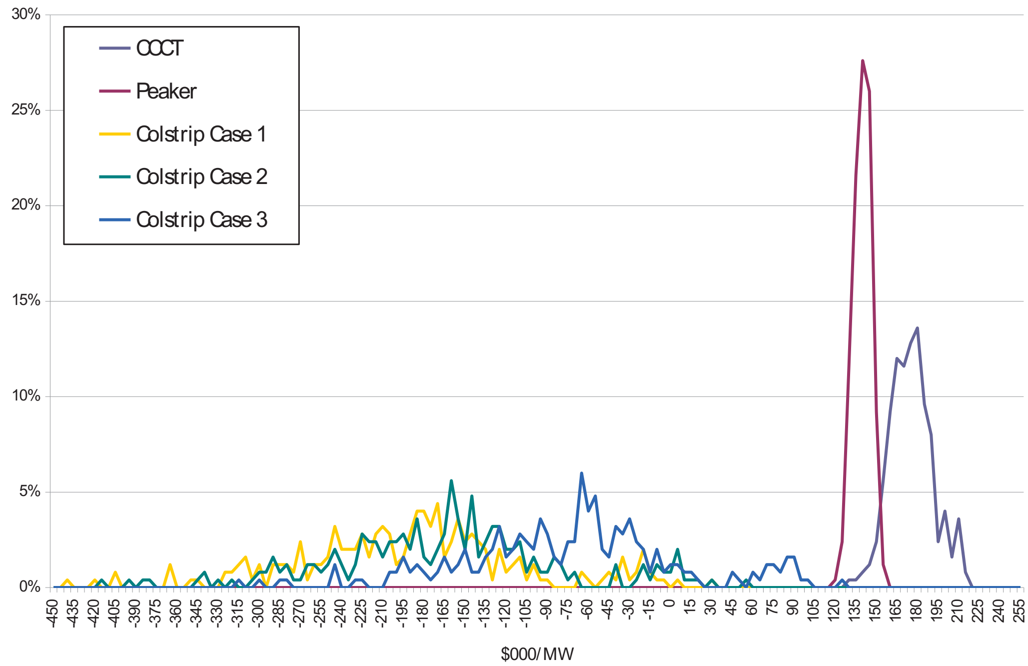
Figure 5-27
Net Cost Distribution



Since lower gas prices and lower loads, or higher CO_2 prices, affected continued operation of Colstrip Units 1 & 2, we tested the least-cost portfolio from the Base Scenario using a stochastic risk analysis. In this analysis, we varied loads (energy and peak), gas prices, power prices, hydro generation and wind generation. We also ran a second risk analysis that added CO_2 policy risk. Figure 5-28 shows the results of the stochastic analysis without reflecting CO_2 policy risk for Cases 1, 2 and 3. Results are all in long-term portfolio NPV, including the full range from minimum to maximum, the median, Tail Var 90 risk, and others as shown.

Figure 5-29 shows the results with the risk of a CO_2 policy. With no CO_2 policy risk, the results show that continuing Colstrip operations significantly reduces risk compared to replacement power under three of the compliance cost cases. When the risks of a CO_2 policy are added, the range of risk grows narrower, but continuing to operate the plant still reduces some risk in the portfolio. Risk is defined as the Tail Var 90 or the average value of the worst 10 percent of outcomes and volatility as the standard deviation of the log of the changes from year to year.

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The replacement power is costlier and riskier than continuing Colstrip operations for two reasons: 1) the capital cost of replacement power through new gas plants is greater than the capital cost of continuing Colstrip operations by meeting environmental requirements; and 2) since gas plants and market purchases replace coal power, variations in gas prices and electric prices have greater upward pressure on revenue requirements, even when the risk of a CO_2 policy exists.

Figure 5-28
Range of Portfolio Costs across 1000 Simulations – No CO₂ Policy Risk

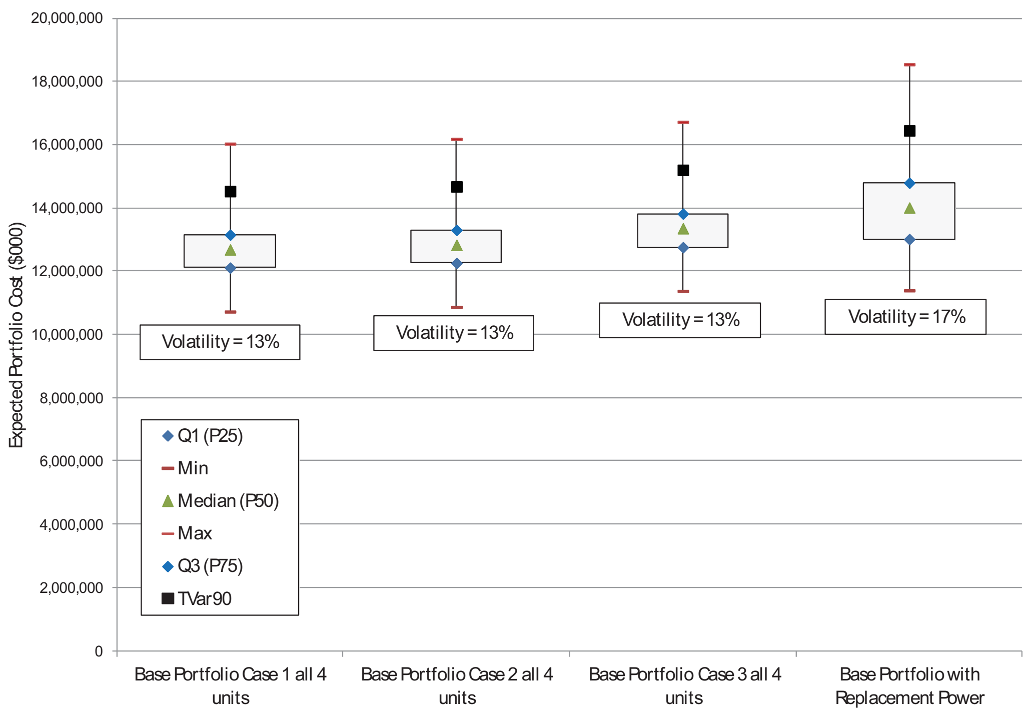


Figure 5-29
Range of Portfolio Costs across 1000 Simulations – with CO_2 Policy Risk

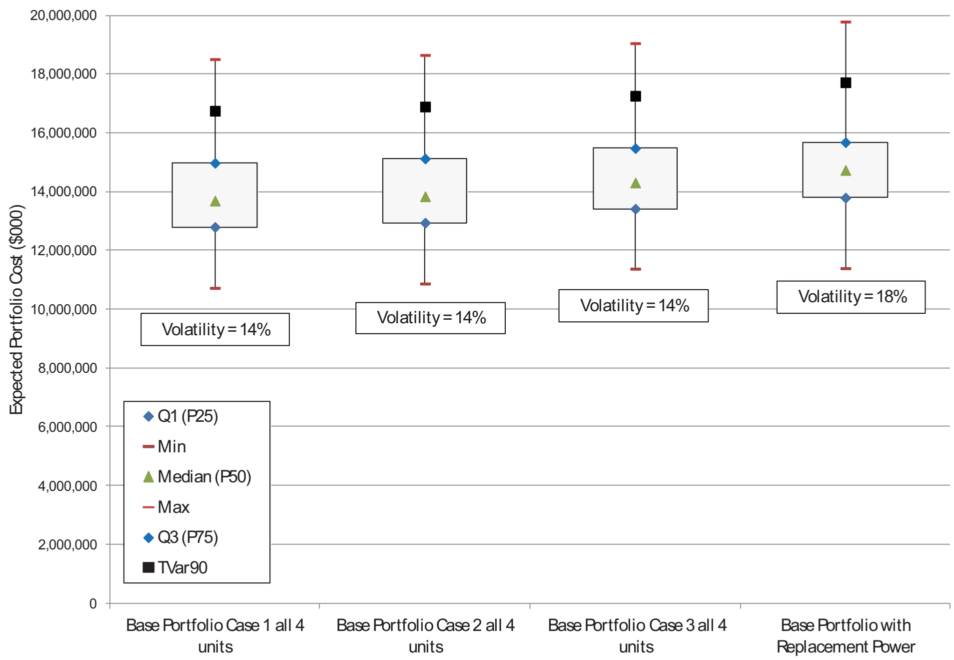
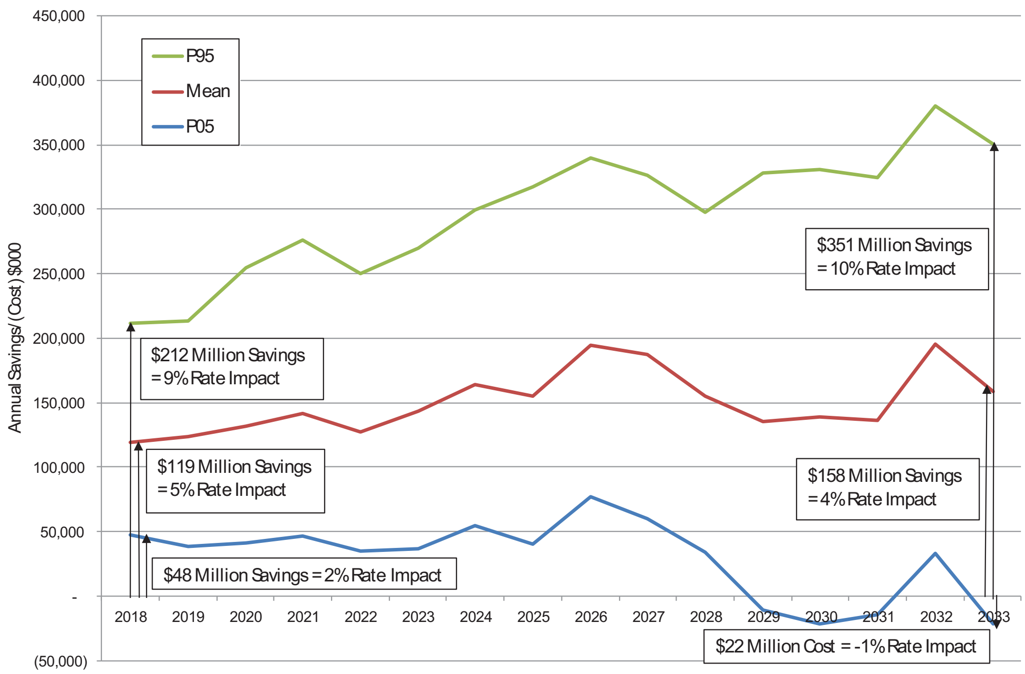


Figure 5-30 below shows the range of savings in annual revenue requirement for the least-cost portfolio in the Base Scenario with Colstrip Case 2, compared to the annual revenue requirement for least-cost portfolio in the Base Scenario with replacement power using the Monte Carlo draws. The middle line shows the mean (or arithmetic average) of the annual cost savings between Colstrip Case 2 costs and replacement power for the 250 trials along with the 5th and 95th percentile of the cost savings. The replacement power has a much higher 95th percentile, meaning that the portfolio has a much higher upside risk. In other words, the replacement power portfolio has much more risk of costing more than the continued operations of Colstrip. In other words, the highest risk for the replacement power portfolio costing more is higher than the highest risk for Colstrip costing more. The rate impacts in 2018 range from an approximate 2 percent increase to a 9 percent increase for replacement power above the cost of continuing operations of Colstrip, adjusting for inflation. By 2033, the rate impacts range from a 1 percent rate decrease to a 10 percent rate increase.

Figure 5-30

Percentile Range of Savings in Annual Revenue Requirement Between Colstrip Case 2 and Replacement Power – Base Case Without CO_2 Policy



Colstrip energy replacement with Montana wind

Colstrip produces approximately 5 million MWh per year of energy for PSE's portfolio and supplies 657 MW of capacity. When looking at wind energy equivalents in Montana, we modeled two capacity factors. Using a 31 percent capacity factor, 5 million MWh per year of energy translates to about 1,800 MW of wind; at 40 percent, it translates to about 1,400 MW. Assuming a 10% capacity credit, the wind will only contribute 180 MW or 140 MW respectively, so peakers will still be needed for capacity replacement. The additional wind was included in the portfolios in 2017 to correspond with the date Colstrip was removed from the portfolios.

Figure 5-31 below compares the total expected portfolio cost for Colstrip Case 2 to replacement power with peakers and market purchases, and to Montana wind and peakers. As illustrated, 1,800 MW of additional wind raises the expected cost by $3.6 billion or 26 percent.

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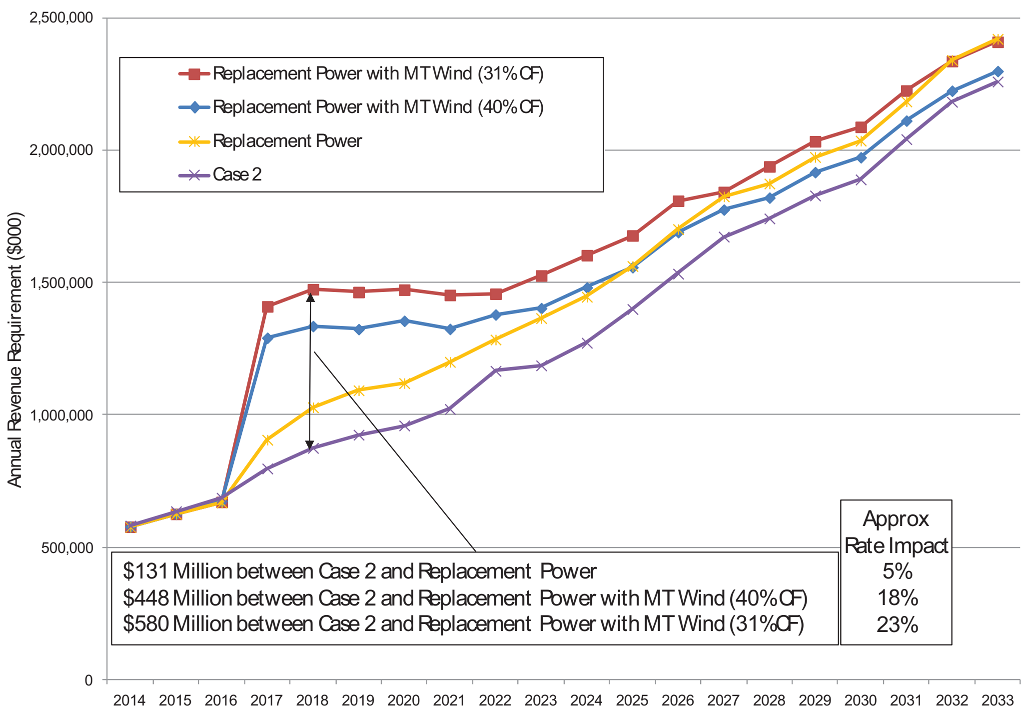
Figure 5-31
Expected Portfolio Cost Comparisons

Scenarios	Expected Portfolio Cost (Incremental Rev Req $Billions)
Base Scenario + Colstrip Case 2	$13.93
Base + Replacement Power	$15.24
Base + Replacement Power MT Wind (31% CF)	$17.53
Base + Replacement Power MT Wind (40% CF)	$16.44

Figure 5-32
Annual Revenue Requirement for Colstrip, Case 2 vs. Replacement Power



As mentioned previously, in 2018 the additional annual revenue required for replacement power compared to Colstrip Case 2 represents approximately a 5 percent rate increase. As Figure 5-32 illustrates, should Colstrip Case 2 be replaced with Montana wind, annual revenue requirements would range from $448 million to $580 million in 2018. This equates to an 18 percent to 23 percent rate increase in one year.

3. Peakers are lower cost than CCCT plants.

Peakers proved to be a lower cost resource alternative than CCCT plants across all planning scenarios except for Base + Very High CO_2. Figure 5-33 below compares the cost of peakers and combined-cycle plants across selected scenarios. Net revenue requirements were calculated by taking all capital and fixed costs of a plant and then subtracting the margin (variable costs less market revenue). This calculation lets one quickly compare how the model evaluated these resources. We considered peaking units both with and without oil back-up. To those without oil back-up, we assigned higher priced firm fuel transportation and storage costs similar to those CCCTs are burdened with. In the table below, plants are assumed to be located on the west side of the Cascades. (See next section for further discussion on how location affects resources costs.) In the Base + Very High CO_2 scenario, the net cost of the CCCT plant drops significantly compared to the peaker plant. This is because in this scenario, the coal plants are no longer economic to dispatch, so the CCCT dispatch increases to make up for the loss of the coal generation in the WECC. This increase in the dispatch increases the revenue of the plant more than the cost to dispatch, resulting in a lower net cost.

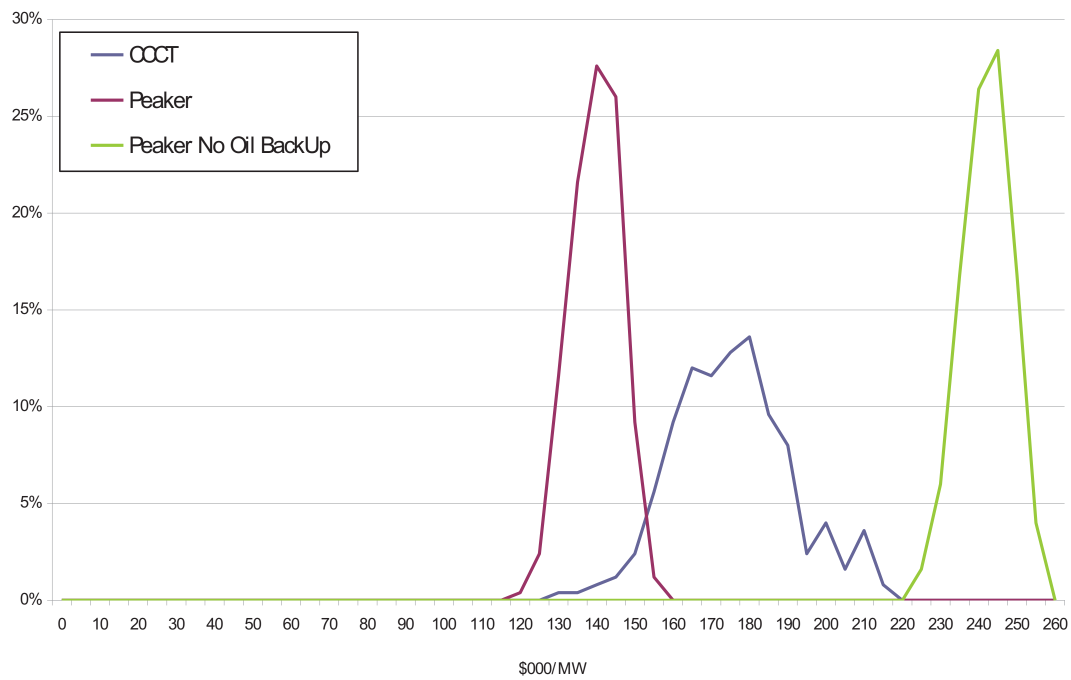
Figure 5-33
Peaker and CCCT Net Costs Compared

	Peaker w/ Oil		Peaker w/o Oil		CCCT	
	Net Cost	$/KW	Net Cost	$/KW	Net Cost	$/KW
Base	$384,636	$1,870	$634,773	$3,086	$931,458	$2,656
Low	$380,269	$1,849	$578,245	$2,811	$991,478	$2,827
High	$381,688	$1,856	$634,997	$3,087	$951,071	$2,712
Base + Low CO2	$385,666	$1,875	$631,685	$3,071	$922,576	$2,631
Base + High CO2	$387,277	$1,883	$634,036	$3,126	$879,234	$2,507
Base + Very High CO2	$409,430	$1,991	$643,243	$3,127	$546,556	$1,559
High + High CO2	$381,571	$1,855	$602,236	$2,928	$934,098	$2,664

The net cost of a CCCT plant is significantly affected by the margin it generates (market revenue less variable operating costs), and that margin varies as market conditions change. Figure 5-34 below illustrates the impact of margin on the net cost per MW of a peaker and CCCT plant in the Base Scenario. This Figure uses a 250-draw Monte Carlo analysis for a 2017 vintage plant to illustrate how the net cost per MW of peakers and

CCCT plants are distributed under different market conditions. The probability distribution of cost for the peakers is very tight, because peakers do not dispatch or create much margin in many draws. In contrast, the margin on CCCT plants is widely dispersed, which spreads out the CCCT probability distribution more broadly than the peaker distribution. The peaker distribution lies entirely below the 90 percent confidence interval for the CCCT plant. This means that while CCCT plants are expected to operate more and generate margins from those operations, the margins are not expected to be large enough to offset the CCCT's higher fixed cost. Net cost is not specifically used as part of the cost minimization function; however, showing net cost may provide useful insights.

Figure 5-34
Comparison of Net Cost Distribution: CCCT and Peakers

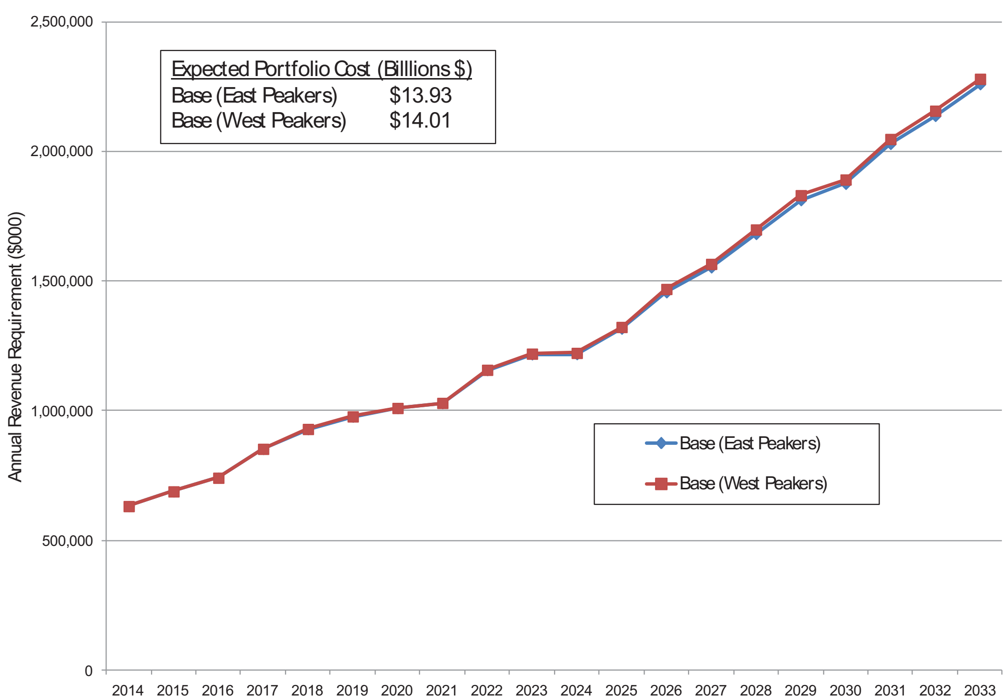


4. Location of resources (east vs. west of the Cascades) involves tradeoffs.

This is the first IRP to analyze how locating resources on the east side of the Cascades vs. the west side affects their value. Eastside resources located within PSE's balancing authority would carry lower transmission costs than westside resources, but higher fuel costs. Westside resources incur lower fuel costs, but higher transmission costs since they require the purchase of transmission contracts from BPA to bring the power to our system.

Figure 5-35, below, indicates that overall costs are very close. The cost of eastside resources may be somewhat understated because Oregon income taxes were not included in the analysis. Also, eastside resources built in Northern Oregon would be located within BPA's balancing authority, subjecting them to the risk of BPA transmission tariff pricing and policy changes. Westside plants, on the other hand, would give PSE access to all of the short-term operational benefits that thermal resources can provide (minute-to-minute up to sub-hourly). Access to these benefits from eastside plants would depend upon BPA transmission policies. Given these considerations, and the small difference in cost between the two, PSE chose to include Westside peakers in the resource plan.

Figure 5-35
Annual Revenue Requirements and Total Portfolio Costs for Peakers Located East and West of the Cascades



5. RPS requirements drive renewable builds.

The amount of renewable resources included in portfolios is driven by RPS requirements. In all scenarios but Base + Very High CO_2, wind resources are added to meet the minimum requirements of RCW 19.285 rather than because they are least cost.

In this IRP, in addition to examining Montana wind, we also include an analysis of adding an additional 300 MW of wind in 2017, above and beyond what is required by the RPS. When modeling wind for the RPS, we include the cost of replacing the plant at the end of its useful life as part of the end effects, but for examining the cost of this extra wind, we did not, so the results would focus just on the impact of this wind on PSE's portfolio costs. Figure 5-36 below summarizes the results. That table shows the additional wind increases total NPV portfolio costs by $358 million. Levelized over the 25-year depreciable life of the project, the $358 million is approximately $33 million per year. Dividing this $33 million/year divided by 793,613 MWh (the total generation of the 300 MW of wind), this results in a fundamental REC cost of $41.54 per MWh above the energy and capacity value of the wind to the portfolio.

Figure 5-36
Fundamental REC Cost

Base Expected Portfolio Cost	$13,930 Million
Base + 300 MW Wind Expected Portfolio Cost	$14,288 Million
Incremental Cost (Difference)	$358 Million
Incremental Cost levelized over 25-years	$33 Million/Year
Annual Energy Output of 300 MW of Wind	793,613 MWh/Year
Levelized Cost (Fundamental REC Cost)	$41.54/MWh

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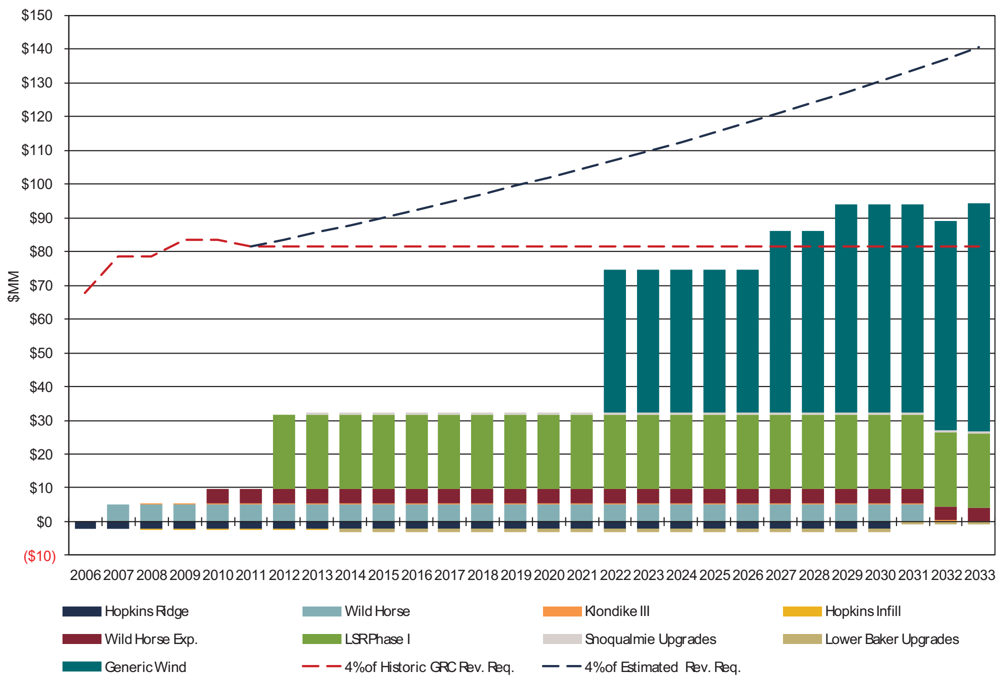
RPS incremental cost cap analysis

As part of RCW 19.285, if the incremental cost of the renewable resources compared to an equivalent non-renewable is greater than 4 percent of its revenue requirement, then the utility will be considered in compliance with the annual renewable energy target.[10]

Each renewable resource that counts towards meeting the renewable energy target was compared to an equivalent non-renewable resource starting in the same year and levelized over the book life of the plant: 25 years for wind power and 40 years for hydroelectric power. Figure 5-37 presents results of this analysis for existing resources and projected resources. This demonstrates PSE expects to meet the physical targets under RCW 19.285 without being constrained by the cost cap. A negative cost difference means that the renewable was lower cost than the equivalent non-renewable, while a positive cost means that the renewable was a higher cost.

Figure 5-37
Equivalent Non-renewable 20-year Levelized Cost Difference
Compared to 4 % of 2011 GRC Revenue Requirement



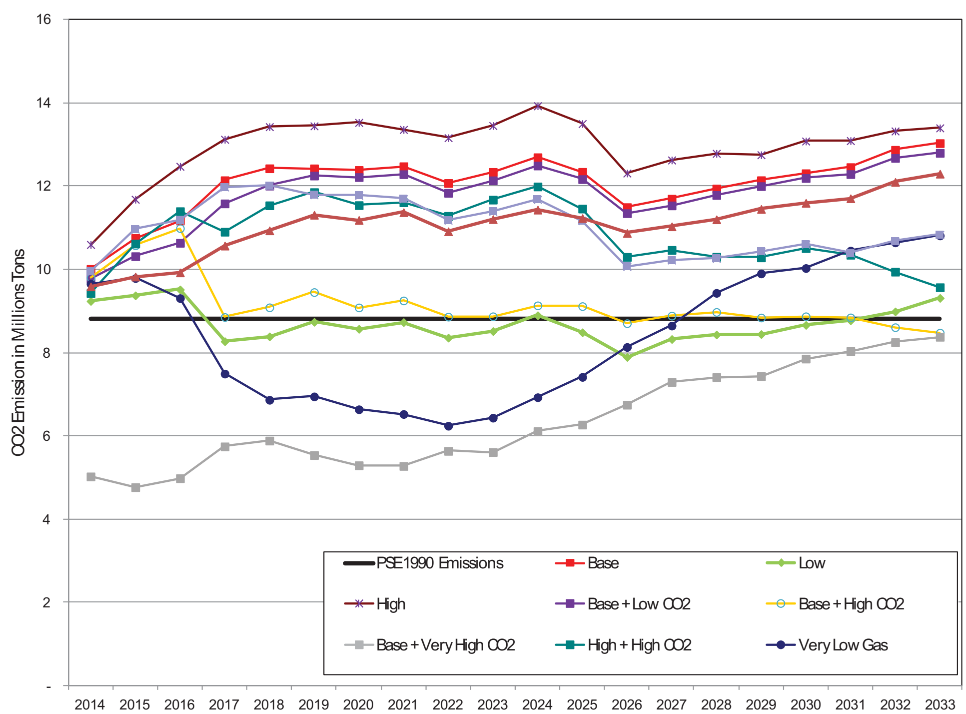
[10] *RCW 19.285.050 (1) (a) (b) "The incremental cost of an eligible renewable resource is calculated as the difference between the levelized delivered cost of the eligible renewable resource, regardless of ownership, compared to the levelized delivered cost of an equivalent amount of reasonably available substitute resource that does not qualify as eligible renewable resources."*

As the chart reveals, even if the company's revenue requirement were to stay the same for the next 10 years, PSE would still not hit the 4 percent requirement. The estimated revenue requirement uses a 2.5 percent assumed escalation from the 2011 General Rate Case revenue requirement. More detailed information can be found in Appendix K, Electric Analysis.

6. Emissions results vary across portfolios.

PSE examined how different carbon mitigation strategies will affect portfolio builds, costs, and emissions. CO_2 emissions for the least-cost portfolio in each scenario is shown in Figure 5-38. As the chart illustrates, only four portfolios/scenarios reduce emissions below 1990 levels. In three of these, the emission levels drop in 2017 when the portfolio replaces Colstrip Units 1 & 2 with other resources. In one scenario, Base + Very High CO_2, all four units of Colstrip are replaced. Many of the portfolios also show a drop in emissions in 2026, which corresponds to the expiration of the Coal Transition PPA at Dec. 31, 2025.

Figure 5-38
Emissions by Portfolio (Colstrip Case 2)



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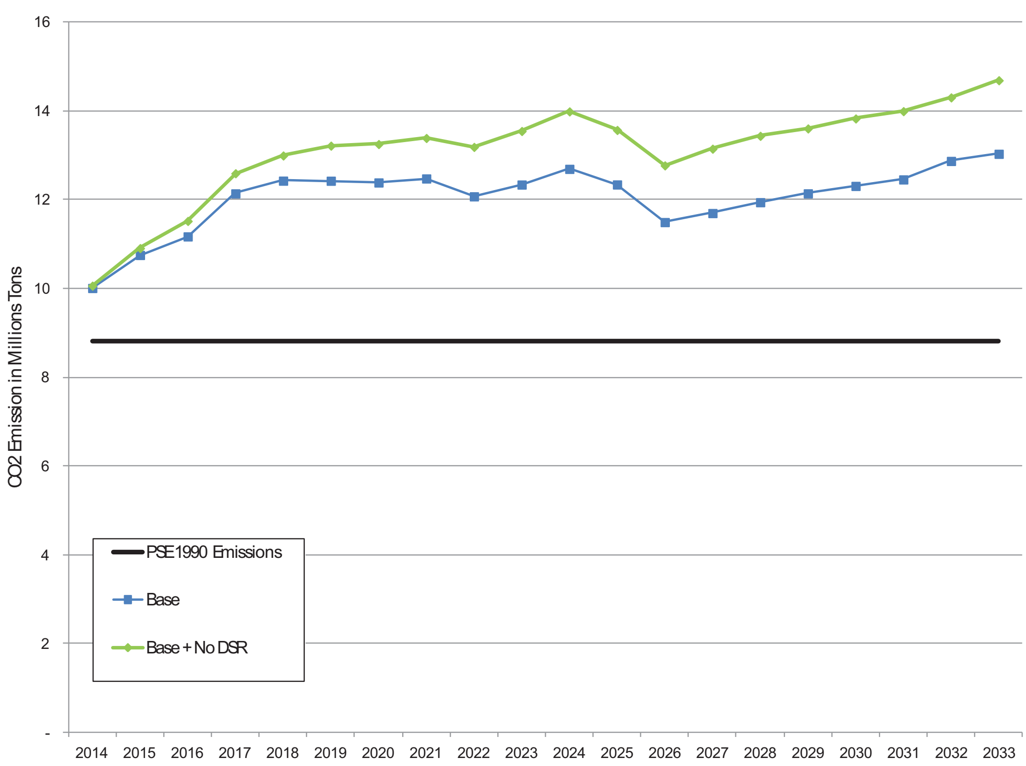
While three of the portfolios modeled achieve emissions below 1990 levels – Base + Very High CO_2, Very Low Gas, and Low (load and gas price) – only the Base + Very High CO_2 portfolio actually sustains emissions levels below 1990; the other two portfolios increase emissions in the later years. In fact, even the Base + Very High CO_2 portfolio steadily increases CO_2 emissions so much over time that by 2033, its emissions levels are approaching 1990 levels; following the growth rate, they will rise above 1990 levels a couple of years later.

DSR and wind resources also affect emissions rates, but to a much smaller extent than Colstrip or the Coal Transition PPA. Figure 5-39 below illustrates the effect that DSR has on the portfolio emission rates for the Base Scenario. By 2033, DSR's effect on load and builds reduces CO_2 emissions by 1.7 million tons, but this does not move the portfolio close to 1990 levels.

Figure 5-39
Emissions by Portfolio (Colstrip Case 2)



Wind to comply with the post 2020 RCW 19.285 requirements has a small effect on reducing CO_2 emissions. Figure 5-40 below illustrates that by 2033, the additional 600 MW of wind resources by 2033 reduces emission by 0.54 million tons.

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Figure 5-40
Emissions by Portfolio (Colstrip Case 2)

Given the relatively small impact on CO_2 emissions from adding wind, we focused on the cost of reducing CO_2 using wind. This analysis built on the fundamental REC cost analysis described above in Figure 5-35. Using the fundamental REC cost derived from adding 300 MW of wind over and above RPS requirements, we calculated the CO_2 savings from the "additional wind" portfolio to estimate a CO_2 abatement cost per MWh of wind shown in Figure 5-41 below. This converts the fundamental REC cost in $ per MWh identified above into a $ per ton cost. The "additional wind portfolio" saves on average 0.22 million tons of CO_2 per year. This translates to about 0.28 tons per MWh. In comparison to the WECC average for the base scenario (0.35 tons per MWh), the wind is only abating CO_2 emissions on 78 percent of market purchases. The total abatement cost of CO_2 from wind comes to $151 ton.

Figure 5 – 41
Fundamental CO_2 Abatement Cost From Wind

Fundamental REC Cost	$41.54/MWh
Average CO2 Savings of 300 MW of Wind	0.22 Million Tons/year
Annual Energy Output of 300 MW of Wind	793,613 MWh/year
Converted to Tons/MWh	0.28 Tons/MWh
Fundamental CO2 Abatement Cost	$151/Ton

7. DSR reduces cost and market risk.

Demand-side resources reduce both cost and market risk in portfolios. They must be cost effective to be included in the plan, so by definition they are also least-cost resources. Figure 5-43 compares the expected power costs and risk ranges for a No DSR portfolio with the optimal Base Scenario portfolio, which includes 1,007 MW of DSR by 2033. Figure 5-44 compares expected costs and cost ranges. Analysis of ramp rates continues to show that the sooner DSR is acquired, the more cost effective it is, so this IRP applies the 10-year ramp rate identified in the 2011 analysis.

The amount of cost-effective conservation acquired varies across scenarios, but by 2033, the range is very tight, 706 MW – 1,021 MW. The avoided cost of capacity plays a big role in the selection of the optimal bundle; this includes energy, capacity, and renewable resources. The avoided cost of energy varies depending on the power price scenario. For example, in the optimal Base portfolio, the least-cost level of DSR is Bundle E, but in the portfolio that analyzes replacement power for Colstrip (the Base replacement power portfolio), the optimal level of DSR is Bundle C. This is because in the Base replacement power portfolio, moving from Bundle C to Bundle E does not supply enough capacity to offset a peaker build; since the same amount of peakers are built in both, the increase in DSR cost is not offset by avoiding the cost of a generic peaker. However, in the optimal Base portfolio that includes Colstrip, moving from Bundle C to Bundle E supplies enough capacity to offset a peaker build so that the increased DSR cost is offset by avoiding the cost to build a generic peaker. (For detailed results by scenario see Appendix K, Electric Analysis.) Figure 5-42 shows the optimal DSR bundle in each scenario when we remove Colstrip as a factor. That is, Colstrip remains in the portfolio in all scenarios. As the table shows, Bundle E is the optimal bundle in all but one scenario; the Very Low Gas scenario is Bundle B.

Figure 5-42

Optimal DSR Results across Scenarios with Continued Colstrip Operations

MW Additions by 2033	Bundle		Demand Response		DE	EISA	Total
Base	E	629	1, 4 ,5	140	29	209	1,007
Low	E	629	1, 5	137	29	209	1,004
High	E	629	1, 5	137	29	209	1,004
Base + Low CO2	E	629	1, 4, 5	140	29	209	1,007
Base + High CO2	E	629	1, 4, 5	140	29	209	1,007
Base + Very High CO2	E	629	5	80	29	209	947
High + High CO2	E	629	1, 5	137	29	209	1,004
Very Low Gas	B	331	1, 5	137	29	209	706
Very High Gas	E	629	1, 4, 5	140	29	209	1,007
Low + Base Load	E	629	1, 4, 5	140	29	209	1,007

Demand response programs were broken down into 5 categories:

1. Residential Direct Load Control (DLC) Space Heating and Water Heating
2. Residential DLC Room Heating and Water Heating
3. Residential Critical Peak Pricing (CPP)
4. Commercial and Industrial Critical Peak Pricing
5. Curtailment

Figure 5-43 below illustrates how DSR reduces cost and risk in the portfolio. The optimal Base portfolio with DSR is lower cost and has a lower Tvar90, which measures the risk of how costly a portfolio can get compared to the optimal Base portfolio with no DSR.

Figure 5-43
Effect of DSR on Costs and Risks

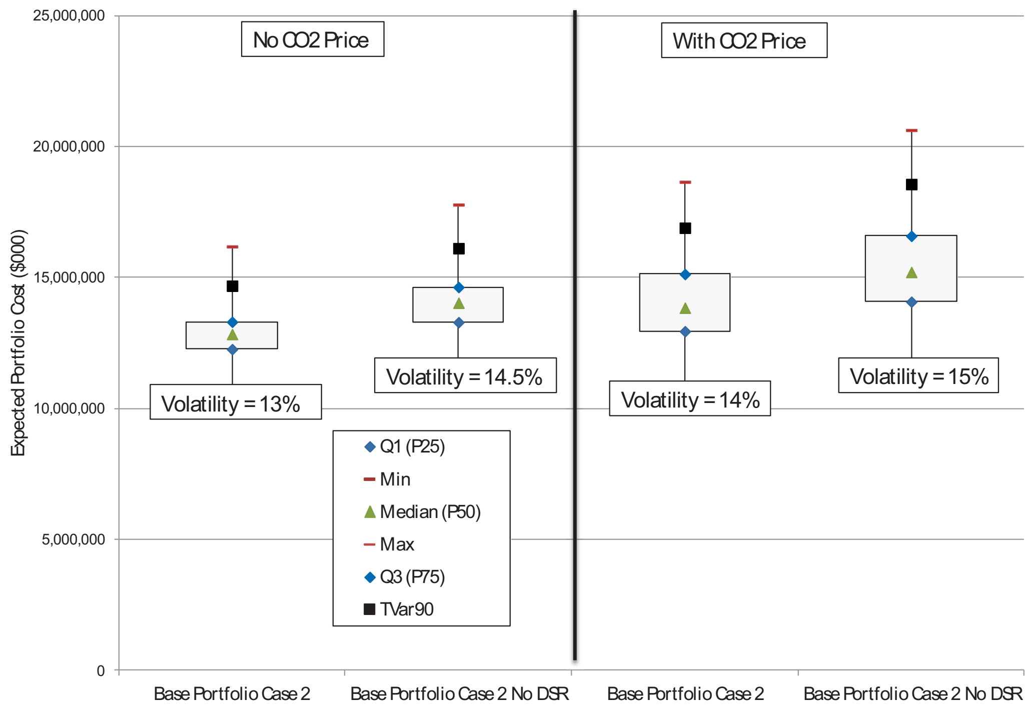


Figure 5-44
Comparison of Expected Costs and Cost Ranges for No-DSR and Optimal Base Scenario Portfolios with Colstrip Compliance Case 2

20-yr NPV Portfolio Cost (dollars in billions)

No CO2 Price	Base	Base + No DSR	Difference
Expected Cost	13.93	15.35	1.42
TVar90	14.68	16.11	1.43

DSR reduces power cost risk relative to No DSR. Figure 5-41 illustrates that the Tail Var 90 of variable costs for the portfolio with No DSR would be a little over $1.43 billion higher than the Base portfolio with DSR. It also illustrates that the No DSR portfolio revenue requirement is $1.42 billion more than the optimal Base portfolio, which reflects the higher costs of adding peakers instead of DSR. This is clearly a reasonable cost/risk trade-off. Adding DSR to the portfolio reduces cost and risk at the same time.

8. Transmission renewals look cost effective, but questions remain.

The IRP analysis indicates that renewing transmission contracts to facilitate purchases of market power remains a low-cost strategy for meeting customer need at this time. Indeed, for more than a decade, the region has been capable of producing more energy than it required; this "surplus" pushed market power prices down and made market purchases a lowest-cost resource alternative. PSE has captured this value for our customers for many years. Today, "transmission to market" is the single largest resource in PSE's electric portfolio; it supplies 1,618 MW of our customers' peak capacity need.

However, the Northwest Resource Adequacy Forum recently forecast that the region will reach load resource balance soon after the end of this decade, and may turn capacity deficit as 2,000 MW of coal-fired generation retires near the mid-point of the planning window.

Should the market tighten in this way, the price of market power would inevitably rise, but the risk to reliability is perhaps of greatest concern. The nature of this risk has more to do with possibility than probability. The region may be able to meet its expected needs with a smaller "cushion" in terms of planning margin reserves (i.e. at a higher loss of load probability), but the possibility of an abnormal event – such as two weeks of extraordinary cold or heat spells during peak seasons – could result in a situation in which transmission is contracted for, but there is nothing to fill it with.

CHAPTER 6

Gas Analysis

Contents

Natural gas has become an increasingly important resource for PSE. Not only do we supply it for end use to more than 770,000 gas sales customers, we also use it as fuel to generate electricity.

1. Gas Resource Need

This IRP develops an integrated resource plan for PSE's gas sales customers, and it also examines the utility's "gas-for-power" need. The former fulfills regulatory requirements, while the latter adds crucial context around a resource that has become increasingly important to meeting customers' electric demand. Here, we present two views of gas resource need – gas sales and gas-for-power – as well as discuss some of the important ways in which they are interrelated.

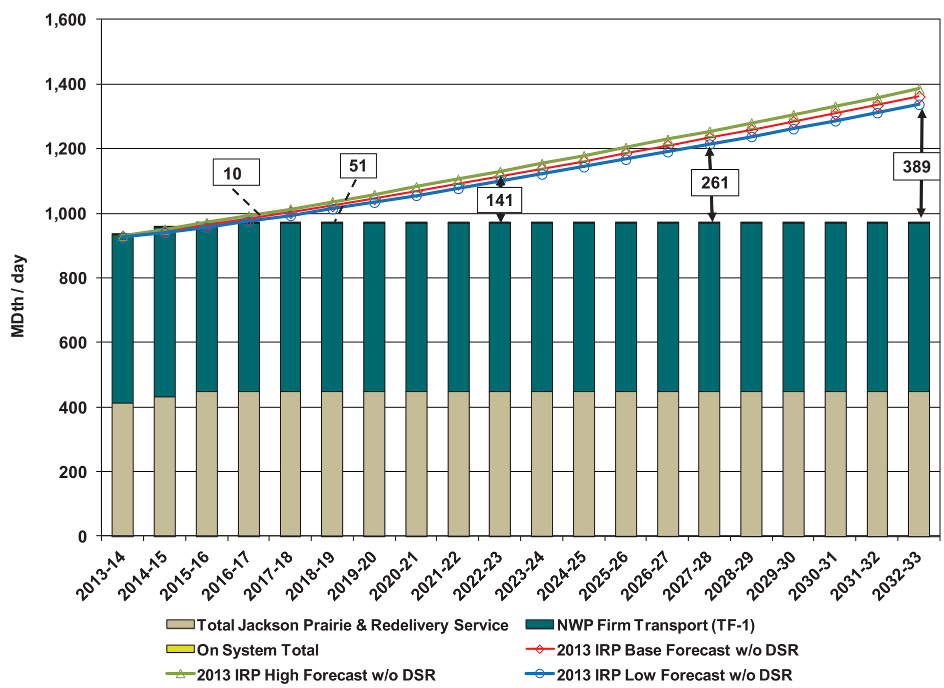
"Gas sales"
refers to PSE's direct delivery of natural gas to end-use customers.

"Gas-for-power"
refers to the fuel needed to run generators that produce electricity.

Gas Sales need

Figure 6-1 illustrates gas sales resource need over the 20-year planning horizon. The lines rising toward the right indicate demand, and the bars below represent current contracts for the pipeline transportation, storage, and peaking capacity that enable PSE to transport gas from points of receipt to customers.

Figure 6-1
Gas Sales Resource Need
Existing Resources Compared to Peak Day Demand
Meeting need on the coldest day of the year



Gas sales need is driven by two factors: peak day demand per customer and the number of customers. For PSE, peak day demand occurs in the winter, when temperatures are lowest and heating needs are highest. Since the heating season and number of lowest-temperature days[1] in the year remain fairly constant, customer count is the biggest factor in load growth.

[1] *For gas peak day planning purposes PSE assumes a day with 52 Heating Degree Days (HDDs) or an average temperature of 13° F.*

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The analysis tested three customer demand forecasts over the 20-year planning horizon: the 2013 IRP Base Demand Forecast, the 2013 IRP High Demand Forecast, and the 2013 IRP Low Demand Forecast. We currently have sufficient resources to meet peak day need until the winter of 2016-17 in all three cases.

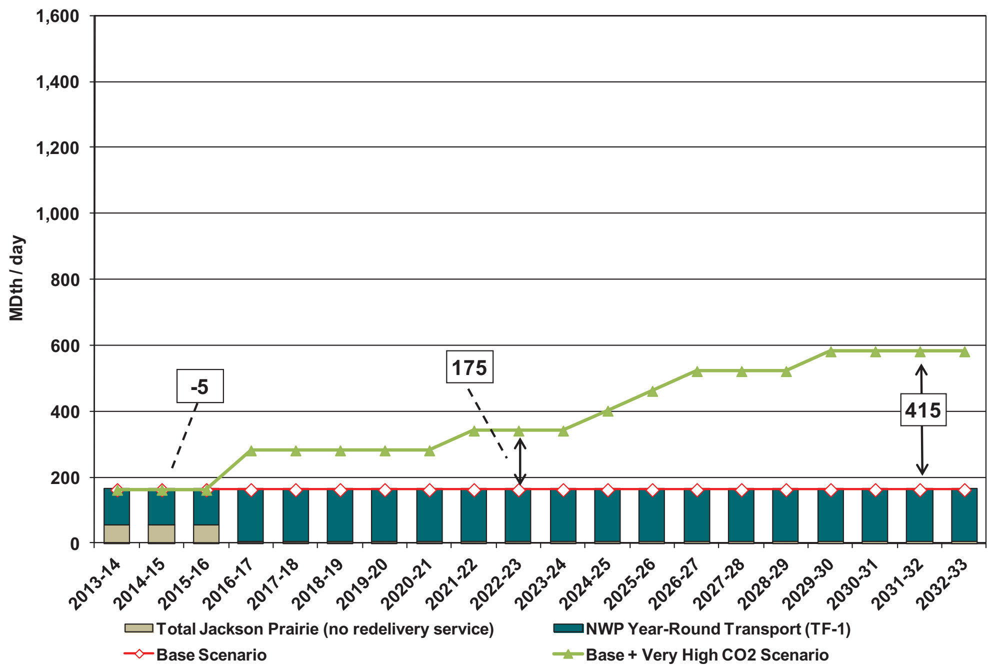
Gas-for-power need

Natural gas for power generation is increasingly important to the electric side of the utility. Every IRP since 2003 has identified natural gas-fired generation as the most cost-effective supply-side resource to include in IRP portfolios. This planning cycle is no different: All of the electric portfolios produced by the analysis include the addition of substantial amounts of gas-fired generation as part of the solution to meeting future electricity demand.

Calculating gas-for-power need is not as straightforward, since different types of gas-fired generating plants require different types of natural gas resources and their dispatch is dependent upon the prevailing market heat rate. Combined-cycle combustion facilities (CCCTs) and simple-cycle combustion engines (peakers) without oil back-up are assumed to need firm gas transportation. Peakers with oil back-up are expected to operate with temporary pipeline capacity purchased from the gas sales book, the pipeline, or through the capacity release market – and to rely on oil back-up when none is available.

The chart below describes gas-for-power needs for the electric scenario portfolios. Peakers with oil back-up are the only gas-fired resource type added in all the electric scenarios except one, and these scenarios require no additional firm pipeline capacity to meet peak needs. However, as shown in the gas-for-power analysis section, a limited amount of additional capacity may be needed to deliver sufficient gas over extended time periods. In the exception, the Base + Very High CO_2 scenario, no peakers are added but 7 CCCTs are included; this scenario also includes a total of 420 MDth per day of additional firm pipeline capacity to meet peak requirements.

Figure 6-2
Two Views of Gas-for-power Resource Need
Existing resources compared to peak day demand



Combined gas resource need

In past IRPs, PSE has included a SENDOUT analysis of the combined gas sales and gas-for-power portfolios. Modeling the two portfolios together contributes some insights but does not provide information on the need and allocation of resources between the two portfolios. Also, since the extreme peak for both gas sales and gas-for-power loads typically occurs on the very coldest days of the winter there are no peak capacity synergies between the two portfolios.

While the combined portfolios are not analyzed using the SENDOUT® model, it is useful to summarize the combined or total capacity needs. To depict combined need, we added the peak gas sales need identified in the gas sales Base Scenario to the two views of gas-for-power need: the electric Base Scenario and the Base + Very High CO_2 scenario. Extreme peak combined need is summarized in Figure 6-3 below. Combined need varies from 389 to 809 MDth per day by 2033, depending upon which gas-for-power scenario is assumed.

Figure 6-3
Combined Gas Resource Need (net need in MDth/day)
Extreme peak for gas sales and gas for power

Gas Sales Base plus . . .	2018-19	2022-23	2032-33
Electric Base Case	51	141	389
Electric Base + Very High CO2	171	321	809

Observations

The yearly demand curves for gas sales and gas for power differ in ways that create some interesting relationships.

Peak events

Perhaps the most significant finding from previous IRP analysis is that there is no savings in peak capacity requirements due to load diversity between the two portfolios. Both portfolios can expect, and need to plan for, peak loads to occur at the same time. Both the gas sales and electric gas loads are largely driven by temperature. Cold weather increases regional demand, which raises the market heat rate; in turn, generating plants with higher heat rates are dispatched. In addition, PSE's gas-fired electric generation plants are typically dispatched in anticipation of higher electric loads when very cold weather is forecasted.

Seasonal synergies

The very coldest winter days create short-term spikes in both portfolios, but in general, gas for sales demand is highest in the winter when heating needs are the greatest, while sustained high demand for gas for power occurs in the summer because the summer electric market is heavily influenced by California air-conditioning loads.

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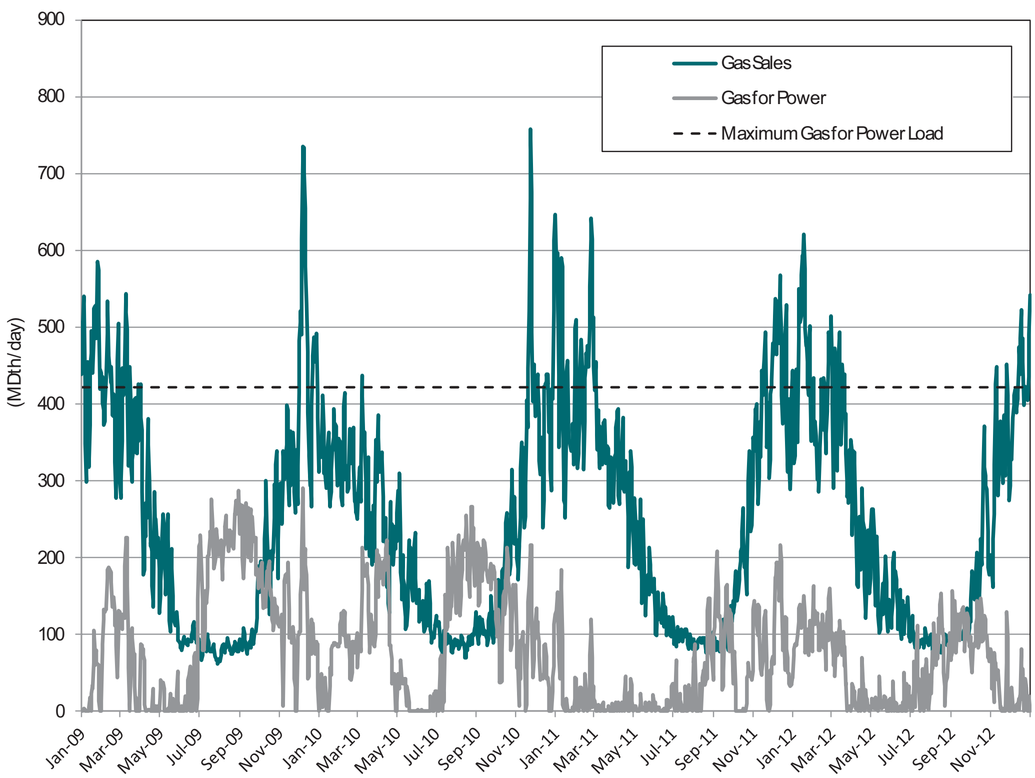
The gas sales portfolio purchases a substantial amount of firm pipeline capacity to make sure it can deliver all the gas customers need in the winter, but when summer comes and demand for gas sales subsides, it has surplus capacity. This means that the gas sales portfolio has excess capacity at the same time the electric utility needs to acquire capacity to meet its high-demand, summer season needs. Per WUTC requirements, short-term surplus capacity of the gas sales portfolio is made available to the generation portfolio at prevailing market rates similar to the rates that would result from release to a third party through FERC-regulated capacity release rules or available for purchase from the pipeline. Short-term pipeline capacity, purchased in this way, is generally less expensive.

Figure 6-4 compares the daily loads for the gas sales and gas-for-power portfolios for 2009 through 2012.

Figure 6-4
Daily Gas Sales and Gas for Power Loads, 2009 – 2012
Comparing demand curves and volatility



Variability and volatility

Gas-for-power loads are much more variable than gas sales loads. Another look at the historical data pictured in Figure 6-4 shows that while average gas-for-power loads are less than a third the size of average gas sales loads – their swings in volume (their maximum daily increase and decrease) are greater relative to the average load. This is confirmed by volatility statistics, which are much higher for gas-for-power loads than gas sales.

Significant additions of gas-fired generation resources – as with the 2,212 MW of peaking plants added in the Base Scenario electric resource portfolio for this IRP – could create unprecedented swings in gas loads. As peakers are switched on to meet demand, a volume of gas equivalent to PSE's entire gas sales load on a typical winter day could be required.

Increasing storage needs

The growing reliance on natural gas to generate electricity also increases the need to add gas storage capacity in the electric resources portfolio. Near-term, using the gas sales portfolio's excess capacity or the capacity release market to supply 2 or 3 additional peaking plants makes a great deal of sense, provided such plants can be permitted to use back-up fuel during peak periods; however, it is not at all clear that the capacity release market and pipeline system can handle the volume of activity required for the 10 peakers projected in the Base Scenario by 2033. Increased storage would greatly improve the ability to manage those swings, and may become a crucial part of the supply chain for generation.

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Figure 6-5
Variability of Gas Sales and Gas-for-power Loads Compared
Volatility and volumes (MDth per day)

	Gas Sales	Gas for Power
Calendar Year 2009		
Maximum	735	290
Minimum	62	0
Average	252	110
Max Daily Increase	133	129
Max Daily Decrease	126	131
Volatility[1]	0.1364	1.3658
Calendar Year 2010		
Maximum	757	266
Minimum	69	0
Average	229	99
Max Daily Increase	147	104
Max Daily Decrease	180	107
Volatility[1]	0.1394	1.1444
Calendar Year 2011		
Maximum	642	216
Minimum	76	0
Average	260	41
Max Daily Increase	119	111
Max Daily Decrease	164	86
Volatility[1]	0.1310	1.8546
Calendar Year 2012		
Maximum	621	163
Minimum	76	0
Average	247	56
Max Daily Increase	127	79
Max Daily Decrease	127	70
Volatility[1]	0.1370	2.7469

Note:
Volatility is defined as the standard deviation of the log of the daily change in gas use for the year.

Different choices, different impacts

Acquisition choices will affect the amount and type of gas resources needed in the electric portfolio. Additional peaking plants proved to be the lowest reasonable cost supply-side resource alternative in the electric portfolio developed for this IRP, but when the time comes to actually make acquisitions, purchased power agreements may be judged more cost effective. Less likely but still possible, CCCT plants may be economically attractive because of their more efficient heat rate. These choices would have very different impacts:

- Choosing purchased power agreements would reduce the amount of natural gas resources needed.
- Choosing CCCTs would increase the need for firm gas transportation.
- Peaking plants without alternate back-up fuel capability would also increase the need for firm gas transportation.

Gas transportation needs are also highly dependent on the specific location of generating plants. For example, plants located near a gas trading hub or storage facility need less pipeline capacity to transport fuel but may need more transmission to transport power; conversely, plants located near PSE loads require less electrical transmission but may require more gas transport capacity.

The gas for power analysis is discussed further in Section 6 of this chapter.

2. Gas Sales Existing Resources

Gas Sales supply-side resources

Supply-side gas resources include pipeline capacity, storage capacity, peaking capacity, and gas supplies.

Existing pipeline capacity

There are two types of pipeline capacity. "Direct-connect" pipelines deliver supplies directly to PSE's local distribution system from production areas, storage facilities, or interconnections with other pipelines. "Upstream" pipelines deliver gas to the direct pipeline from remote production areas, market centers, and storage facilities.

Direct-connect pipeline capacity. All gas delivered to our gas distribution system is handled last by PSE's only direct-connect pipeline, Northwest Pipeline (NWP). We hold the following capacity with NWP.

- 523,053 dekatherms (Dth) per day of year-round TF-1 (firm) transportation capacity
- 110,704 Dth per day of special winter-only firm TF-1 transportation capacity
- 323,903 Dth per day of firm TF-2 capacity

Receipt points on the NWP contracts access supplies from four production regions: British Columbia (BC), Alberta, the Rocky Mountain area, and the San Juan Basin. This provides valuable delivery point flexibility, including the ability to source gas from different regions on a day-to-day basis in some contracts.

Upstream pipeline capacity. To transport gas supply from production basins or trading hubs to the direct-connect NWP system, PSE holds capacity on several upstream pipelines.

Figure 6-6
Pacific Northwest Regional Gas Pipeline Map

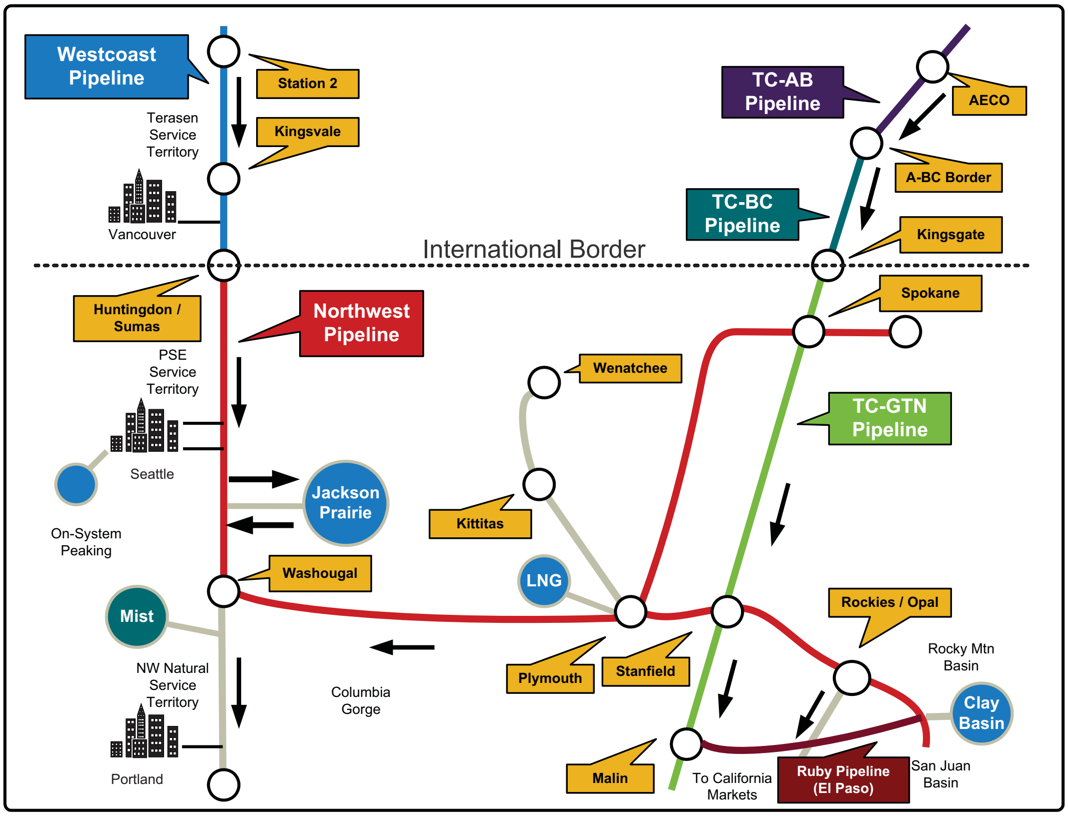

Figure 6-7
Gas Sales Pipeline Capacity as of 1/1/2013 (Dth/day)

Pipeline/Receipt Point	Note	Total	Year of Expiration 2018	2020	Other
Direct Connect					
NWP/Westcoast Interconnect (Sumas)	1	261,501	55,000	198,445	8,056 (2033)
NWP/TC-GTN Interconnect (Spokane)	1	75,936	-	75,936	
NWP/various Rockies	1	185,616	2,464	183,152	
Total TF-1		523,053	57,464	457,533	8,056
NWP/Jackson Prairie	1,2	110,704	-	-	110,704 (2028)
NWP/Jackson Prairie	1,2	333,480	-	333,480	
Total TF-2/Special TF-1		444,184	-	333,480	110,704
Total Capacity to City Gate		**967,237**	**57,464**	**791,013**	**118,760**

Pipeline/Receipt Point	Note	Total	Year of Expiration 2014	2015	Other
Upstream Capacity					
TC-Alberta/from AECO to TC-BC Interconnect (A-BC Border)	3	79,744		79,444	
TC-BC/from TC-Alberta to TC-GTN Interconnect (Kingsgate)	4	78,631	70,604		8,027 (2023)
TC-GTN/from TC-BC Interconnect to NWP Interconnect (Spokane)	5	65,392	-	-	65,392 (2023)
TC-GTN/from TC-BC Interconnect to NWP Interconnect (Stanfield)	5,6	25,000	-	-	25,000 (2023)
Westcoast/from Station 2 to NWP Interconnect (Sumas)	4,7	129,851	75,481	-	36,922 (2017) 17,449 (2018)
Total Upstream Capacity	**8**	**378,618**	**146,085**	**79,744**	**152,790**

Notes:

1) *NWP contracts have automatic annual renewal provisions, but can be canceled by PSE upon one year's notice.*
2) *TF-2 and special TF-1 service is intended only for delivery of storage volumes during the winter heating season; these annual costs are significantly lower than year-round TF-1 service.*
3) *Converted to approximate Dth per day from contract stated in gigajoules per day.*
4) *Converted to approximate Dth per day from contract stated in cubic meters per day.*
5) *TCPL-GTN contracts have automatic renewal provisions, but can be canceled by PSE upon one year's notice.*
6) *Capacity can alternatively be used to deliver additional volumes to Spokane.*
7) *The Westcoast contracts contain a right of first refusal upon expiration.*
8) *Upstream capacity is not necessary for a supply acquired at interconnects in the Rockies and for supplies purchased at Sumas.*

It is helpful to understand the significant differences among transportation types, especially TF-1 and TF-2 service, and firm and interruptible capacity.

TF-1 and TF-2 service. TF-1 transportation contracts are firm contracts, available 365 days each year. TF-2 service is for delivery of storage volumes and is generally intended for use during the winter heating season only; contract costs are based on a quantity related to the storage capacity referenced by each respective agreement. Therefore, TF-2 service has significantly lower annual costs than the 365-day service provided under TF-1. The special winter-only TF-1 service has similar characteristics and pricing as TF-2 service.

Firm and interruptible capacity. Firm transportation capacity carries the right, but not the obligation, to transport up to a maximum daily quantity of gas on the pipeline. Firm transportation requires a fixed payment, whether or not that capacity is used. Interruptible service is subordinate to the rights of shippers who hold and use firm transportation capacity; the rate for interruptible capacity is negotiable, and is typically billed as a variable charge. When firm shippers do not use their firm pipeline capacity, they may release it on the capacity release market.

PSE releases capacity when we have a surplus of firm capacity and when market conditions make such transactions favorable for customers. The company also uses the capacity release market to access additional firm capacity when it is available. Interruptible service plays a limited role in PSE's resource portfolio, because it cannot be relied on to meet peak demand.

Existing storage resources

PSE's natural gas storage capacity is a significant component of the company's gas resource portfolio. Storage capacity improves system flexibility and creates significant cost savings for both the system and customers.

- Ready access to an immediate and controllable source of firm gas supply or storage space enables PSE to handle many imbalances created at the interstate pipeline level without incurring balancing or scheduling penalties.
- Access to storage makes it possible for the company to purchase and store additional gas during the lower-demand summer season, generally at lower prices.
- Combining storage capacity with seasonal TF-2 (or special winter-only TF-1) transportation allows us to contract for less year-round pipeline capacity to meet winter-only demand.
- PSE also uses storage to balance city-gate gas receipts with the actual loads of our gas transportation customers.

We have contractual access to two underground storage projects. Each serves a different purpose. Jackson Prairie storage, in Lewis County, WA is an aquifer-driven storage field designed to deliver large quantities of gas over a relatively short period of time. Clay Basin in northeastern Utah provides supply-area storage and a winter gas supply. Figure 6-8 presents details about storage capacity.

Figure 6-8
Gas Sales Storage Resources[1] (as of 01/01/2013)

	Storage Capacity (Dth)	Injection Capacity (Dth/Day)	Withdrawal Capacity (Dth/Day)	Expiration Date
Jackson Prairie – Owned	8,528,000	147,500	398,667	N/A
Jackson Prairie – Owned[2]	-500,000	-25,000	-50,000	2016
Jackson Prairie – NWP SGS-2F[3]	1,181,021	17,900	48,390	2014
Clay Basin	12,882,750	53,678	107,356	2018/20
Clay Basin[4]	-4,000,000	-37,011	-74,023	2018
Total	**18,091,771**		**430,390**	

Notes:

1) *Storage, injection, and withdrawal capacity quantities reflect PSE's capacity rights rather than the facility's total capacity.*
2) *Storage capacity made available (at market-based price) from PSE gas sales portfolio. Renewal may be possible, depending on gas sales portfolio needs. The gas sales portfolio may recall 15,000, 35,000 and 50,000 Dth per day of firm withdrawal rights for up to 4 days in each winter 2013/14, 2014/15 and 2015/16, respectively.*
3) *NWP contracts have automatic annual renewal provisions, but can be canceled by PSE upon one year's notice.*
4) *Released to third parties through March 2018.*

Jackson Prairie storage. PSE uses Jackson Prairie and the associated NWP TF-2 and special TF-1 transportation capacity primarily to meet the intermediate peaking requirements of core customers – that is, to meet seasonal load requirements, balance daily load, and minimize the need to contract for year-round pipeline capacity to meet winter-only demand. As shown in Figure 6-7, we have 444,184 Dth per day of TF-2 and special winter-only TF-1 transportation capacity from Jackson Prairie.

PSE, NWP, and Avista Utilities each own an undivided one-third interest in the Jackson Prairie Gas Storage Project (Jackson Prairie), operated by PSE under FERC authorizations. In addition to firm daily deliverability and firm seasonal capacity, we have access to deliverability and seasonal capacity through contracts for SGS-2F storage service from NWP. The NWP contracts are automatically renewed each year but we have the unilateral right to terminate the agreement with one year's notice.

Clay Basin storage. Questar Pipeline owns and operates the Clay Basin storage facility in Daggett County, Utah. This reservoir stores gas during the summer for withdrawal in the winter. PSE has two contracts to store up to 12,882,750 Dth and withdraw up to 107,356 Dth per day under a FERC-regulated service. As shown in Figure 6-8, 4,000,000 Dth of this storage capacity has been assigned to third parties through March 2018.

We use Clay Basin for certain levels of base-load supply, and for back-up supply in the case of well freeze-offs or other supply disruptions in the Rocky Mountains during the winter. It provides a reliable source of supply throughout the winter, including peak days; it also provides a partial hedge to price spikes in this region. Gas from Clay Basin is delivered to PSE's system (and other markets) using firm TF-1 transportation.

Treatment of storage cost. Similar to firm pipeline capacity, firm storage arrangements require a fixed charge whether or not the storage service is used. PSE also pays a variable charge for gas injected into and withdrawn from Clay Basin. Charges for Clay Basin service (and the non-PSE-owned portion of Jackson Prairie service) are billed to PSE pursuant to FERC-approved tariffs, and recovered from customers through a purchased gas adjustment (PGA), while costs associated with the PSE-owned portion of Jackson Prairie are recovered from customers through base distribution rates.

Existing peaking supply and capacity resources

Firm access to other resources provides supplies and capacity for peaking requirements or short-term operational needs. The Gig Harbor LNG satellite storage and the Swarr vaporized propane-air (LP-Air) facility provide firm gas supplies on short notice for relatively short periods of time. Generally a last resort due to their relatively higher variable costs, these sources typically meet extreme peak demand during the coldest hours or days. These resources do not offer the flexibility of other supply sources.

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Figure 6-9
Gas Sales Peaking Resources, as of 01/01/2013

	Storage Capacity (Dth)	Injection Capacity (Dth/Day)	Withdrawal Capacity (Dth/Day)	Transport Tariff
Plymouth LNG (1)	241,700	1,208	70,500	TF-1 (1)
Gig Harbor LNG	10,500	2,500	2,500	On-system
Swarr LP-Air	128,440	16,680 (2)	0 (3)	On-system
Total	**380,640**	**20,888**	**73,000**	

Notes:

1) *In the past PSE has relied on TF-2 pipeline delivery service from Plymouth LNG. However, PSE has confirmed that TF-2 pipeline delivery service from Plymouth LNG cannot be counted on as firm. While delivery can be made firm using existing TF-1 capacity, that capacity cannot then be used to deliver other supplies, thus Plymouth LNG no longer supplies an incremental delivered supply. PSE will turn back the Plymouth LS-1 and TF-2 contracts to NWP at the earliest data possible (October 31, 2014).*
2) *Swarr holds 1.24 million gallons. At a refill rate of 111 gallons/minute, it takes 7.7 days to refill, or 16,680 Dth/day.*
3) *Swarr delivery is currently not on-line pending environmental and reliability upgrades.*

Plymouth LNG. NWP owns and operates an LNG storage facility located at Plymouth, Washington, which provides a gas liquefaction, storage, and vaporization service under its LS-1 and LS-2F tariffs. PSE's long-term contract provides for seasonal storage with an annual contract quantity of 241,700 Dth; liquefaction Maximum Daily Quantity (MDQ) of 1,208 Dth per day; and a withdrawal MDQ of 70,500 Dth per day. The ratio of injection and withdrawal rates means that it can take more than 200 days to fill to capacity, but only 3-1/2 days to empty.

NWP has asserted that the TF-2 service related to Plymouth is "secondary firm," and that NWP is not obligated to force other customers to nominate the use of their transportation contracts in a fashion necessary to create the displacement capacity needed to honor PSE's contract. PSE disagrees with NWP's characterization of the service, and we expressed concern to NWP that the "secondary firm" TF-2 service is no longer reliable enough to be counted upon under peak conditions. NWP worked with PSE to analyze how the TF-2 service contract might be modified to guarantee capacity under certain limited but defined conditions, but NWP was unable to define such conditions. Based on those analyses, which reflect changes in pipeline facilities, contracts, and flow patterns since the service was established in the early nineties, PSE has concluded that the TF-2 contract related to Plymouth can no longer be relied upon during the peak conditions that the resource serves. As a result, we have removed the Plymouth LS service (with the associated TF-2 service) from the gas resource stack. PSE will turn back the Plymouth

LS-1 and TF-2 contracts to NWP at the earliest date possible (October 31, 2014). PSE will consider retaining the LS-1 contract if it can provide benefit to customers by being converted to provide LNG to the growing transportation fuel market or released to a third-party.

Gig Harbor LNG. In the Gig Harbor area, a satellite LNG facility ensures sufficient supply during peak weather events for a remote but growing region of our distribution system. The Gig Harbor plant receives, stores, and vaporizes LNG that has been liquefied at other LNG facilities; it represents an incremental supply source and is therefore included in the peak day resource stack. Although the facility directly benefits only areas adjacent to the Gig Harbor plant, its operation indirectly benefits other areas in PSE's service territory since it allows gas supply from pipeline interconnects or other storage to be diverted elsewhere.

Swarr LP-AIR. The Swarr LP-Air facility has a net storage capacity of 128,440 Dth natural gas equivalents, and can produce the equivalent of approximately 10,000 Dth per day. The Swarr LP-Air facility is currently not in service while it awaits upgrades that would incorporate environmental safety and reliability systems and increase the facility's production capacity to 30,000 Dth per day. Swarr connects to PSE's distribution system, so it requires no upstream pipeline capacity. The upgrade is a resource alternative evaluated for this IRP.

Existing gas supplies

Development of the means to economically extract natural gas from shale deposits has changed the picture with regard to gas supplies. Not only has development of shale beds in British Columbia directly increased the availability of supplies in the West, but the east coast no longer relies so heavily on Western supplies now that shale deposits in Pennsylvania and West Virginia are in production.

Within the limits of its transportation and storage network, PSE maintains a policy of sourcing gas supplies from a variety of supply basins. Avoiding concentration in one market helps to increase reliability. We can also mitigate price volatility to a certain extent; the company's capacity rights on NWP provide flexibility to buy from the lowest-cost basin. While we are heavily dependent on supplies from northern British Columbia, we also maintain pipeline capacity access to producing regions in the Rockies, the San Juan basin, and Alberta.

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Price and delivery terms tend to be very similar across supply basins, though shorter-term prices at individual supply hubs may "separate" due to pipeline capacity shortages. This separation cycle can last several years, but should be alleviated when additional pipeline infrastructure is constructed. We expect generally comparable pricing across regional supply basins over the 20-year planning horizon, with differentials primarily driven by differences in the cost of transportation.

We have always purchased our supply at market hubs or pooling points. In the Rockies and San Juan basin, there are various transportation receipt points, including Opal and Clay Basin; but alternate points, such as gathering system and upstream pipeline interconnects with NWP, allow some purchases directly from producers as well as marketers. In fact, PSE has a number of supply arrangements with major producers in the Rockies to purchase supply near the point of production. Adding upstream pipeline transportation capacity on Westcoast, TC-AB, and TC-BC to the company's portfolio has increased our ability to access supply nearer producing areas in Canada as well.

Gas supply contracts tend to have a shorter duration than pipeline transportation contracts, with terms to ensure supplier performance. We meet average loads with a mix of long-term (more than two years) and short-term (two years or less) gas supply contracts. Longer-term contracts typically supply base-load needs and are delivered at a constant daily rate over the contract period. We also contract for seasonal base-load firm supply, typically for the winter months. Near-term transactions supplement base-load transactions, particularly for November through March; we estimate average load requirements for upcoming months and enter into month-long transactions to balance load. PSE balances daily positions using storage (from Jackson Prairie and Clay Basin), day-ahead purchases, and off-system sales transactions, and we balance intra-day positions using Jackson Prairie. PSE will continue to monitor gas markets to identify trends and opportunities to fine-tune our contracting strategies.

PSE's low-load-factor market is highly weather-dependent and therefore seasonal in nature. Our general policy is to maintain firm supply commitments equal to approximately 50 percent of expected seasonal demand, including assumed storage injections in summer and net of assumed storage withdrawals in winter.

Gas Sales demand-side resources

PSE has provided demand-side resources or DSR (that is, resources generated on the customer side of the meter) since 1993. Figure 6-11 shows that energy efficiency measures installed through 2012 have saved a cumulative total of 4.0 million Dth – more than half of which has been achieved since 2007. Through 1998, these programs primarily served residential and low-income customers. In 1999 the company expanded to add commercial and industrial customer facilities. PSE has spent more than $110.9 million for natural gas conservation programs from 1995 to 2012. PSE's energy efficiency programs operate in accordance with requirements established as part of the stipulated settlement of our 2001 General Rate Case.

PSE's energy efficiency programs serve residential, low-income, commercial, and industrial customers. Energy savings targets and the programs to achieve those targets are established every two years. The 2010-2011 biennial program period concluded at the end of 2011; current programs operate January 1, 2012 through December 31, 2013. The majority of gas energy efficiency programs are funded using gas "rider" funds collected from all customers.

For the 2012-2013 period, a two-year target of approximately 950,000 Dth in energy savings has been adopted. This goal was based on extensive analysis of savings potentials and developed in collaboration with key external stakeholders represented by the Conservation Resource Advisory Group (CRAG) and Integrated Resource Plan Advisory Group (IRPAG).

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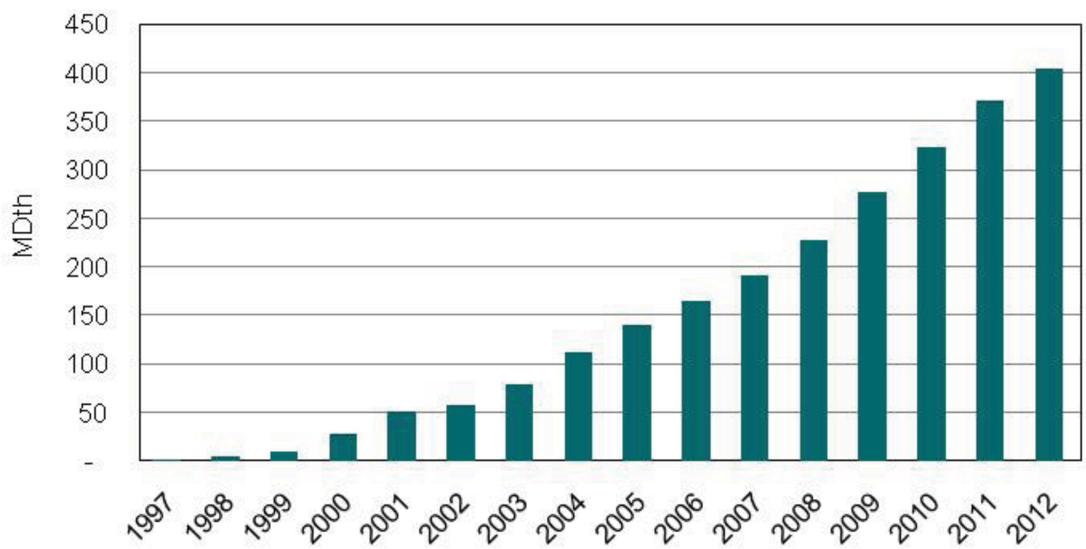
Figure 6-10
Gas Sales Energy Efficiency Program Summary 2010 – 2013
Total savings and costs

Sector	2010-2011 Actual Total Savings (Therms)	2010-2011 Actual Total Costs ($)	2012-2013 Target Total Savings (Therms)	2012-2013 Budget Total Costs ($)	Percent Change in Savings (%)	Percent Change in Costs (%)
Residential	4,305,991	$19,469,988	3,790,600	$13,701,000	-11.9%	-29.6%
Commercial /Industrial	5,914,136	$13,770,017	5,758,000	$10,564,000	-2.6%	-23.2%
Total	10,220,127	$33,240,005	9,548,600	$24,265,000	-14.6%	-5.3%

Figure 6-11
Cumulative Gas Sales Energy Savings from DSR, 1997 – 2012



3. Gas Sales Resource Alternatives

The gas resource alternatives considered in this IRP address long-term capacity challenges rather than the shorter-term optimization and portfolio management strategies PSE uses in the daily conduct of business to minimize costs.

Combinations considered

Transporting gas from production areas or market hubs to PSE's service area generally entails assembling a number of specific pipeline segments and gas storage alternatives. Purchases from specific market hubs are joined with various upstream and direct-connect pipeline alternatives and storage options to create combinations that have different costs and benefits. Within PSE's service territory, demand-side resources are a significant resource.

In this IRP, the alternatives have been gathered into seven broad combinations for analyses. These combinations are illustrated in Figure 6-12. Note that, while not shown, DSR is included in all of the combinations.

Combination #1

This option expands access to northern British Columbia gas (Station 2 hub) with expanded transport capacity on Westcoast pipeline to Sumas and then on expanded NWP to PSE's service area. Gas supplies are also presumed available at the Sumas market hub. In order to ensure reliable access to supply and achieve diversity of pricing, PSE seeks to hold Westcoast capacity equivalent to 50 percent of NWP firm take-away capacity at Sumas.

Combination #2

This combination includes the Kingsvale-Oliver Reinforcement Project (KORP) pipeline proposal sponsored by Fortis BC and Spectra. Essentially, the KORP project expands and adds flexibility to the existing Southern Crossing pipeline. This option would allow delivery of AECO gas to PSE via existing or expanded capacity on the TC-AB and TC-BC pipelines, the KORP pipeline across southern British Columbia to Sumas, and then on expanded NWP capacity to PSE.

Combinations #3 & 4

These options provide for deliveries to PSE via the prospective Palomar/Blue Bridge pipeline. The increased gas supply could either come from Alberta (AECO hub) via existing upstream pipeline capacity on the TC-AB, TC-BC, and TC-GTN pipelines to Stanfield; or from the Rockies hub on the Ruby pipeline to Malin and with backhaul on the TC-GTN pipeline to Stanfield. Final delivery from Stanfield to PSE would be via the proposed Palomar/Blue Bridge pipeline.

Combination #5

This combination entails development of an LNG peak-shaving capability built in conjunction with a potential project that PSE is considering to provide fuel for the natural gas vehicle market – specifically, maritime vessels and large trucks. This project would be located near the existing PSE distribution system.

Combination #6

This is an upgrade to the existing Swarr LP-air facility. This upgrade would increase the peak day planning capability from 10 MDth/day to 30 MDth/day.

Combination #7

This option provides for PSE to lease storage capacity from NW Natural after an expansion of the Mist storage facility. Delivery of gas would require some expansion of pipeline capacity from Mist to PSE's service territory but is assumed to have discounted redelivery service.

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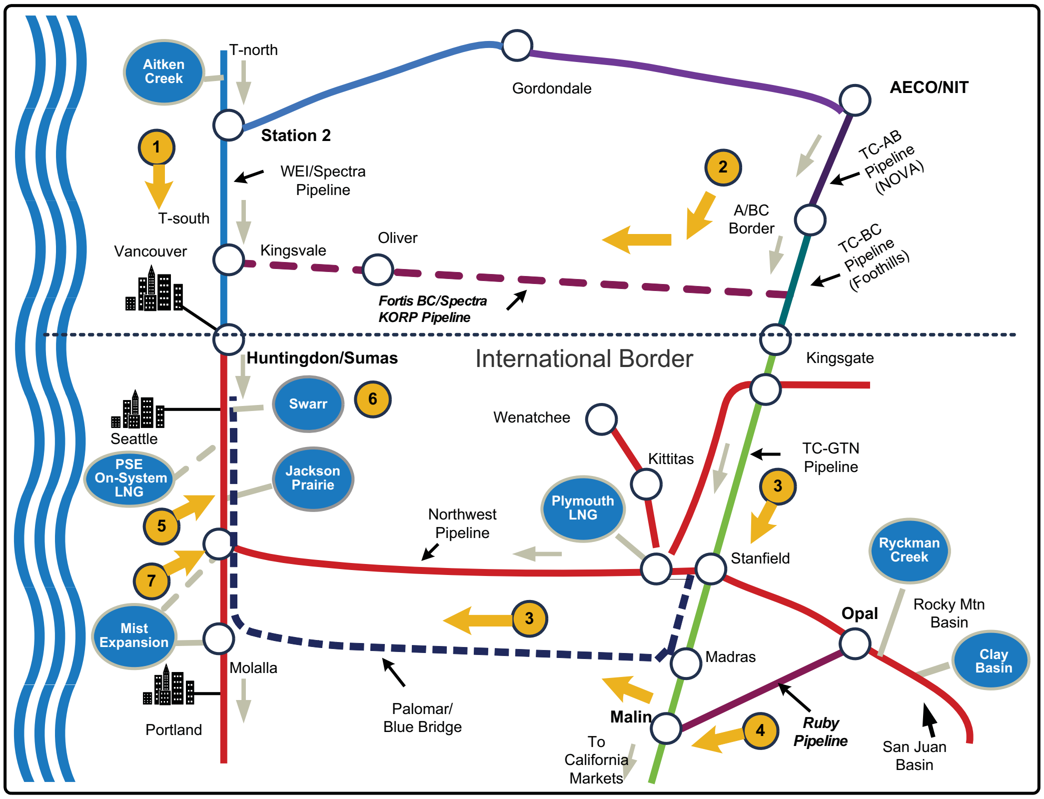
Figure 6-12
PSE Gas Transportation Map Showing Supply Alternatives



Pipeline alternatives

Direct-connect pipeline capacity alternatives. The direct-connect pipeline alternatives considered in this IRP are summarized in Figure 6-13 below.

Figure 6-13
Direct-connect Pipeline Alternatives Analyzed

Name	Description
NWP - Sumas to PSE city gate	Expansions considered either independently or in conjunction with upstream pipeline/supply expansion alternatives (KORP or additional Westcoast capacity). Assumed to be available by 2018.
Palomar/Blue Bridge – Stanfield/TC-GTN to PSE city gate	Representative of costs and capacity of the proposed Palomar/Blue Bridge pipeline with delivery on NWP to PSE city gate. Assumed to be available by 2018.
NWP – Washougal to PSE city gate	Discounted redelivery option considered in conjunction with a possible lease of expanded Mist storage facility. Assumed to be available by 2016.

Upstream pipeline capacity alternatives. In some cases, a tradeoff exists between buying gas at one point, and buying capacity to enable purchase at an upstream point closer to the supply basin. PSE has faced this tradeoff with our supply purchases at the Canadian import points of Sumas and Kingsgate. For example, previous analyses led the company to acquire capacity on Westcoast Energy's BC Pipeline (Westcoast), which allows us to purchase gas at Station 2 rather than Sumas and take advantage of greater supply availability at Station 2. Similarly, acquisition of additional upstream pipeline capacity on TransCanada's Canadian and U.S. pipelines would enable us to purchase gas directly from suppliers at the very liquid AECO trading hub and transport it to interconnect with the proposed Palomar/Blue Bridge pipeline on a firm basis. Fortis BC and Spectra have proposed the KORP, which in conjunction with additional capacity on TransCanada's Canadian pipelines, would also increase access to AECO supplies.

Figure 6-14
Upstream Pipeline Alternatives Analyzed

Name	Description
Increase Westcoast Capacity (Station 2 to Sumas)	Acquisition of currently uncontracted Westcoast capacity is considered to increase access to gas supply at Station 2 and a northern B.C. storage alternative for delivery to PSE on expanded NWP capacity from Sumas.
Increase TransCanada Pipeline Capacity (AECO to Stanfield)	Acquisition of currently uncontracted capacity of TransCanada pipeline capacity in Canada (TC-AB & TC-BC) and on TC-GTN in the U.S. to increase deliveries of AECO gas to Stanfield for delivery to PSE city gate via the proposed Palomar/Blue Bridge pipeline.
KORP	Expansion of the existing Fortis BC Southern Crossing pipeline across southern BC, enhanced delivery capacity on Westcoast from Kingsvale to Huntingdon/Sumas. This alternative would include a commensurate acquisition of uncontracted capacity on the TC-AB and TC-BC pipelines.

The KORP alternative includes PSE participation in an expansion of the existing Fortis BC pipeline across southern British Columbia which includes a cooperative arrangement with Westcoast for deliveries from Kingsvale to Huntingdon/Sumas. Acquisition of this capacity, as well as additional capacity on the TC-AB and TC-BC lines, would improve access to the AECO trading hub. While not inexpensive, such an alternative would increase geographic diversity and reduce reliance on British Columbia-sourced supply connected to upstream portions of Westcoast.

Storage and peaking capacity alternatives

As described in the existing resources section, PSE is a one-third owner and operator of the Jackson Prairie storage facility, and we also contract for capacity at the Clay Basin storage facility located in northeastern Utah. Additional pipeline capacity from Clay Basin is not available and storage expansion is not under consideration. Expanding storage capacity at Jackson Prairie is not analyzed in this IRP although it may prove feasible in the long run For this IRP, the company considered the following storage alternatives:

Mist expansion. NW Natural Gas Company, the owner and operator of the Mist underground storage facility near Portland, Ore., is investigating a potential expansion project to be completed in 2016. PSE is assessing the cost-effectiveness of participating in such an expansion. This could require expansion of discounted winter redelivery service to PSE's city gate.

LNG Peaking Project. PSE is considering development of a mid-scale LNG liquefaction and storage facility within its service territory to serve the growing demand for LNG as a marine and vehicle transportation fuel. Such a facility would be designed to produce LNG fuel at a relatively constant rate year-round and provide modest storage capacity. This IRP evaluates the possibility of enhancing the design of the facility to substantially increase storage capacity and add vaporization equipment; this would make it possible for the facility to also serve as a peaking resource for the PSE gas system. The economies of scale afforded by a combined-use facility may make this a cost-effective alternative.

The LNG Peaking Project would utilize gas purchased by the PSE gas sales portfolio throughout the year, transported over NWP and PSE distribution system to the plant, where it would be liquefied and stored. Under peak demand conditions, up to 30,000 Dth per day of stored LNG would be vaporized and injected back into the PSE gas distribution system to meet customer demand. In addition, under peak demand conditions, up to 20,000 Dth per day of natural gas flowing on NWP to serve the daily liquefaction requirements of LNG transportation fuel customers could be diverted to other PSE gas distribution system interconnects to serve PSE customers. The diverted gas volumes would be replaced with PSE-owned LNG already in storage to keep the LNG transportation fuel customers whole. As configured, the PSE LNG Peaking Project would provide a resource of up to 50,000 Dth per day to PSE gas customers for the equivalent of up to 6 days per year. For analysis purposes, the facility is assumed to enter service in the fall of 2016, with peaking service available at the start of the 2017-18 heating season after the initial fill of the storage tank.

Figure 6-15
Storage Alternatives Analyzed

Name	Description
Expansion of Mist Storage Facility	Based on estimated cost and operational characteristics of expanded Mist storage. Assumes a 20-day supply at full deliverability.
LNG Peaking Project	These analyses assume a 10-day supply at full deliverability of 30 MDth/day, plus possible use of 20 MDth of diverted supply for a net 6-day supply.

Two additional gas storage alternatives, Aitken located in northern BC and Ryckman Creek, located in southwestern Wyoming, were reviewed but not analyzed as alternatives in SENDOUT. Both resources are located relatively far from PSE's service territory and would require incremental firm pipeline capacity in order to meet peaking requirements. The delivered cost of peak capacity from these resources is much higher than other alternatives.

Gas supply alternatives

Figure 6-16
Gas Supply Alternatives Analyzed

Name	Description
Swarr LP-Air Facility Upgrade	This upgrade would return this facility to service and increase the peak day planning capability from 10 MDth/day to 30 MDth/day.

As described earlier, gas supply and production are expected to continue to expand in both northern British Columbia and the Rockies production areas as shale and tight gas formations are developed using horizontal drilling and fracturing methods. With the expansion of supplies from shale gas and other unconventional sources at existing market hubs, PSE anticipates that adequate gas supplies will be available to support pipeline expansion from northern British Columbia or from the Rockies basin.

Additional cost and capacity data for all of the supply-side resource alternatives is presented in Appendix L, Gas Analysis.

Demand-side resource alternatives

There were several steps in evaluating cost-effectiveness of demand-side resource measures.

First, demand-side measures were screened for technical potential. This step assumed that all opportunities could be captured regardless of cost or market barriers, so that the full spectrum of technologies, load impacts, and markets could be surveyed.

A second screen eliminated any resources not considered achievable. To gauge achievability, PSE relied on customer response to past PSE energy efficiency programs and the experience of other utilities offering similar programs. For this IRP, the company assumed that 75 percent and 55 percent of gas demand-side resource potentials in existing buildings and new construction markets, respectively, are likely to be achievable over the planning period.

The remaining measures are considered to have "achievable technical potential." At this point, any measures impacted by changes in code and standards that will go into effect during the study period are grouped together into a standards and codes bundle. This bundle identifies DSR volumes and is assumed to be zero cost, therefore it is always selected in the portfolio model where it represents a decrement to the load. The remaining measures with achievable technical potential are ordered into cost bundles, and the bundles are arranged from lowest to highest cost. (Savings for all measures in each group were adjusted for interactive effects.) The lower cost bundles were sliced into narrower price points than in the 2011 IRP, since current lower gas prices mean that smaller amounts of gas DSR maybe more optimal. Figure 6-17 below lists the cost price points used as inputs into the portfolio model.

PSE currently seeks to acquire as much cost-effective gas demand-side resources as quickly as possible. The acquisition or "ramp rate" of gas sales DSR can be altered by changing the speed with which discretionary DSR measures are acquired. This IRP tested three ramp rates: a 20-year ramp rate, a 10-year ramp rate, and a "delayed" 10-year ramp rate, which suspends deployment of discretionary DSR measures for the first two years of the study. The last option tests whether delaying acquisition during a period of very low gas prices would result in a lower cost portfolio.

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Figure 6-17
DSR Cost Bundles and Savings Volumes for 10-Year Ramp Rate

Bundle	Price Cut-Offs for Bundles	2014 MDth 10-Yr	2033 MDth 10-Yr
Codes & Standards	**$0**	**-**	**1,243**
A	< $2.20/Dth	133	2,134
A1	$2.2 to $3.0	5	58
A2	$3.0 to $4.5	35	465
B	$4.5 to $5.5	5	58
B1	$5.5 to $7.0	70	756
C	$7.0 to $8.5	53	565
C1	$8.5 to $9.5	8	124
D	$9.5 to $12.0	112	1,732
E	$12.0 to $15.0	198	1,988
F	$15.0 to $20.0	120	1,357
G	>= $20	841	10,239

More detail on the measures, assumptions and methodology used to develop potentials can be found in Appendix N, DSR Analysis.

Finally, SENDOUT was used to test the optimal level of demand-side resources in each scenario. To format the inputs for SENDOUT analysis, the cost bundles were further subdivided by market sector and weather/non-weather sensitive measures. Increasingly expensive bundles were added to each scenario until SENDOUT rejected bundles as not cost effective. The bundle that reduced the portfolio cost the most was deemed the appropriate level of demand-side resources for that scenario. Figure 6-18 illustrates the methodology described above.

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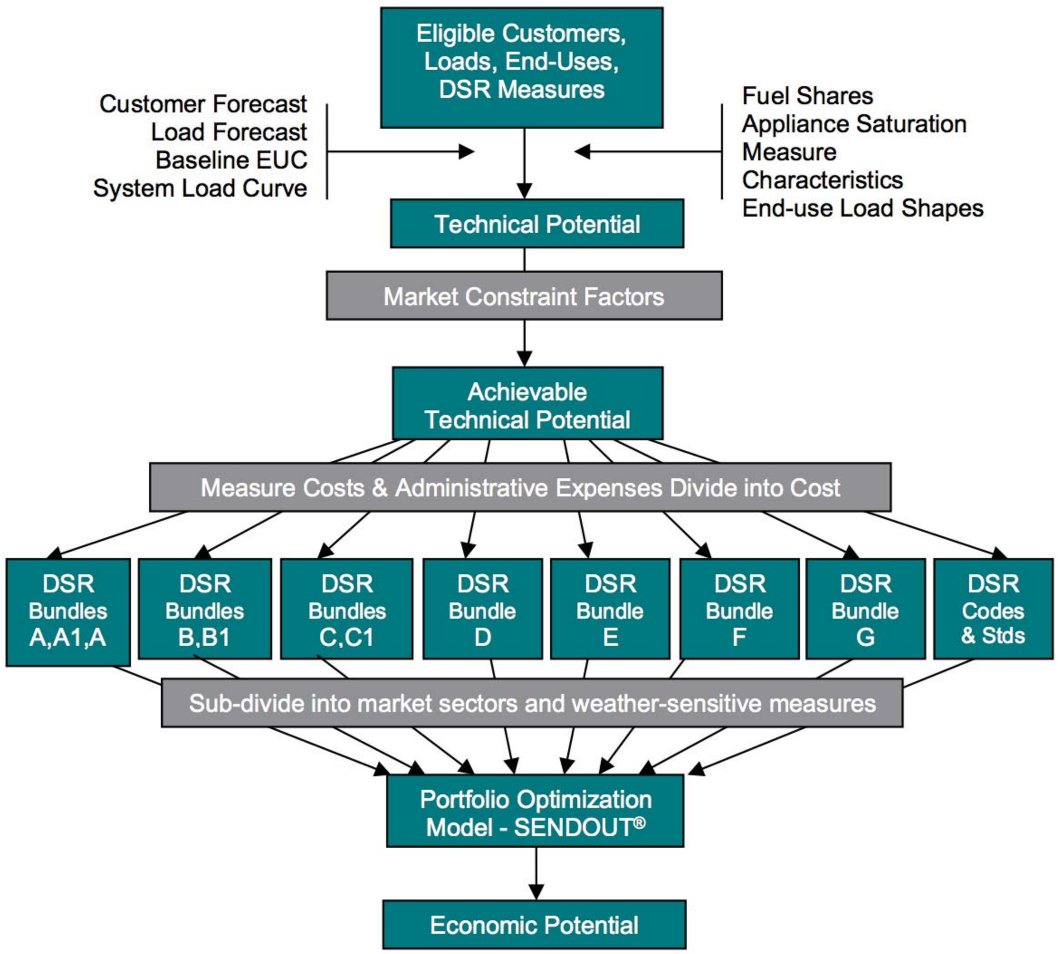
Figure 6-18
General Methodology for Assessing Demand-side Resource Potential



Figures 6-19, 6-20, and 6-21 show the range of achievable technical potential among the eleven cost bundles used in SENDOUT. It selects an optimal combination of each market sector for every bundle to determine the overall optimal level of demand-side gas resource for a particular scenario.

Figure 6-22 shows a sample input format subdivided by market sectors for Bundle A (<$2.20 per Dth) used in the SENDOUT portfolio optimization model for all the IRP scenarios.

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Figure 6-19
Demand-side Resources – 10-year Ramp for Achievable Technical Potential Bundles

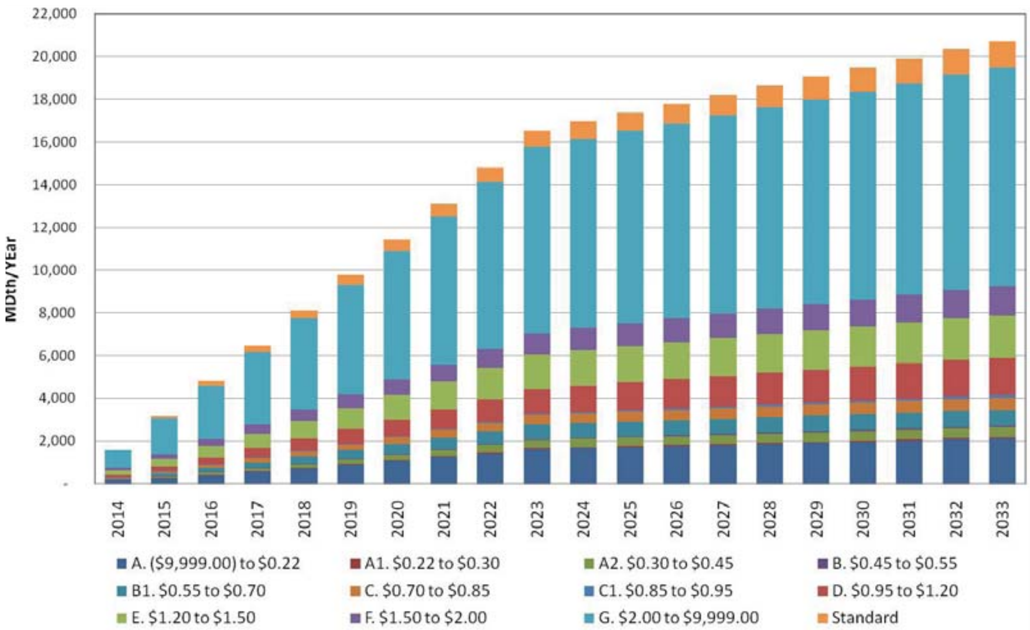

Figure 6-20
Demand-side Resources – 20-year Ramp for Achievable Technical Potential Bundles

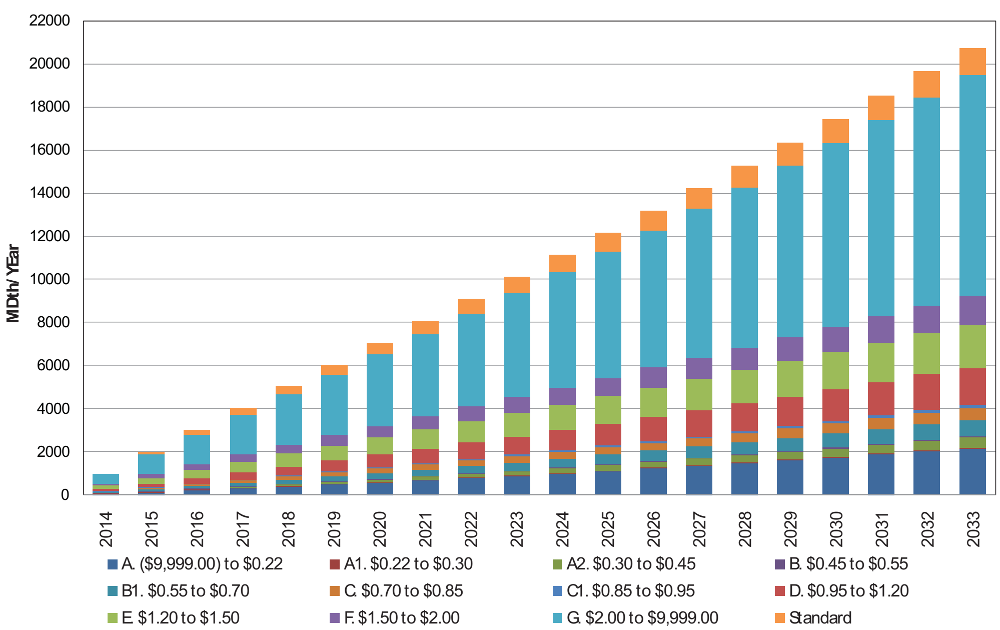

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Figure 6-21
Demand-side Resources – 10-year Delayed Ramp for Achievable Technical Potential Bundles

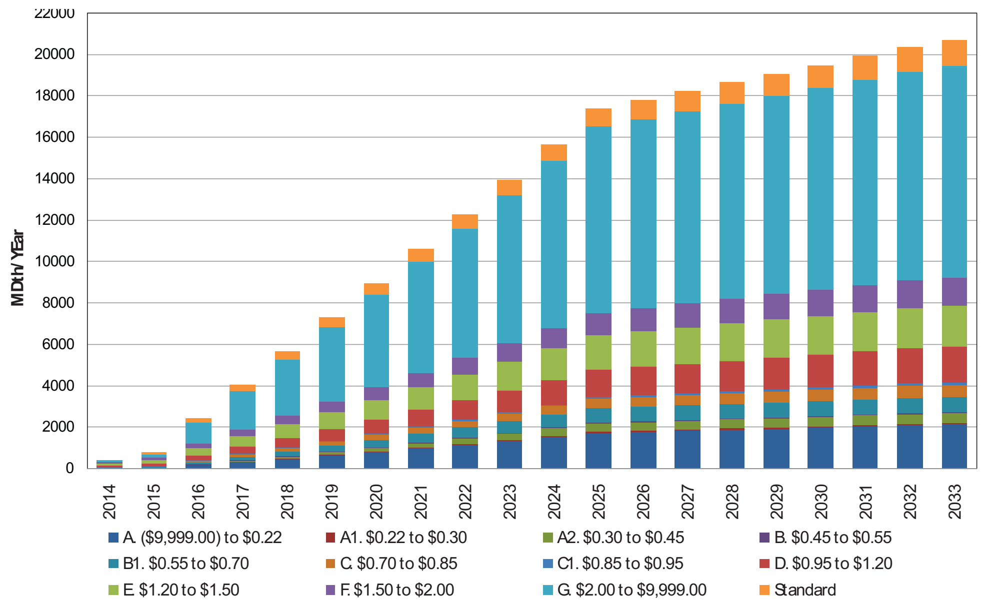
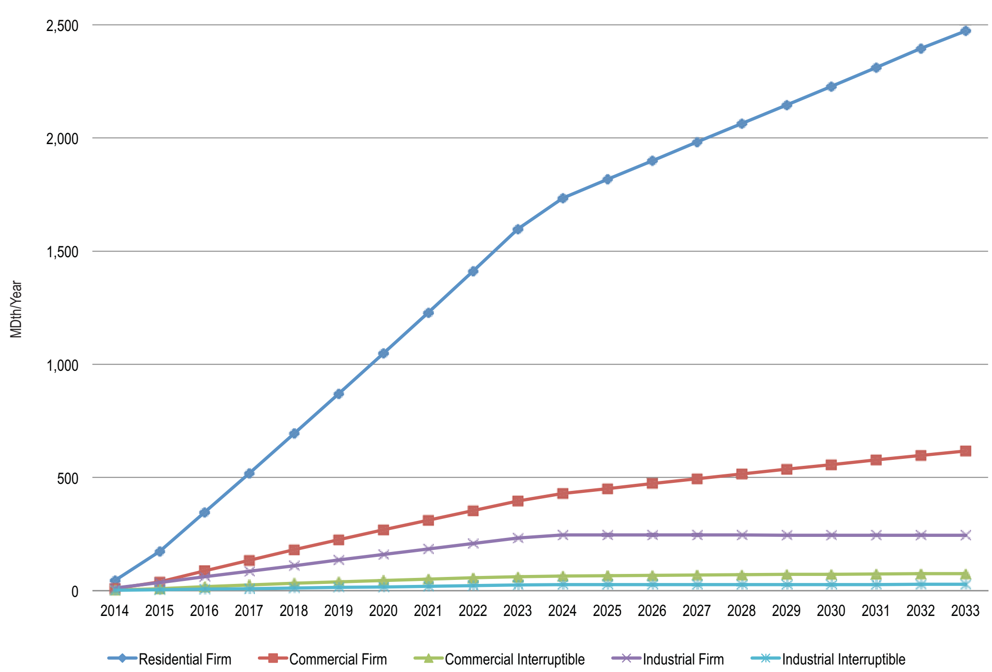


Figure 6-22
Savings Formatted for Portfolio Model Input – Bundle A (< $2.20/Dth) in each scenario of the 10-Year Ramp Rate



4. Gas Sales Analytic Methodology

In general, analysis of a gas supply portfolio begins with an estimate of resource need that is derived by comparing 20-year demand forecasts with existing resources. Once need has been identified, a variety of planning tools, optimization analyses, and input assumptions help PSE identify the lowest-reasonable-cost portfolio of gas resources within a variety of scenarios. (Key assumptions are explained in Chapter 4.)

Optimization analysis tools

PSE uses SENDOUT, from Ventyx, to model gas resources for long-term planning and long-term gas resource acquisition activities. SENDOUT is widely used and employs a linear programming algorithm to help identify the long-term, least-cost combination of resources that will meet stated loads. SENDOUT also has the capability to integrate demand-side resources with supply-side resources to determine an optimal resource portfolio. While the deterministic linear programming approach used in this analysis is a helpful analytical tool, it is important to acknowledge this technique provides the model with "perfect foresight," meaning that its theoretical results may not really be achievable. For example, the model knows the exact load and price for every day throughout a winter period, and can therefore minimize cost in a way that is not possible in the real world. In the real world, numerous critical factors about the future will always be uncertain. Linear programming analysis can help inform decisions, but it should not be relied on to make them.

To incorporate uncertainty about future gas prices and weather-driven loads, PSE acquired the add-in product VectorGas to use with SENDOUT. SENDOUT Version 12.5.5, which PSE currently uses, has integrated VectorGas's Monte Carlo capability into SENDOUT itself. Monte Carlo analysis of physical supply risk indicates whether a portfolio that meets our design peak day forecast is sufficient, in an otherwise normal-temperature winter, to meet our obligations under a variety of possible conditions. See Appendix L, Gas Analysis, for a more complete description of SENDOUT.

Deterministic optimization analysis

As described in Chapter 4, PSE developed ten scenarios to examine the impact of a range of possible future demand and price conditions on resource planning; eight of these were used in the gas sales resource analysis. Scenario analysis allows the company to understand how different resources perform across a variety of economic and regulatory conditions. Scenario analysis also clarifies the robustness of a particular resource strategy. In other words, it helps determine if a particular strategy is reasonable under a wide range of possible circumstances.

Monte Carlo analysis

PSE performed two kinds of Monte Carlo analyses to test different dimensions of uncertainty. The first tested how well a single resource portfolio performs under gas price and load uncertainty over the 20-year planning horizon. For example, this approach can tell under what percentage of the Monte Carlo draws a specific resource portfolio meets design peak day loads.

The second application of the Monte Carlo analyses develops optimal resource portfolios in each of the 100 scenario draws. This approach can be used to generate probability distributions for each potential resource addition; i.e. in what percentage of the Monte Carlo draws is a specific resource added. A deterministic analysis often overemphasizes the importance of the “optimal” portfolio.

PSE used Monte Carlo analyses to generate 100 daily price and temperature scenarios – or draws – for the 20-year planning horizon. For additional details of the SENDOUT analyses, see Appendix L, Gas Analysis.

5. Gas Sales Analysis Results

Key findings

The key findings from this analytical and statistical evaluation will provide guidance for development of PSE's long-term resource strategy, and also provide background information for resource development activities over the next two years.

1. **In the Base Scenario, the gas sales portfolio has adequate resources until the winter of 2016-17.** Under both the Low and High scenarios additional supply-side resources are also not needed until 2016-17.

2. **The acquisition of discretionary demand-side resource measures over a 10-year ramp rate reduces portfolio costs in all scenarios.** Delaying acquisition of discretionary DSR by 2 years in the 10-year ramp increased portfolio costs. Assuming a 20-year ramp rate also increased portfolio costs.

3. **Cost-effective DSR is lower in the 2013 IRP due to lower gas prices and due to past program achievements, updated end-use energy consumption model assumptions, and new standards and codes that resulted in some DSR being shifted out of utility program DSR bundles and into the standards and codes bundle.**

4. **The PSE LNG Project is cost-effective in all scenarios.** As currently envisioned, this project will have a total peaking capacity of 50 MDth per day and be available for service for the 2017-18 winter period.

5. **The Swarr upgrade project is cost-effective in all scenarios.**

6. **The Mist storage expansion is selected in all scenarios.**

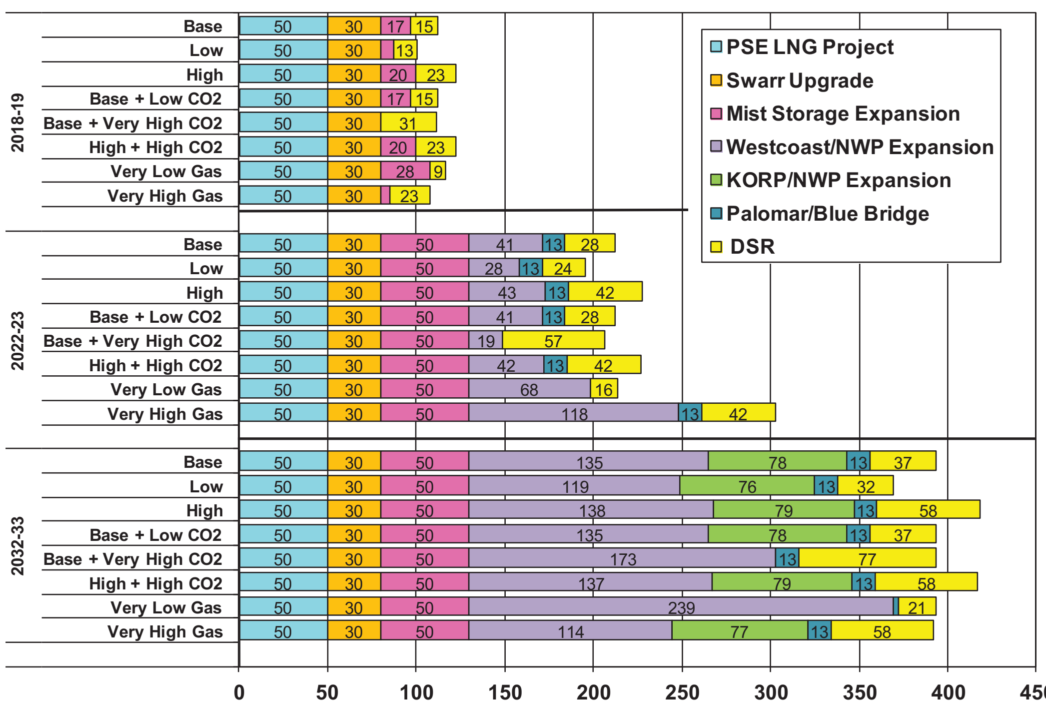
Gas Sales portfolio additions

Differences in resource additions are primarily driven by load growth and the gas and CO_2 price assumptions. Demand-side resources are influenced directly by gas and CO_2 price assumptions because they avoid commodity and emissions costs by their nature. However, the absolute level of efficiency programs is also affected by load growth assumptions.

The optimal portfolio resource additions in each of the eight scenarios are illustrated in Figure 6-23 for 2018, 2022, and 2032.

Figure 6-23
Gas Resource Additions in 2018, 2022, and 2032

(Peak Capacity – MDth/day)



Demand-side resource additions

The optimal level of energy efficiency resources for the integrated gas sales portfolios was determined by SENDOUT, as described earlier. We evaluated three DSR program designs for the gas sales portion of this IRP: one with a 20-year ramp rate for discretionary measures, another with a 10-year ramp rate and a third with a 10-year ramp rate whose start was delayed by two years.

Compared to the 20-year ramp, the 10-year ramp and the 10-year ramp with the two-year delay increased the DSR acquired during the near- and mid-term years and deferred the need for acquisition of some supply-side resources. All three acquired similar amounts of DSR by 2033. Comparing the total portfolio costs of the scenarios for each of the three ramp rates indicates that the 10-year ramp rate results in a lower net present value (NPV) portfolio cost in all scenarios. The NPV results are shown in Figure 6-24.

Figure 6-24
Net Present Value Portfolio Costs for Discretionary DSR Acceleration Rate Alternatives (dollars in billions)

Scenario	10 Year	10 Year Delayed	20 Year
Base	8.142	8.156	8.188
High	10.122	10.143	10.187
Low	6.075	6.084	6.106
High + High CO2	12.175	12.201	12.259
Base + Very High CO2	14.891	14.930	15.009
Base + Low CO2	8.749	8.765	8.799
Very Low Gas Price	4.254	4.259	4.268
Very High Gas Price	11.729	11.757	11.810

Based on these results, the 10-year ramp rate was included in all scenarios.

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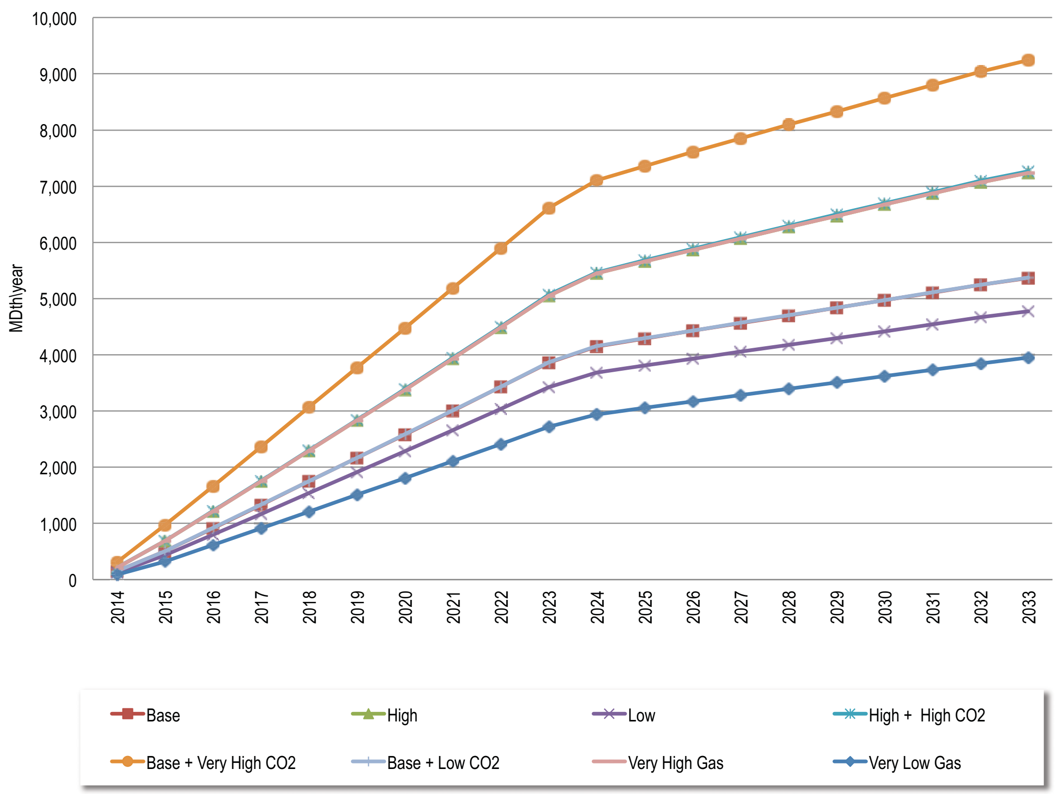
Figure 6-25
Cost-effective Gas Energy Efficiency Savings by Scenario



Compared to the 2011 IRP, there has been a downward shift in gas energy efficiency potentials. This is due to three factors (1) past program accomplishments have lowered future achievable potentials, (2) new, higher DOE efficiency standards for some gas appliances have moved some potentials from utility program bundles to standards and codes bundles, and (3) lower gas commodity prices. For more information on these differences from the 2011 IRP see Appendix N, Demand-side Resources Analysis.

DSR remains relatively sensitive to avoided costs in the gas analysis. The amount of achievable energy efficiency resources selected by the SENDOUT analysis in this plan ranged from roughly 4,000 MDth in 2033 for the Very Low Gas Price scenario to over double that at 9,000 MDth in 2033 in the Base + Very High CO_2 scenario.

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The optimal levels of demand-side resources, selected by market sector in the SENDOUT analysis, are shown in Fig 6-26, below. (For more information on demand-side bundles, see the "Demand-side Resource Alternatives" section in this chapter and Appendix N, Demand-side Resources Analysis.)

Figure 6-26
Gas Sales Cost-effective DSR Bundles by Sector and Scenario

Bundles	Base	High	Low	High+ High CO2	Base + Very High CO2	Base + Low CO2	Very High Gas	Very Low Gas
Residential Firm	C	D	B1	D	E	C	D	B
Commercial Firm	C	D	B1	D	E	C	D	A2
Commercial Interruptible	A2	B1	A1	C	C1	B	B1	A
Industrial Firm	A2	A2	A2	A2	D	A2	A2	A1
Industrial Interruptible	A2	A2	A2	A2	D	A2	A2	A

Overall, the economic potential of DSR in this IRP is lower than in the 2011 gas sales Base Scenario when the 10-year ramp rate is applied. Lower-cost bundles are being selected by the analysis as the most cost-effective level of DSR. In the 2011 IRP, SENDOUT selected the residential bundle up to a cost of $9.50/Dth; in this IRP, the $8.50/Dth residential bundle is the optimal bundle. A similar pattern is seen across sectors and scenarios.

Figure 6-27 compares PSE's energy efficiency accomplishments, current targets and new range of gas efficiency potentials. In the short term, this IRP indicates an economic potential savings of 473,640 to 1,318,000 Dth for the 2014-2015 period. The current target for the 2012-2013 period is within this range, and the scenarios provide guidance on how much cost-effective gas efficiency is possible to attain within the constraints of economic and market factors.

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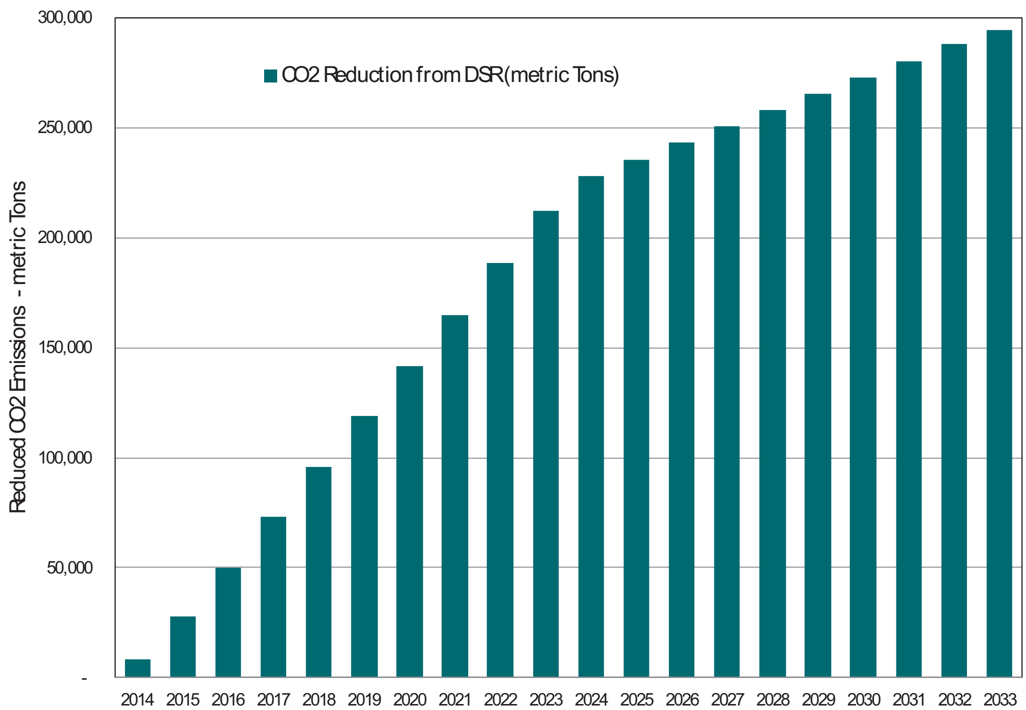
Figure 6-27
Short-term Comparison of Gas Energy Efficiency

Short-Term Comparison of Gas Energy Efficiency	Dth
2010-2011 Actual Achievement	1,022,013
2012-2013 Target (Updated Jan 2013)	954,860
2014-2015 Range of Economic Potential	473,640 – 1,318,000

Figure 6-28 shows the impact on CO_2 emissions at the customer end-use from energy efficiency measures in the Base Scenario.

Figure 6-28
CO_2 Emissions Reduction from Energy Efficiency in Base Scenario



Pipeline additions

Based on lower costs, the predominant pipeline resource addition in all scenarios is the expansion of the Northwest and Westcoast pipelines; this increases access to northern BC gas supplies. The KORP/NWP alternative was selected later in the study period in all but the Low scenario. A limited amount (between 3 and 13 MDth per day) of the Palomar/Blue Bridge project was selected in all the scenarios. Additional upstream pipeline capacity on the TC-AB, the TC-BC, and Westcoast pipelines was selected as needed to deliver supplies to the NWP and Palomar/Blue Bridge direct-connect projects.

Storage additions

Based on lower costs, the LNG Peaking Project and the Mist storage expansion were selected in all scenarios. These results indicate that PSE should continue to consider both projects.

Supply additions

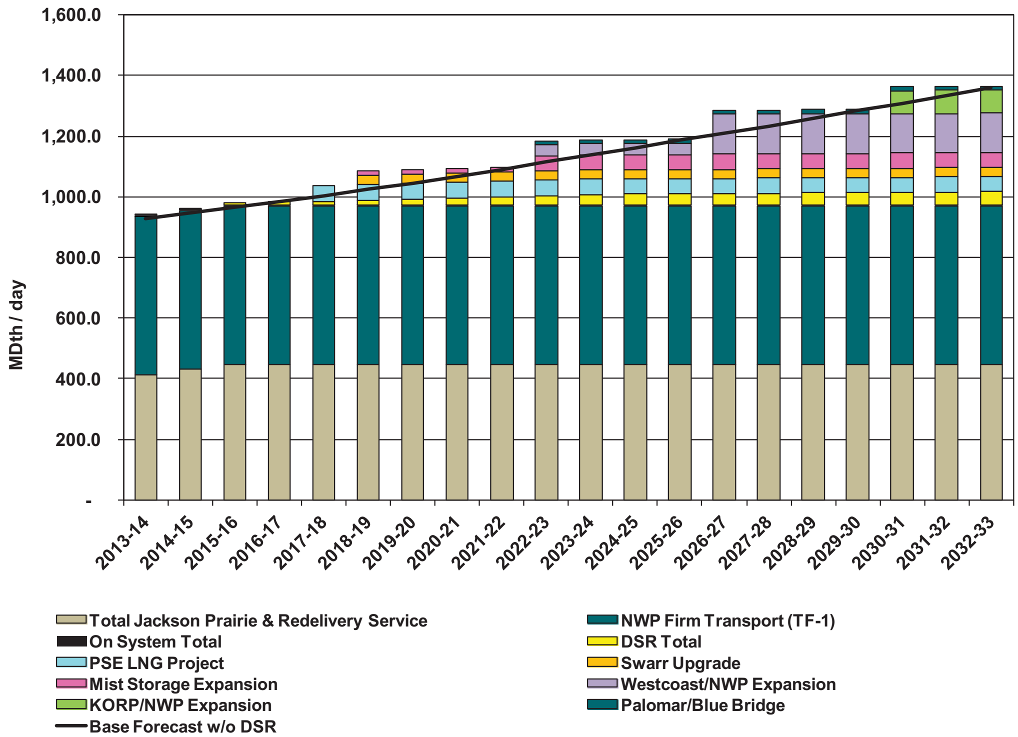
The Swarr LP-Air Upgrade project was the only specific supply alternative considered, and it was selected in all scenarios.

PSE continues to rely on acquisition of natural gas from creditworthy and reliable suppliers at major market hubs or production areas. For the IRP SENDOUT model, we assumed continuation of geographically diverse, long-term supply contracts (currently about two-thirds of annual requirements) throughout the planning horizon. The optimal portfolio would contain additional gas supply from various supply basins or trading locations, along with optimal utilization of existing and new capacity.

Complete picture: Base Scenario

A complete picture of the Base Scenario optimal resource portfolio is presented below in Figure 6-29. Additional scenario results are included in Appendix L, Gas Analysis.

Figure 6-29
Base Scenario Gas Resource Portfolio



Average annual portfolio cost comparisons

Figure 6-30 should be read with caution. Its value is comparative rather than absolute. It is not a projection of average purchased gas adjustment (PGA) rates; instead, costs are based on a theoretical construct of highly incrementalized resource availability. Also, average portfolio costs include items that are not included in the PGA. These include rate-base costs related to Jackson Prairie storage and costs for energy efficiency programs, which are included on an average levelized basis rather than a projected cash flow basis. It should also be noted that the perfect foresight of a linear programming model creates theoretical results that cannot be achieved in the real world.

Figure 6-30
Average Portfolio Cost of Gas for Gas Scenarios

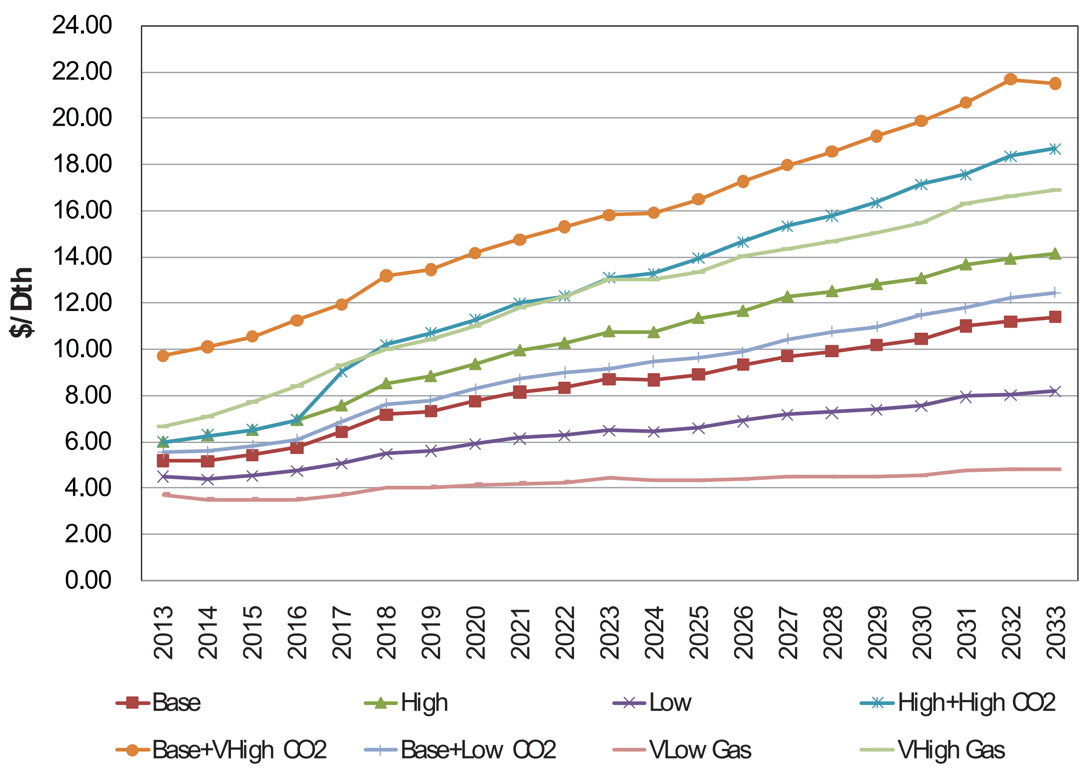


Figure 6-30 shows that average optimized portfolio costs are largely based on the gas price and CO_2 cost assumptions included in each scenario.

- Base Scenario portfolio costs are about $5.18 per Dth in 2014 and increase to about $11.40 per Dth by 2033.
- The Base + Very High CO_2 scenario costs start at about $10.13 per Dth, and rise to about $21.51 per Dth by 2033. (The only difference from the Base Scenario is CO_2 emissions cost.) This is the highest cost scenario primarily due to the very high CO_2 cost assumptions. Similarly the Base + Low CO_2 scenario only differs from the Base Scenario by the CO_2 cost assumptions.
- The High + High CO_2 is similar to the High scenario with the only difference being the high CO_2 cost assumptions. This was the second highest cost scenario.
- The Very Low Gas Price and Low scenarios have the lowest portfolio prices; these reflect lower gas price assumptions and minimal CO_2 costs.

Results of Monte Carlo analysis

Monte Carlo analyses on the Base Scenario optimal resource portfolio provided a reasonable test of whether the company's current planning standard (using normal weather with one design peak day per year) creates a portfolio that will meet firm demand under a wide range of temperature conditions. Results indicate that the Base Scenario resource portfolio, which incorporates the current standard, will meet firm demands in over 96 percent of the winter periods draws. The current peak planning standard will be compared with an alternative winter design peak standard later in this chapter.

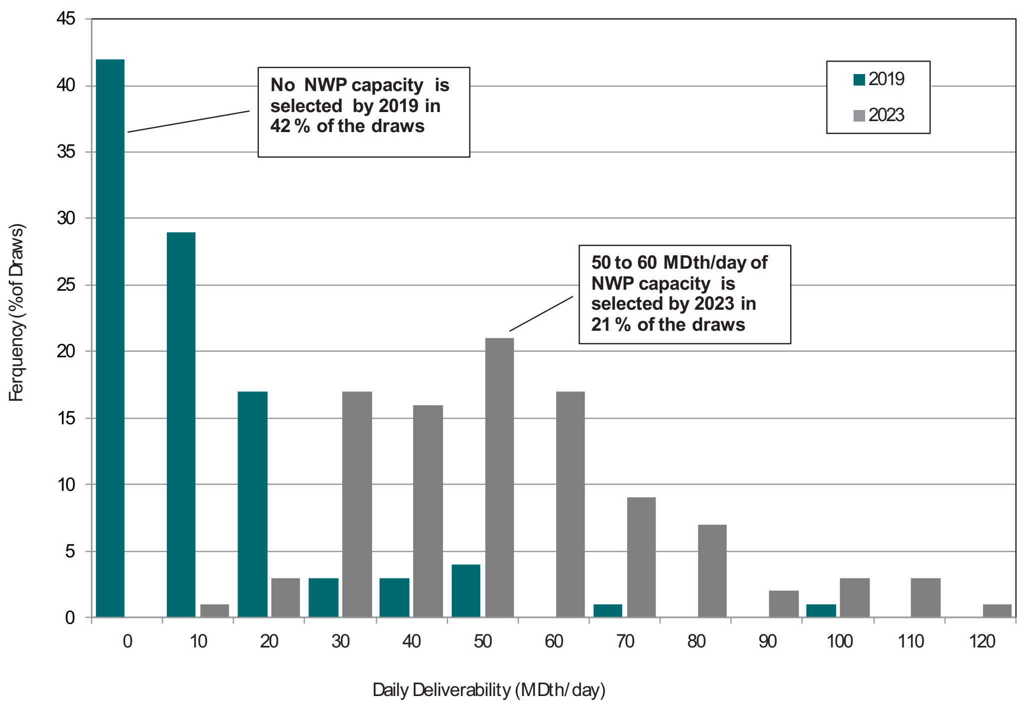
The Monte Carlo analysis also tested the sensitivity of resource additions in the Base Scenario. Analyses examined seven specific resource addition alternatives: the various DSR bundles, Mist storage, the LNG Peaking Project, NWP from Sumas to PSE, KORP, the Palomar/Blue Bridge pipeline alternative, and the Swarr LP-Air Upgrade project. This discussion compares the deterministic analysis results with the Monte Carlo resource optimization analysis.

The Monte Carlo results were evaluated to check the resources selected as of October 2019 and October 2023. The DSR bundles selected in the Monte Carlo analyses were essentially the same as those selected in the deterministic case; both the deterministic and Monte Carlo analysis selected a mix of DSR with 16 MDth per day of peak savings in

2019 and 31 MDth per day of savings in 2023. There were only 2 to 3 draws with minor differences. The Swarr LP-Air Upgrade project is also selected in all draws.

NWP from Sumas to PSE service territory. Figure 6-31 shows the frequency distribution with which the NWP pipeline alternative is selected across the 100 draws by the year 2019 and 2023. As shown, no NWP capacity is selected by 2019 in 42 percent of the draws and between 50 and 60 MDth per day of capacity is selected in 21 percent of the draws. In the deterministic analyses, no capacity was selected by 2019 and 37 MDth per day of capacity was selected by 2023.

Figure 6-31
Frequency Distribution of NWP Pipeline Development by 2019 and 2023



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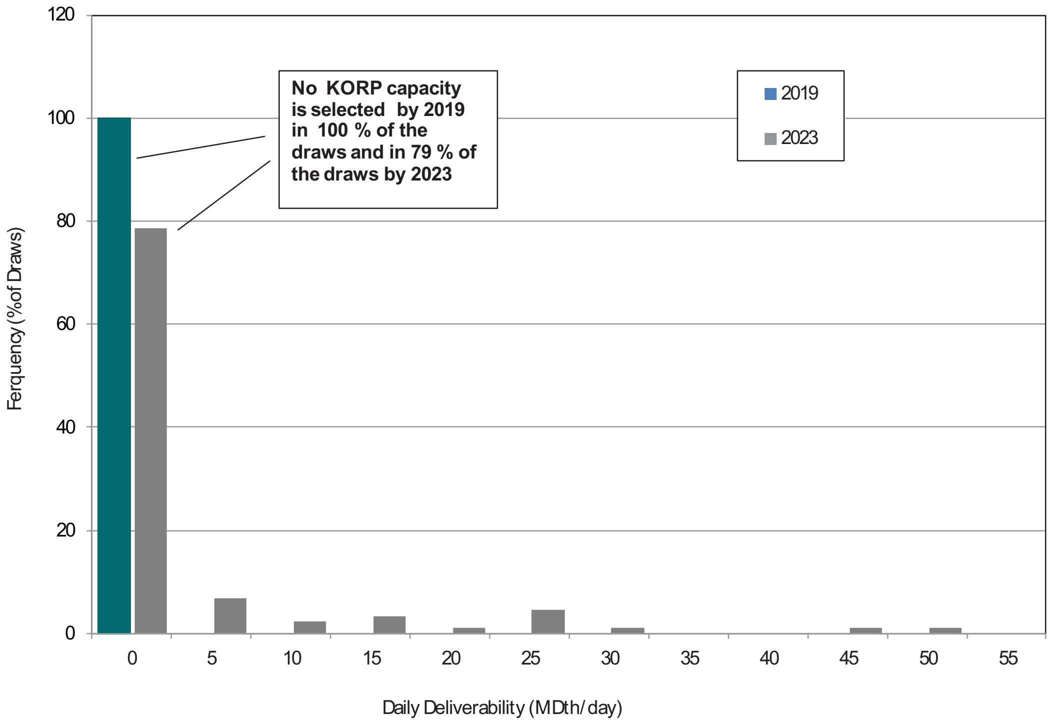
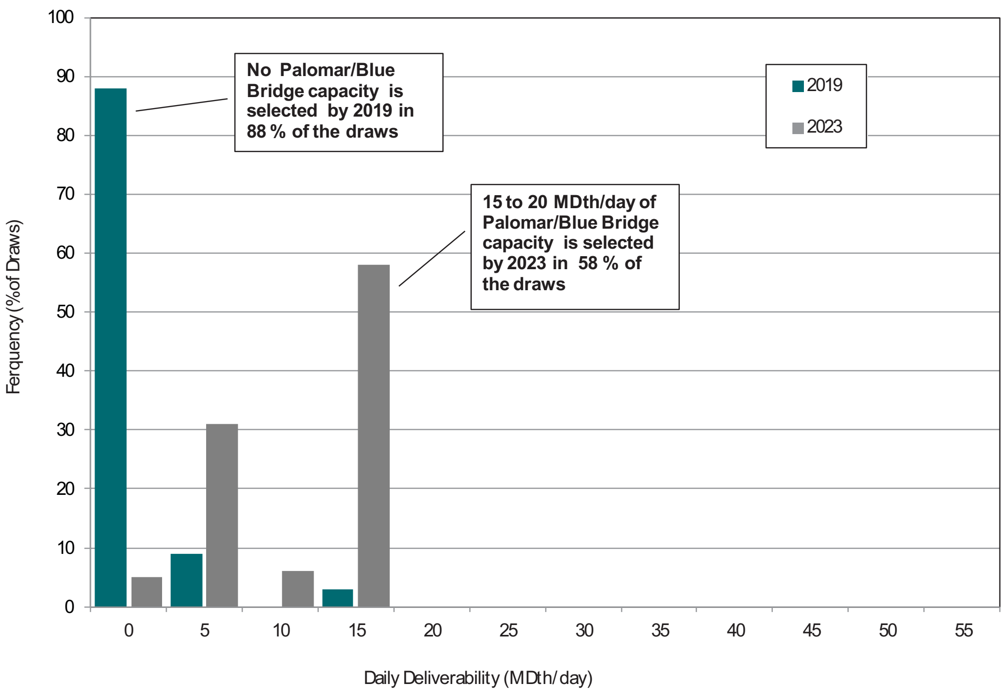
KORP pipeline. Figure 6-32 illustrates the frequency distribution for the KORP pipeline alternative. As shown, no KORP capacity is selected by 2019 in 100 percent of the draws and in 79 percent of the draws by 2023. Note that this option was not selected until 2030 in the deterministic analyses.

Figure 6-32
Frequency Distribution for the KORP Pipeline by 2019 and 2023



Palomar/Blue Bridge pipeline. Figure 6-33 illustrates the frequency distribution for the Palomar/Blue Bridge pipeline alternative. As shown, no Palomar/Blue Bridge capacity is selected by 2019 in 88 percent of the draws and 15 to 20 MDth per day of capacity is selected by 2023 in 58 percent of the draws by 2023. Note that 13 MDth per day of capacity was selected by 2023 in the deterministic analyses.

Figure 6-33
Frequency Distribution for the Palomar/Blue Bridge Pipeline by 2019 and 2023



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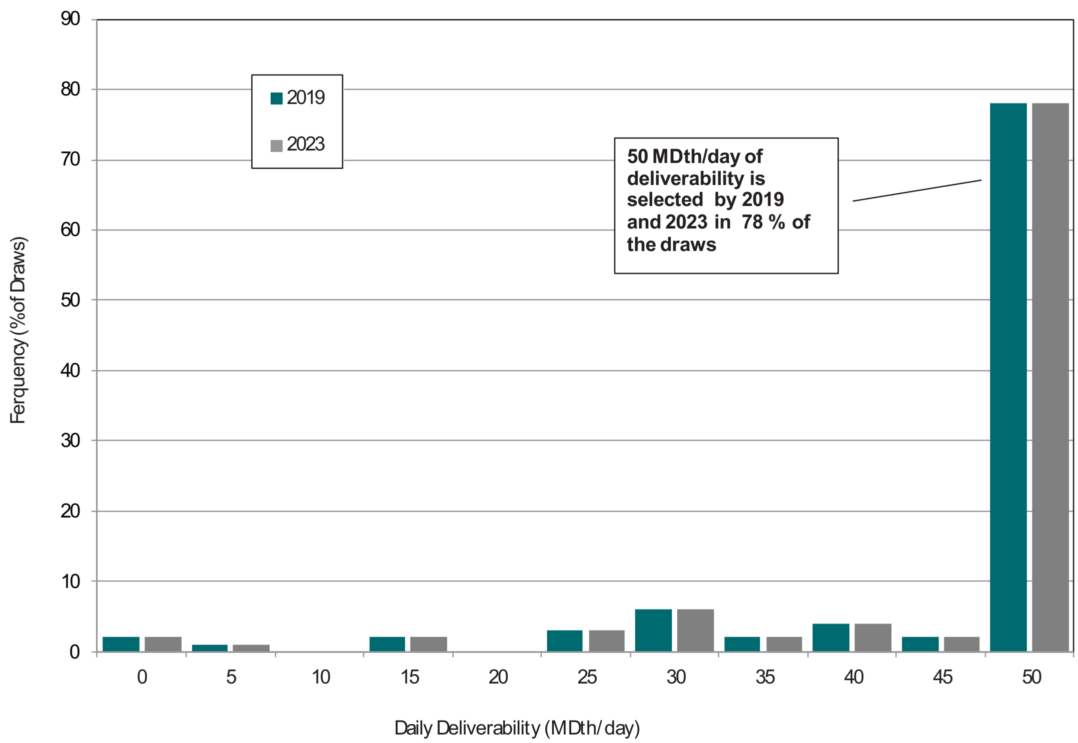
LNG Peaking Project. Figure 6-34 shows the frequency distribution for the LNG Peaking Project alternative. In 78 percent of the Monte Carlo scenarios, the LNG Peaking Project alternative is selected at the full deliverability of 50 MDth per day by 2019 and 2023. In the deterministic analysis the project is selected with a deliverability of 50 MDth per day.

Figure 6-34
Frequency Distribution for LNG Peaking Project by 2019 and 2023



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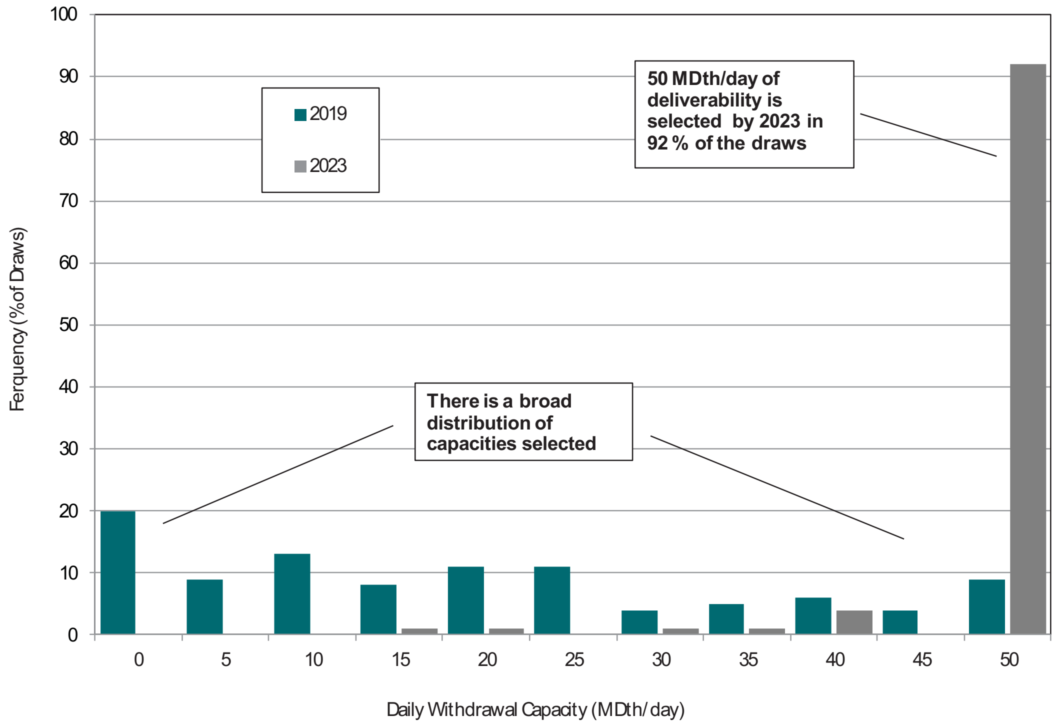
Mist storage. Figure 6-35 shows the frequency distribution for the Mist storage expansion project.

Figure 6-35
Frequency Distribution for Mist Storage Expansion by 2019 and 2023

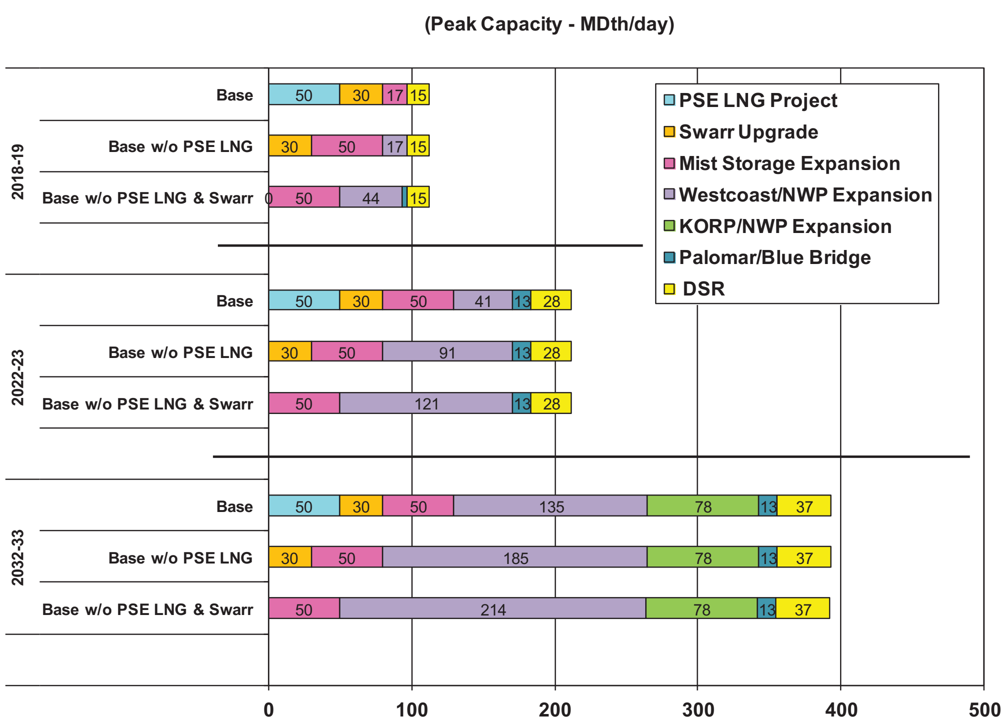


Evaluation of resource additions without LNG Peaking Project and Swarr Upgrade

The LNG Peaking Project and Swarr Upgrade project are selected by 2018 in all the scenarios evaluated; however, it is important to realize that these projects are in the evaluation stages and may never be implemented. The LNG project depends upon final cost-effectiveness, and it will require agreements with transportation customers for the sale and purchase of LNG. Completion of the Swarr Upgrade project will depend upon cost-effectiveness and an evaluation of environmental safety.

Two additional SENDOUT evaluations were done to determine least-cost resource alternatives in the event either or both of projects are not completed. One case assumes the LNG Peaking Project is not built, but the Swarr Upgrade project is. The second case assumes that neither project is completed. These results are compared to the Base Scenario results in Figure 6-36.

Figure 6-36
Gas Resource Additions without the LNG Peaking Project & Swarr Upgrade



In both cases, additional NWP and Westcoast pipeline capacity to Sumas and Station 2, respectively, are added to replace the LNG Peaking and Swarr projects.

The net present values of these three cases are shown in Figure 6-37. As expected, the portfolio costs are higher for the cases without the LNG Peaking and Swarr Upgrade projects.

Figure 6-37
Net Present Value Portfolio Costs for Portfolios without LNG Peaking Project & Swarr Upgrade (dollars in billions)

	NPV Portfolio Costs
Base	8.142
Base w/o PSE LNG	8.180
Base w/o PSE LNG & Swarr	8.243

Evaluation of alternative extreme winter design peak criteria

For the gas sales portfolio PSE currently uses an extreme design peak day planning standard consisting of an extreme peak day with an average temperature of 13 degrees in January and 30-year average daily temperatures for the rest of the year. The derivation of this planning standard is summarized in PSE's 2005 Least Cost Plan, Appendix I-Gas Planning Standard.

There is some concern that the current planning standard does not adequately address the reliability of supply during periods of sustained cold weather. Current pipeline capacity alone cannot meet loads when average temperatures go below approximately 35 degrees. During cold periods PSE relies heavily on the Jackson Prairie gas storage project for gas supply. The storage facility accounts for about 44 percent of peak supply capacity. However, Jackson Prairie's withdrawal capacity decreases by 2 percent for every 1 percent that the inventory drops below 60 percent full. At full withdrawal rates Jackson Prairie can operate at full capacity for about 10 days before capacity begins to decline. (This assumes full inventory at the start.) During extended periods of cold weather when loads exceed firm pipeline capacity, it is not possible to refill Jackson Prairie while also meeting customer loads.

An alternative winter design peak planning standard was developed using historical temperature data from 1950 through 2011. This standard includes both an extended cold period as well as a day with an average temperature of 13 degrees F. This alternative standard uses historical December and January Heating Degree Days (HDDs) that rank at approximately the 95th percentile for these months. The historical months closest to the 95th percentile are December 1964 and January 1969. The combined December and January temperatures result in a 98th percentile 2-month period. Including data from a normal November and February results in a four-month cold period that ranks at approximately the 86th percentile.

The daily average temperatures for the two winter planning standards for December and January are shown in Figure 6-38 below.

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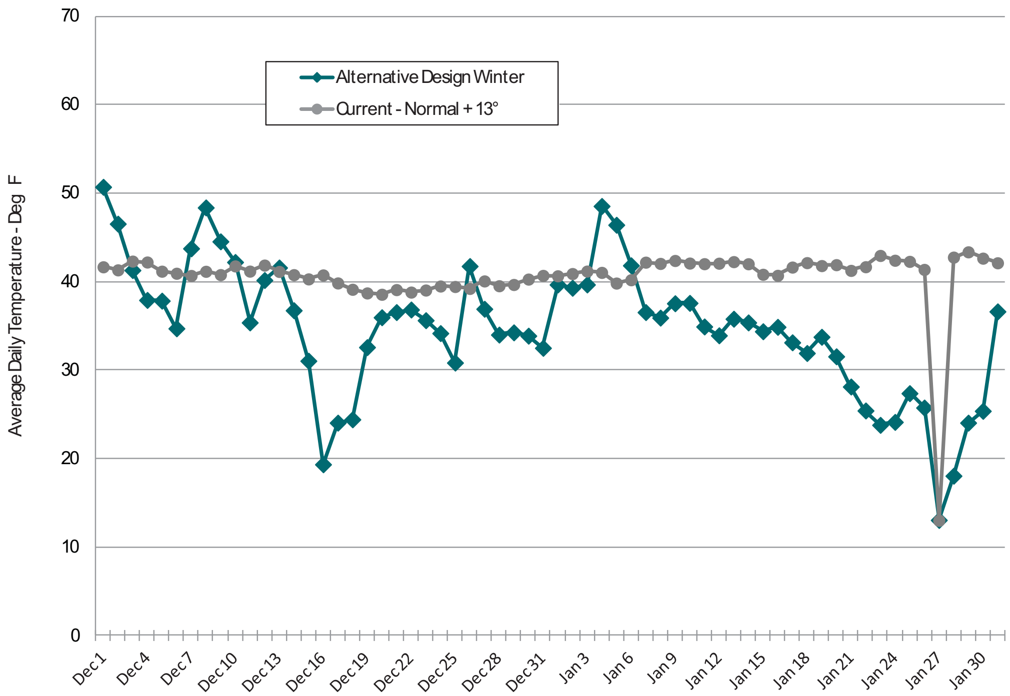
Figure 6-38
Comparison of Daily Temperatures for Current and Alternative Winter Design Peak Planning Standards



A number of SENDOUT model runs were performed using the current and alternative planning standards to evaluate differences in portfolio costs and reliability benefits.

Two SENDOUT model analyses were performed for each standard. First the analysis made deterministic runs to select the optimal set of resources for each of the design peak standards. These resources were then selected or “fixed” in the resource portfolios over the time period of the study (through 2033).

The optimal portfolios developed for the two standards included essentially the same resources, except that the alternative standard added more NWP capacity. The amount of NWP capacity added in the two cases is shown in Figure 6-39.

Figure 6-39
Comparison of NWP Capacity Additions for Current and Alternative Winter Planning Standards (MDth/day)

	2018-19	2022-23	2026-27	2032-33
Current - Normal+13°	-	36	132	207
Alternative Design Peak Winter	21	45	139	215

The next step of the analyses was to include these fixed resource portfolios in stochastic, Monte Carlo model runs where the monthly and daily temperatures were varied based on historic weather conditions. Gas prices were also varied based on historic gas price volatility. One hundred Monte Carlo draws were done over the 20-year planning horizon. In total, the analyses included 2,000 winter periods (20 years x 100 draws). In both planning standard cases, there were periods where resources were not sufficient to supply the load. In some cases the peak loads in the Monte Carlo runs exceeded the design peak load used to develop the portfolio (13 degrees or 52 HDDs). In other cases a series of high-load days resulted in declines in the Jackson Prairie withdrawal capacity that resulted in unserved load.

The impact on costs and the number of unserved energy events are compared in Figure 6-40. For the alternative standard, levelized annual fixed costs are about $1.8 million higher per year, reflecting the increased NWP capacity included in this case. The increased pipeline capacity reduces the number and magnitude of the periods with unserved energy. There are 12 less outage events in the case using the alternative standard than in the case using the existing Normal+13 degree standard. The amount of unserved energy and the maximum percent of load not served are also less in the case using the alternative design peak standard.

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Figure 6-40
Comparison of Costs and Outages for Current and Alternative Winter Design Peak Standards

	Normal+13° Design	Alternative Standard	Difference
Levelized Annual Fixed Costs ($-millions)	169	171	1.8
Total Unserved Demand (MDth)	19,031	12,229	-6,802
Number of Outage Events	61	49	-12
% of Years with an Outage Event	3.1%	2.5%	-0.6%
Average Load Unserved During an Outage Events (MDth)	312	245	-67
Average % of Load Unserved During Outage Events	1.7%	1.3%	-0.4%
Maximum % of Load Unserved During Outage Events	6.5%	5.5%	-1.0%

Based on the analyses done to date, it is not yet clear whether changing to the alternative design peak winter planning standard is justified. Further analyses and review will be needed before a change is made.

6. Gas-for-power Portfolio Analysis Results

In past IRPs, PSE has included a SENDOUT analysis of the combined gas sales and gas-for-power portfolios. Modeling the two portfolios together contributes some insights but does not provide information on the need and allocation of resources between the two portfolios.

The results discussed in this section are for the electric Base Scenario. As discussed in Chapter 5, the Base Scenario results call for 10 additional gas-fired peakers to be added over the next 20 years. It is assumed that these plants will be located along the I-5 corridor.

Key findings

The key findings provide guidance for development of PSE's long-term resource strategy, and also provide background information for resource development activities over the next two years.

1. **As with the gas sales portfolio analysis, the Mist storage expansion alternative appears cost-effective for the gas-for-power portfolio.**

2. **Over the longer term, a limited amount of additional NWP capacity is selected.**

Gas-for-power supply-side resources

Pipeline and storage capacity

Figure 6-41 summarizes the firm pipeline transportation capacity for delivery of fuel to PSE's gas-fired generation plants.

Figure 6-41
Power Generation Gas Pipeline Capacity (Dth/day, as of 01/01/2013)

Direct-connect Capacity						
Plant	**Transporter**	**Service**	**Capacity (Dth/day)**	**Primary Path**	**Year of Expiration**	**Renewal Right**
Whitehorn	Cascade Natural Gas	Firm	(1)	Westcoast (Sumas) to Plant	2013	Yr. to Yr.
Ferndale	Cascade Natural Gas	Firm	(2)	Westcoast (Sumas) to Plant	2037	Yr. to Yr.
Encogen	Cascade Natural Gas	Firm	(2)	NWP (Bellingham) to Plant	2013	Yr. to Yr.
Fredonia	Cascade Natural Gas	Firm	(2)	NWP (Sedro-Woolley) to Plant	2021	Yr. to Yr.
Mint Farm	Cascade Natural Gas	Firm	(2)	NWP (Longview) to Plant (6)	2013,2018	Yr. to Yr.
Freddy 1	NWP	Firm	21,747	Westcoast (Sumas) to Plant	2018	Yr. to Yr.
Goldendale	NWP	Firm	45,000	Westcoast (Sumas) to Everett (4)	2018	Yr. to Yr
Upstream Capacity						
Plant	**Transporter**	**Service**	**Capacity (Dth/day)**	**Primary Path**	**Year of Expiration**	**Renewal Right**
Various	Westcoast	Firm	21,829 (3)	Station 2 to Sumas	2014	Yes
Various	Westcoast	Firm	51,345 (3)	Station 2 to Sumas	2018	Yes
Various	Westcoast	Firm	33,313 (3)	Station 2 to Sumas or Kingsgate (7)	2017	Yes
Various	NWP	Firm	2,128	Stanfield to Deer Island	2025	Assumed (8)

Plant	Transporter	Service	Capacity (Dth/day)	Primary Path	Year of Expiration	Renewal Right
Various	NWP	Firm	4,928	Stanfield to Bellingham	2025	Assumed (8)
Various	NWP	Firm	21,872	Stanfield to Jackson Prairie	2025	Assumed (8)
Various	NWP	Firm	2,000	Sumas to Tacoma	2013	Yes
Various	NWP	Firm	25,000	Sumas to Deer Island	2013	Yes
Various	NWP	Firm	6,829	Sumas to Longview	2013	Yes
Various	NWP	Firm	18,171	Sumas to Jackson Prairie	2014	Yes
Various	NWP	Firm	10,710	Sumas to Stanfield	2044	Yes
Various	NWP	Firm	500	Sumas to Longview	2044	Yes
Various	NWP	Firm	9,000	Sumas to Longview	2012	Yes
Storage Capacity						
Plant	**Transporter**	**Service**	**Deliverability (Dth/day)**	**Storage Capacity (Dth)**	**Year of Expiration**	**Renewal Right**
Jackson Prairie	NWP	Firm	6,704	140,622	2026	Yes
Jackson Prairie (5)	PSE	Firm	50,000	500,000	2016	No

Notes:

1) 50% of plant requirements.
2) Full plant requirements.
3) Converted to approximate Dth/day from contract stated in cubic meters/day.
4) Gas transported from Everett to Goldendale under NWP flex rights, backed by exchange agreement with PSE's gas sales portfolio.
5) Storage capacity made available (at market-based price) from PSE gas sales portfolio. Renewal may be possible, depending on gas sales portfolio needs. The gas sales portfolio may recall 15,000, 35,000 and 50,000 Dth per day of firm withdrawal rights for up to 4 days in each winter 2013/14, 2014/15 and 2015/16, respectively.
6) 30,000 Dth/day is year to year; 22,000 terminates in 2018.
7) 29,488 Dth/day has an option for Kingsgate delivery; this option terminates 10/31/2014.
8) PSE does not have guaranteed renewal rights on this segmented capacity, however, the releasing shipper has indicated willingness to renew the agreement, subject to approval by the pipeline. PSE assumes for planning purposes that such release would be renewed.

PSE has firm NWP pipeline capacity to serve our combined-cycle generating plants that require NWP service (Encogen, Freddy 1, Goldendale, and Mint Farm); Sumas is directly connected to Westcoast. Ferndale is connected to Sumas via firm capacity on Cascade Natural Gas. All of our simple-cycle combustion turbine generation units (Whitehorn, Fredonia, and Frederickson) have back-up fuel-oil firing capability and thus do not require firm pipeline capacity on NWP.

Existing gas-for-power supplies

As discussed earlier, gas supply contracts tend to have a shorter duration than pipeline transportation contracts, with terms to ensure supplier performance. We meet average loads with a mix of long-term (more than two years) and short-term (two years or less) gas supply contracts. Longer-term contracts typically supply base-load needs and are delivered at a constant daily rate over the contract period. We estimate average load requirements for upcoming months and enter into transactions to balance load. PSE balances daily and intra-day positions using storage (from Jackson Prairie), day-ahead purchases, and off-system sales transactions. PSE will continue to monitor gas markets to identify trends and opportunities to fine-tune our contracting strategies.

Biogas supplies. PSE has purchased biogas from King County's wastewater treatment plant in Renton, Wash. since 1985. The daily output of this plant is approximately 500 Dth per day.

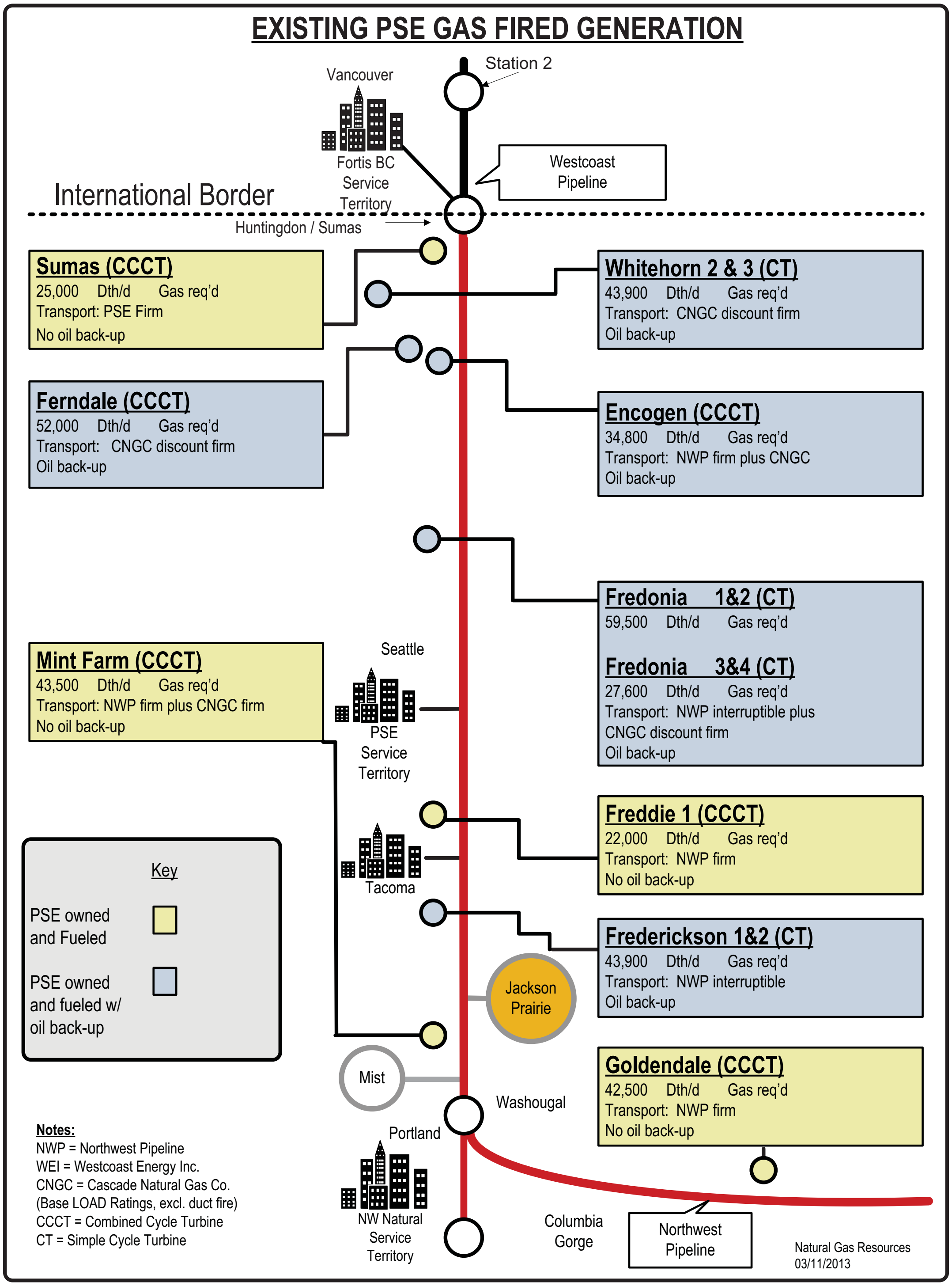
PSE also purchases pipeline-quality gas processed by Bio-Energy-Washington from landfill gas produced at the King County Cedar Hills Regional Landfill. The gas is delivered into NWP (which is adjacent to the landfill) and from there to both intrastate and interstate biogas markets. PSE captures the market value of the bio-gas and the associated environmental attributes and credits the net benefit of the transaction to PSE's electric customers. Cedar Hills is expected to supply an average of approximately 4 to 5 MDth per day of methane.

Gas-fired generating plants

PSE's existing gas-fired generating plants are located generally along the I-5 corridor in western Washington, as the map in Figure 6-42 shows. The exception is Goldendale, which is located near Goldendale, Washington. The peak gas requirement and the type of gas pipeline delivery are also listed. The capacity and heat rates for the plants are included in Chapter 5, Electric Analysis.

Figure 6-42

PSE's Existing Gas-fired Generating Plants



Gas-for-power analytic methodology

For this IRP, PSE developed a separate SENDOUT database to evaluate the resource needs of the gas for power portfolio. Two primary sets of data are required to model this portfolio: 1) the costs and capacities for the existing pipeline, storage, and gas supply markets as well as for the new supply resources, and 2) forecasts of the loads of the existing and future gas-fired plants. The existing and possible new supply resources are generally the same and are described earlier in this chapter. The Aurora model develops forecasts of the gas required for the gas-fired plants when performing the stochastic analyses of the various electric portfolio scenarios; Aurora also dispatches the resources and calculates the electric generation and gas burned.

SENDOUT modeling methodology was discussed earlier in this chapter. While the methodology for the gas-for-power portfolio is very similar, the approach to developing the electric loads is different from gas sales loads. In general, the gas-fired plants are economically dispatched based on the relationship of the market heat rate to the plant heat rate.

Because electric and gas prices vary based on regional factors such as loads and hydro generation as well as demand for electricity from adjoining regions, the dispatch of gas-fired plants varies greatly depending on market and weather conditions. The stochastic approach used by the Aurora model incorporates these conditions SENDOUT modeling for the gas for power portfolio is also done using a Monte Carlo approach.

Several statistics of the monthly gas loads from the Aurora stochastic analysis (250 Monte Carlo draws) were calculated and used as input to SENDOUT. These statistics included the average, maximum, minimum, and standard deviation for each month for the 250 draws. Using these statistics SENDOUT determines the monthly gas use for each generating plant over the 20-year analysIs period for each Monte Carlo draw. The SENDOUT approach used 100 Monte Carlo draws.

The daily plant dispatch patterns from the Aurora stochastic analysis were used to allocate monthly gas use across to the days of the month. This data allows SENDOUT to represent the daily gas loads over the 20-year study period for each of the 100 draws. The results shown in the next section are based on these stochastic results.

Gas-for-power analysis results

Two basic resource alternatives were evaluated for additional supply for the gas for power portfolio. These alternatives are the expansion of NWP and Westcoast pipeline to Sumas and northern BC, and expansion of the Mist storage facility.

The average amount of these resources selected across the 100 Monte Carlo draws is shown in Figure 6-43. The Mist storage expansion is assumed to be available by 2016 with withdrawal capacity of 50 MDth per day available. Essentially this expansion replaces the Jackson Prairie capacity currently leased by the gas-for-power portfolio from the gas sales portfolio. This lease is assumed to end in 2016. An additional 50 MDth per day of capacity is selected by 2018, and 50 MDth per day is added in 2026. Additional NWP capacity is also added over the period for a total of 156 MDth per day of capacity additions by 2032.

As discussed earlier and illustrated in Figure 6-2, all of the gas-fired plants added in the Base Scenario are peakers with oil back-up, so no additional firm pipeline capacity would be needed – if the plant needs are considered independently. However, when analyzed as part of a supply portfolio (with other gas-fired plants' needs) additional gas pipeline capacity may be required to supply the volumes needed to support the total load and maintain sufficient storage to ensure reliable service. This is the case in the majority of the Monte Carlo draws; an average of 31 MDth per day of capacity is added by 2019, 86 MDth per day is added by 2023 and 156 MDth per day is added by 2033.

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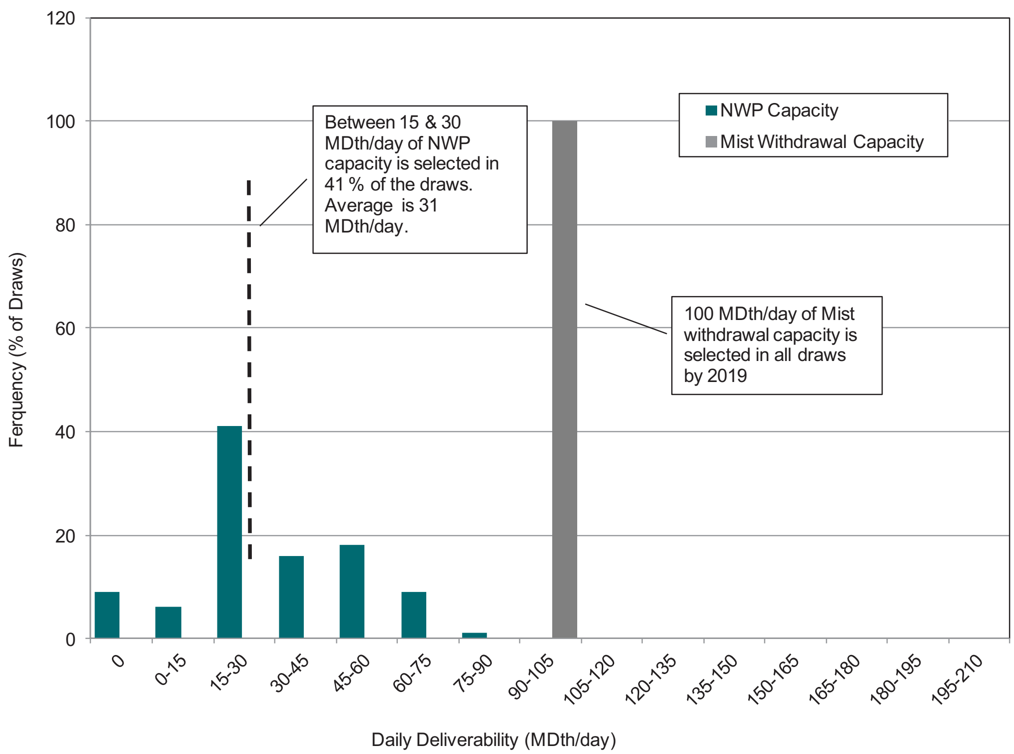
Figure 6-43
Average Resource Capacities Selected for the Gas for Power Portfolio (MDth/day)

	2018-19	2022-23	2032-33
NWP/Westcoast Expansion	31	86	156
Mist Expansion	100	100	150

Figure 6-44 shows the frequency distribution with which the NWP pipeline and Mist storage alternatives are selected across the 100 draws by the year 2019. As shown, the average amount of NWP capacity selected shows a relatively wide distribution from 0 to 82 MDth per day. The average amount selected in the 100 draws was 31 MDth per day. The full amount of Mist storage expansion available is selected in all 100 draws.

Figure 6-44
Frequency Distribution of NWP and Mist Storage Development by 2019



CHAPTER 6 – GAS ANALYSIS

As noted earlier, ten peakers with a total capacity of 2,212 MW are added to the portfolio in the electric Base Scenario by 2033. The peak gas need of these plants is approximately 543 MDth per day. It is assumed that these peakers have 2 days of oil back-up supply sufficient to meet extreme peak needs and that additional firm pipeline capacity will not be required. However, the SENDOUT analysis indicates that on a portfolio basis, additional pipeline capacity will be required to meet portfolio needs when a number of peakers are added.

A total of 150 MDth per day of Mist expansion storage capacity is added in the SENDOUT analysis. This is in line with the estimate of having storage capacity equal to approximately 20 percent of the peak gas-supply needs for gas-fired plants. Twenty percent of the 543 MDth per day peak gas need is 109 MDth per day.

CHAPTER 7

Delivery Infrastructure Planning

Contents

This chapter addresses planning for the PSE-owned delivery system that delivers electricity and natural gas within our local service area to more than 1.8 million customers. Merchant-based delivery systems that involve arrangements with outside companies and organizations to transport power and natural gas to our service area are discussed in Chapter 5, Electric Analysis.

1. System Overview

Responsibilities

PSE's delivery system is responsible for delivering natural gas and electricity through pipes and wires safely, reliably, and on demand. We are also responsible for meeting all regulatory requirements that govern the system. To accomplish this, we must do the following.

- Operate and maintain the system safely and efficiently on a year-by-year, day by-day, and hour-by-hour basis.
- Accomplish timely maintenance and reliability improvements.
- Meet state and federal regulations and complete compliance-driven system work.
- Ensure that gas and electric systems meet both peak demands and day-to-day demands.

- Ensure that localized growth needs are addressed when they differ from overall system growth needs.
- Meet the interconnection needs of independent power generators that choose to connect to our system.
- Plan for future needs so that infrastructure will be in place when the need arrives.

Some of these are regional responsibilities. For instance, all PSE facilities that are part of the Bulk Electric System and the interconnected western system must be planned and designed in accordance with the latest approved version of the North American Electric Liability Corporation (NERC) Transmission Planning Reliability Standards. These standards set forth performance expectations that affect how the transmission system – 100 kV and above – is planned, operated, and maintained. PSE also must follow Western Electricity Coordinating Council (WECC) reliability criteria; these can be more stringent than NERC standards at times.

PSE must also ensure that the system is flexible enough to adapt to coming changes. Smart Grid components, electric vehicles, customer distributed resources, and demand response programs are some of the effective solutions the industry is moving toward in the future, and we need to be prepared to integrate them for the benefit of our customers.

The goal of PSE's planning process is to help us fulfill these responsibilities in the most cost-effective manner possible. Through it, we evaluate system performance and bring issues to the surface. We identify and evaluate possible solutions. And we explore costs and consequences of potential alternatives. This information helps us make the most effective, and cost-effective decisions going forward.

Existing system

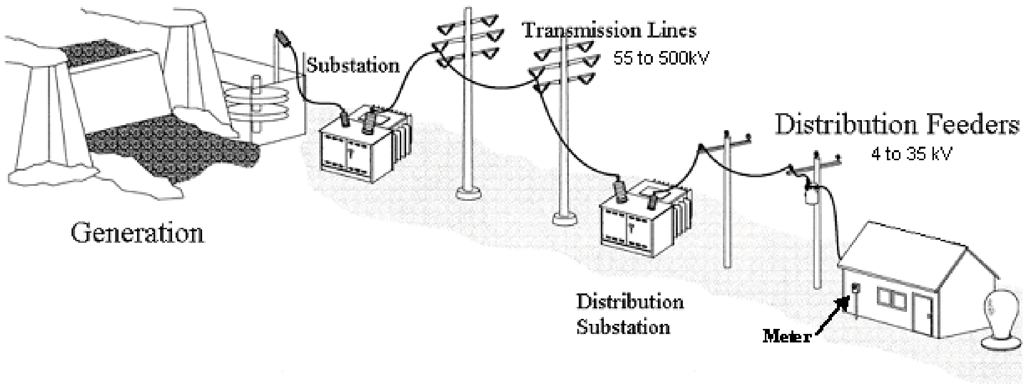
The table below summarizes PSE's existing delivery infrastructure as of December 31, 2012. Electric delivery is accomplished through wires, cables, substations, and transformers. Gas delivery is accomplished by means of pipes and pressure regulating stations.

Figure 7-1
PSE-owned Transmission and Distribution System as of December 31, 2012

Electric	Gas
Customers: 1,092,306	*Customers: 767,601*
Service area: 4,500 square miles	*Service area: 2,800 square miles*
Substations: 362	*City gate stations: 40*
Miles of transmission line: 2,619	*Pressure regulating stations: 652*
Miles of overhead distribution line: 10,643	*Miles of pipeline: 12,041*
Miles of underground distribution line: 10,232	*Supply system pressure: 150–550 psig*
Transmission line voltage: 55-500 kV	*Distribution pipeline pressure: 45-60 psig*
Distribution line voltage: 4-34.5 kV	*Customer meter pressure: 0.25 psig*
Customer site voltage: less than 600 V	

CHAPTER 7 – DELIVERY INFRASTRUCTURE PLANNING

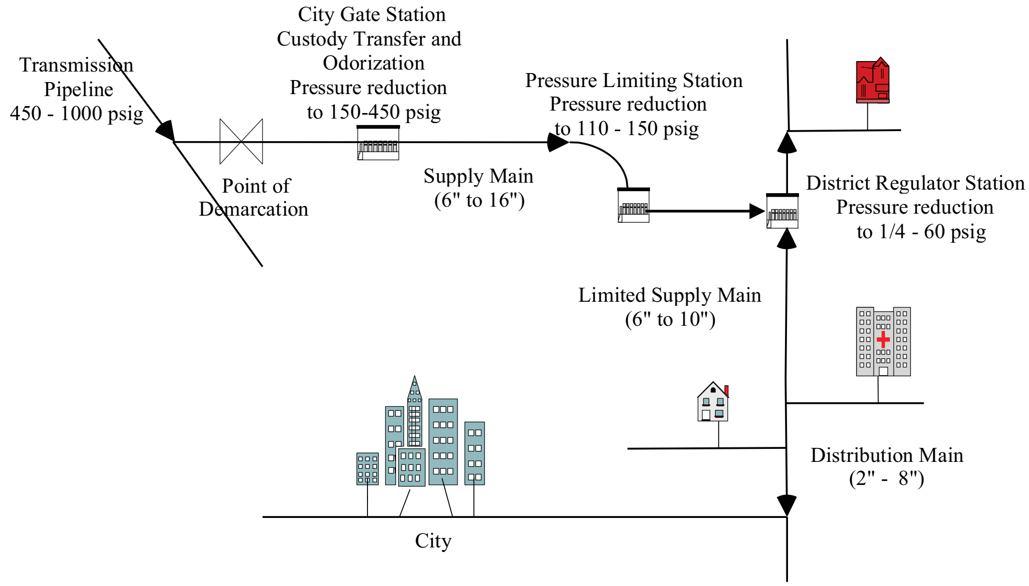
How electric delivery systems work



Electricity is transported from power generators to consumers over wires and cables, using a wide range of voltages and capacities. The voltage at the generation site must be stepped up to high levels for efficient transmission over long distances (generally 55 to 500 kilovolts). Substations receive this power and reduce the voltage in stages to levels appropriate for travel over local distribution lines (between 4 and 34.5 kV). Finally, transformers at the customer's site reduce the voltage to levels suitable for the operation of lights and appliances (under 600 volts). Wires and cables carry electricity from one place to another. Substations and transformers change voltage to the appropriate level. Circuit breakers prevent overloads, and meters measure how much power is used.

CHAPTER 7 – DELIVERY INFRASTRUCTURE PLANNING

How natural gas delivery systems work



Natural gas is transported at a variety of pressures through pipes of various sizes. Large transmission pipelines deliver gas under high pressures (generally 450 to 1,000 pounds per square inch gauge [psig]) to city gate stations. City gate stations reduce pressure to 150 to 450 psig for travel through supply main pipelines. Then district regulator stations reduce pressure to less than 60 psig. From this point the gas flows through a network of piping (mains and services) to a meter set assembly at the customer's site where pressure is reduced to what is appropriate for the operation of the customer's equipment (0.25 psig for a stove or furnace) and the gas is metered to determine how much is used.

2. What drives infrastructure investment?

Despite a slow economy and minimal load growth, infrastructure expenditures may stay the same or even increase. This is because load growth is only one of the drivers of infrastructure investment. Aging equipment must be maintained or replaced; regulatory requirements may require spending on upgrades or alterations; public projects can necessitate equipment relocation; and we are required to integrate new generation resources. Below, we describe the six factors that drive infrastructure investment. Some can be known in advance, others can be forecasted, and some circumstances arise from external events.

Load growth

PSE's first and foremost obligation is to serve the gas and electric loads of our customers; when customers turn on the switch or turn up the heat, sufficient gas and electricity need to be available. Load drives system investment in three ways: We must meet overall system loads. We must meet short-term peak loads. And we must meet point (block) loads

Overall system growth

Demands on the overall system increase as the population grows and economic activity increases in our service area even given the increasing role of demand-side resources. PSE regularly evaluates economic and population forecasts in order to stay abreast of where and when additional infrastructure, including electric transmission lines, substations, and high-pressure gas lines may be needed to meet growing loads.

Peak loads

Peak loads occur when the weather is most extreme. To prepare for these events, PSE carefully evaluates system performance during periods of peak loading each year, updates its system models, and compares these models against future load and growth predictions. This prepares us to determine where additional infrastructure investment is required to meet peak loads.

Electric delivery design is based on an expected winter peak of 23 degrees F[1] (which we expect to experience once every two winters), and a summer peak of 86 degrees F (which is a planning criteria used uniformly by electric utilities throughout western Washington). The gas system is designed to operate on a day with an average temperature of 10 degrees F. The gas system is designed more conservatively than the electric system because during a peak event the gas system pressure is drawn to zero as loads increase. Once gas pressure reaches zero, customers lose gas to pilot lights in their appliances. For this reason, gas outages have much greater public and restoration impacts than electric outages, and must be avoided for all but the most extreme conditions. The electric system is more flexible. For short periods of time components can often carry more current than their nameplate ratings call for with no adverse effects, and restoration is achieved instantly when power is rerouted and switches are reset.

Point loads

System investments are sometimes required to serve specific “point loads” that may appear at a specific geographic location in our service territory. Electrical infrastructure to serve a computer server facility is one example, gas infrastructure to serve an industrial facility such as an asphalt plant is another.

Reliability

The energy delivery system is reviewed each year to improve the reliability of service to existing customers. Past outages, equipment inspection and maintenance records, customer feedback, and PSE field input help identify areas where improvements should be made. Additional consideration is given to system enhancements that will improve redundancy (such as being able to provide a second power line from one substation to another). Some of the investments to improve reliability include replacing aging conductors, installing covered conductors (tree wire), and converting overhead lines to underground.

[1] *We also evaluate the electric system at 13 degrees F (a one-in-twenty-year condition) for operational planning considerations such as load shifting, the use of a mobile substation, etc., but this lower temperature is not used to justify infrastructure investments.*

Regulatory compliance

PSE is committed to operating our system in accordance with all regulatory requirements. The gas and electric delivery systems are highly regulated by several state and federal agencies including NERC, FERC (Federal Energy Regulatory Commission), the WUTC (Washington Utilities and Transportation Commission), and various safety regulations. Infrastructure investments driven by compliance requirements include electric transmission projects that are aimed at preventing cascading power outages that could extend outside PSE's system. Gas regulations drive very specific inspection and maintenance activities and often require the replacement of assets based upon age and/or condition.

External commitment

PSE must respond to city, county, and state jurisdictions within our service area when government-sponsored projects impact our facilities. Where PSE gas and electric facilities are installed in public rights of way, we must relocate them to accommodate public projects such as road widening or underground conversion of electrical facilities. We look for opportunities to minimize future costs and disruptions by using these construction events to install larger or additional infrastructure that will accommodate anticipated load growth.

Aging infrastructure

With continued maintenance, gas and electric infrastructure can provide safe, reliable service for decades. PSE has a number of programs in place that address aging infrastructure by replacing poles, pipes, and other components that are nearing the end of their useful life. Our goal is to maximize the life of the system and at the same time minimize customer interruptions by replacing major infrastructure components prior to unplanned failure.

Integration of resources

FERC and state regulations require PSE to integrate generation resources into our electric system per processes outlined in federal and state codes. A new generation plant, whether it is owned by PSE or operated by others, can require significant electric infrastructure investment to integrate and maintain appropriate electrical power flows within our system and across the region.

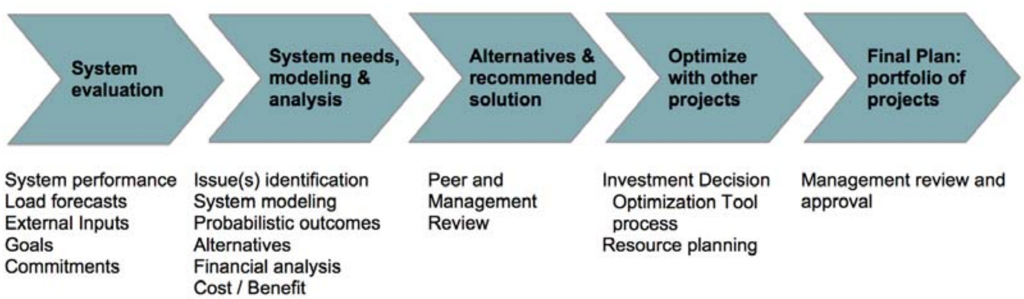
3. Planning Process

The planning process begins with an evaluation of the system's current performance and future need through data analysis and modeling tools. Next project alternatives are developed, those alternatives are vetted and reviewed, and projects are compared against one another. Performance criteria include, but are not limited to, reliability, compliance, and customer expectations. Finally, a portfolio of projects is adopted. The process is the same for both long-term and short-term planning.

The IRP produces a long-term view, a general 10-year projection of infrastructure investments that can be expected based on today's conditions and forecasts. As the horizon shortens and the actual plan year approaches, those projections are refined based on new developments and actual rather than hypothetical conditions. Even after the portfolio for a given year is approved, we continue to monitor changing conditions and make alterations as necessary.

Figure 7-2

Delivery System Planning Process



System evaluation

System evaluation begins with an evaluation of system performance, a review of existing operational challenges, and consideration of load forecasts and known commitments and obligations. Performance is measured by the system's ability to maintain quality and continuous service during normal and peak loads throughout the year while meeting the regulatory requirements that govern them.

Performance criteria for electric and gas delivery systems lie at the heart of the process and are the foundation of PSE's infrastructure improvement planning.

Electric delivery system performance criteria are defined by:	Gas delivery system performance criteria are defined by:
Safety and compliance	Safety and compliance
The temperature at which the system is expected to perform	The temperature at which the system is expected to perform
The nature of service and level of reliability that each type of customer is contracted for	The nature of service each type of customer is contracted for (interruptible vs. firm)
The minimum voltage that must be maintained in the system	The minimum pressure that must be maintained in the system
The maximum voltage acceptable in the system	The maximum pressure acceptable in the system
The level of reliability that customers are willing to pay for	The target levels of performance that customers are willing to pay for
The interconnectivity with other utility systems and resulting requirements; including compliance with NERC Planning Standards	

PSE collects system performance information from field charts, remote telemetry units, supervisory control and data acquisition equipment (SCADA), employees, and customers. Some information is analyzed over multiple years to normalize the effect of variables like weather that can change significantly from year to year. For near-term load forecasting at the local city, circuit, or neighborhood level, we use system peak load and customer growth trends augmented by permitted construction activity for the next two years. For longer-term forecasting, we use an econometric forecasting method that includes population growth and employment data by county (see Appendix H, Load Forecasting Models). External inputs such as new regulations, municipal and utility improvement plans, and customer feedback, as well as company objectives, are also included in the system evaluation.

System needs, modeling, and analysis

PSE relies on several tools to help identify and weigh the benefits of alternative actions. Figure 7-3 provides a brief summary of these tools, the planning considerations (inputs) that go into each, and the results (outputs) that they produce.

Figure 7-3
Delivery System Planning Tools

Tool	Use	Inputs	Outputs
SynerGEE®	Network modeling	Gas and electric distribution infrastructure and load characteristics	Predicted system performance
Power World Simulator – Power Flow	Network modeling	Electric transmission infrastructure and load/generation characteristics	Predicted system performance
PSS/E Power Flow & Stability	Network modeling	Electric transmission infrastructure and load/generation characteristics	Predicted system performance
PSLF Power Flow & Stability	Network modeling	Electric transmission infrastructure and load/generation characteristics	Predicted system performance
Electric Predictive Spreadsheet	Predictive analysis	Outage history	Predicted outage savings
Gas Outage Spreadsheet	Predictive Analysis	Network model output for future capacity	Predicted outage savings
Investment Decision Optimization Tool (iDOT)	Project data storage & portfolio optimization	Project scope, budget, justification, alternatives and benefits; resources/financial constraints	Optimized project portfolio; benefit cost ratio for each project; project scoping document
Area Investment Model (AIM)	Electric Financial analysis	Project costs; 8760 load data; load growth scenarios	NPV; income statement; load growth vs. capacity comparisons; EUE

PSE's ***gas system model*** is a large integrated model of the entire delivery system. It uses a software application (SynerGEE® Gas) that is continually updated to reflect new customer loads and system and operational changes. This model helps predict capacity constraints and subsequent system performance on a variety of degree days and under a variety of load growth scenarios. Results are compared to actual system performance data to assess the model's accuracy. Where issues surface, the model can be used to evaluate alternatives and their effectiveness. PSE augments potential alternatives with cost estimates and feasibility analysis to identify the lowest reasonable cost solution for both current and future loads.

For our ***electric distribution system***, PSE also uses SynerGEE software. Here, the feeder systems within PSE's service territory are modeled rather than the entire system at once, because of the limited connectivity between regions and the complexity of modeling such a large system. As with gas, PSE uses the model to evaluate system performance and predict capacity constraints on a variety of degree days and under a variety of load growth scenarios.

Modeling is ***a three-step process***. First, we build a map of the infrastructure and its operational characteristics. For gas, these include the diameter, roughness and length of the pipe, connecting equipment, regulating station equipment, and operating pressure. For electric infrastructure, these include conductor cross-sectional area, resistance, length, construction type, connecting equipment, transformer equipment, and voltage settings. Next, we identify customer loads, either specifically (for large customers) or as block loads for address ranges. Existing customer loads come from PSE's customer information system or actual circuit readings. Finally, we vary temperature conditions, types of customers (interruptible vs. firm), time of daily peak usage, and the status of components (valves or switches closed or open) to model scenarios of infrastructure or operational adjustments. The goal is to find the optimal solution to a given issue.

To simulate the performance of the ***electric transmission system***, PSE uses three different programs: Power World Simulator, PSS/E (from Siemens Power Technologies International), and PSLF (from General Electric). These simulation programs use a transmission system model that spans 11 western states, 2 provinces in western Canada, and parts of northern Mexico. The power flow and stability data for these models is collected, coordinated, and distributed through regional organizations including Columbia Grid and WECC, one of 8 regional reliability organizations under NERC. These power system study programs support PSE's planning process and facilitate demonstration of compliance with WECC and NERC reliability performance standards.

System alternatives

The alternatives available to address delivery system capacity and reliability issues are listed below. Each has its own costs, benefits, challenges, and risks.

Figure 7-4

Alternatives for Addressing Delivery System Capacity and Reliability

Electric

- Add energy source
  - Substation
- Strengthen feed to local area
  - New conductor
  - Replace conductor
- Improve existing facility
  - Substation modification
  - Expanded right-of-way
  - Uprate system
  - Rebalance load
  - Modify automatic switching scheme
- Load reduction
  - Distributed energy resource
  - Conservation / Demand response
  - Load control equipment
  - Possible new tariffs
- Do nothing

Gas

- Add energy source
  - City-gate station
  - District regulator
- Strengthen feed to local area
  - New high pressure main
  - New intermediate pressure main
  - Replace main
- Improve existing facility
  - Regulation equipment modification
  - Uprate system
- Load reduction
  - Fuel switching
  - Conservation
  - Load control equipment
  - Possible new tariffs
- Do nothing

The same alternatives can be used to manage short-term issues like peaking events or conditions created by a construction project. For example:

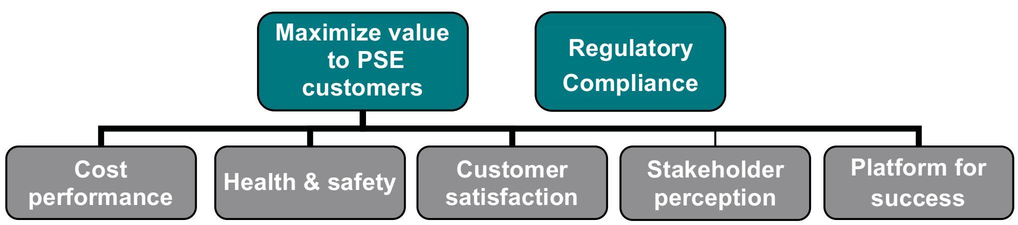
- Temporary adjustment of regulator station operating pressure, as executed through PSE's Cold Weather Action Plan.
- Temporary adjustment of substation transformer operating voltage, as done using load tap changers to alter turn ratios.
- Automatic capacitor bank switching to optimize VAR consumption and maintain adequate voltage.
- Temporary siting of mobile equipment such as compressed natural gas injection vehicles, liquid natural gas injection vehicles, mobile substations, and portable generation.

Evaluating alternatives and recommended solutions

When it's time to evaluate alternatives, PSE compares the relative costs and benefits of various solutions (i.e. projects) using the Investment Decision Optimization Tool (iDOT). iDOT allows us to capture project criteria and benefits and score them across multiple factors including reliability, safety, capacity addition, deferred future costs, and external stakeholder inputs. iDOT makes it easier to conduct side-by-side comparisons of projects of different types, thus helping us evaluate infrastructure solutions that will be in service for 30 to 50 years.

Figure 7-5

Benefit Structure to Evaluate Delivery System Projects



Project costs are calculated using a variety of tools, including historical cost analysis and unit pricing models based on service provider contracts. Cost estimates are refined as projects move through detailed scoping. Through this process, alternatives are reviewed and recommended solutions are vetted and undergo a peer review process. Further minor adjustments are made to ensure that the portfolio addresses resource planning and other applicable constraints or issues.

In the case of the IRP, a general, long-term projection of likely infrastructure expenditures is produced. Annual plans approved by operations management provide a specific portfolio of projects for the year. While annual plans are considered final, throughout the year they continue to be adjusted based on changing factors (e.g. public improvement projects that arise or are deferred; changing forecasts of new customer connections; project delays in permitting) so that we can ensure the total portfolio financial forecast remains within established budget parameters.

4. 2013-2023 Infrastructure Plans

PSE develops both short-range and long-range infrastructure plans based upon economic, population, and load growth projections, as well as information from large customers and government stakeholders. The plan is reviewed annually and remains dynamic. As the plan year gets closer, the company refines plan projections based on new developments or information, and performs additional analyses to reveal and evaluate additional alternatives. The plan may change as a result of these investigations.

The infrastructure additions described below are intended to indicate the scope of investment that will be required over the next ten years in order to serve our customers reliably and fulfill regulatory requirements. They are expressed in general terms.

Electric infrastructure plan

Transmission lines

In the next decade, PSE anticipates building approximately 200 plus miles of new transmission lines (100 kV and above) and upgrading over 300 miles of existing transmission lines to carry greater loads. In addition, we anticipate needing to add up to six 230 kV bulk power transformation across our service area.

Distribution substations

Distribution infrastructure additions are highly dependent on localized patterns of load increases and known planned "point loads" at specific geographic locations in our service territory. In the next decade, PSE anticipates the need to build approximately eight new distribution substations to help serve new load and where adjacent existing substations cannot adequately serve. Additionally, we are monitoring preliminary "point load" needs where another four to eight new substations maybe needed to serve this load. The timing of the construction of these substations will be aligned with the customer plans to add the point loads and available capacity from existing substations to serve this load. We also anticipate upgrading approximately three existing substations in the coming decade to replace aging substation infrastructure and to add additional capacity to serve local load growth.

Ongoing maintenance

Based upon current projections and past experience, PSE expects to replace 500 to 1,000 miles of underground cable, approximately 2,000 transmission poles, and up to 10,000 distribution poles over the next 10 years. Additionally, PSE replaces many major substation components on a continuous basis as a result of ongoing inspection and diagnostics.

Figure 7-6

Summary of 2013-2023 Electric Infrastructure Potential Projects

Asset	Number	Location
New Distribution Substations	Eight	System-wide
Upgraded Distribution Substations	Three	System-wide
New Transmission	200 miles	System-wide
Upgraded Transmission	300 miles	System-wide
New Bulk Power Transformation	Up to Six	System-wide
Cable Replaced	500 – 1,000 miles	System-wide
Distribution Poles Replaced	Up to 10,000	System-wide
Transmission Poles Replaced	1,000	System-wide

Gas infrastructure plan

Gate stations

PSE plans to build or upgrade approximately seven gate or limit stations where we take gas from the Northwest Pipeline.

Pipelines and mains

We expect to add approximately 27.5 miles of high pressure main and 28 miles of intermediate pressure main as loads grow in our service area.

Ongoing maintenance

As with the electric system, PSE is always addressing aging gas infrastructure within the system in accordance with regulatory requirements and prudent operating practices. In the next decade, PSE plans to replace over 200-300 miles of gas main that is reaching the end of its useful life.

Figure 7-7
Summary of Gas Infrastructure Potential Projects.

Asset	Number	Location
New High Pressure Pipe	27.5 miles	System-wide
New Intermediate Pressure Pipe	28 miles	System-wide
Gate or Limit Station Upgrades	Seven	System-wide
Gas Main Replaced	200-300 miles	System-wide

5. Challenges and Opportunities

New regulations

Regulatory compliance is a significant driver of PSE infrastructure investment, but it is difficult to anticipate what rules may be adopted in the future or to predict how they may impact spending on our delivery systems. NERC, FERC, and the WUTC are among the agencies and organizations that regulate our businesses. Examples from the last decade illustrate the kind of expenditures that regulatory activity can necessitate.

Gas system

Beginning with the Pipeline Safety Improvement Act (PSIA) of 2002 and again in 2006 with the Pipeline Inspection, Protection, Enforcement, and Safety (PIPES) Act, Congress has directed the Pipeline and Hazardous Materials Safety Administration to increase the strength of integrity management programs covering natural gas transmission and distribution pipelines. These programs require PSE to perform detailed inspections and analysis of pipeline systems to gain more knowledge of pipeline integrity risks and to devise measures to mitigate these risks. Numerous actions have resulted from this effort, including expanded pipe replacement programs, enhanced damage prevention activities, and increased inspection intervals. Recent pipeline safety incidents have occurred across the country, and this continues to focus the attention of state and federal regulators and lawmakers on improving pipeline and public safety performance. Proposed legislation includes:

- expanding the mileage of pipelines subject to more rigorous inspection and testing,
- requiring the use of automatic and remote controlled shut-off valves,
- expanding the use of excess flow valves, and
- requiring more timely notification of pipeline incidents.

All require additional investment in processes and infrastructure to support compliance with new regulations.

Electric system

In 2007, new regulations mandated by The Energy Policy Act of 2005 became effective and enforceable by regional electric reliability organizations. This act was triggered by concern about the robustness and reliability of nation's electrical grid, and it moved the industry into an era where system planning, performance, and operating requirements are mandated by law, audited, and enforced by fines and sanctions. Complying with these new reliability standards has required PSE to make significant investments in both hardware and software assets for the portions of our system operating above 100 kV.

Emerging alternatives

PSE and the region's utilities have a vested interest in finding optimal solutions to transmission constraints and bulk power delivery problems, and we are studying several emerging alternatives that have the potential to help meet today's transmission and distribution challenges. Among them are the following.

Distributed generation

Distributed generation is the name for incorporating small-scale generation into the electric grid close to where the users are (close to load). Many such sources exist: internal combustion engines, fuel cells, gas turbines and micro-turbines, hydro and micro-hydro applications, photovoltaics, wind energy, solar energy, and waste/biomass. The challenge for the delivery system is how to integrate this power into a system that was designed to move electricity in only one direction – typically from large, remote generating plants to far-away end users.

Conservation voltage reduction

Reducing the voltage at an end-user's site by a small percentage can result in energy savings without compromising the operation of customers' equipment. In 2006, PSE began a conservation voltage reduction (CVR) pilot program in conjunction with Northwest Energy Efficiency Alliance (NEEA). The homes of 10 residential customers in two locations were fitted with meters capable of monitoring energy usage at the residence and transmitting that information back to PSE every 15 minutes over telephone lines. On alternate days, PSE reduced the substation bank voltage from a set 123 volts to a range of 119 volts. This resulted in a feeder voltage reduction of 3%. (Two-way communication helped PSE determine whether the reduced voltage adversely affected any customers.) Results from the study were favorable, indicating a 2% energy savings at both pilot locations with no adverse effects. As technology for two-way communication over the electric grid advances, making it easier to implement this technique, conservation voltage reduction has the potential to play a much larger role in the delivery system. PSE continues to evaluate locations where conservation voltage reduction may be practical to implement and similar energy savings may be realized.

In 2013, three substations are scheduled to implement CVR. This involves three things: installing several new customer meters to verify end of line (EOL) voltage is within standard, phase balancing, and adjusting voltage settings. After CVR is implemented, the substations will be monitored and evaluated for cost effectiveness. In 2014, six more substations will implement CVR. The results of the cost-benefit analysis from these nine substations will help guide future development of the CVR program.

Demand response alternatives

When demand for power is at its highest and customers reduce their energy use in response, utility delivery system planners call it "demand response." Based on estimated demand response capacity for residential, commercial, and industrial customer sectors in our 2007 and 2009 IRPs, PSE developed two voluntary demand response pilots, one for residential loads that was conducted from 2009-2011, and one for commercial/industrial loads that was conducted from 2008-2010. While most participating residential customers were comfortable with direct load control, participation rates and system impacts were low, and costs were high. Commercial/industrial customers present a more cost-effective market, but prefer manual (non-automated) control of their loads with 1-hour-ahead notice.

With regard to *managing* peak load, automated demand response with 10-minute response time is preferable to manual control from the utility perspective. Future residential load control programs will greatly benefit from improvements in technology and two-way communication. Demand response program costs are higher than supply-side alternatives at this time, and PSE does not currently have a program in place. We will continue to monitor industry news regarding demand response technologies and benefits.

Electric vehicles

PSE's customers are adopting electric and plug-in hybrid vehicles. We have developed estimates of expected energy needs, performed initial assessment of distribution impacts on select circuits, and performed some tests of the effectiveness of curtailed charging. All of these studies determined that initial adoption of electric vehicles and plug-in hybrids would not have significant effects on PSE's energy needs or distribution system. As the trend continues, PSE will expand data collection efforts to develop better models based on real-world conditions. Simulations will be performed to determine when system upgrades are needed.

Smart grid technologies

Smart grid is a term used to describe the integration of intelligent devices and new technologies into the electrical grid to optimize the system to a degree not possible with existing infrastructure. It is less well developed than demand response technologies, but has the potential to connect all parts of the electric power system – production, transmission, and distribution – in ways that would be very beneficial to customers. In 2012, PSE submitted a Smart Grid report to the Washington Utility & Transportation Commission detailing the company's plans for Smart Grid technology and development. The report can found at the following link:

http://www.utc.wa.gov/docs/Pages/DocketLookup.aspx?FilingID=121426

Key Definitions and Acronyms

Abbreviation	Meaning
ACE	Area Control Error
AECO	Alberta Energy Company,the gas hub in Alberta, Canada
AFUDC	allowance for funds used during construction
AGC	automatic generation control
AIM	Area Investment Model, used to calculate financial performance indicators for projects
aMW	The average number of megawatt-hours (MWh) over a specified time period; for example, 295,650 MWh generated over the course of one year equals 810 aMW (295,650/8,760 hours).
AOC	Administrative Order Of Consent
AURORA	one of the models PSE uses for integrated resource planning, which uses the western power market to produce hourly electricity price forecasts of potential future market conditions
BA	Balancing Authority, the area operator that matches generation with load
BACT	best available control technology (required of new power plants and those with major modifications
BART	best available retrofit technology
balancing reserves	reserves sufficient to maintain system reliability within the operating hour; this includes frequency support, managing load and variable resource forecast error, and actual load and generation deviations. Balancing reserves do not provide the same kind of short-term, forced-outage reliability benefit as contingency reserves, which are triggered only when certain criteria are met; balancing reserves must be able to ramp up and down as loads and resources fluctuate instantaneously each hour.
BcF	billion cubic feet

KEY DEFINITIONS AND ACRONYMS

Abbreviation	Meaning
BOP	balance of plant (work inclusive of project substations, turbine foundations, collection system, roads and the operations and main building)
BPA	Bonneville Power Administration
BTA	Best Technology Available
CAGR	compounded average growth rate
CAIR	Clean Air Interstate Rule
CAISO	California Independent System Operator
case	a set of assumptions designed to test the economic viability of an existing resource under a variety of regulatory conditions
CARB	California Air Resources Board
CCCT	combined cycle combustion turbines
CCR	coal combustion residuals
CCS	carbon capture and sequestration
CEC	California Energy Commission
CFL	compact fluorescent light
CI	confidence interval
CNG	compressed natural gas
CNGC	Cascade Natural Gas Corporation
CO_2	Carbon dioxide
COE	U.S. Army Corps of Engineers
COL	construction and operating license
contingency reserves	reserves intended to bolster short-term reliability in the event of forced outages (for up to one hour). Under the Northwest Power Pool’s contingency reserve sharing agreement, generators must reserve an additional 5% of hydro or wind resources and 7% of thermal resources, when such units are dispatched to meet firm sales obligations. This capacity must be available within 10 minutes, and 50% of it must be spinning.
Council	Northwest Power Planning Council
CPUC	California Public Utility Commission
CRAG	Conservation Resource Advisory Group
CSAPR	Cross State Air Pollution Rule

KEY DEFINITIONS AND ACRONYMS

Abbreviation	Meaning
CT	natural gas-fired combustion turbine
CT peaker	natural gas-fired combustion turbine used for meeting peak resource need (also simply referred to as a "peaker")
CVR	conservation voltage reduction
DSO	Dispatcher Standing Order
DOE	Department of Energy
DSO	dispatch standing order (BPA's protocol to manage a growing amount of wind on its system)
DSR	Demand Side Resources
Dth	dekatherms
EIA	U.S. Energy Information Agency
EIA	RCW 19.285, Washington's State's Energy Independence Act, commonly referred to as the state's renewable portfolio standard ("RPS")
EISA	Energy Independence and Security Act
ELCC	equivalent load carrying capability
EPA	Energy Policy Act (2005)
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
EPS	Washington state's Emissions Performance Standard
ESP	electric service provider
ESP	electro-static precipitator
FERC	Federal Energy Regulatory Commission
FIP	Federal Implementation Plan
GDP	gross domestic product
GHG	greenhouse gas
GRC	General Rate Case
GTN	Gas Transmission Northwest
HDD	heating degree days
HHV	high heating value
HVAC	heating, ventilation and air conditioning

KEY DEFINITIONS AND ACRONYMS

Abbreviation	Meaning
I-937	Washington state's renewable portfolio standard (RPS), a citizen-based initiative codified as RCW 19.285, Energy Independence Act
ICE	incremental capacity equivalent, defined as the change in capacity of a generic natural gas peaking plant that results from adding a new type of resource with any given energy production characteristics to the system while keeping the LOLP target constant at 5 percent. This allows us to identify the capacity contribution of the new resource relative to a gas peaker, and it is especially useful for variable energy resources.
iDOT	Investment Optimization Tool to identify a set of projects that will create maximum value
IGCC	integrated gasification combined cycle (generally refers to a model in which syngas from a gasifier fuels a combustion turbine to produce electricity, while the combustion turbine compressor compresses air for use in the production of oxygen for the gasifier)
IOU	investor owned utility
IPP	Independent power producers
IRP	Integrated Resource Plan
IRPAG	Integrated Resource Plan Advisory Group
ISO	independent system operator
ITC	Investment Tax Credit, a federal tax credit currently amounting to 30% of the eligible capital cost for renewable resources; it expires at the end of 2013.
KORP	Kingsvale-Oliver Reinforcement Project, a pipeline project proposed by Fortis BC and Spectra that expands and adds flexibility to the existing Southern Crossing pipeline across southern British Columbia to Sumas
kV	kilovolt
kW	kilowatt
kWh	kilowatt hours
LADWP	Los Angeles Department of Water and Power

KEY DEFINITIONS AND ACRONYMS

Abbreviation	Meaning
LBNL	Lawrence Berkeley National Laboratory
LNG	liquefied natural gas
load	the total generated demand plus planning margins and operating reserve obligations
LOLP	loss of load probability
LP	linear program
LP-Air	vaporized propane air
MATS	Mercury Air Toxics Standard
MDEQ	Montana Department of Environmental Quality
MDQ	maximum daily quantity
MDth	thousand dekatherms
Mid-Columbia (Mid-C) market hub	principle electric power market hub in the Northwest and one of the major trading hubs in the WECC, located on the Mid-Columbia River
MMBtu	million British thermal units
MSTI	Northwestern Energy's Mountain States Transmission Intertie
MW	megawatt
MWe	megawatts electric
MWh	megawatt hours
NAAQS	National Ambient Air Quality Standards (set by the EPA, which enforces the Clean Air Act, for six criteria pollutants: sulfur oxides, nitrogen dioxide, particulate matter, ozone, carbon monoxide and lead)
NARUC	National Association of Regulatory Utility Commissions
NEEA	Northwest Energy Efficiency Alliance
NEEDS	National Electric Energy Data System
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Council
net maximum capacity	the capacity a unit can sustain over a specified period of time -in this case 60 minutes - when not restricted by ambient conditions or deratings, less the losses associated with auxiliary loads
NGV	natural gas vehicles

KEY DEFINITIONS AND ACRONYMS

Abbreviation	Meaning
NOS	Network Open Season, a BPA transmission planning process
NO_x	nitrogen oxides
NPV	net present value
NRC	Nuclear Regulatory Commission
NREL	National Renewables Energy Laboratories
NSPS	new source performance standards (new plants and those with major modifications must meet these EPA standards before receiving permit to begin construction)
NUG	nonutility generator
NWGA	Northwest Gas Association
NWP	Northwest Pipeline (only pipeline directly to west WA)
NPCC	Northwest Power & Conservation Council
NWPP	Northwest Power Pool
NYMEX	New York Mercantile Exchange
OASIS	Open Access Same-Time Information System
OATT	Open Access Transmission Tariff
OFM	Washington state Office of Financial Management
OTC	once-through cooling
PCA	power cost adjustment (electric)
PCORC	power cost only rate case
peaker	natural gas-fired combustion turbine used for meeting peak resource need (also sometimes referred to as a “CT peaker”)
PEFA	ColumbiaGrid’s planning and expansion functional agreement, which defines obligations under its planning and expansion program
PGA	purchased gas adjustment
PG&E	Pacific Gas & Electric
PGE	Portland Gas Electric
PIPES Act	Pipeline Inspection, Protection, Enforcement, and Safety Act (2006)
PM	planning margin = (generation capacity – normal peak loads)/normal peak loads
PM	particulate matter

KEY DEFINITIONS AND ACRONYMS

Abbreviation	Meaning
PNUCC	Pacific Northwest Utilities Coordinating Committee
portfolio	specific mix of generic power resources
PPA	purchased power agreement (a bilateral wholesale or retail power short term or long term contract, wherein power is sold at either a fixed or variable price and delivered to an agreed-upon point).
PTP	point-to-point
PTSA	Precedent Transmission Service Agreement
PSE	Puget Sound Energy
PSIA	Pipeline Safety Improvement Act (2002)
PSM	portfolio screening model (one of the two models PSE uses for integrated resource planning, which tests electric supply and demand portfolios to evaluate PSE's long-term revenue requirements for incremental portfolio)
PSO	Power Supply Operations
PTC	Production Tax Credit, a federal subsidy for production of renewable energy. Currently, the PTC amounts to approximately $22 (in 2012 dollars) per MWh for 10 years of production after a project is placed into service for projects that begin construction in 2013. The PTC is indexed for inflation.
PUD	public utility district
PV	photovoltaic
R&D	research and development
RAS	remedial action scheme
rate base	the amount of investment in plant devoted to the rendering of service upon which a fair rate of return is allowed to be earned. In the State of Washington, rate base is valued at the original cost less accumulated depreciation and deferred taxes.
RCRA	Resource Conservation Recovery Act
RCW	Revised Code of Washington
RCW 19.285	Washington's State's Energy Independence Act, commonly referred to as the state's renewable portfolio standard ("RPS")
REC	renewable energy credit

KEY DEFINITIONS AND ACRONYMS

Abbreviation	Meaning
REC banking	Washington's renewable portfolio standard allows for unused RECs to be banked forward one year or borrowed from one year in the future
regulatory lag	the time that elapses between establishment of the need for funds and the actual collection of those funds in rates
revenue requirement	Rate Base * Rate of Return + Operating Expenses
RFP	request for proposal
RPG	Renewable Portfolio Goal
RPS	renewable portfolio standard (mandates 3% renewables by 2012, 9% by 2016 and 15% by 2020)
RTO	regional transmission organization
SCADA	supervisory control and data acquisition
SCCT	Simple cycle combustion turbine, natural gas-fired unit used for meeting peak resource need (also sometimes referred to as a "peaker")
SCR	selective catalytic reduction
scenario	consistent set of data assumptions to define a specific future; takes holistic approach to uncertainty analysis
sensitivity	a set of data assumptions based on the Base Scenario in which only one input is changed. Used to isolate the effect of a single variable.
SENDOUT	PSE's model used to help identify the long-term least cost combination of gas resources to meet stated loads.
SIP	State Implementation Plan
SNCR	selective non-catalytic reduction
SNL	a company that collects and disseminates corporate, financial and market data on several industries including the energy sector (www.snl.com). The letters SNL stand for savings and loan.
SO_2	sulfur dioxide
SOFA system	separated over-fire air system
TailVar90	a metric for measuring risk defined as the average value of the

KEY DEFINITIONS AND ACRONYMS

Abbreviation	Meaning
	worst 10 percent of outcomes
TEPPC	WECC Transmission Expansion Planning Policy Committee
TCPL-Alberta	TransCanada's Alberta System (also referred to as TC-AB)
TCPL-British Columbia	TransCanada's British Columbia System (also referred to as TC-BC)
TF-1	firm gas transportation contracts, available 365 days each year
TF-2	gas transportation service for delivery or storage volumes generally intended for use during the winter heating season only
T&D	transmission and distribution
TOP	transmission operator
Treasury Grant	The Treasury Grant ("Grant) is a federal subsidy in the form of a cash payment that amounts to 30% of the eligible capital cost for renewable resources; it expires at the end of 2013. For projects placed in service in 2013, construction must have started in 2009, 2010 or 2011 and the project must meet eligibility criteria.
UPC	use per customer
VERs	Variable energy resources
VectorGas	facilitates the ability to model price and load uncertainty
WAC	Washington Administrative Code
WACC	weighted average cost of capital
WCI	Western Climate Initiative
WECC	Western Electric Coordinating Council
WECo	Western Energy Company
WEI	Wescoast Energy, Inc.
WIEB	Western Interstate Energy Board
WUTC	Washington Utilities and Transportation Commission

2013 Integrated Resource Plan

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May 30, 2013

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APPENDIX A

Public Participation

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PSE is committed to public involvement in the planning process. Stakeholder meetings generated valuable constructive feedback, and the suggestions and practical information we received from both organizations and individuals helped guide the development of this 2013 IRP. We wish to thank all who participated.

By the time this plan was filed with the Washington Utilities and Transportation Commission (WUTC), eight formal Integrated Resource Plan Advisory Group (IRPAG) meetings had been held, as well as numerous Conservation Resource Advisory Group (CRAG) meetings and dozens of informal meetings and communications. Stakeholders who actively participated in one or more meetings include WUTC staff, Public Counsel, Northwest Industrial Gas Users, Northwest Gas Association, Northwest Pipeline, conservation and renewable resource advocates, the Northwest Power and Conservation Council, project developers, other utilities, customers, the City of Bellevue and the Washington State Department of Commerce.

This appendix briefly describes the purpose of the IRPAG and CRAG, and summarizes the formal IRPAG meetings held to date. We especially want to thank those who attended these meetings, for both the time and energy they invested, and we encourage their continued participation. The IRPAG covers all elements of the IRP, while the CRAG focuses on energy efficiency and demand-side resources. While the two groups meet separately, they have many members in common.

1. Integrated Resource Planning Advisory Group (IRPAG)

Throughout the development of the IRP, PSE works with external stakeholders through an informal group called the IRPAG. WAC 480-90/100-238 requires PSE to develop the IRP and implement the two-year action plan it recommends; the IRPAG is the primary means of satisfying the public involvement requirements of the law. While the IRP document is not a product of "consensus," the IRPAG engages PSE and stakeholders in a consultative process that has proven to be an effective means for PSE planning staff to receive input on many key framework assumptions and related issues.

Since the 2003 Resource Plan, PSE has kept the IRP Advisory Group process informal, loosely structured, and without formal notes to better encourage brainstorming. Feedback about the process from the Advisory Group was overwhelmingly positive through the 2011 IRP, but this planning cycle has been different. Part way through, some stakeholders requested PSE hire a facilitator, so we engaged Milepost Consulting, which has also facilitated PSE's CRAG meetings. By the end of the planning cycle, it was clear that PSE needed to reassess and revise the stakeholder process for the next IRP. This goal is included in the Action Plan presented in Chapter 1, Executive Summary.

Dialogue with stakeholders during this IRP cycle was very useful for the company in developing the plan, and we are grateful for the time each individual took to help provide input, feedback, and alternative perspectives. Here are two examples of how this dialog with stakeholders influenced the 2013 IRP.

CO_2 costs and environmental risks. The topic of carbon "costs" versus "potential taxes" generated considerable dialog among the group. Stakeholders provided numerous journal article references and also suggested we discuss the issue with staff at Lawrence Berkley Labs. PSE staff reviewed the articles and contacted the lab. Ultimately, this led us to the "social costs" for carbon that are modeled in this IRP analysis: A contact at Lawrence Berkley Lab recommended using the *Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis under Executive Order 12866*. Dialogue with stakeholders also led directly to an updated discussion of the potential regional impacts of climate change in Appendix C, Environmental Matters.

APPENDIX A – PUBLIC PARTICIPATION

Colstrip analysis. Stakeholders influenced two key aspects of the Colstrip analysis through the IRPAG process. The first was to focus the analysis on market conditions that could impact the economic viability of continuing to operate Colstrip, rather than on a "what if PSE sold its interest" scenario. PSE agreed the former was a more appropriate focus for the IRP analysis. Second, stakeholders – specifically the Sierra Club – reviewed the assumptions in the three environmental compliance cost cases we developed for Colstrip in detail and provided thorough feedback. In response to this feedback, we developed a fourth case that modeled significantly higher costs for disposal of coal combustion residuals (CCR) should federal guidelines designate CCR as "hazardous waste." This provided a wider bookend of potential results than the initial three cases PSE developed.

During the development of the 2013 IRP, PSE engaged the IRPAG in two ways: through a series of structured IRPAG meetings, and in individual discussions with various IRPAG members. IRPAG meetings are open to all, including individual customers and other utilities.

As part of the formal IRPAG meetings, each building block of the IRP was presented and discussed. Often the group worked through significant levels of detailed analysis. Other PSE departments also spoke about topics of interest, such as the 2011 Request for Proposals (RFP).

In addition to the structured IRPAG meetings, PSE spoke one-on-one with individual IRPAG members. These conversations were very productive, allowing a freer flow of ideas than is often possible to achieve in a group setting. The combination of one-on-one discussions and group meetings was particularly helpful in gaining feedback.

Discussions with IRPAG members often broadened the scope of information available to PSE for use in the planning process. Also, these interactions brought a variety of perspectives to the process that enhanced our thinking.

Summary of IRPAG meetings

Summaries of each meeting are included below. Copies of the full presentations made by PSE staff at the IRP Advisory Group Meetings are posted on PSE's website at: http://pse.com/aboutpse/EnergySupply/Pages/Resource-Planning.aspx

Kick-off meeting, March 6, 2012

A presentation on how Washington state law defines integrated resource planning kicked off the 2013 IRP meetings followed by a discussion about how IRP planning relates to PSE's resource acquisition process. We described how the IRP process unfolds, suggested potential subject matter for future meetings, and sought feedback from IRPAG members regarding topics of interest and the level of detail they would like to see. Key uncertainties, scenarios and sensitivities, and resource alternatives for this IRP were introduced to the group. The company's Resource Acquisition department gave a presentation on the status of the evaluation process for PSE's Request for Proposals for All Generation Sources, which was underway at the time.

May 1, 2012 IRPAG meeting

After a quick review of the definition of integrated resource planning and how it fits into the overall resource acquisition cycle, the proposed assumptions, scenarios and sensitivities introduced in March were discussed in more detail. PSE then proposed a strategy for analyzing the Colstrip generating plant, of which the company is a part owner. In response to input from the group, PSE agreed to model the "social" costs of CO_2 in addition to the CO_2 tax approach we have used in the past.

June 21, 2012 IRPAG meeting

After an overview of the IRP (what the document does and does not do), and a summary of the outputs produced and how they are used, PSE updated the group on the developing scenarios and sensitivities, identified new questions to be considered in the IRP analysis, and discussed a variety of assumptions including draft CO_2 costs and draft gas and power prices for the 2013 IRP Base Scenario.

APPENDIX A – PUBLIC PARTICIPATION

September 6, 2012 IRPAG meeting

PSE summarized highlights of the 2012 IRPAG meetings to date, and looked ahead to review upcoming objectives. PSE presented power prices for all scenarios, and the assumptions and results associated with the market power price analysis. PSE also discussed analyzing electric operational flexibility – physical and financial – and an approach to incorporating this kind of analysis into the 2013 IRP.

November 14 & 15, 2012 IRPAG meeting

This two-day workshop began with a brief overview of material covered to date in the 2012 IRPAG meetings, a review of PSE's draft scenarios and sensitivities, and another look at various cost assumptions. PSE’s F2012 electric and gas load forecast and the methodology and assumptions involved in its development were discussed in detail. PSE presented electric and gas resource needs and introduced a discussion of regional electric resource adequacy. Electric and gas resource alternatives were described, including demand-side resources. The Cadmus Group (PSE consultants) presented an overview of their methodology for calculating demand-side resource potentials, their assumptions, and their results. PSE also hosted a Colstrip discussion. This covered the facility's ownership and decision-making structure, the role Colstrip plays PSE's power portfolio and the transmission that serves the plant. PSE also discussed approaches and assumptions for modeling Colstrip in the 2013 IRP.

January 22, 2013 IRPAG meeting

This meeting reviewed a number of key inputs to PSE's modeling process: scenarios and sensitivities, gas prices, CO_2 costs and power prices. PSE also presented electric capacity need, renewables need for RCW 19.285 compliance, and the initial electric portfolio and Colstrip analyses. A discussion of PSE's gas resource need and the initial analysis results for the gas sales portfolio followed.

APPENDIX A – PUBLIC PARTICIPATION

March 5, 2013 IRPAG meeting

This meeting reviewed and discussed the results of PSE's IRP modeling. After a brief process "check-in," discussion of gas analysis results began with an update on gas price forecasts and recent developments in PSE's gas book, followed by current load-resource balance outlooks for gas for sales and gas for power. Results for the demand-side resources and gas sales portfolio analyses were presented next. Gas for power analysis was still in progress at the time of this meeting. An "alternative winter design planning standard" that may be better able to address supply adequacy during sustained cold periods was introduced at the conclusion of the gas portion of the meeting. PSE reviewed current and proposed planning standards, but indicated that further study will be necessary before a recommendation can be made. Electric analysis results were discussed next. PSE reviewed the Colstrip cases considered in the electric analysis and introduced the new Very High Cost Case (Case 4). PSE also presented a detailed overview of the stochastic model and process, including a variety of modeling inputs and outputs. The meeting concluded with a look at the results of PSE's electric portfolio and Colstrip analyses and a discussion of key findings.

April 23, 2013 IRPAG meeting

This meeting reviewed and discussed the final results of PSE’s IRP analysis, and presented updates since the draft IRP was released for public preview on April 1, 2013. PSE specifically focused on Chapter 2 of the draft IRP, which describes PSE’s electric and gas resource plans and how those plans were developed. PSE also scheduled additional unstructured time to allow stakeholders an opportunity to raise questions and discuss any part of the draft IRP. Finally, there was a structured dialogue about what worked well and what could be improved for future IRP stakeholder processes.

2. Conservation Resources Advisory Group (CRAG)

The CRAG was formally established as part of the settlement of PSE's 2001 General Rate Case, which the WUTC approved in Docket No. UE-11570 and UG-011571. The group specifically works with PSE on development of energy efficiency plans, targets and budgets. The CRAG consists of ratepayer representatives, regulators and energy efficiency policy organizations.

The CRAG participated in the development of the 2013 IRP and energy efficiency program review through formal meetings in which it reviewed and offered feedback on the assessment of all demand-side resources (energy efficiency, fuel conversion, and demand response). The CRAG is also instrumental in reviewing IRP guidance to develop PSE's biennial energy efficiency targets and programs, as well as to review our progress toward achieving those targets. Many members participated in other aspects of the IRP advisory process as well.

APPENDIX B

Legal Requirements and Other Reports

Contents

PSE is submitting this IRP pursuant to state regulations contained in WAC 480-100-238 regarding electric resource planning, and WAC 480-90-238 regarding natural gas resource planning. Section 1 of this chapter outlines the regulatory requirements for electric and gas integrated resource plans, and identifies where each of these requirements is addressed within the IRP. Section 2 reports on the electric and gas resource action plans put forward in the previous IRP. Section 3 offers two additional reports. The first is a table illustrating the consistency of PSE's electric demand-side resources assessment with the Northwest Power Planning Council's methodology. The second is a table summarizing the load-resource balance information presented in this IRP.

This IRP is the product of robust analysis that considered a wide range of future risks and uncertainties. PSE believes this plan meets applicable statutory requirements, and seeks a letter from the WUTC accepting this filing.

APPENDIX B – LEGAL REQUIREMENTS/OTHER REPORTS

1. Regulatory Requirements

Tables B-1 and B-2 delineate the regulatory requirements for electric and natural gas integrated resource plans, and identify the chapters of this plan that address each requirement.

Figure B-1
Electric Integrated Resource Plan Regulatory Requirements

Statutory/Regulatory Requirement	Chapter
WAC 480-100-238 (3) (a) A range of forecasts of future demand using methods that examine the effect of economic forces on the consumption of electricity and that address changes in the number, type and efficiency of electrical end-uses.	• Chapter 4, Key Assumptions • Appendix H, Demand Forecasts
WAC 480-100-238 (3) (b) An assessment of commercially available conservation, including load management, as well as an assessment of currently employed and new policies and programs needed to obtain the conservation improvements.	• Chapter 5, Electric Analysis • Appendix N, Demand-side Resources Analysis
WAC 480-100-238 (3) (c) An assessment of a wide range of conventional and commercially available nonconventional generating technologies.	• Chapter 5, Electric Analysis • Appendix D, Electric Resource Alternatives
WAC 480-100-238 (3) (d) An assessment of transmission system capability and reliability, to the extent such information can be provided consistent with applicable laws.	• Chapter 7, Delivery Infrastructure Planning • Appendix E, Regional Transmission Resources
WAC 480-100-238 (3) (e) A comparative evaluation of energy supply resources (including transmission and distribution) and improvements in conservation using the criteria specified in WAC 480-100-238 (2) (b), Lowest reasonable cost.	• Chapter 5, Electric Analysis • Chapter 2, Developing the Resource Plan • Appendix E, Regional Transmission Resources • Appendix K, Electric Analysis

APPENDIX B – LEGAL REQUIREMENTS/OTHER REPORTS

Statutory/Regulatory Requirement	Chapter
WAC 480-100-238 (3) (f) Integration of the demand forecasts and resource evaluations into a long-range (e.g., at least ten years; longer if appropriate to the life of the resources considered) integrated resource plan describing the mix of resources that is designated to meet current and projected future needs at the lowest reasonable cost to the utility and its ratepayers.	• Chapter 5, Electric Analysis • Chapter 2, Developing the Resource Plan
WAC 480-100-238 (3) (g) A short-term plan outlining the specific actions to be taken by the utility in implementing the long-range integrated resource plan during the two years following submission.	• Chapter 1, Executive Summary (Section 3, Action Plans)
WAC 480-100-238 (3) (h) A report on the utility's progress towards implementing the recommendations contained in its previously filed plan.	• Appendix B, Legal Requirements and Other Reports
WAC 480-100-238 (4) Timing. Unless otherwise ordered by the commission, each electric utility must submit a plan within two years after the date on which the previous plan was filed with the commission. Not later than twelve months prior to the due date of a plan, the utility must provide a work plan for informal commission review. The work plan must outline the content of the integrated resource plan to be developed by the utility and the method for assessing potential resources.	• 2013 Integrated Resource Plan Work Plan filed with the WUTC in May 2012 • Chapter 1, Executive Summary (Section 3, Action Plans)
WAC 480-100-238 (5) Public participation. Consultations with commission staff and public participation are essential to the development of an effective plan. The work plan must outline the timing and extent of public participation. In addition, the commission will hear comment on the plan at a public hearing scheduled after the utility submits its plan for commission review.	• Appendix A, Public Participation

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Figure B-2

Gas Integrated Resource Plan Regulatory Requirements

Statutory/Regulatory Requirement	Chapter
WAC 480-90-238 (3) (a) A range of forecasts of future natural gas demand in firm and interruptible markets for each customer class that examine the effect of economic forces on the consumption of natural gas and that address changes in the number, type and efficiency of natural gas end-uses.	• Chapter 4, Key Assumptions • Appendix H, Demand Forecasts
WAC 480-90-238 (3) (b) An assessment of commercially available conservation, including load management, as well as an assessment of currently employed and new policies and programs needed to obtain the conservation improvements.	• Chapter 6, Gas Analysis • Appendix N, Demand-side Resources Analysis
WAC 480-90-238 (3) (c) An assessment of conventional and commercially available nonconventional gas supplies.	• Chapter 6, Gas Analysis
WAC 480-90-238 (3) (d) An assessment of opportunities for using company-owned or contracted storage.	• Chapter 6, Gas Analysis
WAC 480-90-238 (3) (e) An assessment of pipeline transmission capability and reliability and opportunities for additional pipeline transmission resources.	• Chapter 6, Gas Analysis • Chapter 2, Developing the Resource Plan • Appendix L, Gas Analysis
WAC 480-90-238 (3) (f) A comparative evaluation of the cost of natural gas purchasing strategies, storage options, delivery resources, and improvements in conservation using a consistent method to calculate cost-effectiveness.	• Chapter 6, Gas Analysis
WAC 480-90-238 (3) (g) The integration of the demand forecasts and resource evaluations into a long-range (e.g., at least ten years; longer if appropriate to the life of the resources considered) integrated resource plan describing the mix of resources that is designated to meet current and future needs at the lowest reasonable cost to the utility and its ratepayers.	• Chapter 6, Gas Analysis • Chapter 2, Developing the Resource Plan
WAC 480-90-238 (3) (h) A short-term plan outlining the specific actions to be taken by the utility in implementing the long-range integrated resource plan during the two years following submission.	• Chapter 1, Executive Summary (Section 3, Action Plans)
WAC 480-90-238 (3) (i) A report on the utility's progress towards implementing the recommendations contained in its previously filed plan.	• Appendix B, Legal Requirements and Other Reports

APPENDIX B – LEGAL REQUIREMENTS/OTHER REPORTS

Statutory/Regulatory Requirement	Chapter
WAC 480-90-238 (4) Timing. Unless otherwise ordered by the commission, each natural gas utility must submit a plan within two years after the date on which the previous plan was filed with the commission. Not later than twelve months prior to the due date of a plan, the utility must provide a work plan for informal commission review. The work plan must outline the content of the integrated resource plan to be developed by the utility and the method for assessing potential resources.	• 2013 Integrated Resource Plan Work Plan filed with the WUTC in May 2012 • Chapter 1, Executive Summary (Section 3, Action Plans)
WAC 480-90-238 (5) Public participation. Consultations with commission staff and public participation are essential to the development of an effective plan. The work plan must outline the timing and extent of public participation. In addition, the commission will hear comment on the plan at a public hearing scheduled after the utility submits its plan for commission review.	• Appendix A, Public Participation

2. Report on Previous Action Plans

2011 Electric Resources Action Plan

Per WAC 480-100-238 (3) (i), each item from the 2011 IRP electric resources action plan is listed below, along with the progress that has been made in implementing those recommendations.

Item: Resource adequacy

Continue to refine PSE's analysis of resource need, including the impacts of demand-response. Also, remain actively engaged in regional groups and forums focused on regional resource adequacy for energy and capacity.

Progress made

- Refine PSE's analysis of resource need: The resource need assessment in the 2013 IRP includes several refinements:

  Weather sensitivity of heating-related energy efficiency measures are now reflected in PSE's loss of load probability (LOLP) analysis. The conservation effect is now a function of temperature in that analysis. That is, as loads increase because temperatures fall, the amount of energy efficiency from heating measures increases.

  The planning margin – the amount of capacity needed above a normal peak to achieve a 5 percent LOLP target – now changes across time as additional sample years have been added. In the 2011 IRP, the planning margin was 15.7 percent across the planning horizon. In this IRP, the planning margin is 13.5 percent through winter 2017 to 2018, rises to 14.5 percent through winter 2023 to 2024, and is 16 percent for the rest of the period.

  The capacity contribution of all resources was adjusted using an incremental capacity equivalence (ICE) analysis. In the 2011 IRP, such an analysis was used only to estimate the capacity contribution of additional wind. In this IRP, ICE calculations were made for Colstrip, DSR, wind, CT, CCCT, and battery storage.

In this IRP, a check-in on performance of the planning methodology was included. That is, we ran the portfolio from the electric optimization analysis back through the LOLP analysis, to make sure application of the planning margin and ICE calculations were operating as intended.

- Engage in regional groups and forums focused on regional resource adequacy for energy and capacity:

PSE was actively engaged in the Pacific Northwest Resource Adequacy Forum in that organization's Technical and Steering committees.

PSE staff co-chaired the Pacific Northwest Utilities Coordinating Committee's (PNUCC) System Planning committee.

PSE staff has also been actively engaged in the joint PNUCC and Northwest Gas Association's (NWGA) Power and Natural Gas Task Force to examine and address planning and operational issues that arise from increasing use of natural gas for electric generation.

PSE has participated in the Western Interstate Energy Board's Western Gas-Electric Regional Assessment Task Force and related subcommittees.

Item: Electric demand-side resources

Work with external stakeholders in the CRAG process to separate demand-side resources in the plan into non-programmatic and programmatic potentials. Consider real-world risks to achieving conservation potentials as we work with the CRAG in establishing goals and targets for compliance and tariff filings, using this IRP as a starting point. Also, begin ramping up efforts to increase demand-response programs based on cost effectiveness. Issue RFPs, as appropriate, to assist with efficient acquisition of demand-side resources.

Progress made

- Separate programmatic and non-programmatic demand-side resources potentials in the plan: We identified the measures impacted by the Energy Independence and Security Act (EISA) as a distinct non-programmatic bundle. That assisted the Energy Efficiency Services group in setting their targets based on the remaining programmatic conservation selected to be cost effective in the IRP. We have also included this approach for gas measures as new federal standards have impacted gas programs in the current IRP.
- Ramp up efforts to increase cost effective demand-response programs, including issuing requests for proposals (RFPs) as appropriate: An RFP was issued based on the results of the 2011 IRP, several bids were shortlisted and one was selected for evaluation against other supply-side bids. It was not the least-cost resource, and so the proposal was not selected.

Item: Renewable resources

Continue to work toward meeting renewable energy targets via the formal RFP process and by looking for market opportunities to capture cost-effective renewable resource acquisitions for our customers. Continue refining our forecasting capabilities for wind-related ancillary service needs.

Progress made

- Meet renewable energy targets: With the addition of the 343-megawatt Lower Snake River Wind Facility in Garfield County, which began commercial operations in February 2012, PSE is expected to meet its near-term renewable energy milestones.
- Refine wind-related ancillary service need forecasting capabilities: Details of these efforts are described in Appendix G, Operational Flexibility.

Item: Transmission to market

Develop actionable alternatives for additional transmission to market. Consider those alternatives along-side other supply-side resource alternatives in the acquisition process.

Progress made

- PSE solicited transmission-only products as part of its 2011 Request for Proposals for All Generation Sources, but received no viable offers.
- Information presented in the 2013 IRP highlights significant concerns with reliance on existing firm transmission to market as a long-term strategy. Renewal of expiring transmission contracts have been reviewed on a consistent basis with other supply-side acquisitions.

Item: Thermal resources/additional resources

Use the formal RFP process, seek market opportunities, and consider self-build alternatives for base-load and peaking resources to capture cost-effective thermal resource acquisitions for our customers, and to ensure reliable and stable operation of the electric system. Develop actionable thermal resource plans informed by results of the RFP/acquisition process.

Progress made

PSE filed and conducted a Request for Proposals for All Generation Sources in October 2011. The 2011 RFP updated the assumptions from the 2011 IRP and sought resources to help the company meet the following capacity needs:[1]

	2013	2014	2015	2016
Projected MW shortfall	242	460	554	728

In response to the RFP PSE received and evaluated 29 resource proposals. In the end PSE selected the following two proposals for execution.

1. Ferndale combined-cycle combustion turbine (CCCT) natural gas-fired plant purchase option, 280 MW capacity beginning in December 2012.

2. Centralia Coal Transition purchased power agreement (PPA), up to 380 MW of firm energy beginning in December 2014, ending in December 2025.

[1] *These expected shortfalls reflect the mix of energy efficiency programs deemed cost effective in the 2011 IRP.*

APPENDIX B – LEGAL REQUIREMENTS/OTHER REPORTS

With the addition of the Ferndale CCCT plant and the Centralia Coal Transition PPA, PSE expects to have sufficient resources to meet its long-term capacity need through the foreseeable future.

Item: Resource needs as balancing authority

Engage in discussions with the Commission and other stakeholders on how balancing authority-level operational issues should be addressed in the company's resource planning process. Work toward investigating whether it is worthwhile to reflect this level of operating detail in the resource planning framework.

Progress made

- PSE's effort has been directed at refining the analysis of flexibility and system volatility, rather than focused on native load versus BA operations.

2011 Gas Resources Action Plan

Per WAC 480-90-238 (3) (i), each item from the 2011 IRP gas resources action plan is listed below, along with the progress that has been made in implementing those recommendations.

Item: Gas demand-side resources

Work with external stakeholders in the CRAG process to separate demand-side resources in the plan into non-programmatic and programmatic potentials. Consider real-world risks to achieving conservation potentials as we work with the CRAG in establishing goals, targets, and tariff filings, using this IRP as a starting point. Issue RFPs, as appropriate, to assist with efficient acquisition of demand-side resources.

Progress made

- Separate programmatic and non-programmatic demand-side resources potentials in the plan: There were no non-programmatic potentials for gas measures.
- Consider real-world risks to achieving potentials: Lower gas prices meant lower avoided costs. The program cost effectiveness was reviewed mid-period in the 2012-2013 program cycle, and program delivery was adjusted accordingly.
- Issue RFPs as appropriate: An energy efficiency RFP were issued for the 2012-2013 Biennium, and some contracts were awarded, to augment PSE program delivery.

Item: Supply-side resource alternatives

Prepare for potential need for additional capacity in the future. Work with other owners of Jackson Prairie to study the feasibility and possible costs of future expansion. Look for opportunities to possibly acquire existing capacity in the next two years which may be more cost effective than waiting until 2013/2014 to begin pipeline expansion/acquisition designed to meet 2016/17 needs.

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Progress made

PSE's gas sales load growth has slowed under forecasts subsequent to the 2011 IRP, delaying need for a few more years. Jackson Prairie staff has begun more detailed and extensive reservoir modeling that may eventually lead to a potential expansion opportunity. (The reservoir expansion that commenced in 2002 was just completed in the summer of 2012.) PSE has remained actively engaged in the market, watching for opportunities and participating in Northwest Pipeline's recent non-binding Expansion Open Season for capacity that may be available in the 2016 through 2020 timeframe. PSE is also analyzing other short and long-term solutions to mitigate the loss of Plymouth LNG, including permanent releases of pipeline capacity held by others, a more creative use of Jackson Prairie storage, and the potential of LNG peak-shaving within the service territory.

Item: Generation fuel supply

Coordinate fuel supply planning with energy supply acquisitions. As additional gas-fired generation requirements are added to the portfolio, additional regional storage resources may be needed to manage the physical swings in gas supply needed for generation fuel.

Progress made

PSE obtained additional pipeline capacity in conjunction with the Ferndale acquisition, in part through an amendment providing greater flexibility within an existing agreement. PSE continues to remain engaged with another developer of incremental storage capacity in the region and is monitoring their progress. PSE has extended the generation portfolio's access to Jackson Prairie storage until the expected availability of third-party storage by implementing a creative sharing of the resource with the gas sales portfolio.

3. Other Reports

Electric demand-side resource assessment: Consistency with Northwest Power Planning Council Methodology

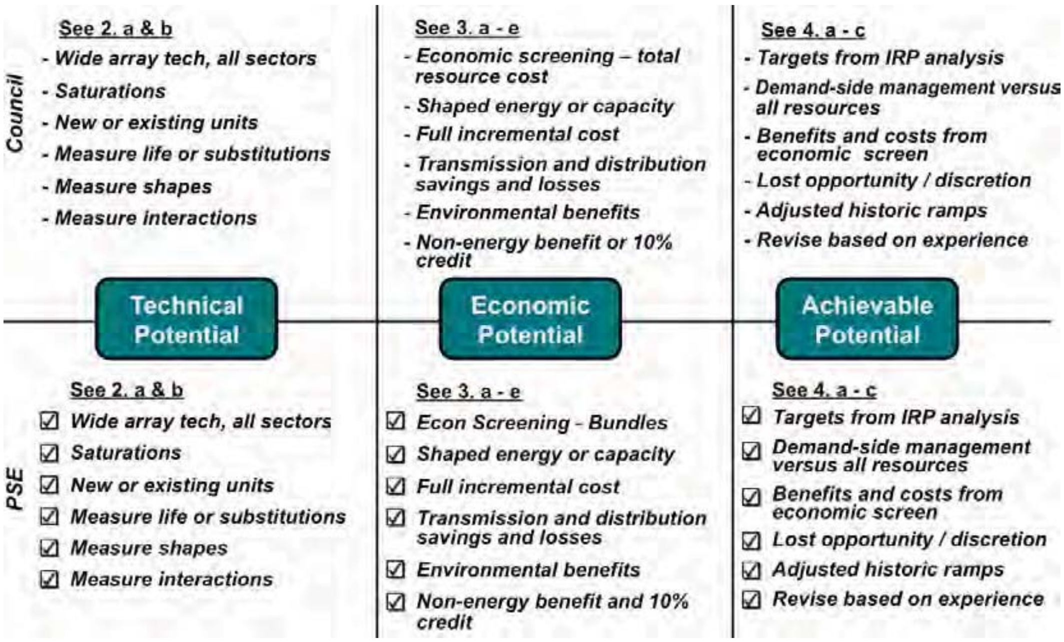
There are no legal requirements for the IRP to address the Northwest Power Planning Council's (Council) methodology for assessing demand-side resources. Such comparison, however, may be useful for PSE and stakeholders in implementing sections of WAC 480-109. PSE has worked closely with Council staff on several aspects of our analytical process, including approaches to modeling demand-side resources. We're most grateful for the dialogue, and very much appreciate the opportunity to work with Council staff. WAC 480-109 does not define "methodology." PSE developed the detailed checklist that follows to demonstrate that our process in the IRP is consistent with the Council's methodology.[2] This checklist was presented and discussed during the January 22, 2013 IRP Advisory Group meeting. Additional information on consistency with Council methodology can be found in the Cadmus report, attached as Appendix N to this IRP.

[2] *References in Figure B-4 refer to the Council's assessment of its methodology, found at: http://www.nwcouncil.org/energy/powerplan/6/supplycurves/I937/default.htm*

APPENDIX B – LEGAL REQUIREMENTS/OTHER REPORTS

Figure B-4

PSE is consistent with NW Power and Conservation Council's Conservation Assessment Methodology



Integrated resource plan cover sheet: Department of Commerce

The WUTC is required to provide summary information about IRPs of investor-owned utilities to the Department of Commerce. Information for the cover sheet is included in Table B-5, below.

Figure B-5

Load-resource Balance Summary

Resource Plan Year:	2014
Base Year Start:	01/01/2014
Base Year End:	12/31/2014
Five-year Report Year:	2019
Ten-year Report Year:	2024

Report Years	*Base Year*			*2019*			*2024*		
Period	*Winter*	*Summer*	*Annual*	*Winter*	*Summer*	*Annual*	*Winter*	*Summer*	*Annual*
Units	*(MW)*	*(MW)*	*(MWa)*	*(MW)*	*(MW)*	*(MWa)*	*(MW)*	*(MW)*	*(MWa)*
Loads	4,922	3,167	2,644	5,423	3,603	2,957	5,963	4,077	3,291
Exports	36	336	70	21	321	68	0	319	63
Resources									
Conservation/ Efficiency	75	36	26	391	250	242	703	469	473
Demand Response	13			80			116		
Cogeneration									
Hydro	914	829	523	879	794	509	864	779	519
Wind	82	82	251	82	82	251	82	82	251
Other Renewables							25		21
Thermal - Gas	2,024	1,572	1,107	2,024	1,572	1,107	2,024	1,572	1,107
Thermal - Coal	592	592	565	592	592	565	592	592	565
Long Term: BPA Base Year or Tier 1									
Net Long Term Contracts: Other	402	20	88	432	422	408	418	407	396
Net Short Term Contracts	1,618	1,606		1,673	1,635		1,666	1,647	
Other									
Imports	383	83	73	308	8	49	308	8	49
Total Resources	6,067	4,484	2,564	6,439	5,033	3,064	6,773	5,236	3,297
Load Resource Balance	-1,145	-1,316	80	-1,016	-1,430	-107	-810	-1,159	-7

APPENDIX C

Environmental Matters

Contents

Climate and environmental impact policies continue to evolve at the state, regional, and federal levels, and PSE remains involved in these policymaking activities. This appendix summarizes the main rules and regulations that apply to PSE activities.

1. Federal Legislative Activity

The 112th Congress (2011-2012) blocked all efforts to curb carbon emissions during its tenure. A total of 113 bills, resolutions and amendments related to climate change were introduced. Many more focused on energy, transportation, agriculture, and other areas that have an impact on climate change. However, Congress enacted very few of these proposals, and for the first time since the introduction of the McCain-Lieberman greenhouse gas cap-and-trade bill in 2003, not one greenhouse gas cap-and-trade bill was introduced. Two bills proposed a comprehensive approach to reducing greenhouse gas (GHG) emissions by establishing a carbon tax, but neither passed. The measures that did pass were simply small steps towards climate change adaptation; these preserved voluntary greenhouse gas reduction programs and funding for certain carbon sequestration projects.

2. Environmental Protection Agency Regulations

Most of the rules recently proposed and enacted by the Environmental Protection Agency (EPA) are directed at the power sector, particularly coal-fired generating sources. These include new standards that address toxic emissions, coal-ash disposal, greenhouse gases, and water discharges. According to the EPA, these rules reflect statutory mandates and court orders that require the agency to act.

Mercury and Air Toxics Standard (MATS). The EPA published the final Mercury and Air Toxics Standard in February 2012. The MATS rule establishes emissions limitations at coal-fired power plants for mercury (1.2 lb/TBtu), acid gases and certain toxic heavy metals using a particulate matter surrogate (0.03 lb/MMBtu). Generating units have 3 years, until April 2015, to comply with MATS and could receive up to a 1-year extension from state permitting authorities if necessary for the installation of controls. Various industry and environmental groups have challenged the MATS rule in the courts.

Coal combustion residuals (CCR). On June 21, 2010, the EPA issued proposed rules for the “Identification and Listing of Special Wastes: Disposal of Coal Combustion Residuals (CCR) from Electric Utilities.” These proposals concern the regulation of coal ash. The EPA received over 450,000 comments on more than 2 million pages for the respective proposals in November 2010. No schedule for issuing a final regulation has been adopted.

Three proposals were put forward. Under the first two, coal ash would continue to be regulated as a solid waste under Subtitle D provisions of the Resource Conservation and Recovery Act (RCRA). This would give authority to the states to oversee a set of performance standards for handling and disposal. Coal ash would continue to be listed as non-hazardous, but wet handling would not be allowed to continue. Under the third option, coal ash would be regulated as a hazardous waste under Subtitle C provisions of the RCRA. This would make coal ash subject to a comprehensive program of federally enforceable requirements for waste management and disposal. Regulation under Subtitle C would essentially require the phase-out of wet handling and surface impoundments. The EPA estimates over 500 surface impoundments would be affected by this ruling.

APPENDIX C – ENVIRONMENTAL MATTERS

Cooling water intake and discharge. On March 28, 2011, EPA proposed a new standard under Section 316(b) of the Clean Water Act affecting the intake and discharge of cooling water at steam electric generating units that withdraw water from a body of water through cooling water intake structures. These standards will reflect the Best Technology Available (BTA) to protect water quality from cooling water intake and discharges. Section 316(b) will affect all existing and new fossil steam and nuclear steam electric generating units. The EPA estimates the BTA standard will apply to over 440 power plants (approximately 325 GW), but because 316(b) permits are written on a case-by-case basis, the actual number of retrofits to meet compliance is difficult to estimate. Forced retrofits are expected to begin between 2015 and 2018. EPA recently agreed to finalize the 316(b) rule by July 27, 2013.

National Ambient Air Quality Standards. As part of the Clean Air Act, every five years the EPA is required to review and revise, if needed, the National Ambient Air Quality Standards (NAAQS). There are two types of standards, a primary standard whose level is set with an adequate margin of safety to protect public health, and a secondary standard whose level is set to protect public welfare values. The standards in and of themselves do not directly mandate pollution control requirements on the electric power sector. EPA is proposing to tighten the health-based standards for Particulate Matter 2.5 (PM2.5) from 15 to 12-13 micrograms per cubic meter (ug/m3). Tightening the PM2.5 standard will create new non-attainment areas, state implementation plans, and new control measures. EPA is expected to release a proposal in the fall of 2013, and intends to implement a final rule by the end of 2014.

Regional Haze Rule. Following a recent lawsuit, the EPA is working under a consent decree to take action on visibility impacts (regional haze) in western states by requiring a review of the Regional Haze Rule. The Regional Haze Rule review applies to facilities built between 1962 and 1977 with a potential to emit more than 250 tons a year of visibility-impairing pollution in classified areas. The rule requires the states to consider the visibility impacts from each affected facility, and to assess whether they have to install Best Available Retrofit Technology (BART) controls. Below is a summary of SIP mandates considered or implemented so far in Montana, Oregon, Washington, and California.

APPENDIX C – ENVIRONMENTAL MATTERS

Montana

The EPA finalized a Federal Implementation Plan (FIP) on October 18, 2012 to address regional haze in Montana. EPA developed this FIP in response to Montana's decision in 2006 to not submit a regional haze SIP revision. The FIP satisfies requirements of the Clean Air Act that require states or the EPA to promulgate an FIP, to assure reasonable progress towards the national goal of preventing any future impairment of visibility in mandatory areas, and to remedy any existing impairments.

Oregon

On May 23, 2012, EPA proposed to approve portions of a State Implementation Plan (SIP) revision submitted by Oregon on December 10, 2010 and supplemented on February 1, 2011, as meeting the Regional Haze Rule requirements in 40 CFR 51.308. In a previous action on July 5, 2011, EPA approved portions of the December 10, 2010, SIP submittal as meeting the requirements for interstate transport for visibility and certain requirements of the program including the requirements for BART.

California

The California Regional Haze Plan fulfills all the relevant requirements of the Regional Haze Rule. EPA has ruled the state has established baseline visibility conditions and reasonable progress goals for each of its classified areas, and has developed a long-term strategy with enforceable measures ensuring reasonable progress towards meeting the Reasonable Progress Goals for the first ten-year planning period, through 2018.

Washington

EPA has partially approved and partially disapproved parts of Washington's SIP to address regional haze. However, on December 6, 2012 EPA took final action to approve the BART determination for the TransAlta coal-fired power plant in Centralia, Washington. EPA plans to act on the remaining regional haze SIP elements for Washington in the near future.

Tailoring Rule. In the absence of meaningful greenhouse gas legislation, the Administration directed the EPA to regulate certain industries by imposing new standards limiting carbon emissions. The Tailoring Rule, which became effective January 2, 2011, sets permitted levels for greenhouse gas emissions in two phases for power plants and other large stationary sources. The ruling limits the amount of greenhouse gas emissions a facility can emit by requiring installation of Best Available Control Technology (BACT). Phase I requires existing facilities that emit more than 100,000 tons of GHG emissions per year to comply with the new BACT rules when air permits are renewed or when major modifications are made after January 2011. Phase II, which began in July 2011, requires preconstruction permits using BACT for new projects that emit 100,000 tons of emissions per year, or existing projects that make major modifications and that emit more than 75,000 tons per year. Currently the EPA has released BACT guidance only for coal technology; work on natural gas turbine guidance is ongoing.

New Source Performance Standard (NSPS). On March 27, 2012, the EPA proposed a New Source Performance Standard to limit carbon dioxide from new fossil fuel-fired electric generation units. The proposed standard would apply only to new generating units. The EPA did not propose standards for existing fossil fuel power plants, nor did it indicate a timeline for proposing these in the future. The proposed output-based standard for new units is 1,000 pounds of carbon dioxide per megawatt-hour (MWh).

3. State & Regional Activity

Washington Emissions Performance Standard (EPS). On July 19, 2008, an Emissions Performance Standard went in to effect in Washington state. It required base-load electric generation facilities to meet a greenhouse gas emission limit of 1,100 pounds of carbon dioxide per megawatt hour (lb/MWh). The EPS applies to new, in-state base-load electric generation, power plants that undergo a change in ownership, and to generation delivered under long-term contracts that begin on July 1, 2008 or later. Every five years the Department of Commerce (Commerce) is required to update the EPS to match the average emissions rate of new combined-cycle natural gas power plants. Commerce initiated the update in March 2012 and finalized the revised value of 970 lbs/MWh on March 17, 2013.

Renewable portfolio standards (RPS). Renewable portfolio ptandards require utilities to obtain a specific portion of their electricity from renewable resources. Currently 29 states, the District of Columbia, Puerto Rico, and Northern Mariana Islands have RPS mandates; an additional eight states and two territories have renewable portfolio goals. Washington state’s RPS requires PSE and other utilities to meet 3

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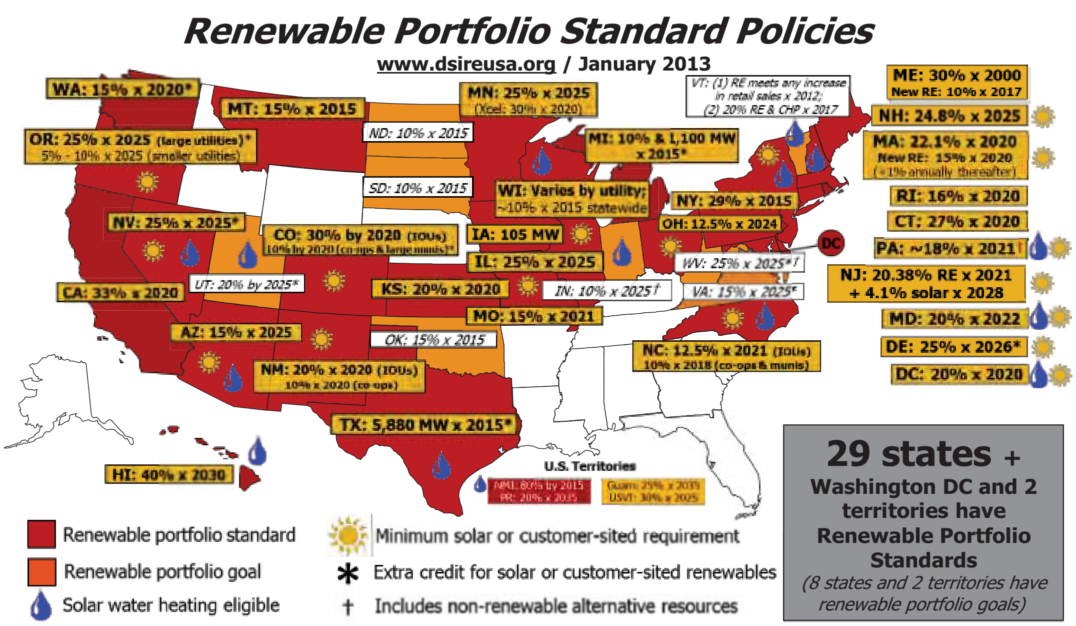
percent of load with renewable resources by 2012, 9 percent by 2016, and 15 percent by 2020, but RPS provisions vary widely among the different jurisdictions in the absence of a federal mandate. Differences include the specific portion of renewable resources required, the timeline to meet the requirements, the types of resources that qualify as "renewable," the geographic location renewable resources can be sourced from, eligible commercial on-line dates, and any applicable technology carve-outs (such as solar). The result is a patchwork of regulatory mandates, evolving regulations, and segregated environmental markets. Managing these moving parts is complex from both a resource acquisition perspective and an environmental markets perspective. Figure C-1, below, illustrates the wide variety of RPS requirements that exist.

Figure C-1
RPS Requirements by State



PSE must actively monitor RPS requirements throughout the Western region, because the interconnectedness of the grid and regional energy markets means that changes in one state can have a pronounced impact on the entire system. In particular, PSE pays close attention to requirements in Oregon, California, and Idaho (which currently has no RPS).

Because of California's decade-long commitment to an RPS mandate and its relentless efforts to increase the state's renewable requirements, California utilities have been extremely active in acquiring renewable resources located both inside and outside of the state, effectively increasing competition for renewable resources, renewable energy credit (REC) products, and available transmission.

On the flip side, Idaho does not currently have an RPS mandate. Therefore, Idaho utilities are not required to purchase environmental attributes associated with the acquisition of the underlying energy, effectively bringing additional RECs to the Pacific Northwest market. Should Idaho adopt an RPS mandate in the future, one would expect to see additional heightened competition for renewable resources (and thus their associated environmental attributes in the form of RECs).

California renewable portfolio standard. The size and the aggressiveness of California's RPS mandate make it the region's primary driver of renewable resource availability and cost, REC product availability and cost, and transmission and integration.

California has one of, if not *the* most aggressive RPS mandate in the nation. Senate Bill 1078 established the California RPS program in 2002. Governor Schwarzenegger sought to accelerate the standard, asking for 20 percent by 2010; this became law when he signed Senate Bill 107. In 2008, Schwarzenegger signed Executive Order S-14-08, which increased requirement to 33 percent by 2020. Two RPS bills were passed at the end of the 2009 legislative session, however, the governor elected not to sign either. Instead, he signed Executive Order S-21-09, which allowed the California Air Resources Board (CARB), under its AB 32 authority, to adopt a regulation consistent with the 33 percent RPS target established in Executive Order S-14-08. In 2010, the CARB adopted its Renewable Electricity Standard (RES), requiring 33 percent by 2020. Legislative endorsement of this standard was achieved when Governor Jerry Brown signed Senate Bill SB 2 (1X) into law in April 2011.

SB 2 (1X) extends the original RPS goal from 20 percent of retail sales by the end of 2010 to 33 percent of retail sales by 2020 for all California independently owned utilities (IOUs), electric service providers (ESPs), and the community choice aggregators (CCAs); it also obligates publically owned utilities to meet these goals. In addition, the new law modifies many details of the program and creates portfolio content categories for RPS procurement. The California Public Utilities Commission (CPUC) and the California Energy Commission (CEC) were tasked with implementing the expanded RPS. In December 2011, the CPUC issued a decision that addressed the criteria for inclusion in each of the new RPS portfolio content categories and the percentage of the annual

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procurement target that could be sourced from unbundled RECs. The use of unbundled renewable energy credits was capped at 25 percent of a utility's RPS requirement through December 31, 2013; this steps down to 15 percent in 2014 and 10 percent in 2017. The decision applies to contracts and ownership agreements entered into after June 1, 2010.

After many years of speculation and uncertainty, the CPUC rules established clearer guidelines regarding the criteria for eligible resources. Renewable projects located outside of California will now be in a better position to support future California renewables demand if they are able to interconnect to a California balancing area or if they can schedule or dynamically transfer energy directly into a California balancing area. As a result of the new rules, much of the Pacific Northwest REC supply that had been held back in hopes of selling into the California market is now added to other local supply, which in turn has contributed to significantly lower REC values for renewable energy generated in the Pacific Northwest.

California cap and trade. On December 16, 2010, the California Air Resources Board (CARB) adopted final rules to enact cap-and-trade provisions in accordance with California's Global Warming Solutions Act of 2006 (Assembly Bill 32). The final rule defines the ground rules for participating in the cap-and-trade program, including enforcement and linkage to outside programs. The compliance obligations became binding on January 1, 2013.

The cap is designed to reduce carbon emissions to 1990 levels by the year 2020 in two phases. In phase one, electricity generation, electricity imports and large industrial polluters must comply with the cap. Beginning in 2015, transportation fuels and all other fuel distributors will be brought into the program. The proposal includes a number of mechanisms designed to minimize the costs of reducing GHGs. Some of the mechanisms include three-year compliance periods, banking, offsets, an allowance price containment reserve, and linkage to other trading systems.

The first auction for emission allowances was conducted by CARB in November 2012. Approximately 75 participants, ranging from utilities to large financial institutions, were authorized to bid in the first auction. All 23 million allowances offered for 2013 compliance were purchased.

CARB intends to auction close to 95 million greenhouse gas allowances in 2013, starting with a floor price of $10.71 per metric ton (tonne). CARB will offer about 56.85 million

2013 vintage allowances and 38.24 million 2016 vintage allowances. Starting in 2013, auctions will be held quarterly on February 19, May 16, August 16 and November 19.

Western Climate Initiative. In 2007, the governors of Arizona, California, Montana, New Mexico, Oregon, Utah, and Washington, along with the premiers of British Columbia, Manitoba, Ontario, and Quebec, signed the Western Regional Climate Action Initiative Agreement (WCI). In doing so, they agreed to reduce regional greenhouse gas emissions to 15 percent below 2005 levels by 2020. The group identified cap-and-trade as a means of achieving the reductions, and began a multi-year process to design a regional system of tradable permits.

In September 2008, the WCI commissioned a report entitled "Design Recommendations for the WCI Regional Cap-and-Trade Program." The report recommended a broad-based cap-and-trade system to achieve the reduction goal. Covered industries included electric utilities, large industrial and commercial facilities, industrial processing (including oil and gas), residential, commercial, and fuel combustion facilities, and transportation fuels.

However, the economic recession that began in 2008 ultimately sapped the political appetite for cap-and-trade in most of the Western states, and by November 2011 Washington had joined Arizona, Montana, New Mexico, Oregon, and Utah in abandoning the Western Climate Initiative. The WCI now consists of California and four Canadian Provinces (British Columbia, Manitoba, Ontario, and Quebec).

4. Climate Change Impacts on the Northwest

Scientists are studying recent trends and using various models to consider the impact of climate change on the Northwest. Two particular areas interest utilities: changes in temperature, which affect energy loads; and changes in stream flows, which affect the seasonality and availability of hydro-generated electricity. Other issues – such as irrigation, water flows for fish, and flood control – are also factors since they may take priority over power generation.

In 2009, the Climate Impacts Group (Impacts Group) at the University of Washington completed a study on the potential effects of climate change on regional energy demand for heating and cooling and on hydropower production from the Columbia River system. The study explored the following questions:[1]

> *"How will seasonal and annual total hydropower production from the Columbia River basin change over the next century in response to projected warming and changes in precipitation?"*
>
> *"How will heating and cooling energy demand change over the next century in response to warming and population growth?"*
>
> *"How do electrical peak energy demand sensitivities to temperature compare in the PNW and California, and how can this information be used to understand potential changes in peak energy demand in the region related to warming?"*

Hydropower production. The Columbia River basin depends on snowpack as a natural reservoir to hold winter precipitation until it runs off as stream flow in spring, summer, and fall. Modeling by the Impacts Group suggests hydropower production on the Columbia River will increase in winter and decline in summer, with a slight overall decline on an annual basis by the middle of the twenty-first century. A summary of these findings appears below.

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[1] *Effects of projected climate change on energy supply and demand in the Pacific Northwest and Washington State; University of Washington Climate Impacts Group; Alan F. Hamlet, Se Yeun Lee, Kristian E.B. Mickelson, Marketa M. Elsner; published May 5, 2010.*

Figure C-2

Hydropower Production Findings

Year	Winter	Summer	Annual
2020	Increase by 1 – 4.5%	Decrease by 8.6 – 11%	Total reduction of 0.8 – 3.4%
2040	Increase by 4.7 – 5%	Decrease by 12.1 – 15.4%	Total reduction of 2 – 3.4%
2080	Increase by 7.7 – 10.9%	Decrease by 17.1 – 20.8%	Total reduction of 2.6 – 3.2%

Heating and cooling energy demand. According to the Impacts Group, heating energy demand is expected to increase in Washington state. If no regional warming occurred, population growth is expected to drive up heating demand by 38 percent in the 2020s, 68 percent in the 2040s, and 129 percent in the 2080s. With regional warming and population held to year 2000 levels, the heating demand would still increase in Washington by 11-12 percent in the 2020s, 15-19 percent in the 2040s, and 24-32 percent in the 2080s. When regional warming and increased demand from population growth are combined, the model indicates regional heating demand will increase in Washington by 22-23 percent in the 2020s, 35-42 percent in the 2040s, and 56-74 percent in the 2080s.

Cooling energy demand is also expected to increase in Washington. As with heating energy demand, without regional climate warming, population growth in the region is expected to increase demand by 38% in the 2020s, 69 percent in the 2040s, and 131 percent in the 2080s. With regional warming and population held to year 2000 levels, cooling demand would increase in Washington by 92-118 percent in the 2020s, 174-289 percent in the 2040s, and 371-749 percent in the 2080s. When regional warming and increased demand from population growth are combined, regional cooling demand is modeled to increase in Washington by 165-201 percent in the 2020s, 363-555 percent in the 2040s, and 981-1,845 percent in the 2080s.

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Impacts to regional energy demand. The combined effects from changes to the hydropower production system and the energy demand requirements suggest that adaptation to climate change will be easier in the cool season than in the warm season. However, Columbia River flow will decrease in May, June, July, and August, thus reducing hydropower supplies and the ability to deliver power to local energy demand and to outside markets like California and the Southwest.

APPENDIX D

Electric Resource Alternatives

Contents

Section one of this appendix is designed to provide additional information about PSE's existing fleet of electric resources. Section two offers context related to a variety of electric resource alternatives, including a brief technology summary, information about the viability and availability of each resource for PSE, and estimated ranges for anticipated capital and operating costs.

1. Existing Resources

PSE's existing resources include supply-side resources, demand-side resources, and Green Power and small-scale renewables. Supply-side resources include power generated by PSE-owned and contracted facilities, primarily hydroelectric power and power from coal-fired plants, natural gas-fueled turbines, and wind-powered resources. Demand-side resource contributions to the resource pool are generated on the customer side of the meter, primarily through energy efficiency programs. Green Power and small-scale renewables are two renewable energy programs offered by PSE, one for customers who want to support additional development of renewable energy through voluntary bill payments, and one for customers who produce their own power from small-scale renewables.

Supply-side resources

The following tables describe PSE's existing electric resources using the Net Maximum Capacity of each plant in megawatts. Net Maximum Capacity is the capacity a unit can sustain over a specified period of time – in this case 60 minutes – when not restricted by ambient conditions or deratings, less the losses associated with auxiliary loads. This is consistent with the way plant capacities are described in the 10K report[1] that PSE files with the U.S. Securities and Exchange Commission and the Form 1 report we file with the Federal Energy Regulatory Commission.

You may notice that PSE sometimes references different plant capacity values in different publications. This is because plant output varies depending upon a variety of factors, among them ambient temperature, fuel supply, whether a natural gas plant is using duct firing, whether a combined-cycle facility is delivering steam to a steam host, outages, upgrades, and expansions. When describing the relative size of resources, it is often necessary to select a single reference point based on a consistent set of assumptions. Depending on the nature and timing of the discussion, these assumptions – and thus the expected capacity – may vary.

Hydroelectricity

While restrictions to protect endangered species limit the operational flexibility of hydroelectric resources, these generating assets remain valuable because of their ability to track customer load, and because of their low cost relative to other power resources. High precipitation levels generally allow more power to be generated, while low-water years produce less power. During low-water years, the utility must rely on other, more expensive, self-generated power or market sources to meet load. The analysis conducted for this IRP accounts for both seasonality and year-to-year variations in hydroelectric generation. PSE owns hydroelectric projects in western Washington and has long-term purchased-power contracts with three public utility districts (PUDs) that own and operate large dams on the Columbia River in Central Washington. In addition, we contract with smaller hydroelectric generators.

[1] PSE's most recent 10K report was filed with the U.S. Securities and Exchange Commission in March 2013 for the year ending December 31, 2012.

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Figure D-1
Hydroelectric Resources

PLANT	OWNER	PSE SHARE %	NET MAXIMUM CAPACITY (MW)[1]	CONTRACT EXPIRATION DATE
Upper Baker River	PSE	100	91	None
Lower Baker River	PSE	100	79	None
Snoqualmie Falls	PSE	100	54[2]	None
Electron	PSE	100	22[3]	None
Total PSE-Owned			246	
Wells	Douglas Co. PUD	29.9	251	3/31/18
Rocky Reach	Chelan Co. PUD	25.0	325	10/31/31
Rock Island I & II	Chelan Co. PUD	25.0	156	10/31/31
Wanapum	Grant Co. PUD	0.8[4]	9	04/04/52
Priest Rapids	Grant Co. PUD	0.8[4]	9	04/04/52
Mid-Columbia Total			750	
Total Hydro			996[5]	

NOTES
1 Net maximum capacity reflects PSE's share only.
2 Snoqualmie Falls is running at partial capacity while powerhouse 1 is off-line for redevelopment. The plant is expected to be fully operational and provide a net maximum capacity of approximately 54 MW upon completion of powerhouse 1, which is expected in the second quarter of 2013.
3 As of December 31, 2012, Electron project output is limited to approximately 7 MW due to the condition of the flume that conveys water to the plant. This limitation is expected to continue in 2013.
4 Based on Grant Co. PUD current load forecast for 2012; our share will be reduced to this level in 2013.
5 Individual resource and Mid-Columbia totals are rounded to the nearest megawatt.

BAKER RIVER HYDROELECTRIC PROJECT. This facility is located in Washington's north Cascade Mountains. It consists of two dams and is the largest of PSE's three hydroelectric power facilities. The project contains modern fish-enhancement systems including a "floating surface collector" to safely capture juvenile salmon in Baker Lake for downstream transport around both dams, and a second, newer collector on Lake Shannon for moving young salmon around Lower Baker Dam. In addition to generating electricity, the project provides public access for recreation and significant flood-control storage for people and property in the Skagit Valley. Hydroelectric projects require a license from the Federal Energy Regulatory Commission (FERC) for construction and operation. These licenses normally are for periods of 30 to 50 years and then they must be renewed. In October 2008, after a lengthy renewal process, FERC issued a 50-year license allowing PSE to generate 707,600 MWh (average annual output) from the Baker River project.

SNOQUALMIE FALLS HYDROELECTRIC PROJECT. Located east of Seattle on the Cascade Mountains' western slope, the Snoqualmie Falls Hydroelectric Project consists of a small diversion dam just upstream from Snoqualmie Falls, and two powerhouses. The first powerhouse, which is encased in bedrock 270 feet beneath the surface, was the world's first completely underground power plant. Built in 1898-99, it was also the Northwest's first large hydroelectric power plant. FERC issued PSE a 40-year license for the Snoqualmie Falls Hydroelectric Project in 2004. The terms and conditions of the license allow PSE to generate an estimated 300,000 MWh per year.

ELECTRON HYDROELECTRIC PROJECT. Located about 25 miles southeast of Tacoma in the western foothills of Mount Rainier, this facility was completed in 1904. The project draws water from the Puyallup River and funnels it to the power plant via a 10-mile span of wooden flume that runs through the winding river valley.

MID-COLUMBIA LONG-TERM PURCHASED POWER CONTRACTS. Under long-term purchased-power agreements with three PUDs, PSE purchases a percentage of the output of five hydroelectric projects located on the Columbia River in Central Washington. PSE pays the PUDs a proportionate share of the operating expenses for these hydroelectric projects. The agreement with Douglas County PUD for the purchase of 29.89 percent of the output of the Wells project expires in 2018. PSE has a 20-year agreement with Chelan County PUD for the purchase of 25 percent of the output of the Rocky Reach and Rock Island projects. The agreement extends through October 2031. PSE has two agreements with Grant County PUD for a share of the output of the Wanapum and Priest Rapids developments. PSE receives a combined share of power from both projects; this share declines over time as the PUD's loads increase. The agreements with Grant County PUD will continue through the term of any new FERC license, which is through April 4, 2052.

WHITE RIVER PROJECT. In January 2004, PSE stopped generating electricity at White River because relicensing and environmental expenses would have driven power costs well above available alternatives. The utility subsequently sold the assets of its White River Hydroelectric Project, including the Lake Tapps reservoir, to the Cascade Water Alliance. The lake will be used to support a new regional source of drinking water.

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Coal

The **COLSTRIP GENERATING PLANT** supplies PSE customers with reliable, low-cost electric power. It also contributes diversity to the electric resource portfolio. Currently the facility supplies 18 to 20 percent of the baseload energy that serves PSE demand. The plant consists of four coal-fired steam electric plant units located in eastern Montana about 120 miles southeast of Billings. PSE owns 50 percent each of Units 1 & 2 and 25 percent each of Units 3 & 4. PSE's total ownership in Colstrip contributes 677 MW Net Maximum Capacity to the existing portfolio.

Gas-fired Combined-cycle combustion turbines

PSE has six combined-cycle combustion turbine (CCCT) resources with a combined net maximum capacity of 1,256 MW. In a CCCT, the heat that a simple-cycle combustion turbine produces when it generates power is captured and used to create additional energy. This makes it a more efficient means of generating power than simple-cycle turbines.

PSE's CCCT fleet includes **MINT FARM** in Cowlitz County, **FREDERICKSON 1** in Pierce County, **GOLDENDALE** in Klickitat County, and **ENCOGEN, FERNDALE,** and **SUMAS** in Whatcom County. We own 49.85 percent of Frederickson 1, a combined-cycle plant co-owned and operated by a subsidiary of Atlantic Power.

Wind energy

PSE is the largest utility owner and operator of wind-power facilities in the Northwest. **HOPKINS RIDGE**, located in Columbia County, Wash., has a net maximum capacity of 157 MW and began commercial operation in November 2005. **WILD HORSE**, located in Kittitas County near Ellensburg, has a net maximum capacity of 273 MW and came online in December 2006. (The facility originally had a 229 MW capacity, but was expanded by 44 MW in 2010.) Combined, the two projects generate enough electricity, on average, to power approximately 120,000 homes. Both projects have contributed to their respective local economies by providing permanent family-wage jobs, local supply and services procurement, and payment of production royalties to local landowners. In addition, they have increased county tax bases, enabling local government to provide additional services (for example, Columbia County launched a new health clinic). The

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Wild Horse site also features the Pacific Northwest's largest solar power array, with 2,723 photovoltaic solar panels, including the first made-in-Washington solar panels.[2] The Wild Horse array can produce up to 500 kW of electricity with full sun. Panels can also produce power under cloudy skies – 50 to 70 percent of peak output with bright overcast and 5 to 10 percent with dark overcast. The site receives approximately 300 days of sunshine per year, roughly the same as Houston, Texas.

In February 2012, PSE brought online its third and largest wind farm, the **LOWER SNAKE RIVER WIND FACILITY.** The 343 MW operation is located in Garfield County, Wash. The project generates enough electricity, on average, to power approximately 100,000 homes.

Figure D-2 presents details about the company's coal, CCCT, and wind resources.

[2] *Outback Power Systems (now Silicon Energy) in Arlington produced the first solar panels in Washington. The Wild Horse Facility was Outback Power Systems' launch facility, utilizing 315 of their panels. The remaining panels were produced by Sharp Electronics in Tennessee.*

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Figure D-2

Coal, CCCT, and Wind Resources

POWER TYPE	UNITS	PSE OWNERSHIP	NET MAXIMUM CAPACITY (MW)[1]
Coal	Colstrip 1 & 2	50%	307
Coal	Colstrip 3 & 4	25%	370
Total Coal			677
CCCT	Encogen	100%	165
CCCT	Ferndale	100%	253
CCCT	Frederickson 1[2]	49.85%	136
CCCT	Goldendale	100%	278
CCCT	Mint Farm	100%	297
CCCT	Sumas	100%	127
Total CCCT			1,256
Wind	Hopkins Ridge	100%	157
Wind	Lower Snake River, Phase 1	100%	343
Wind	Wild Horse	100%	273
Total Wind			773

NOTES
1 Net maximum capacity reflects PSE's share only.
2 Frederickson 1 CCCT unit is co-owned with Atlantic Power Corporation - USA.

Gas-fired simple-cycle combustion turbines.

PSE’s four simple-cycle combustion turbine plants contribute a net maximum capacity of 612 MW. Although they typically operate only a few days each year, they provide important peaking capability and help us meet operating reserve requirements. The company displaces these resources when lower-cost energy is available for purchase. The **FREDONIA** facility is located near Mount Vernon, about 75 miles north of Seattle in Skagit County. In February 2009, PSE purchased **WHITEHORN** units 2 & 3 in northwestern Whatcom County. The **FREDERICKSON GENERATING STATION**, located south of Seattle in east Pierce County, is comprised of two combustion turbine units with a combined net maximum capacity of 149 MW. Details are shown in Figure D-3 below.

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Figure D-3
Simple-cycle Combustion Turbines

NAME	PSE OWNERSHIP	NET MAXIMUM CAPACITY (MW)[1]
Fredonia 1 & 2	100%	207
Fredonia 3 & 4	100%	107
Whitehorn 2 & 3	100%	149
Frederickson 1 & 2	100%	149
Total		612

[1] Net maximum capacity reflects PSE's share only.

Other long-term contracts

Long-term contracts consist of agreements with independent producers and other utilities to supply electricity to PSE. Fuel sources include hydropower, gas, waste products, and system deliveries without a designated supply resource. These contracts are summarized in Figure D-4. Short-term contracts negotiated by PSE's energy trading group are not included in this listing.

BPA – WNP-3 BONNEVILLE EXCHANGE POWER. This is a system-delivery, not a unit-specific, purchased power contract. The agreement resulted from PSE claims against the Bonneville Power Administration (BPA) regarding its action to halt construction on nuclear project WNP-3, in which PSE had a 5 percent interest. Under the agreement, in effect until June 2017, PSE receives power during the winter months from BPA according to a formula based on the average equivalent annual availability and cost factors of four surrogate nuclear plants similar in design to WNP-3. In exchange, PSE provides power to BPA from its combustion turbines, if requested, except during the month of May.

POWEREX PURCASE FOR POINT ROBERTS. Powerex delivers electric power to PSE's retail customers in Point Roberts, Wash. The Point Roberts load, which is physically isolated from PSE's transmission system, connects to British Columbia Hydro's electric distribution facilities. We pay a fixed price for the energy during the term of the contract.

BPA BAKER REPLACEMENT. Under a 20-year agreement signed with the U.S. Army Corps of Engineers (COE) PSE provides flood control for the Skagit River Valley. Early in the flood control period, we draft water from the Baker Reservoir at the request of the COE. Then, during periods of high precipitation and runoff between October 15 and March 1, we store water in the Upper Baker Reservoir and release it in a controlled manner to reduce downstream flooding. In return, PSE receives power from BPA from November through February; this compensates for the lower generating capability caused by reduced head due to the early drafting at the plant during the flood control months.

PACIFIC GAS & ELECTRIC COMPANY (PG&E) SEASONAL EXCHANGE. Each calendar year PSE exchanges 300 MW of seasonal capacity, together with 413,000 MWh of energy, on a one-for-one basis under this system-delivery purchased power contract. PSE is a winter-peaking utility and PG&E is a summer-peaking utility, so we provide power to PG&E from June through September, and PG&E provides power to us November through February.

CANADIAN ENTITLEMENT RETURN. Under a treaty between the United States and Canada, one-half of the firm power benefits produced by additional storage capability on the Columbia River in Canada accrue to Canada. PSE's benefits and obligations from this storage are based on the percentage of our participation in the Columbia River projects. Agreements with the Mid-Columbia PUDs specify PSE's share of the obligation to return one-half of the firm power benefits to Canada until the expiration of the PUD contracts or 2024, whichever occurs first. This is energy that PSE provides rather than receives, so it is a negative number (-38.6 aMW for 2013).

BARCLAYS BANK. Under this agreement, which runs through February 2015, Barclays delivers around-the-clock power to PSE during the winter months of November through February. This is a system-delivery of 75 MW per hour, not a unit-specific, purchased power contract.

TRANSALTA CENTRALIA. Under the terms of this agreement, PSE will buy 180 MW of firm, base-load coal transition power from TransAlta starting in December 2014. In the following 12 months the contract increases to 280 MW. From December 2016 to December 2024 the contract is for 380 MW, and in the last year the contract volume drops to 300 MW. This contract will benefit PSE customers by providing a source of low-cost power, while advancing a separate TransAlta agreement with state government and the environmental community to phase out coal-fired power generation in Washington by 2025. The state Legislature in 2011 passed a bill codifying a collaborative agreement between TransAlta, lawmakers, environmentalists, and labor representatives. The timelines agreed to by the parties enable the state to make the transition to cleaner fuels, while preserving the family-wage jobs and economic benefits associated with the low-cost, reliable power provided by the Centralia plant. The legislation allows long-term contracts, through 2025, for sales of coal transition power associated with the 1,340-megawatt (MW) Centralia facility, Washington's only coal-fired plant.

KLAMATH TOLL. This tolling contract between PSE and Iberdrola Renewables is designed to help PSE meet its customers' peak winter electricity demand. During winter months (November through February) through February 2016, PSE will receive 100 MW of energy from the Klamath natural gas-fired peaking facility in Klamath Falls, Ore.

KLONDIKE III. PSE's wind portfolio includes a power purchase agreement with Iberdrola Renewables for a 50 MW share of electricity generated at the Klondike III wind farm in Sherman County, Ore. The wind farm has 125 turbines with a project capacity of 224 MW total. This agreement remains in effect until November 2026.

SCHEDULE 91 CONTRACTS. PSE's portfolio includes a number of Schedule 91 electric power contracts (included in Figure D-4) with small power producers – 5 MW or less – in PSE's electric service area offering output pursuant to WAC-107-095. Part one of this statute states that "A utility must purchase electric energy, electric capacity, or both from a qualifying facility on terms that do not exceed the utility's avoided costs for such electric energy, electric capacity, or both." A qualifying facility is defined by WAC 480-107-007 as a generating facility "that meet(s) the criteria specified by the FERC in 18 C.F.R. Part 292 Subpart B."

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Figure D-4

Long-term Contracts for Electric Power Generation

NAME	POWER TYPE	CONTRACT EXPIRATION	CAPACITY (MW)[1]
BPA- WNP-3 Exchange	System	6/30/2017	82
Powerex/Pt.Roberts	System	Ongoing	8
BPA Baker Replacement	Hydro	9/5/2029	7
PG&E Seasonal Exchange-PSE	Thermal	Ongoing	300
Canadian EA	Hydro	09/15/2024	- 40.5
Barclays Bank	System	02/28/2015	75
Centralia Transition Coal	Transition Coal	12/31/2025	180[2]
Klamath Toll	Natural Gas	2/29/2016	100
Klondike III	Wind	11/31/2026	50
Twin Falls	Hydro-QF	3/8/2025	20
Koma Kulshan	Hydro-QF	3/31/2037	10.9
Weeks Falls	Hydro-QF	12/31/2022	4.6
Hutchison Creek	Hydro-QF	9/30/2016	1.0
Cascade Clean Energy- Sygitowicz	Hydro-QF	2/21/2014	<1
Qualco Dairy	Biogas	12/11/2013	<1
Farm Power Lynden	Schedule 91 - Biogas	12/31/2019	<1
Farm Power Rexville	Schedule 91 - Biogas	12/31/2019	<1
Rainier Biogas	Schedule 91 – Biogas	12/31/2020	1.0
Vanderhaak Dairy	Schedule 91 – Biogas	12/31/2019	<1
Van Dyk	Schedule 91 – Biogas	12/31/2020	<1
Bio Energy	Schedule 91 - Biogas	12/31/2021	4.88
Edaleen Dairy	Schedule 91 – Biogas	12/31/2021	<1
Bio fuels, WA	Schedule 91 – Biogas	12/31/2021	4.5
Skookumchuck	Schedule 91 – Hydro	12/31/2020	1
Smith Creek	Schedule 91 – Hydro	12/31/2020	<1
Black Creek	Schedule 91 – Hydro	3/24/2021	4.2
Nooksack Hydro	Schedule 91 – Hydro	12/31/2021	3.5
Island Solar	Schedule 91 – Solar	12/31/2021	<1
Finn Hill Solar (Lake Wash SD)	Schedule 91 – Solar	12/31/2021	<1
Knudson Wind	Schedule 91 – Wind	12/31/2019	<1
3 Bar-G Wind	Schedule 91 – Wind	12/31/2019	1.395
Swauk Wind	Schedule 91 – Wind	12/31/2021	4.25
Total			828

Notes
1 Capacity reflects PSE share only.
2 The capacity of the TransAlta Centralia PPA is designed to ramp up over time to help meet PSE's resource needs. According to the contract, PSE will receive 180 MW from 12/1/2014 to 11/30/2015, 280 MW from 12/1/2015 to 11/30/2016, 380 MW from 12/1/2016 to 12/31/2024, and 300 MW from 1/1/2025 to 12/31/2025.

Transmission contracts

Transmission capacity to the Mid-Columbia (Mid-C) market hub gives PSE access to the principle market hub in the Northwest and one of the major trading hubs in the WECC. It is the central market for northwest hydroelectric generation. As shown in Chapter 5, Figure 5-1, Mid-C transmission access to market is a significant portion of PSE's peak supply portfolio. The majority of this transmission is contracted from BPA on a long-term basis. PSE owns 450 MW of capacity to Mid-C.

PSE's transmission contracts with BPA and owned capacity are shown in Figure D-5 below.

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Figure D-5

Transmission Resources as of 12/31/12

NAME	EFFECTIVE DATE	TERMINATION DATE	TRANSMISSION DEMAND
BPA Mid-C Transmission			
Midway	11/1/2012	11/1/2017	100
Midway	10/1/2008	10/1/2013	115
Midway	3/1/2009	3/1/2014	35
Midway	4/1/2008	11/1/2035	5
Rock Island	7/1/2007	7/1/2037	400
Rocky Reach	11/1/2012	11/1/2017	100
Rocky Reach	11/1/2012	11/1/2017	100
Rocky Reach	11/1/2009	11/1/2014	40
Rocky Reach	11/1/2009	11/1/2014	40
Rocky Reach	11/1/2009	11/1/2014	40
Rocky Reach	11/1/2009	11/1/2014	5
Rocky Reach	11/1/2009	11/1/2014	55
Rocky Reach	11/1/2011	11/1/2031	160
Vantage	11/1/2012	11/1/2017	100
Vantage	12/1/2010	12/1/2014	235[1]
Vantage	11/1/2009	11/1/2014	27
Vantage	11/1/2009	11/1/2014	27
Vantage	11/1/2009	11/1/2014	27
Vantage	11/1/2009	11/1/2014	3
Vantage	11/1/2009	11/1/2014	36
Vantage	11/1/2009	11/1/2014	5
Wells	1/24/1966	8/31/2018	266
NWE Purchase IR Conversion	10/1/2011	10/1/2016	94
Spokane Municipal Waste	3/1/2011	3/1/2016	23
Total BPA Mid-C Transmission			2038

PSE Owned Mid-C Transmission			
McKenzie to Beverly	-	-	50
Rocky Reach to White River	-	-	400
Total PSE Mid-C Transmission	-	-	450

Total Mid-C Transmission			2488

Notes:
1 The capacity of this contract decreases from 235 to 209 MW upon expiration of the existing contract as of 12/1/2014

As shown, PSE has 2,038 MW of BPA transmission capacity and owns 450 MW of capacity for a total of 2,488 MW. Also shown in Figure D-5 are the capacities and contract periods for the various BPA contracts. By December 2014, BPA contracts totaling 664 MW will be evaluated for renewal.

Demand-side resources

Existing demand-side resources

Demand-side resources (DSR) are generally generated or saved on the customer side of the meter, with the exception of distributed generation, which is on the company's distribution system.[3] While DSR includes demand-response, fuel conversion, distributed generation, and distribution efficiency, energy efficiency measures are by far the most substantial contributor to resource need. During the 2010-2011 tariff period, the 72.7 aMW contributed by these programs amounted to enough energy to power approximately 55,000 homes. Since 1978, the annual first-year savings (as reported at the customer meter) has increased more than 300%, from 9 aMW in 1978 to 39.1 aMW in 2011. The cumulative investment and savings from 1978 through 2011 are over $800 million and 490 aMW respectively. This represents more than the annual output from PSE's share of Colstrip 1 & 2, and is equivalent to the electricity used by about 372,000 homes for a year. As with supply-side resources, PSE evaluates energy efficiency programs for cost-effectiveness and suitability within a lowest reasonable cost strategy.

[3] *The WA State Energy Independence Act RCW19.285.030 (5) defines conservation as follows: "Conservation" means any reduction in electric power consumption resulting from increases in the efficiency of energy use, production, or distribution.*

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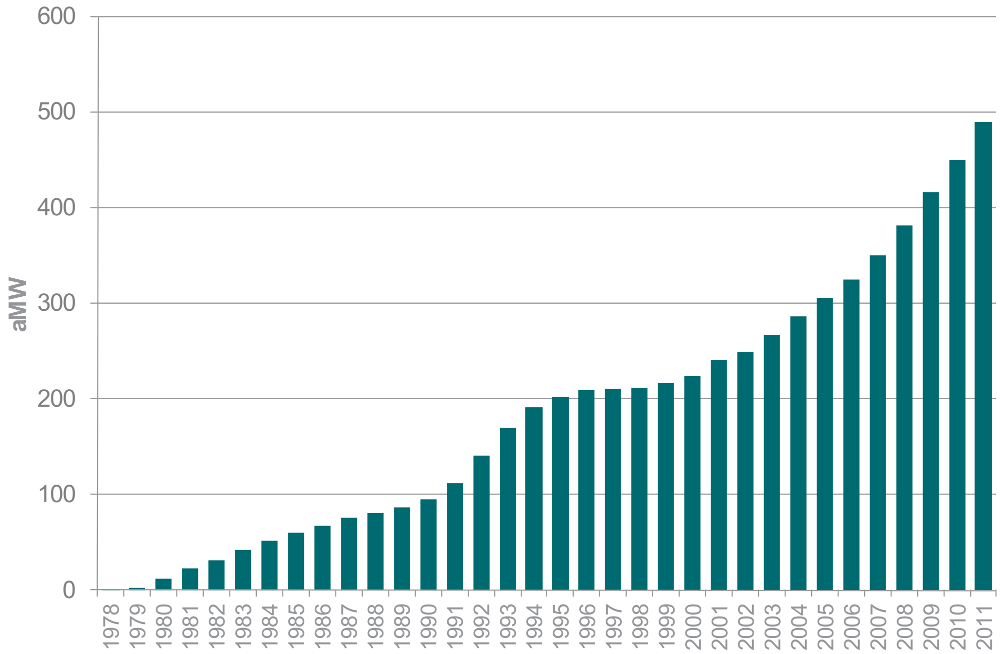
Figure D-6
Cumulative Electric Energy Savings from DSR, 1978 to 2011



Our energy efficiency programs serve all types of customers – residential, low-income, commercial, and industrial. Energy savings targets and the programs to achieve those targets are established every two years. The 2010-2011 biennial program period concluded at the end of 2011; current programs operate January 1, 2012 through December 31, 2013. The majority of electric energy efficiency programs are funded using electric "rider" funds collected from all customers.[4]

For the 2012-2013 period, a two-year target of approximately 76 aMW in energy savings was adopted. This goal was based on extensive analysis of savings potentials and developed in collaboration with key external stakeholders represented by the Conservation Resource Advisory Group (CRAG) and Integrated Resource Plan Advisory Group (IRPAG).

[4] *See Electric Rate Schedule 120 for more information.*

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Current electric energy efficiency programs

The two largest programs offered by PSE to customers are the Commercial and Industrial Retrofit Program and the residential Energy Efficient Lighting Programs.

The **COMMERCIAL AND INDUSTRIAL RETROFIT PROGRAM** offers expert assistance and grants to help existing commercial and industrial customers use electricity and natural gas more efficiently via cost-effective and energy efficient equipment, designs, and operations. This program gave out grants totaling more than $13.6 million to over 830 business customers in 2012 to achieve a savings of over 70,000 MWh.

The **ENERGY EFFICIENT LIGHTING PROGRAMS** offer instant rebates for residential customers and builders who purchase Energy Star fixtures and compact fluorescent light bulbs. This program provided incentives totaling more than $6 million, which resulted in the installation of over 3.5 million CFL lamps and fixtures in 2011 to achieve savings of over 86,000 MWh.

Figure D-7
Annual Energy Efficiency Program Summary, 2010-2013
(Dollars in millions, savings in megawatt hours and average megawatts)

Program	2010 - 2011 Actual	’10-’11 2-Year Budget./Goal	’10-’11 Actual vs. Budget % Total	2012 Actual	’12-’13 2-Year Budget./Goal	’12 Actual vs. ‘12-‘13 % Total
Electric Program Costs	$ 153	$ 167	92.0%	$ 92	$ 193	48%
Savings - MWh	636,000	622,000	102%	339,500	666,000	51%
Savings - aMW	72.60	71.00		38.76	76.03	

Figure D-7 shows program performance compared to two-year budget and savings goals for the biennial 2010-2011 electric energy efficiency programs, and records 2012 progress against 2012-2013 budget and savings goals.

During 2010-2011, electric energy efficiency programs saved a total of 77 aMW of electricity at a cost of $153 million. The company surpassed two-year savings goals while operating at a cost that was under budget. In 2012, these programs saved 39 aMW of electricity at a cost of $92 million. The average cost for acquiring energy efficiency in 2010-2011 was approximately $240 per MWh, compared to a budgeted cost of approximately $290 per MWh in the 2012-13 program cycle.

Green power and small-scale renewables

PSE's customer renewable energy programs continue to grow. The Green Power Program serves customers who want additional renewable energy, and the Customer Renewables Program serves those who generate renewable energy on a small scale. Our customers find value as well as social benefits in the programs, and PSE embraces and encourages their use.

Green Power Program

PSE's Green Power Program, launched in 2001, allows customers to voluntarily purchase retail electric energy from qualified renewable energy resources. Since 2005, the National Renewable Energy Laboratory has recognized PSE as one of the top 10 utilities for Renewable Energy Sales and Total Number of Green Power Participants. Between 2010 and 2012, the number of subscribers increased from 29,398 to 34,962, and the number of megawatt-hours purchased increased from 314,893 to 365,796.

To supply green power, the program purchases renewable energy credits (RECs) from a variety of sources. In the past two years, the majority of RECs have come from the Bonneville Environmental Foundation (BEF), a nonprofit environmental organization in Portland, Ore.; Acciona Energy, a broker of national wind RECs; and 3Degrees, a REC broker based in San Francisco. These suppliers provide PSE's Green Power Program with a portfolio of resources including wind, biomass, low-impact hydropower, biogas and biomass. In addition, the Green Power Program currently purchases RECs directly from eleven small, local producers in order to support the development of new small renewable resources. The list includes the Vander Haak Dairy (now FPE Renewables), Farm Power Rexville, Farm Power Lynden, Qualco Energy, Edaleen Cow Power, Van Dyk-S Holsteins, Rainier Biogas, Ellensburg Community Solar, 3Bar G community wind, and First Up! Knudson community wind, and the Nooksack Hydro Facility.

The Green Power Program has also provided over $150,000 in grant funding to six cities for solar demonstration projects located on municipal facilities. For example, in 2011, the Green Power Program awarded a $20,000 grant to the City of Olympia for a project to be installed on the Olympia Timberland Library; and a $10,000 grant to the City of Lacey for a site to be determined. The grants were in recognition of a successful Green Power Community Challenge in which the two cities increased the net participation in the program by over 500 participants. In addition, the Green Power Program awarded a

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$25,000 grant to the City of Mercer Island after a successful Green Power Challenge, where the Island residents increased participation in the program by 55 percent during 2012. The funds will be used toward a solar project to be installed on the island's community center. Other projects have been installed in Bellingham, Whidbey Island, and Vashon Island.

This past spring, PSE's Green Power Program issued a request for proposals (RFP) for RECs to help supply the balance of our portfolio needs in the next 2 to 3 years. After several years of climbing REC prices, we noted that Washington and Northwest REC prices had fallen significantly since our last RFP, issued three years earlier. This is largely due to an increasing supply of renewable energy and initial compliance targets having been met by the region's utilities. As a result, the Green Power Program has been able to focus on building a portfolio of RECs generated from wind, solar, biogas, and low-impact hydro located primarily in Washington, with some additional supply from Oregon and Idaho.

Rates

The standard rate for green power is $0.0125 per kWh. Customers can purchase 160 kWh blocks for $2 per block with a two-block minimum, or they can choose to participate in the "100% Green Power Option." Introduced in 2007, this option adjusts the amount of the customer's monthly green power purchase to match their monthly electric usage.

The large-volume green power rate – $0.006 cent per kWh for customers who purchase more than 1,000,000 kWh annually – has attracted 25 customers since it was introduced in 2005.

Since 2000, PSE has been working to increase participation in the Green Power Program to five percent of all electric customers. To help achieve that goal, PSE contracted with 3Degrees, a third-party REC broker. 3Degrees has developed and refined education and outreach techniques while working with other utility partners across the country. Since their contract was initiated with PSE in January 2009, customer growth has increased by over 62 percent. Participation has increased by 10 percent and 8 percent in 2011 and 2012, respectively. As of December 31, 2012, over 3 percent of electric customers are participating in the program.

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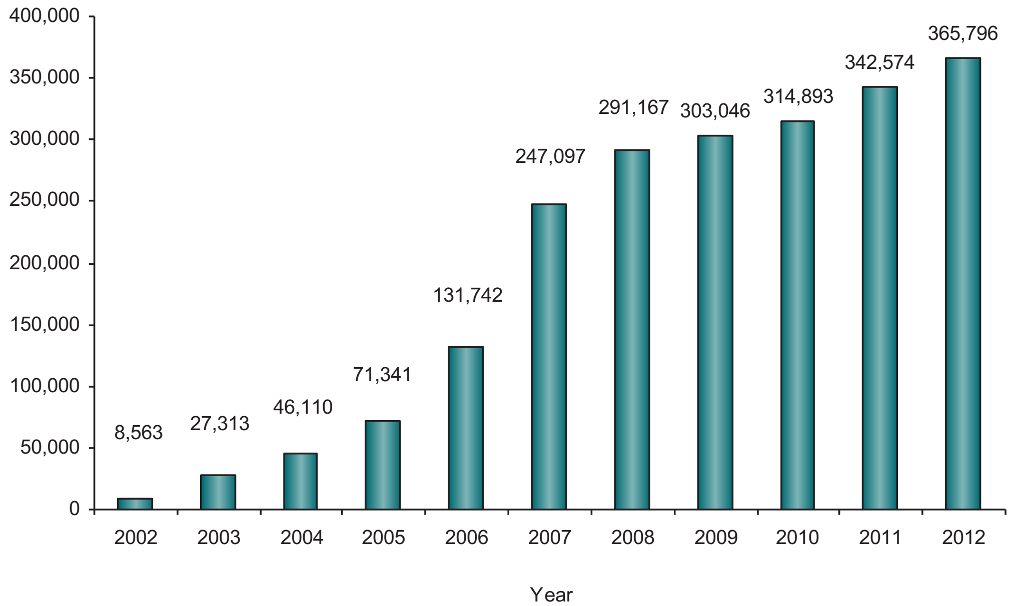
Figure D-8

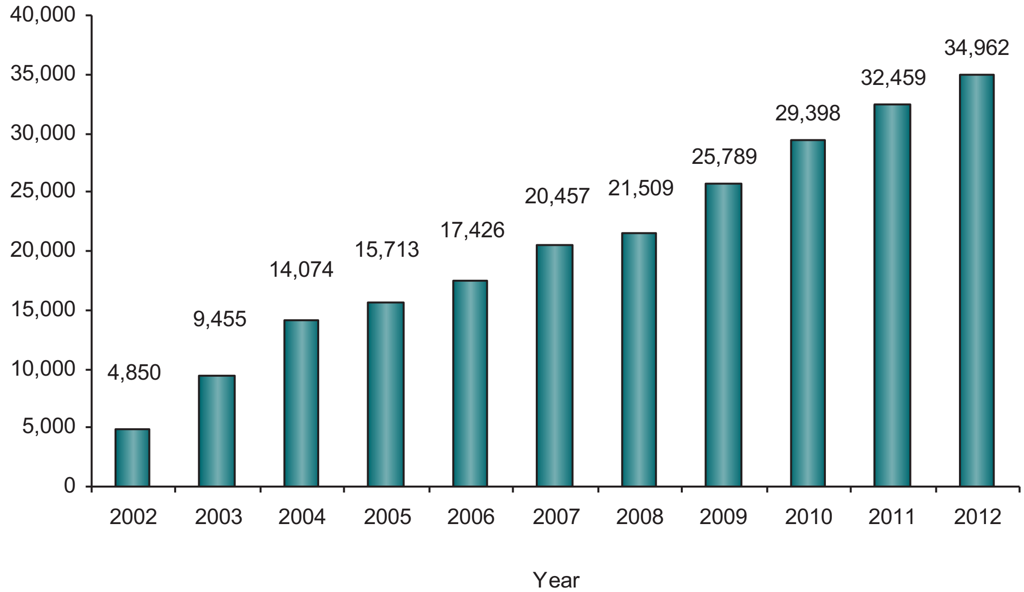
Green Power Kilowatt-hours Sold, 2002-2012



In 2012, the average residential customer purchase was 626 kWh per month, and the average commercial customer purchase was 2,188 kWh. The average 2012 large-volume purchase, by account, under Schedule 136 was 27,065 kWh per month.

Figure D-9 illustrates the number of subscribers by year. Of our 34,962 Green Power subscribers at the end of 2012, 34,014 were residential customers, 627 accounts were commercial accounts, and 321 accounts were assigned under the large-volume commercial agreement. Cities with the most residential and commercial participants include Olympia with 4,329, Bellingham with 4,186, Bellevue with 2,208, Kirkland with 1,609, and Redmond with 1,314. Vashon Island has the highest percentage of participants, with more than 13 percent of customers enrolled.

Figure D-9
Green Power Subscribers, 2002-2012



Customer renewables programs

PSE offers two customer renewables programs.

The **NET METERING PROGRAM**, which began in 1999, provides a way for customers who generate their own renewable electricity to offset the electricity provided by PSE. The amount of electricity that the customer generates and sends back to the grid is subtracted from the amount of electricity provided by PSE, and the net difference is what the customer pays on a monthly basis. A kWh credit is carried over to the next month if the customer generates more electricity than PSE supplies over the course of a month. The "banked" energy can be carried over until every April 30, when the account is reset to zero according to state law. The interconnection capacity allowed under net metering is 100 kW.

Customer interest in small-scale renewables has increased significantly over the past ten years, as Figure D-10 shows. For 2012, PSE added 414 new net metered customers for a total of 1,476.

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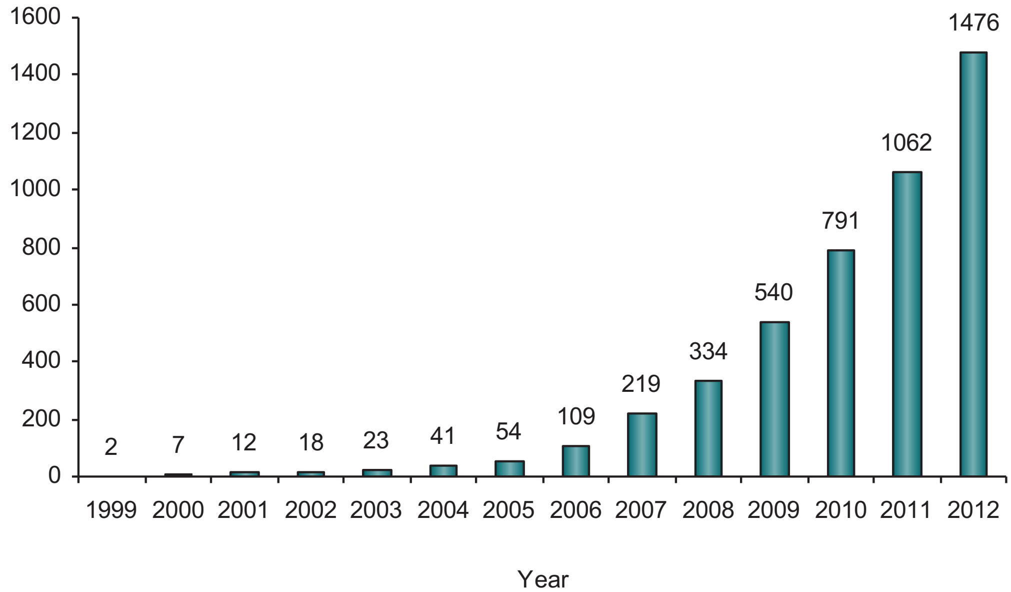
Figure D-10

Net Metered Customers Total Per Year, 1999-2012



The vast majority of customer systems (96 percent) are solar photovoltaic (PV) installations with an average generating capacity of 5.3 kW, but there are also small-scale hydroelectric generators, and wind turbines. These small-scale renewable systems are distributed over a wide area of PSE's service territory. The median generating capacity of all net metered systems is 4.3 kW. Overall, the program was capable of producing more than 7.8 MW of nameplate capacity at the end of 2012.

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Figure D-11
Interconnected System Capacity by Type of System

System Type	Number of Systems	Average Capacity per System Type (kW)	Sum of all Systems by Type (kW)
Hybrid: solar/wind	13	6.99	90.88
Micro hydro	5	4.14	20.70
Solar array	1,420	5.32	7,550.95
Wind turbine	38	2.93	111.22
Total Number of Systems	1,476	Total Capacity of All Systems	7,773.74

Figure D-12
Net Metered Systems by County

County	Number of Net Meters
Whatcom	226
King	420
Jefferson	138
Skagit	121
Island	108
Kitsap	182
Thurston	191
Kittitas	39
Pierce	51

RENEWABLE ENERGY COST RECOVERY. In 2005, PSE launched Production Metering in response to WAC 458-20-273. The program is voluntary for Washington state utilities, but we embraced the opportunity to participate because we have such a large and committed group of interconnected customers. Payments are made to interconnected electric customers who own and operate eligible renewable energy systems including solar PV, wind, or anaerobic digesters (the four micro hydroelectric customers are not eligible under the current law). Annual amounts range from 12 cents to

$1.08 per kWh produced by their system. PSE receives a state tax credit equal to the aggregate incentive payments made to customers. By the end of 2012, PSE had paid $1,106,000 to 1,200 customers eligible for production payments. The PSE tariff governing Production Metering is Schedule 151.

2. Electric Resource Alternatives

This section is designed to provide a brief overview of technology alternatives for electric power generation. It encompasses mature technologies, but emphasis is placed on new methods of power generation with near- and mid-term commercial viability.

All data has been gathered from public sources except where noted, and in these instances it is non-sensitive PSE data. It should be noted that many data sources are the manufacturers themselves, who may provide optimistic availability, cost, and production figures.

Summary table of electric generating technologies

Figure D-13

Cost and Performance of New Central Station Electricity Generating Technologies[5]

Technology	Online Year	Size (MW)	Lead Time (Years)	Overnight Cost in 2010 (2010 $/kW)	Variable O&M ($2010 Mills/kWh)	Fixed O&M ($2010/kW)	Heat Rate in 2011 (Btu/kWh)
Scrubbed Coal New	2015	1300	4	2,844	4.25	29.67	8,800
Integrated Coal-Gasification Comb Cycle (IGCC)	2015	1200	4	3,220	6.87	48.90	8,700
IGCC with carbon sequestration	2017	520	4	5,348	8.04	69.30	10,700
Conv Gas/Oil Comb	2014	540	3	977	3.43	14.39	7,050

[5] *Source: U. S. Energy Information Administration/Assumptions to the Annual Energy Outlook August 2012*

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Technology	Online Year	Size (MW)	Lead Time (Years)	Overnight Cost in 2010 (2010 $/kW)	Variable O&M ($2010 Mills/kWh)	Fixed O&M ($2010/kW)	Heat Rate in 2011 (Btu/kWh)
Cycle							
Advanced Gas/Oil Comb Cycle (CC)	2014	400	3	1,003	3.11	14.62	6,430
Advanced CC with carbon sequestration	2017	340	3	2,060	6.45	30.25	7,525
Conv Combustion Turbine	2013	85	2	974	14.70	6.98	10,745
Adv Combustion Turbine	2013	210	2	666	9.87	6.70	9,750
Fuel Cells	2014	10	3	6,836	0.00	350.00	9,500
Advanced Nuclear	2017	2236	6	5,335	2.04	88.75	10,460
Distributed Generation - Base	2014	2	3	1,434	7.46	16.78	9,050
Distributed Generation - Peak	2013	1	2	1,722	7.46	16.78	10,056
Biomass	2015	50	4	3,859	5.00	100.55	13,500
Geothermal	2011	50	4	2,513	9.64	108.62	9,760
MSW - Landfill Gas	2011	50	3	8,233	8.33	378.76	13,648
Conventional Hydropower	2015	500	4	2,347	2.55	14.27	9,760
Wind	2011	100	3	2,437	0.00	28.07	9,760
Wind Offshore	2015	400	4	5,974	0.00	53.33	9,760
Solar Thermal	2014	100	3	4,691	0.00	64.00	9,760
Photovoltaic	2013	150	2	4,755	0.00	16.70	9,760

Biomass

Biomass in this context refers to the burning of woody biomass in boilers. Most existing biomass in the Northwest is tied to steam hosts (also known as “cogeneration” or “combined heat and power”), and is found mostly in the timber, pulp and paper industries. This dynamic has limited the size of power available for export to date. The typical plant size we have observed is 25 MW to 50 MW. One major advantage of biomass plants is that they provide firm capacity and can operate as a base-load resource. Also, they do not impose generation variability on the grid, unlike wind and solar. Municipal solid waste, landfill, and wastewater treatment plant gas are discussed in the section on waste-to-energy technologies.

Commercial availability. This technology is commercially available. Greenfield development of a new biomass facility would require approximately four years: two years for development and permitting, and two years for major equipment lead-time and construction. The U.S. Energy Information Administration estimates capital costs of approximately $3,859/kW in its *Annual Energy Outlook 2012*.

Coal

Coal fuels a significant portion of the electricity generated in the United States. Most coal-fired electric generating plants combust the coal in a boiler to produce steam that drives a turbine-generator. A small number of plants gasify coal to produce a synthetic gas that fuels a combustion turbine.

Of the fuels commonly used to produce electricity, coal produces the most greenhouse gases (GHGs) per MWh of electricity. Technologies for reducing or capturing some of the GHGs produced are currently in the research and development phase. A report recently released by the National Energy Technology Laboratory of the U.S. Department of Energy indicates it may take 20 years for carbon capture and storage (CCS) technology for power generating plants to become commercially available.

Commercial availability. RCW 80.80 sets a generation performance standard for electric generating plants and prohibits Washington utilities from building plants or entering into long-term electricity purchase contracts from units that emit more that 1,100 pounds of GHGs per MWh. With currently available technology, coal-fired generating plants produce GHGs, primarily carbon dioxide, at a level two or more times greater than the performance standard. This regulation makes it unlawful for PSE to build a new coal-fired power plant or enter a long-term purchase agreement to buy electricity produced by coal unless the plant includes carbon capture and sequestration (CCS) technology to reduce GHG emissions to a level below the RCW 80.80 standard. The status of CCS development makes it impossible to accurately estimate the cost of electricity from a coal-fired generating plant that meets these requirements.

There are no new coal-fired power plants under construction or development in the Pacific Northwest.

Energy storage

The term "energy storage" may refer to a wide range of technologies from batteries to flywheels, and superconducting magnets to large-scale pumped storage. There are a variety of potential technology options for the electric sector, each with unique operational, performance, cost, and technological maturity characteristics. For the purposes of this section, we intend to refer more to emerging forms of energy storage such as batteries, flywheels, and compressed air. Pumped hydro is addressed in its own section of this chapter.

Commercial availability. Energy storage devices vary widely in their technological maturity and commercial availability, with new technologies and variants continuing to emerge. Two studies are particularly helpful in surveying the technology landscape: In February 2010, Sandia National Labs published *Energy Storage for the Electric Grid: Benefits and Market Potential Assessment Guide* (Sandia Report No. SAND2010-0815). In December 2010, EPRI published Electricity Energy Storage Technology Options (EPRI Report No. 1020676). This section relies heavily on insights from these reports.

The anticipated need for energy storage within the electric system has channeled over $700 million in funding from the Dept. of Energy for at least three dozen demonstration projects. Such real-world tests will soon provide needed data and information on the robustness of such systems, including performance and durability, life-cycle costs, and risks. Some storage companies are finding success, while others have struggled, such as Beacon Power, manufacturer of flywheel storage system, and A123 Systems, a manufacturer of grid-scale and automotive lithium-ion batteries. Both recently announced bankruptcy. That said, other companies see opportunity and PSE received two energy storage proposals in the 2011 RFP, one of which was a tolling arrangement for up to 200 MW of peaking capacity, from a major multinational power company. We see this as a sign that energy storage hold promise and merits continued evaluation.

Cost and performance assumptions. Each type of energy storage technology has its own cost and operating cost parameters. In general, based on present-day technology, some energy storage systems will not be economical because more technology development is needed to lower their capital costs. PSE is hopeful that costs will continue to decline with scale, and that the technologies continue to improve. Technology costs and application benefits are sensitive to the configuration of the storage system both in terms of discharge capacity (MW) and energy storage capacity (MWh). The following data from EPRI serves as useful guide through the diverse landscape of energy storage technologies, performance characteristics, and estimated costs.

Figure D-14
Energy Storage Characteristics by Application (Megawatt-scale)[6]

Technology Option	Maturity	Capacity (MWh)	Power (MW)	Duration (hrs)	% Efficiency (total cycles)	Total Cost ($/kW)	Cost ($/kW-h)
Bulk Energy Storage to Support System and Renewables Integration							
Pumped Hydro	Mature	1680-5300	280-530	6-10	80-82 (>13,000)	2500-4300	420-430
		5400-14,000	900-1400	6-10		1500-2700	250-270
CT-CAES (underground)	Demo	1440-3600	180	8	See note 1 (>13,000)	960	120
				20		1150	60
CAES (underground)	Commercial	1080	135	8	See note 1 (>13,000)	1000	125
		2700		20		1250	60
Sodium-Sulfur	Commercial	300	50	6	75 (4500)	3100-3300	520-550
Advanced Lead-Acid	Commercial	200	50	4	85-90 (2200)	1799-1900	425-475
	Commercial	250	20-50	5	85-90 (4500)	4600-4900	920-980
	Demo	400	100	4	85-90 (4500)	2700	675
Vanadium Redox	Demo	250	50	5	65-75 (>10,000)	3100-3700	620-740

6 *Electric Power Research Institute (EPRI), "Electricity Energy Storage Technology Options: A White Paper Primer on Applications, Costs, and Benefits," (Technical Update, December 2010), p. xxiii-xxiv.*

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Technology Option	Maturity	Capacity (MWh)	Power (MW)	Duration (hrs)	% Efficiency (total cycles)	Total Cost ($/kW)	Cost Cost ($/kW-h)
Zn/Br Redox	Demo	250	50	5	60 (>10,000)	1450-1750	290-350
Fe/Cr Redox	R&D	250	50	5	75 (>10,000)	1800-1900	360-380
Zn/air Redox	R&D	250	50	5	75 (>10,000)	1440-1700	290-340
Energy Storage for ISO Fast Frequency Regulation and Renewables Integration							
Flywheel	Demo	5	20	0.25	85-87 (>100,000)	1950-2200	7800-8800
Li-ion	Demo	0.25-25	1-100	0.25-1	87-92 (>100,000)	1085-1550	4340-6200
Advanced Lead-Acid	Demo	0.25-50	1-100	0.25-1	75-90 (>100,000)	950-1590	2770-3800
Energy Storage for Utility T&D Grid Support Applications							
CAES (aboveground)	Demo	250	50	5	See note 1 (>10,000)	1950-2150	390-430
Advanced Lead-Acid	Demo	3.2-48	1-12	3.2-4	75-90 (4500)	2000-4600	625-1150
Sodium-Sulfur	Commercial	7.2	1	7.2	75 (4500)	3200-4000	445-555
Zn/Br Flow	Demo	5-50	1-10	5	60-65 (>10,000)	1670-2015	340-1350
Vanadium Redox	Demo	4-40	1-10	4	65-70 (>10,000)	3000-3310	750-830
Fe/Cr Flow	R&D	4	1	4	75 (10,000)	1200-1600	300-400
Zn/air	R&D	5.4	1	5.4	75 (4500)	1750-1900	325-350
Li-ion	Demo	4-24	1-10	2-4	90-94 (4500)	1800-4100	900-1700
Energy Storage for Commercial and Industrial Applications							
Advanced Lead-Acid	Demo-Commercial	0.1-10	0.2-1	4-10	75-90 (4500)	2800-4600	700-460
Sodium-Sulfur	Commercial	7.2	2	7.2	75 (4500)	3200-4000	445-555
Zn/Br Flow	Demo	0.625 2.5	0.125 0.5	5 5	60-63 (>10,000)	2420 2200	485-440
Vanadium Flow	Demo	0.6-4	0.2-1.2	3.5-3.3	65-70 (>10,000)	4380-3020	1250-910
Li-ion	Demo	0.1-0.8	0.05-0.2	2-4	80-93 (4500)	3000-4400	950-1900

Table Notes:

1. Refer to the full EPRI report for important key assumptions and explanations behind these estimates. All systems are modular and can be configured in both smaller and larger sizes not represented. Figures are estimated ranges for the total capital installed cost estimates of "current" systems based on 2010 inputs from vendors and system integrators. Included are the costs of power electronics if applicable, all costs for installation, step-up transformer, and grid interconnection to utility standards. Smart-grid communication and controls are also assumed to be included. For batteries, values are reported at rated conditions based on reported depth of discharge. Costs include process and project contingency depending on technical maturity. The cost in $ per kW-h is calculated by dividing the total cost by the hours of storage duration.
2. For CAES and Pumped Hydro, larger and smaller systems are possible. For below ground CAES the heat rate may range from ~3,845-3,860 Btu per kWh and the energy ratio is 0.68-0.78; for aboveground CAES the heat rate is ~4,000 Btu per kWh and the energy ratio is ~1.0.

3. For C&I and Residential applications lower CapEx costs may be possible if the battery system is integrated and installed with a photovoltaic system.
4. First-of-a-kind system costs will be higher than shown. Future system costs may be lower than shown after early demonstrations are proven and products become standardized.

Preliminary cost-benefit analysis. One of the advantages of energy storage is that it can theoretically provide more than one benefit to the electric system, such as peak shaving, grid balancing, and T&D upgrade deferral. The particular challenge for a vertically integrated utility such as PSE is assigning value to those particular services. With no market and price signal for ancillary services such as frequency regulation, an avoided-cost methodology must be used. PSE has been observing developments in energy storage for some time, and when two proposals were received in the 2011 RFP, we performed a preliminary cost-benefit analysis based on storage system pricing contained in those proposals. The methodology for our analysis follows.

Capacity was valued at the incremental avoided cost of the frame peaker simple-cycle combustion turbine (SCCT) with oil back-up. Further, the storage system with 4 hours of discharge capacity was run though a loss of load probability (LOLP) analysis, which indicated that due to the limited discharge duration, the storage system would provide 82% as much capacity value as a typical SCCT. Typical SCCTs can operate indefinitely during system-wide contingency events, whereas energy storage systems with limited discharge cannot.

Distribution upgrade deferral was valued at the incremental avoided cost for upgrading a standard 25 MVA substation at $280/kW. While few distributed storage systems can completely eliminate the need for system upgrades, they can reasonably defer them for several years.

Transmission was valued at the avoided cost of average transmission contracts, at $30 per kW-yr. The value assigned was taken from the Electric Conservation Cost Effectiveness Standard Model.

Grid balancing was valued using a proprietary production cost model that is used to simulate various levels of wind interconnected to our system and the flexibility need and cost to integrate wind and balance load. The primary benefit of energy storage is reducing the number and duration of operating peakers when uneconomical. This analysis is preliminary.

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Arbitrage was valued using actual market data for 9/1/2011 – 8/31/2012, assuming our traders executed perfect peak/off-peak scheduling and trades. Given the generally low spreads in the region, and the losses from charging and discharging, as well as transmission and distribution losses, the value of arbitrage is low.

Oversupply reduction was estimated by combining the peak/off-peak spread from capturing surplus energy plus the value of PTC's and RECs from curtailed wind for 15 days per year of oversupply situations. Because these events generally involve very large amounts of energy relative to the storage system and generally occur infrequently, the value of the benefit is not large.

Figure D-15
Preliminary Storage Analysis Summary

Value Stream	$/kW-yr
Avoided Capacity	$ 85
Substation Upgrade Deferral	$ 26
Avoided Transmission	$ 30
Grid Balancing	$ 39
Arbitrage	$ 7
Oversupply Reduction	$ 2
Total Value	**$ 189**
Total Storage System Cost	**$ 300**

While there still appears to be a large gap between the annual levelized cost of the storage system and the combined potential avoided costs to PSE, our valuation methodology needs improvement, which may increase the value of some value streams. In addition, we anticipate continued technology improvement and declining costs.

Energy storage pilot project

In collaboration with Primus Power, Pacific Northwest National Labs, and with funding from the Bonneville Power Administration and the Dept. of Energy, PSE will be undertaking a potential pilot project to investigate and demonstrate distributed energy storage on the PSE system. The goal of this project will be to assess and then demonstrate the net benefits of using energy storage located close to the customer in the distribution grid to manage demand. The project will take place in three phases, where the objective of the first phase will be to analyze the values storage located in the distribution grid can bring to Puget Sound Energy (PSE) and BPA. In the second phase, Primus Power EnergyPods will be installed at a high value location and piloted. Operations will then be demonstrated, optimized, and evaluated in third phase of the study.

Fuel cells

Fuel cells combine fuel (typically carbon-based) and oxygen to create electricity, heat, water, and other byproducts through a chemical process. Fuel cells have high conversion efficiencies from fuel to electricity compared to many traditional combustion technologies, on the order of 25 percent to 60 percent. In some cases, conversion rates can be boosted higher using heat recovery and reuse. Fuel cells operate or are being developed at sizes that range from hundreds of watts to tens of megawatts. Smaller fuel cells power items like portable electric equipment, larger ones can be used to power equipment, buildings, or provide back-up power. Fuel cells differ in the membrane materials used to separate fuels, the electrode and electrolyte materials used, operating temperatures, and scale (size). Reducing cost and improving durability are the two most significant challenges to fuel cell commercialization. Fuel cell systems must be cost-competitive with, and perform as well as, traditional power technologies over the life of the system. (Source: Department of Energy, Energy Efficiency and Renewable Energy, Fuel Cell Technologies Program.)

Provided that feedstocks are kept clean of impurities, fuel cell performance is very reliable. They are often used as back-up power sources for telecommunications and data centers, which require very high reliability. In addition, fuel cells are starting to be used for commercial combined heat and power applications, though mostly in states with significant subsidies or incentives for fuel cell deployment.

Commercial availability. Fuel cells have been growing in both number and scale, but they do not yet operate at a gross generation scale. The largest fuel cell project underway in the United States is a 154.5 MW project being built in Connecticut at a cost of over $5,000/kW. Another project in Delaware will distribute up to 30 MW of fuel cells in blocks at several substations. In some states, incentives are driving fuel cell pricing economics to be competitive with retail electric prices, especially where additional value can be captured from waste heat. Currently, Washington state has no incentives specific to fuel cells. Fuel cell costs are estimated to be at least $5,000/kW, and some projects appear to be as high as $10,000/ kW before subsidies.

Geothermal

Geothermal generation technologies use the natural heat under the surface the earth to provide energy to drive turbine generators for electric power production. Geothermal energy production falls into four major types.

DRY STEAM PLANTS use hydrothermal steam from the earth to power turbines directly. This was the first type of geothermal power generation technology developed, but few sites offer very hot (greater than 235 degrees Celsius) hydrothermal fluids that are predominantly steam.[7]

FLASH STEAM PLANTS operate similarly to dry steam plants, but they use low-pressure tanks to vaporize hydrothermal liquids into steam. Like dry steam plants, this technology is best suited to high temperature geothermal sources (greater than 182 degrees Celsius).[8]

BINARY-CYCLE POWER PLANTS can use lower temperature hydrothermal fluids (107 degrees Celsius to 182 degrees Celsius) to transfer energy through a heat exchanger to a fluid with a lower boiling point. This system is completely closed-loop, no steam emissions from the hydrothermal fluids are released at all. The majority of new geothermal installations are likely to be binary-cycle systems due to the limited emissions and the greater number of potential sites with lower temperatures.[9]

The United States, Japan, England, France, Germany, and Belgium are testing **ENHANCED GEOTHERMAL** or “hot dry rock” technologies.[10] These systems involve the drilling of deep wells into hot dry or nearly dry rock formations and injecting water to develop the hydrothermal working fluid. The heated water is then extracted and used for generation. There are small operating facilities in Germany and France, and several

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[7] *Renewable Energy Policy Project, http://repp.org/geothermal/geothermal_brief_power_technologyandgeneration.html*
[8] *EERE, http://www1.eere.energy.gov/geothermal/gerthermal_basics.html*
[9] *Ibid*
[10] *Geothermal Education Office, 2000, http://geothermal.marin.org/pwrheat.html*

commercial facilities are under development in Australia. The U.S. Department of Energy has funded a test project in the United States.

Geothermal plants typically run with high uptime, often exceeding 85 percent. However, plants sometimes do not reach their full output capacity due to lower than anticipated production from the geothermal resource. This issue affected the largest geothermal complex in the United States, the Geysers projects in California, due to resource depletion. Additional water recycling has been improved the situation in recent years.

Commercial availability. Currently, approximately 3,187 MW of geothermal generating capacity is online in the United States, with 97 percent of that capacity in California or Nevada.[11] The only operating geothermal plants in the Northwest are the 0.28 MW plant in Klamath Falls, Ore., and the 15.8 MW Raft River plant in Idaho.

The Northwest has been subject to considerable exploration activity over the past several years, with an estimated 900 MW in some stage of development.[12] Most of this is in very early development, and may or may not have obtained site access and drilled exploratory wells. Most projects have not yet proven their output, though several are in testing at this time. Currently, three projects in the Northwest, a total of approximately 70 MW in capacity, are reported to be under construction, Neal Hot Springs and Crump Geyser in Oregon, and an expansion of the Raft River project in Idaho.

Other Northwest projects are planned in Oregon and Idaho, but these are further behind in development. It would take at least four years before they were ready for commercial operation, if the resources prove viable.

Geothermal energy plants are capital intensive, with estimated capital costs of approximately $5,580/kW for traditional dual flash geothermal steam plants according to the U.S. Department of Energy in 2010. Other large-scale technologies, including binary plants, are similar in cost. Overall, site-specific factors including resource size, depth, and temperature can significantly affect costs. Generally, operating costs are relatively low due to a zero fuel cost, but this can vary due to site conditions as well.

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[11] *Geothermal Energy Association*
[12] *U.S. Geothermal Power and Production Update, April 2012.*

Natural gas

Combined-cycle combustion turbines (CCCT)

Combined-cycle combustion turbine power plants consist of one or more combustion turbine generators equipped with heat recovery steam generators that capture heat from the combustion turbine (CT) exhaust. This otherwise wasted heat is then used to produce additional electricity via a steam turbine generator. Many plants also feature "duct firing." Duct firing can produce additional capacity from the steam turbine generator, although at less efficiency than the primary unit. CCCT plants currently entering service can convert about 50 percent (HHV) of the chemical energy of natural gas into electricity. Because of their high thermal efficiency and reliability, relatively low initial cost, and low air emissions, CCCTs have been a popular source of electric power and process steam generation since the 1960s.

This technology is commercially available. Greenfield development requires approximately five years: two years for development and permitting; two years for major equipment lead-time; and one year for construction.

Natural gas supply is assumed to be firm year round and based on projected Northwest Pipeline firm rates. The unit is assumed to be connected to the PSE transmission system and as such does not incur any direct transmission cost, but the capacity contribution to peak load should be reduced by 7 percent to account for reserves.

Simple-cycle combustion turbines

There are three principal types of simple-cycle combustion turbines for "peaking" applications: frame, aeroderivative (aero), and reciprocating (recip) engines. Frame CTs are also known as "industrial" or "heavy-duty" CTs; these are generally larger in capacity and feature frames, bearings, and blading of heavier construction. In 2012, PSE reviewed the typical cost and performance characteristics of these technology types and determined that frame and aero CTs are the best fit economically for the Pacific Northwest market and PSE's needs.

FRAME COMBUSTION TURBINE. Conventional frame CTs are a mature technology. They can be fueled by natural gas, distillate oil, or a combination of fuels (dual fuel). Typical units have efficiencies in the range of 15 percent to 35 percent (HHV) at full load. These units are typically less flexible than their aero and recip counterparts, meaning they cannot reduce output beyond about 50 percent to 60 percent, they have slower ramp rates (on the order of 15 MW/min), and though some can start in ten minutes, the output achieved in ten minutes is typically not base-load.

Frame CTs are commercially available. Greenfield development requires approximately four years: two years for development and permitting, one-and-a-half years for major equipment lead-time, and a half-year for construction.

AERODERIVATIVE (AERO) COMBUSTION TURBINES. Aeroderivative (aero) combustion turbines are a mature technology, however, new aeroderivative features and designs are continually being introduced. They can be fueled by natural gas, oil, or a combination of fuels (dual fuel). Typical aero units have efficiencies in the range of 25 percent to 38 percent (HHV) at full load. Aero units are typically more flexible than their frame counterparts and many can reduce output to nearly 30 percent. Most can start and achieve full output in less than ten minutes and start multiple times per day without maintenance penalties. Ramp rates range from 50 to 90 MW per min. Another key difference between aero and frame units is size. Aero CTs are typically smaller in size, from 40 to 100 MW each. This small scale allows for modularity and reducing shaft risk, but also tends to reduce economies of scale.

This technology is commercially available. Greenfield development requires approximately four years: two years for development and permitting, one-and-a-half years for major equipment lead-time, and a half-year for construction.

RECIPROCATING (RECIP) ENGINES. Compared to the frame and aeroderivative technologies, reciprocating engines are a relatively newer technology; consequently they are less commonly used in power generation. The reciprocating engine technology evaluated is based on a four-stroke spark-ignited gas engine which uses a lean burn method to generate power. The lean burn technology uses a relatively higher ratio of oxygen to fuel, which allows the reciprocating engine to generate power more efficiently. Lean burn reciprocating engines typically show HHV efficiencies in the range of 30% to 40% while some newer units claim efficiencies as high as nearly 50%. However, reciprocating engines are constrained by their size. The largest commercially available reciprocating engine produces just 18 MW, much less than the typical frame or aero turbine. Larger sized generation projects would require a relatively greater number of reciprocating units compared to an equivalent-sized project implementing either an aero or frame turbine, reducing economies of scale.

Greenfield development requires approximately four years: two years for development and permitting, one-and-a-half years for major equipment lead-time, and a half-year for construction. PSE does not take the risk of contracting for major equipment before permits are in hand. Private developers, on the other hand, are often willing to take that risk and can accelerate the development timeframe by about one year.

Nuclear

Like other types of thermal generating resources (coal-, oil-, and gas-fired), nuclear power plants produce electricity by boiling water into steam at elevated temperature and pressure. The thermal energy of the steam is converted to mechanical energy in a steam turbine driving an electrical generator to produce electricity. Instead of burning fossil fuels, the nuclear power plant uses solid ceramic pellets of uranium, developing heat in a process called "fission" or the splitting of uranium atoms in a nuclear reactor.

Nuclear fuel consists of two types of uranium, U-238 and U-235. The atomic nucleus of uranium is composed of 92 protons and 143 neutrons. When split, the uranium nuclei break up, releasing high energy neutrons and heat. As these neutrons impact other uranium atoms, those atomic nuclei also split, releasing neutrons of their own, along with additional heat. These neutrons in turn strike other atoms, splitting them and triggering other such collisions in a chain reaction. When that happens, a self-sustaining fission reaction has begun.

To control the nuclear fission reaction, control rods are inserted into the reactor vessel that absorb neutrons without contributing to the fission reaction. These control rods may be inserted or withdrawn to varying degrees, slowing or accelerating the reaction.

The nuclear fleet

Today, there are 104 commercial nuclear power plants operating in the United States, the largest of which is Palo Verde in Arizona, whose three nuclear reactors together produce 3,942 MW.[13] The performance of the 104 U.S. nuclear plants has been excellent, with a combined energy output of 821 million MWh in 2011.[14] The total number of kWh produced by the reactors has steadily increased over the last five years. The fleet-

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[13] *Source: Nuclear Energy Institute – Resources & Stats*
[14] *Source: World Nuclear Association – Nuclear Power in the U.S. – January 2013*

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averaged capacity factor for 9 of the last 10 years has been maintained at about 90 percent.[15] Approximately two-thirds of U.S. nuclear plants are pressurized water designs while the remaining one-third use boiling water designs.

In 2012, over 80 percent of the 104 licensed reactor units have either received a new license or are under review for license renewal; 31 units operate under their original license. At this time, 14 nuclear power plants are in varying stages of decommissioning, including Trojan,[16] which is located in Oregon.

The Nuclear Regulatory Commission (NRC) is reviewing new reactor applications and issued its first combined Construction and Operating Licenses in early 2012 (called a combined license or COL) to Southern Nuclear Operating Company for Vogtle 3 & 4 and to South Carolina Electric and Gas for V.C. Summer 2 & 3. The NRC expects to review approximately 10 additional COL applications for 16 new reactors over the next several years. Lessons learned from the Fukushima accident in Japan are being included in new design certification, COL, and ESP reviews.

Globally, there were 437[17] operating commercial nuclear power reactors in 31 countries (including the U.S. fleet) with a total installed capacity of 372,210 megawatts electric (MWe). Worldwide, there are 68[18] nuclear plants under construction, including in China (29), Russian Federation (11), India (7), Korea (3), Japan (3),Bulgaria (2), Taiwan (2), Slovakian Republic (2), Ukraine (2), Japan (2), Argentina (1), Brazil (1), Finland (1), France (1), Iran (1), Pakistan (1), and the UAE (1).

In the United States, five nuclear power reactors are under construction, including TVA's Watts Bar 2 in Tennessee with a capacity of 1,165 MW, which is scheduled to begin operation in 2016 and 2017; and V.C. Summer 2 & 3 in South Carolina with a capacity of 1,154 MW, which is scheduled to begin operation in 2017 and 2018.

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15 *Source:* http://www.nei.org/corporatesite/media/filefolder/US_Nuclear_Generating_Statistics.xls

16 *Trojan is currently in DECON status: Equipment, structures, and portions of the facility containing radioactive contaminants have been removed or decontaminated to a level that permits release of the property and termination of the NRC license.*

17 *Source: European Nuclear Society - Nuclear power plants, world-wide – January 2013*

18 *Source: European Nuclear Society - Nuclear power plants, world-wide – January 2011*

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Fukushima accident[19]

On March 11, 2011, a magnitude 9.0 earthquake, centered 130 km offshore from the city of Sendai on the eastern cost of Honshu Island, produced devastating infrastructure damage in Japan. What is known as the Great East Japan Earthquake was a double quake lasting about 3 minutes, and it produced a tsunami that inundated about 560 square kilometers in Japan, resulting in over 19,000 deaths and extensive damage to coastal ports and towns.

Four Fukushima reactors were damaged beyond recovery in the tsunami and subsequent meltdown and/or explosion, and they will be completely demolished in 30-40 years – much the same time frame as for any decommissioned nuclear plant.

In April 2012, the US Electric Power Research Institute published Fukushima Daiichi Accident – Technical Causal Factor Analysis, which identified the accident's root cause (beyond tsunami flooding and its effects) as a "…failure to consider the possibility of the rupture of combinations of geological fault segments in the vicinity of the plant." This lesson has not been lost on the global nuclear industry, and license review procedures in most countries have been revised to reflect this higher level of geological scrutiny.

Select U.S. nuclear construction projects update[20]

WATTS BAR UNIT 2. The 1,165 MW reactor is expected to come online in 2015 at a cost of about $4.3 billion, a projected cost increase of 72 percent since the 2011 IRP. Its twin, Watts Bar Unit 1, started operation in 1996. Watts Bar 2 is expected to provide power at 5.6 ¢ per kWh, an increase of 27percent since the 2011 IRP. Even with schedule delays and cost increases, TVA projects that energy from Watts Bar 2 will be approximately equal to the levelized cost of a natural gas-fired plant, assuming fuel pricing of $2.50 per mmBTU, albeit with far greater commercial and technology risk.

VOGTLE 3 & 4. In February 2012, the NRC issued the combined Construction and Operating Licenses (COL) for Vogtle Units 3 & 4. These were the first COLs ever issued in the United States for a new nuclear energy facility. The Vogtle 3 & 4 construction project is approximately one-third complete. Site works are largely complete in preparation for the two 1,200 MWe Westinghouse AP1000 reactors. The unit 3 reactor

[19] *Source: Abridged from http://www.world-nuclear.org/info/fukushima_accident_inf129.html*
[20] *Source: World Nuclear Association - Nuclear Power in the USA – December 2010*

vessel has shipped from South Korea, the unit 3 condenser is nearly complete, and the unit 4 condenser is under construction.

Overall project cost is running about 4 percent below the cost estimate prepared in 2009. The two units are expected to start commercial service in 2016 and 2017.

V.C. SUMMER 2 & 3. In March 2012, the NRC issued the combined Construction and Operating Licenses (COL) for V.C Summer Units 2 & 3. Construction ramped up considerably after receipt of the COLs with site work already quite advanced. Foundation work is ongoing at both units; however, delays related to placement of the lower reactor vessel containment bowl rebar mat have caused the layoff of an undisclosed number of construction workers while the issue is analyzed and the project schedule is reevaluated. A similar problem has surfaced at Vogtle as well. The total project cost of $9.8 billion includes forecast inflation and owners' costs for site preparation, contingencies and project financing. Actual expenditures are reported to be running about 2 percent under budget, and the project is still scheduled to enter commercial service in 2017 and 2018.

Policy considerations. The Energy Policy Act of 2005 provided financial incentives for the construction of advanced nuclear plants. The incentives include a 2.1¢ per kWh tax credit for the first 6,000 MWe of capacity in the first 8 years of operation, and federal loan guarantees for the project cost. After putting this program in place in 2008, the Department of Energy (DOE) received 19 applications for 14 plants involving 21 reactors. The total amount of guarantees requested is $122 billion, but only $18.5 billion has been authorized for the program, and a further $2 billion for construction of nuclear front-end facilities – uranium enrichment plants. The Department of Energy also contributed to front-end funding with an additional $2 billion allocation. No additional loan guarantees have been authorized, nor were any included in the budget request for fiscal year 2013.

Following the requirements of the Nuclear Waste Policy Act, the DOE submitted a license application for the Yucca Mountain repository in 2008. Congress mandated and is providing the funding for the NRC to complete a license review. The Obama administration has stated that Yucca Mountain is no longer an option for nuclear waste disposal.

In January 2013, the DOE announced a new waste strategy that would create a new organization to manage the siting, development, and operation of the future waste stores, to be established with "an appropriate balance between independence ... and the need for oversight by Congress and the Executive Branch." This strategy may take the form of a federal government corporation or an independent government agency. It envisions a “pilot interim store” opening by 2021, with a priority on taking used nuclear fuel from current shutdown power plant sites. By 2025, a larger “full-scale interim store” would open, and by 2048 an underground disposal facility would be in place to permanently store and dispose of the material. The mandate for the new organization excludes reprocessing of used fuel. At this time, Congress has not acted to fund the development any such organization.

Cost assumptions. There is little hard data on recent U.S. nuclear developments from which reasonable cost estimates can be made. The construction costs track record for nuclear plants completed in the United States during the 1980s and early 1990s was certainly poor. Actual costs were far higher than projected, construction schedules experienced long delays, and interest rate increases resulted in high financing charges. Changing regulatory requirements also contributed to project cost increases, and in some instances, the public controversy over nuclear power contributed to some of the construction delays and cost overruns. The situation is little changed today, with regulatory uncertainty from the Fukushima accident, commercial uncertainty from the falling cost of natural gas, construction uncertainty for any large and complex project, and policy uncertainty for ongoing construction loan guarantees.

As indicated in Figure D-13, the capital cost of developing a new nuclear power plant is higher than most conventional and renewable technologies, as is the fixed and variable operations cost. Nuclear carries significant technology, credit, permitting, policy, and waste disposal risks; and design revision implications following the Fukushima accident are still not yet fully appreciated. Its high cost and high uncertainty make nuclear technology an undue risk for PSE at this time. PSE will continue to follow emerging trends in this technology, and may include it in future resource plans if evolving national policies and the technological maturity of newer designs sufficiently reduce project risks and cost uncertainty for our customers.

In 2012, a senior analyst for Moody’s stated that building a nuclear power plant is perceived as risky by credit rating agencies – and in some cases could lead to a ratings downgrade of the utility concerned. “The risks are writ larger when you think of a nuclear project [than for other forms of generation], because construction and planning is that much more tortuous, construction risk is higher and from an operational point of they have a high fixed cost base."[21]

In July 2012, Jeff Immelt, CEO of General Electric, acknowledged, "When I talk to the guys who run the oil companies they say look, they're finding more gas all the time. It's just hard to justify nuclear, really hard. Gas is so cheap and at some point, really, economics rule. So I think some combination of gas, and either wind or solar…that's where we see most countries around the world going."[22]

Pumped hydro

Pumped hydro is large, mature, and utility-scale technology currently used at many locations in the United States and around the world. A pumped-hydro plant generally resembles a conventional dam, except that instead of impounding water, the water is raised to the reservoir level by consuming electricity. Pumped-hydro employs off-peak electricity to pump water from a reservoir up to another reservoir at a higher elevation. When electricity is needed, water is released from the high reservoir through a turbine into the low reservoir to generate electricity. With each round-trip, some of the energy being converted is lost, typically about 15-25%. Energy storage capability is limited only by the size of the available upper reservoir.

PSE has met with several pumped-hydro developers in the past few years and will continue to explore the benefits and costs of pumped hydro and the value it could bring as a viable peaking, flexibility, and reliability resource.

Commercial availability. Pumped-hydro facilities are commercially available, but the siting, permitting, and associated environmental impact processes can be complex and take many years. Access to supplemental external water refill can also be a concern. There is growing interest in re-examining opportunities for pumped hydro in the United States, particularly in view of the large amounts of wind, solar, and nuclear generation that may be deployed over the next few decades, driving additional system flexibility needs. New variable-speed drive technology is being applied to new sites allowing for more flexible operation and faster switching between pumping and discharging modes.

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[21] *Source: ICIS "New nuclear electricity costs hit utility ratings - Moody's" March 2012*
[22] *Source: Financial Times, June 30, 2012; Pilita Clark, Environment Correspondent*

Cost and performance assumptions. Projects may be sized in a wide range from 200 to 4,000 MW with between 6 and 20 hours of storage. Pumped hydro plants typically operate at about 76 percent to 85 percent efficiency depending on design. Pumped hydro plants have very long lives on the order of 50 years, and fast response times that enable them to participate equally well in voltage and frequency regulation, spinning reserve, and non-spinning reserves markets, as well as energy arbitrage and system capacity support. The following table from EPRI illustrates the most common configurations and associated performance and cost characteristics.

Figure D-16

Pumped Hydro Plant Capacity, Energy, Efficiency, and Cost

Plant Size	Capacity (MW)	Energy (MWh)	Duration (hrs)	Efficiency (%)	Total Cost ($/kW)
Small	280-530	1,680-5,300	6-10	80-82	2,500-4,300
Large	900-1,400	5,400-14,000	6-10		1,500-2,700

Source: Electric Energy Storage Technology Options: A White Paper Primer on Applications, Costs and Benefits. EPRI, Palo Alto, CA, 2010. 1020676.

Solar energy

Solar energy uses the light and radiation from the sun to directly generate electricity with photovoltaic (PV) technology, or to capture the heat energy of the sun for either heating water or for creating steam to drive electric generating turbines.

PHOTOVOLTAICS are semiconductors that generate direct electric currents. The current then typically runs through an inverter to create alternating current; then it can be tied into the grid. Photovoltaics have been in use for decades, but only recently, as costs have dropped, has their use started to grow significantly. Most photovoltaics are based on silicon imprinted with electric contacts, much like computer chips, but other technologies, notably several chemistries of thin-film photovoltaics, have gained substantial market share. Thin-film photovoltaics offer lower production costs, but also have lower efficiencies (up to 12 percent efficiency) than silicon-based photovoltaics (up to 24 percent efficiency), so thin-film technology requires greater surface area than silicon-based technology to generate the same amount of electricity. All photovoltaic technologies have significant ongoing research efforts, which have been increasing conversion efficiencies and decreasing costs. Photovoltaics are installed in arrays that range from a few watts for sensor or communication applications, up to hundreds of MW for utility-scale power generation.

CONCENTRATING PHOTOVOLTAICS use lenses to focus the sun's light onto special, high-efficiency photovoltaics, which creates higher amounts of generation for the given photovoltaic cell size. The use of concentrating lenses requires that these technologies be precisely oriented towards the sun so they typically require active tracking systems.

SOLAR THERMAL PLANTS focus the direct irradiance of the sun to generate enough heat to produce steam, which in turn drives a conventional turbine generator. Two general types are in use or development today, trough-based plants and tower-based plants. Trough plants use horizontally mounted parabolic mirrors or Fresnel mirrors to focus the sun onto a horizontal pipe that carries water or a heat transfer fluid. Tower plants use a field of mirrors that focus sunlight onto a central receiver. A heat transfer fluid is used to collect the heat and transfer it to make steam.

As of late 2012, there were approximately 5,900 MW of installed photovoltaics in the United States. Over 500 MW of solar thermal plants operate in the United States, and projects totaling more than 1,300 MW are currently under development.

Commercial availability. Currently, renewable portfolio standards (RPS) drive most utility-scale solar development in the United States. Customer preference, not cost-effectiveness, drives residential development, and is supported with generous state and federal incentives. At the end of 2012, PSE had 7.2 MW of solar photovoltaics installed (about 60 percent of Washington's total), Idaho 0.2 MW, and Oregon 14 MW. Collectively, these amount to an output of approximately a 3 aMW over a year. Oregon's solar development is growing because the state's RPS requires the installation of about 20 MW of solar photovoltaics, and because of the state's Business Energy Tax Credit. In comparison, California had over 750 MW installed photovoltaics as of the end of 2009 and approximately 300 MW of solar thermal plants.

With less sunlight than other areas of the country, and incentive structures that limit development to smaller systems, photovoltaic development has been slow in the Northwest. Likewise, concentrating PV and concentrating solar thermal systems have not been developed, again because of the Northwest's relatively low percentage of direct sunlight, which these systems require for generation.

Cost and performance assumptions. PSE has had a positive experience with the performance of our 500 kW Wild Horse Solar Demonstration Project, which has outperformed its pre-construction production estimates. PV systems in western Washington are expected to have capacity factors of approximately 10 percent to 11 percent, while those in eastern Washington could achieve capacity factors as high as 18 percent.

Since PSE built the Wild Horse Solar Demonstration Project in 2007, costs have declined considerably, reaching national averages of approximately $6.50 per Watt-dc for residential systems, $5.75 per Watt-dc for commercial systems, and $4.00 per Watt-dc for utility scale systems (Solar Electric Industry Association, 2010). Many residential customers have seen costs below $4.00 per Watt –dc with larger systems. PSE's calculations of the lowest levelized cost for utility-scale solar systems located in eastern Washington have ranged from $0.18 to $0.25 per kWh, which significantly exceeds costs for other renewable energy sources, such as wind.

Solar thermal plants have proven reliable over time, with the SEGS plants in California operating since the 1980s. While the limited number of recent developments makes it difficult to estimate current costs, best-known current costs are shown in Figure D-16.

Waste-to-energy technologies

Converting wastes to energy is a means of capturing the inherent energy locked into wastes. Generally, these plants take one of the following forms.

WASTE COMBUSTION FACILITIES. These facilities combust waste in a boiler, and use the heat to generate steam to power a turbine that generates electricity. This is a well-established technology, with 86 plants operating in the United States, representing 2,500 MW in generating capacity.

WASTE THERMAL PROCESSING FACILITIES. This includes gasification, pyrolisis, and reverse polymerization. These facilities add heat energy to waste and control the oxygen available to break down the waste into components without combusting it. Typically, a syngas is generated, which can be combusted for heat or to produce electricity. A number of pilot facilities once operated in the United States, but only a few remain today.

LANDFILL GAS AND MUNICIPAL WASTEWATER TREATMENT FACILITIES. Most landfills in the United States collect methane from the decomposition of wastes in the landfill. Many larger municipal wastewater plants also operate anaerobic systems to produce gas from their organic solids. Both of these processes produce a low quality gas with approximately half the methane content of natural gas. This low quality gas can be collected and scrubbed to remove impurities or improve the heat quality of the gas. The gas can then be used to fuel a boiler for heat recovery, or a turbine, or reciprocating engine, to generate electricity. As of June 2012, approximately 59,453 U.S. landfills generate electricity today with a combined capacity of 18,351 MW.

Commercial availability. Under Washington's RPS, landfill gas qualifies as a renewable energy resource, but municipal solid waste does not. Under proposed revisions to the RPS that were being considered in the state legislature at the time PSE was developing its 2013 IRP, the definitions of wastes and biomass would be clarified to allow some new wastes, such as food wastes, to qualify as renewable energy sources.

Currently, several waste-to-energy facilities are operating in or near PSE's electric service area. Two landfills use landfill gas for electric generation in Washington state; combined, they produce an output of approximately 12.4 MW. The largest landfill in PSE's service territory, the Cedar Hills landfill, currently purifies its gas to meet pipeline natural gas quality; then they sell that gas to PSE rather than using it to generate electricity. Two waste combustion facilities operate in the Northwest: the 13.1 MW Covanta facility in Brooks, Ore., and the 26 MW Spokane waste-to-energy facility. The Spokane facility currently holds a purchased power agreement (PPA) with PSE. The only waste thermal processing facility known in the Northwest is a test facility operated by InEnTec in Richland, Wash. Several wastewater treatment plants in PSE's electric service area use gas from their digestion processes to generate electricity for their facility operations, but typically not enough to make surpluses available to PSE.

No waste-to-energy facilities are currently planned or under construction in the Northwest.

Cost and performance assumptions. Eight hundred sixty-seven waste combustion facilities and 59,453 landfill gas-to-energy facilities were operating in the United States by the end of 2010, but relatively few have been built in recent years. This makes reliable cost data difficult to obtain. The U.S. Department of Energy estimates capital costs for landfill gas projects at approximately $2,400 per kW. Waste combustion projects are similar to biomass projects, which have estimated construction costs of approximately $3,400 per kW.

In general, waste-to-energy facilities are highly reliable, as they've used proven generation technologies and gained considerable operating experience over the past 30 years. Some variation of output from landfill gas facilities and municipal wastewater plants is expected due to uncontrollable variations in gas production. For waste combustion facilities, output is typically more stable, as the amount of input waste and heat content can be more easily controlled.

Water-based generation – wave and tidal

The natural movement of water can be used to generate energy through the flow of tides, or the rise and fall of waves.

TIDAL GENERATION TECHNOLOGY uses tidal flow to spin rotors and the rotors then turn a generator. Two major plant layouts exist: barrages, which use artificial or natural dam structures to accelerate flow through a small area; and in-stream turbines, which are placed in natural channels. Currently, the largest operating tidal generation facility in the world is the Rance Tidal Power barrage system in France, which has a generating capacity of approximately 240 MW. In-stream turbines up to 1.2 MW in size have been tested in Canada, Scotland, and South Korea.

WAVE GENERATION TECHNOLOGY uses the rise and fall of waves to drive hydraulic systems, which in turn fuel generators. Technologies tested include floating devices, such as the Pelamis, and bottom-mounted devices such as the Oyster. The largest wave power plant in the world was the 2.25 MW Agucadoura Wave Farm off the coast of Portugal, which opened in 2008. It has since been shut down because of the developer's financial difficulties. Significant testing has occurred off of Scotland's coast, and developments are underway in Scotland, Australia, and England.

Commercial availability. Currently, only one tidal power site is under development in the Northwest, Snohomish PUD's Admiralty Inlet site. Plans call for the installation of 2 to 3 test turbines, producing a total of 1 MW by mid-2014 with an estimated cost of $20 million. Snohomish PUD also holds preliminary permits for developments of other sites in Puget Sound, though Admiralty Inlet is by far the largest. Tacoma Power considered development in the Tacoma Narrows, but ultimately abandoned the project. A small system has been tested off Vancouver Island, B.C, but no further development is planned at this time.

Several sites have been tested for wave power in the Northwest. The Reedsport, Ore. Site is the furthest along in development. Current plans call for 10 buoy-type floating tidal power generators, with a combined capacity of 1.5 MW.

In general, the limiting factors in development of wave and tidal power projects have been long and complex permitting process timelines, relatively little experience with siting, and the early-stage nature of the generation technologies. FERC oversees permitting processes for tidal power projects, but state and local stakeholders can also be involved. After permits are obtained, studies of the site's water resource and aquatic habitat must be made prior to installation of test equipment. From initial permit application until equipment installation, the process can take up to five years.

Few wave and tidal technologies have been in operation for more than a few years and their production volumes are limited, so costs remain high and the durability of the equipment over time is uncertain.

Cost and performance assumptions. Tidal and wave generation technologies are very early in development, making cost estimates difficult. Most developers have not produced more than one full-scale device, and some have not even reached that point. The best-known cost estimates for development at scale are shown below. These are subject to considerable uncertainty, as they assume a certain scale-up in the respective industries, with the attending decrease in costs.

Figure D-17
Tidal and Wave Energy Plant Cost Estimates

Resource Type	Capital Cost ($/kW)	Levelized Cost ($/MWh)	Commercial Installation Size (kW)	Expected Life (years)	Typical Capacity Factor
Tidal1	$2,300 / kW	$112	16,000	20	35 %
Wave2	$3,375 – 6,747/ kW	$150-240	90,000	20	40 %

Table Notes:
(1) Source: Electric Power Research Institute, EPRI
(2) Sources: UK Carbon Trust, EPRI

Wind energy

Off-shore wind resources

Off-shore wind generation uses horizontal-axis wind turbines specifically designed for use in harsh marine environments. Offshore wind resources are abundant, stronger, and blow more consistently than land-based wind resources. Data on the resource potential suggest more than 4,000,000 MW could be accessed in state and federal waters along the coasts of the United States and the Great Lakes, approximately four times the combined generating capacity of all U.S. electric power plants.[23]

Globally, approximately 8,975 MW of off-shore wind resources are currently planned or in operation, in Europe, China, Japan, and the United Kingdom.[24] The largest offshore wind farm is Walney 1 & 2 located in the Irish Sea in the UK. The number of people working in the UK's offshore sector grew from 700 in 2007 to around 3,200 in 2011.

Existing offshore wind installations have mainly been located in water depths of less than 30 meters and constructed with driven-pile foundations, though some gravity foundations exist and a number of new designs are under development for tripod platforms and floating platforms. One floating platform wind turbine is currently in operation off Norway.

Commercial availability. Currently, no offshore wind projects are under development on the West Coast of the United States.[25] Most U.S. projects have been proposed for the East Coast and Great Lakes regions. The nearest proposed project to PSE's service territory is the Naikun Offshore Wind Project in British Columbia. The developer has selected Siemens SWT-4.0-130 4 MW turbines, and Siemens will assist NaiKun Wind Energy Group with project development. The NaiKun Wind project has achieved an advanced stage of development with environmental approvals from the Provincial and Federal Governments, and agreements are in place with key suppliers and First Nations. Given its development status, construction can begin within two years of the award of a purchased power agreement.

According to the Department of the Interior, the U.S. will offer leases to federal acreage off the coasts of Virginia, Massachusetts, and Rhode Island for offshore wind farm

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[23] *Source: U.S. Department of Energy Wind Program*
[24] *Source: Lindoe Offshore Renewables Center, http://www.lorc.dk/offshore-wind-farms-map/list*
[25] *Source: U.S. Offcoast Wind Collective - http://www.usowc.org/*

development during the first half of 2013. These competitive lease sales will be the first held under an Obama administration's initiative to fast-track permitting for offshore wind farms. The leases would grant wind-development rights to about 277,550 acres, though the winning bidders would still have to clear additional environmental reviews and secure financing.[26]

Cost and performance pssumptions. Due to sustained winds, off-shore wind is expected to operate at higher capacity factors than land-based wind projects. However, the costs of marine construction and operations considerably exceed those of land-based construction and operation. Since no projects have been successfully developed or constructed in the United States at this time, the capital cost of off-shore wind development is difficult to predict. Estimates indicate these could be at least $4,000 per kW, which is far from competitive with land-based turbines.[27] As a point of reference, the 130-turbine Cape Wind PPA is priced at 18.7¢ per kWh, while the weighted average cost of land-based wind energy is less than 6¢ per kWh.[28] Given this 3x cost differential, off-shore wind energy is simply not cost competitive with land-based developments unless significant technological improvement takes place.

Policy considerations. To encourage development of off-shore wind resources, the Obama administration announced funding in 2012 for seven projects. The Department of Energy says the funding of up to $168 million over six years will expedite development of the nation's first off-shore wind farms. None are operational yet, but 9 have reached the advanced development phase and 24 more are in earlier development stages.

Under the Department of Energy's new funding, which builds upon $42 million in R&D awards given last year, each project will receive up to $4 million to complete engineering, site evaluation and planning. The department will then select up to three of the projects and offer each up to $47 million to facilitate commercial operation by 2017. The seven projects are in six states; the closest to PSE is Principle Power's proposed wind farm off Coos Bay, Ore.

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[26] *Source: Wall Street Journal, Washington Wire, November 2012*
[27] *Source: NREL - Large Scale Offshore Wind Power in the United States, Opportunities and Barriers, 2010*
[28] *Source: Berkeley Lab, 2011*

APPENDIX D – ELECTRIC RESOURCE ALTERNATIVES

Land-based wind resources

Wind turbine generator technology is mature and the dominant form of new renewable energy generation in the Pacific Northwest. While the basic concept of a wind turbine has remained generally constant over the last several decades, the technology continues to evolve, yielding larger towers, wider rotor diameters, greater nameplate capacity, and increased wind capture. Commercially available machines are in the 2.0 to 3.0 MW range with hub heights of 80 to 100 meters and blade diameters topping out around 110 meters. These changes have come about largely because development of premium high-wind sites has pushed new development into less-energetic wind sites. The current generation of turbines is pushing the physical limits of existing transportation infrastructure. In addition, if nameplate capacity and turbine size continue to increase, the industry must explore creative solutions, such as concrete tower foundations poured on site.

Commercial availability. The market for turbines appears to be in favor of buyers at the moment. Greenfield development of a new wind facility requires approximately three to five years, and consist of the following activities at a minimum: one to two years for development, permitting and major equipment lead-time; and one year for construction.

APPENDIX E

Regional Transmission Resources

Contents

The Pacific Northwest's regional transmission system and policies have undergone significant change and reform over the last several years. This change is marked by increasing frequency and duration of transmission constraints, changes in transmission policy and transmission projects, and promising steps in studying and implementing regional transmission solutions. Of these items, some stand out as particularly important.

Existing flowgates and paths managed by the Bonneville Power Administration (BPA) continue to experience congestion resulting in curtailment. BPA has identified and implemented new flowgates and paths on its system to help manage new congestion, signaling the increasingly strained nature of the transmission system and the increasing risks of curtailment.

Analysis of internal PSE transmission constraints in the Puget Sound area needs to continue to be refined as generation alternatives are considered.

The two-year delay and proposed changes in the BPA Network Open Season (NOS) structure add uncertainty for PSE and other customers seeking transmission service. The previous annual NOSs have initiated new transmission construction and granted PSE new transmission to meet resource needs; however, PSE should consider other opportunities to obtain transmission capacity to meet future needs.

ColumbiaGrid and its members have completed several studies and developed transmission reinforcement plans that will address regional congestion. PSE will continue to look to ColumbiaGrid to provide the region with an understanding of where future transmission reinforcements should occur, and what implementation is most effective

These items will be explored in the sections below.

1. The Pacific Northwest Transmission System

Regionally constrained flowgates and paths on BPA's transmission system

BPA provides roughly 70 percent of the high-voltage transmission in the Pacific Northwest region. Historically, PSE and other regional utilities have relied on BPA's transmission system to transport energy and capacity resources. However, as PSE and the region's resource portfolios have grown in conjunction with increasing loads and renewable energy standards, the Pacific Northwest's transmission system has not kept pace with the increasing demands. As a result, the region experiences transmission constraints during various times of the year, sometimes resulting in curtailments of firm contractual transmission rights.

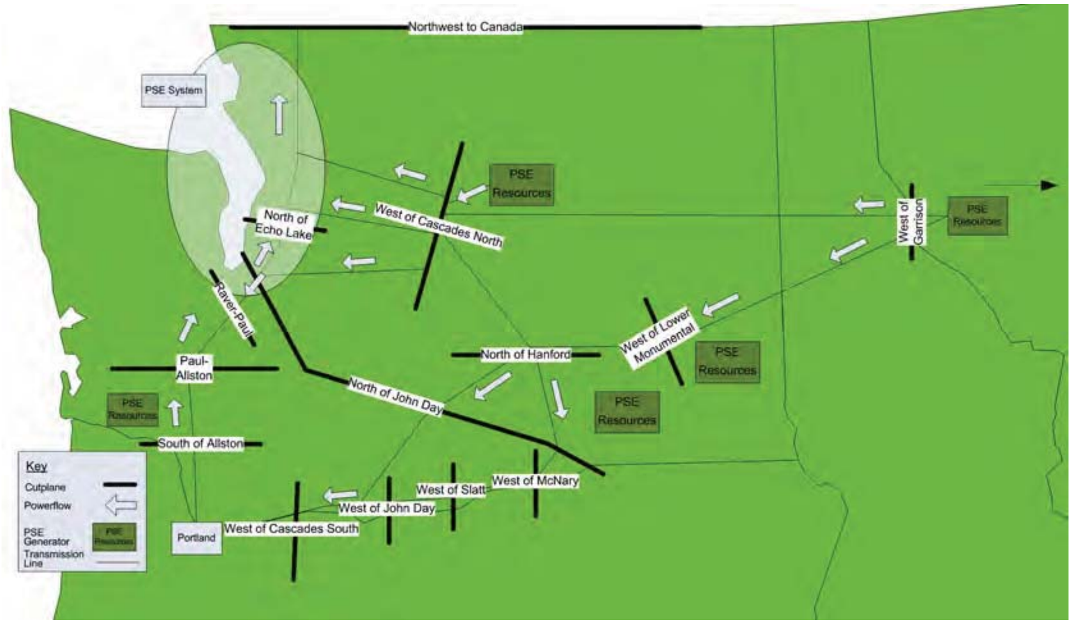
The situation poses an operational challenge for PSE in particular, since we move significant amounts of energy and capacity resources to the west from eastern Washington (east of the Cascades) and from the south through the I-5 corridor and into the Puget Sound area.

Figure E-1 illustrates how power travels from remote resources, generally located south of Seattle and east of the Cascades, to PSE's service area. The thick, black bars in Figure E-1 represent a flowgate or path, often consisting of several transmission lines or sets of lines in parallel to each other. The flow of power is indicated by the arrow symbol and typically flows in the following direction from PSE resources.

APPENDIX E – REGIONAL TRANSMISSION RESOURCES

Figure E-1

BPA Transmission System Constraints on PSE Remote Resource Delivery



Some of the flowgates and paths shown in Figure E-1 have been operated by BPA for many years. These are discussed below:

- The large majority of energy from PSE's eastern Washington resources flow across the constrained West of Cascades North flowgate and into the Puget Sound area. This flowgate is most constrained during heavy winter loading periods.
- A portion of the energy flowing from eastern Washington resources also flows over the West of Cascades South flowgate, and in the process of traveling to loads in the Puget Sound area, flows over the North of John Day and Raver – Paul flowgates. The West of Cascades South flowgate is most constrained during heavy winter loading periods, while the North of John Day and Raver – Paul flowgates are typically most constrained during heavy summer loading periods.
- In addition to the paths mentioned above, energy from PSE's resources in Montana flow over the West of Garrison path.

More recently, BPA has implemented new flowgates, reflecting new constraints on the transmission system that must be monitored for congestion:

- Congestion issues in the Puget Sound area once monitored by BPA using the Northern Intertie path (called Northwest to Canada on the figure below) will now be monitored on a new flowgate called North of Echo Lake. Generation support from PSE resources located in Skagit and Whatcom Counties is particularly important in reducing curtailment risk on this flowgate.
- Energy from PSE's Lower Snake River Wind Project flows across the new West of Lower Monumental flowgate.

Constrained paths and flowgates indicate that a part of the transmission system has little to no capacity available to sell and could be more vulnerable to congestion and curtailments. While some paths were designed to operate close to their limits (like West of Garrison), others were not; these present areas of the system where PSE sees a particular importance in continuing to study, develop, and possibly construct new transmission.

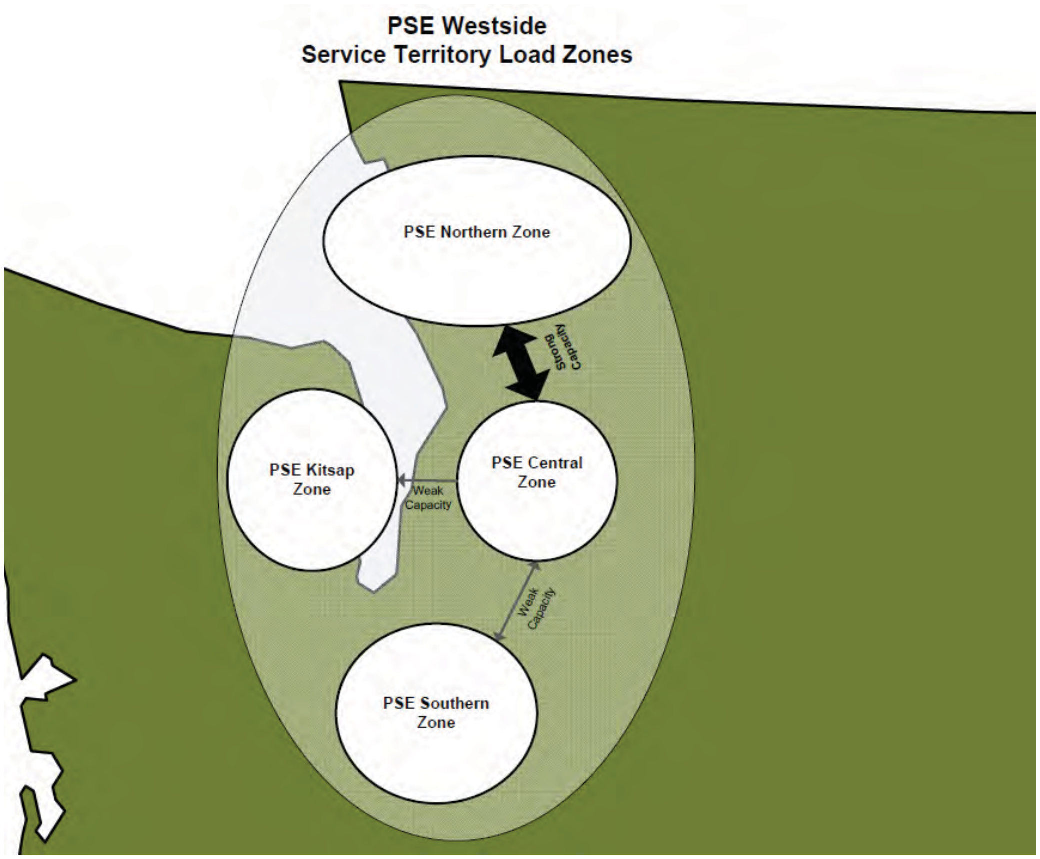
PSE Westside Service Area transmission constraints

Generally, resources located west of the Cascades near PSE load centers and natural gas pipelines have fewer delivery constraints because they are located next to the company's own local transmission system. Currently, there is sufficient transmission capacity on PSE's westside system to move energy produced in one part of the service territory to another part (essentially from surplus to deficit areas). However, constraints could develop within the system if new resources are added or imported in certain areas.

Figure E-2 illustrates the PSE Westside Load Zones and transmission paths.

APPENDIX E – REGIONAL TRANSMISSION RESOURCES

Figure E-2.
Transmission System Constraint on PSE Internal Resource Delivery



The illustration above divides PSE's Westside Service Territory into four geographic load areas, connected by different sets of transmission facilities. The arrows indicate relative transmission capacity between the load areas; the thicker the arrow the greater the transmission capacity. Capacity from the Central Zone to the Northern Zone is adequate in the near term. In the ten-year timeframe examined here, it is unlikely that new resources located in (or imported into) the Central Zone would cause PSE to experience limitations in moving energy from the Central to the Northern zone. Transmission capacity from the Central to Southern Zone is more limited, however; here, PSE could experience limitations in moving energy from the Central to the Southern zone if new resources are added or imported in the next ten years. Regarding movement from the Central or Southern Zones to the Kitsap Zone, unless new transmission capacity is built or obtained between these zones, PSE may begin to see resource deficits in the Kitsap Zone after 2024.

Purchased power agreements (PPAs) also impact energy transfer needs, as do capacity constraints, the geographic location of PSE's loads and existing resources, and the physical delivery points of remote resources.

PSE will consider these implications as we continue to analyze and study the location of loads, existing resources, and transmission limitations.

2. PSE Transmission Efforts

There may be growing opportunities for PSE to join with other regional utilities on transmission projects to solve congestion issues in the Pacific Northwest. PSE is considering the following regional transmission projects:

Puget Sound Area / North of Echo Lake / Northern Intertie Improvements

As part of the ColumbiaGrid "Transmission Expansion Plan for the Puget Sound Area," PSE has committed to addressing Puget Sound area congestion through rebuilding its Sammamish – Lakeside – Talbot 115kV lines from 115kV to 230kV (or a similar performing alternative). Only one line will initially be energized at 230kV. PSE's role in this larger plan of service for the Puget Sound area will significantly increase reliability and reduce curtailment risk for imports. This will be discussed further in the ColumbiaGrid section below.

West of Cascades North Improvements

Near-term improvements to the West of Cascades North flowgate will be constructed solely by BPA (see Attachment K section below), but long-term solutions could be improved through joint transmission development. As identified in the ColumbiaGrid Cross Cascades North Study team, the most effective transmission project for the West of Cascades North flowgate is the Chief Joseph – Monroe 500kV #2 transmission line. PSE will continue to participate in the study team and work with regional utility partners to determine the most beneficial transmission project and construction time for West of Cascades North transmission improvements.

3. BPA Transmission Efforts

Network Open Season

The primary option for acquiring contractual transmission in the Northwest is through BPA. While this has historically involved submitting an OASIS (Open Access Same-time Information System) transmission service request to BPA, the agency now requires participation in its Network Open Season (NOS), which was designed to obtain financial commitments from transmission customers to purchase transmission from BPA. The NOS process utilizes cluster studies to analyze impacts and new transmission facility requirements on an aggregated basis for long-term transmission requests. Commencing in 2008 and in accordance with FERC approval, BPA initiated a NOS process under its Open Access Transmission Tariff (OATT). A multi-step process was implemented beginning with transmission customers submitting Transmission Service Requests (TSR) for desired transmission. BPA responded with an offer of a corresponding Precedent Transmission Service Agreement (PTSA), requiring a security deposit in an amount equal to the charge for 12 months of transmission service at the tariff rate. The PTSA obligates the customer to take service for its TSR if BPA satisfies the following precedent: (1) BPA determines that it can reasonably provide service for the TSR in the cluster at embedded cost rates, and (2) if facilities must be built to provide the service, BPA decides, after completion of a BPA-funded NEPA study, to build the facilities.

Currently, NOS has been postponed since the conclusion of the NOS 2010 process so that BPA and stakeholders can work through reform of NOS policies. Expected changes include:

- Longer duration between submitting transmission request and rolled-in rate determination
- Sharing of construction costs and risks among participants
- Regional planning inputs considered on system expansion

Even with postponement, BPA was able to make significant progress on transmission projects resulting from the 2008, 2009, and 2010 NOS processes. From the 2008 NOS, BPA authorized four transmission reinforcement projects that include the McNary – John Day 500kV line (completed), Big Eddy – Knight 500kV (in construction), Central Ferry – Lower Monumental (delayed), and the I-5 Corridor Reinforcement Project (delayed).

There were no additional projects in 2009. In the 2010 NOS, BPA authorized the Northern Intertie Reinforcement Project and Colstrip Upgrade Project West. These projects will help to integrate thousands of MW of new resources into the Northwest.

Wind curtailment

Wind power plays a major role in both meeting the region's future energy needs and satisfying RPS requirements. In fact, approximately 5,000 MW total of renewable generation (predominantly wind power) will be necessary to fulfill the combined RPS requirements of Washington and Oregon. To meet this increase, BPA must continue to build transmission lines and substations to deliver renewable electricity from new wind projects that are often located in remote areas. Integrating this amount of wind energy into the region's electrical grid poses many challenges, and BPA's role will certainly require innovative and cooperative approaches to manage the variability of wind power effectively.

One operational protocol BPA implemented in order to manage the growing amount of wind energy on its system is Dispatcher Standing Order (DSO) 216. DSO 216 enables BPA to either curtail generation schedules or limit generation to the scheduled amount when there is insufficient regulating capacity on the federal hydroelectric system. Regulating capacity is an ancillary service that BPA provides to integrate wind. However, that service is not always available, as shown by the historical frequency of DSO 216 curtailments. Curtailments may result in lost energy and/or renewable energy credits (RECs) without compensation.

Another operational protocol BPA implemented to manage wind energy is Oversupply Management Protocol. Similar to DSO 216, BPA utilizes Oversupply Management Protocol to curtail wind energy, but in this case due to the oversupply of hydroelectric and wind generation in the region. Curtailments may result in lost energy and/or RECs with compensation.

PSE's future resources – especially renewables – will most likely face tough economic and technical challenges, along with business uncertainties. Continuing to rely on BPA to integrate our wind resources has a limit, which means we must continue to look for alternatives to integrate wind either directly into our Balancing Authority (BA), or seek other innovative, lower-cost approaches.

BPA transmission planning and Attachment K projects

Through its various forums (Attachment K, Capital Investment Review), BPA is planning to construct two projects that are particularly important for PSE's customers:

- Monroe Substation 500kV Capacitors, in service 2014
- Schultz – Raver 500kV Series Capacitors, in service 2017/2018

These projects enable new capacity on the West of Cascades North flowgate, increasing reliability to Puget Sound area loads and decreasing potential congestion experienced in heavy winter loading periods. These projects are also important because they could make new capacity available for PSE requests for transmission service from eastside generation alternatives to PSE loads.

4. Regional Transmission Efforts

Major proposed projects

Several major transmission projects are proposed for the Pacific Northwest. These projects may impact each other as well as the existing Western Electric Coordinating Council (WECC) paths. WECC maintains a public transmission project database where project sponsors can post information and updates for their projects. The projects listed below can all be found in the WECC database or at BPA's website. All are assumed to have some effect on the paths and flowgates that PSE uses to transmit energy from remote resources to load.

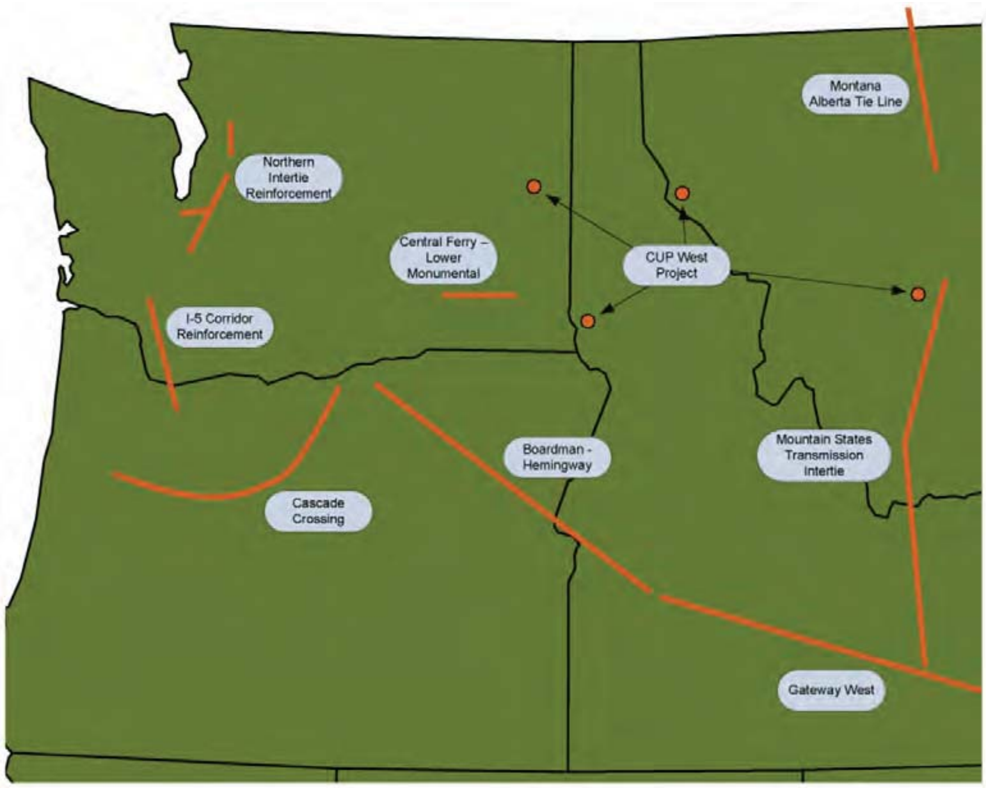
1. PacifiCorp's Gateway West: ~ $2.7 billion, 2018 - 2021, WECC rating process
2. Idaho Power's Boardman to Hemmingway: ~ $900 million, 2018, WECC rating process
3. Northwestern Energy's Mountain States Transmission Intertie (MSTI): ~$1 billion, 2017, WECC rating process
4. PGE's Cascade Crossing: ~ $800 million to $1 billion, 2017, WECC rating process
5. BPA's Central Ferry – Lower Monumental Project: ~ $90 million, 2014, delayed
6. BPA's I-5 Corridor Reinforcement: ~ $340 million, 2018, environmental review
7. BPA's Path 8 Upgrade/Colstrip Transmission Upgrade (CUP West) ~$90 million, 2014
8. BPA's Northern Intertie Reinforcement Project: ~ $70M, 2013 - 2015
9. Enbridge's Montana Alberta Tie Line: ~$300 million, 2013, WECC rating process

These projects are also displayed in Figure E-3. The complete listing of WECC projects can be found at http://www.wecc.biz/Planning/TransmissionExpansion/Transmission/Pages/default.aspx

APPENDIX E – REGIONAL TRANSMISSION RESOURCES

Figure E-3

Proposed Regional Transmission Projects



These projects bring three main benefits to the region: 1) access to significant incremental renewable resources in Canada and in the northwestern states, 2) improvement in regional transmission reliability, and 3) market opportunities in dealing with participants outside of the region.

ColumbiaGrid efforts

ColumbiaGrid is a non-profit membership corporation formed in 2006 to improve the operational efficiency, reliability, and planned expansion of the Pacific Northwest's transmission grid. While ColumbiaGrid does not own transmission, PSE, other members, and additional parties to ColumbiaGrid's agreements do own and operate an extensive network of transmission facilities. ColumbiaGrid's members are PSE, Avista, BPA, Chelan County PUD, Grant County PUD, Seattle City Light, Snohomish PUD, and Tacoma Power.

ColumbiaGrid has substantial responsibilities for transmission planning, reliability, OASIS and other development services. These tasks are defined and funded through a series of "Functional Agreements" with members and other participants. Development of these agreements is carried out in a public process with broad participation. ColumbiaGrid's transparent processes encourage broad participation and interaction with stakeholders, including customers, transmission providers, states, and tribes. It also provides a non-discriminatory forum for interested parties to receive and present pertinent information concerning the regional interconnected transmission system.

1. Planning and expansion

ColumbiaGrid's planning and expansion efforts are intended to promote single-utility planning and expansion of the regional grid. The Planning and Expansion Functional Agreement (PEFA), which has been signed by all of ColumbiaGrid's members and three non-member participants (Cowlitz County PUD, Douglas County PUD, and Enbridge, Inc.), defines the obligations under this program.

The PEFA charges ColumbiaGrid with answering three key questions concerning the transmission network: what should be built, who should build it, and who should pay for it. ColumbiaGrid will provide a number of services in this planning program, including performing annual transmission adequacy assessments, producing a Biennial Transmission Plan and identifying transmission needs. ColumbiaGrid also will facilitate a coordinated planning process for the development of multi-transmission system projects.

Since the adoption of the 2012 Update to the 2011 Biennial Transmission Expansion

Plan, ColumbiaGrid has completed the 2012 System Assessment, which served as an input to the 2013 Biennial Transmission Expansion Plan by highlighting areas of the system where there may be deficiencies in meeting reliability standards.[1] In support of the Biennial Plan, PSE participated in three study teams addressing specific regions: the Puget Sound Area Study Team (PSAST), the Wind Integration Study Team (WIST) and the Cross Cascades North Study Team.

2. Puget Sound Area Study Team

The PSAST originally published its "Transmission Expansion Plan for the Puget Sound Area" in October 2010, with an additional update in October 2011. Since then, area utilities have continued to meet and develop additional scenarios to be studied. The following six projects were identified as being the most effective at reducing risk of curtailing firm transfers for south-to-north congestion on the North of Echo Lake flowgate:

- Reconductor the Bothell - SnoKing 230kV double-circuit line
- Add series inductors to the Massachusetts-Union-Broad Street and Broad Street-East Pine 115kV underground cables
- Extend the Northern Intertie Remedial Action Scheme (RAS) for the combined loss of Monroe-SnoKing-Echo Lake and Chief Joseph-Monroe 500kV lines
- Add a Raver 500/230kV transformer and a 230kV Raver – Covington line
- Rebuild both the Sammamish-Lakeside-Talbot 115kV lines to 230kV. Energize one line at 230kV and the other at 115kV
- Reconductor the Duwamish – Delridge 230kV line

The PSAST is also updating the north-to-south portion of the "Transmission Expansion Plan for the Puget Sound Area," with a plan to have the report finalized in early 2013. Preliminary results suggest that two projects will be the most effective at correcting major limitations for north-to-south transfers in the Puget Sound area:

- Add a second Portal Way 230/115kV transformer
- Upgrade Monroe – Novelty 230kV line to operate at 80 degrees Celsius

[1] *The referenced plans and assessments can be found on ColumbiaGrid's web site at http://www.columbiagrid.org/documents-search.cfm by using the document search function.*

3. Wind Integration Study Team (WIST)

WIST was formed by the Northern Tier Transmission Group (NTTG) and ColumbiaGrid to facilitate the integration of renewable generation into the northwest transmission grid. Its current focus is to study and address system constraints related to increased use of dynamic transfers for variable energy resources. The study team produced a set of reports in 2011 that confirmed the need for dynamic transfer capability limits, explored dynamic transfer capability study methodologies and applied the methodology to several NW paths. Work continued through 2012 to quantify dynamic transfer capability of NW paths and to help identify other dynamic transfer impacts on reliability.

4. Cross Cascades North Study Team

The Cross Cascades North Study Team is currently investigating the extent of system problems on the Cross Cascades North flowgate. It is also evaluating the performance and interaction of various potential transmission projects. As discussed previously, this path delivers remote resources from east of the Cascade Mountains to westside load areas. Should increasing amounts of eastside remote renewable generation displace westside thermal generation, there is the potential for the path to exceed its system operating limits and cause critical outages.

To mitigate these issues, the team studied the incremental transfer capability benefits of potential system expansion alternatives. Alternatives were categorized as short lead-time construction or long lead-time construction. These studies showed that the most beneficial short lead-time alternative was the addition of series capacitors at the Schultz Switching Station on the Raver #3 and Raver #4 lines. The studies also showed that the most beneficial long lead-time alternative was a new 500kV transmission line between the Chief Joseph and Monroe substations. The timing of long lead-time construction is assumed to be at least 10 years from present.

APPENDIX E – REGIONAL TRANSMISSION RESOURCES

Order 1000

The Federal Energy Regulatory Commission's (FERC) Order 1000 requires transmission providers to 1) participate in a transmission planning process that evaluates alternatives that may resolve the transmission planning region's needs in a more cost effective and efficient manner than local planning processes; 2) have a methodology for cost allocation for such projects within the region; and 3) consider public policy requirements in its planning process. The order further requires transmission providers to improve coordination across regional transmission planning processes by developing and implementing procedures for joint evaluation and sharing of information regarding both the transmission needs of the region as well as potential interregional transmission facilities that would be located in more than one region. The order also requires regions to have a common methodology for allocating costs of interregional projects.

For PSE, ColumbiaGrid is recognized as its regional planning entity. While the ColumbiaGrid PEFA addresses many of the Order 1000 requirements for PSE, several amendments were made to comply with the order regarding regional planning. The amended PEFA and corresponding changes to the Attachment K to PSE's OATT were filed with FERC on October 11, 2012. FERC has yet to issue an order on the filings. For the interregional portion of the order, PSE has been working with ColumbiaGrid and the other regions in the western interconnection (the California Independent System Operator, WestConnect, and Northern Tier Transmission Group) to develop the required common language for interregional coordination and cost allocation. Further amendments to the PEFA and PSE's Attachment K are anticipated. These will be filed with FERC prior to the July 10, 2013 filing deadline.

Information regarding Order 1000 is available on the ColumbiaGrid website under Order 1000 at https://www.columbiagrid.org/1000-overview.cfm.

5. Outlook and Strategy

PSE needs to advocate and participate in local and regional transmission projects that relieve congestion, increase transfer capacity, and improve reliability for its electric customers. This can be accomplished through the following actions:

- **Participate in efforts focusing on relieving existing and future transmission congestion.** PSE should continue to participate in the planning of regional transmission projects that decrease congestion and curtailment risk, increase regional reliability, and help maintain low power prices for its customers. PSE will pursue these opportunities through various forums, including ColumbiaGrid, BPA Network Open Season and Attachment K, and through its utility partners in the Puget Sound area. Because of our geographical location, PSE will focus on efforts to study and develop projects that relieve congestion on the West of Cascades North, North of Echo Lake, and Raver – Paul flowgates.

- **Refine assessment of future internal transmission constraints related to westside generation alternatives.** PSE has begun to lay out the methodology for determining which internal transmission constraints may interfere with bringing new westside resource options to load. To the extent that PSE acquires incremental westside generation in the future, we will need to determine the quantitative and qualitative constraints involved in bringing that resource to load.

- **Identify opportunities to obtain additional transmission capacity necessary to deliver energy from eastside generation alternatives.** If PSE identifies cost effective resources located east of the Cascades, we need to consider the means to build or acquire additional transmission service from those remote resources. PSE should continue to assess the quantitative and qualitative strengths and weaknesses of taking additional transmission service (through a BPA NOS process), or obtaining physical transmission capacity. PSE should continue to participate in ColumbiaGrid study groups which seek to refine which West of Cascades North transmission project is most beneficial to the region.

APPENDIX F

Financial Considerations

Contents

1. Cost to PSE's Customers

Revenue requirement

The financial calculations in the IRP are based on customer revenue requirement. The revenues collected by PSE are determined by the Washington Utilities and Transportation Commission (WUTC or Commission). Before any regulated company can change its service or rates, the proposal must be approved by the Commission. By law the Commission must set rates that are fair, just, reasonable and sufficient. Revenue requirement equals the operating expenses plus the rate of return, which is the cost of capital to finance the company's investment. The rate of return is set to enable the utility to maintain its credit standing, financial integrity, and to attract new capital at reasonable costs. The rate of return is commensurate with returns being earned on investments attended by corresponding risks. It recognizes that the utility's rate base is financed by two types of capital sources:

- Fixed-income securities (debt and preferred stock)
- Variable-income securities (common equity)

*Revenue Requirement = Rate Base * Rate of Return + Operating Expenses*

Rate base is the amount of investment in plant devoted to the rendering of service upon which a fair rate of return is allowed to be earned. In the State of Washington, rate base is valued at the original cost less accumulated depreciation and deferred taxes.

The rate of return used in the IRP, shown in Figure F-1, is based on the rate established in the company's most recent General Rate Case. The WUTC decided on a capital structure and allowed cost of capital of 7.8 percent in Order 08 to DOCKETS UE-111048 and UG-111049 (consolidated) issued May 7, 2012 (page 34, table 6).

APPENDIX F – FINANCIAL CONSIDERATIONS

Figure F-1

Approved Capital Structure and Cost of Capital

	Share percent	Cost percent	Weighted Cost percent
Equity	48.00	9.80	4.70
Long-Term Debt	48.00	6.22	2.99
Short-Term Debt	4.00	2.68	0.11
OVERALL ROR			7.80

In the IRP's Portfolio Screening Model, new resource additions are treated as if they are owned by PSE and included in the rate base. In Washington state, PSE does not generally earn a regulated rate of return on power purchase agreements (PPAs). When modeling PPAs, PSE assumes perfect regulation and does not take regulatory lag into consideration. (Regulatory lag is the time that elapses between establishment of the need for funds and the actual collection of those funds in rates.)

Incremental revenue requirement in the Portfolio Screening Model includes the revenue requirement of the new resource additions, the variable costs associated with PSE's existing fleet, and market purchases or sales in hours when the economic dispatch of PSE's portfolio – existing fleet and new resource additions – is deficient or surplus to meet PSE's hourly load. For the specific resource acquisition analysis, PSE will include as appropriate the revenue requirement associated with power purchase agreements and an imputed debt cost as explained in the next section. Appendix K of the IRP describes in further detail PSE's Portfolio Screening Model.

2. Resource Specific Financial Considerations

Power purchase agreement (PPA)

As mentioned in Chapter 5, PPAs were not considered as a resource option in this IRP since the costs and terms of individual PPAs are not known until the time they are offered. However, since PSE expects to receive PPAs during our RFP process, it is important to understand how they will be evaluated. The following section describes what imputed debt is, and how it is calculated and used in evaluation.

Imputed debt methodologies

Utilities have used PPAs in the past as an alternative to the risk and expense of new plant development, construction, and operation. However, entering into long-term PPAs creates fixed obligations that can increase a utility's financial risks. Both Moody's Investors Service and Standard & Poor's (S&P) use a quantitative methodology to calculate the risk of PPAs and the impact of that risk on the creditworthiness of electric utilities. The methodologies, while different from one another, were designed to make a fair comparison between electric utilities that own and generate power vs. utilities that contract for power. In general, imputed debt is described in the 1994 update of S&P 1992 Corporate Finance Criteria.

To analyze the financial impact of purchased power, S&P employs the following financial methodology. The net present value of future annual capacity payments (discounted at 6.1 percent), multiplied by a "risk factor" (which in PSE's case is 25 percent) represents a potential debt equivalent – the off-balance-sheet obligation that a utility incurs when it enters into a long-term power purchase contract.

APPENDIX F – FINANCIAL CONSIDERATIONS

PSE's IRP, and our screening of potential resource acquisitions, includes a cost of equity to neutralize the reduction in credit quality from imputed debt for all PPAs. As described previously, the debt rating agencies consider long-term take-or-pay and take-and-pay contracts equivalent to long-term debt; hence there is a cost associated with issuing equity to rebalance the company's debt/equity ratio. Imputed debt in the IRP is calculated using a similar methodology to that applied by S&P. The calculation begins with the determination of the fixed obligations that are equal to the actual demand payments, if so defined in the contract, or 50 percent of the expected total contract payments. This yearly fixed obligation is then multiplied by a risk factor. PSE's current contracts have a risk factor of 25 percent, as assessed by S&P. Imputed debt is the sum of the present value, using a 6.1 percent discount rate (the company's current average cost of long-term debt), and a mid-year cash flow convention of this risk-adjusted fixed obligation. The cost of imputed debt is the return on the amount of equity that would be acquired to offset the level of imputed debt to maintain the company's capital and interest coverage ratios.

Sensitivity of imputed debt cost

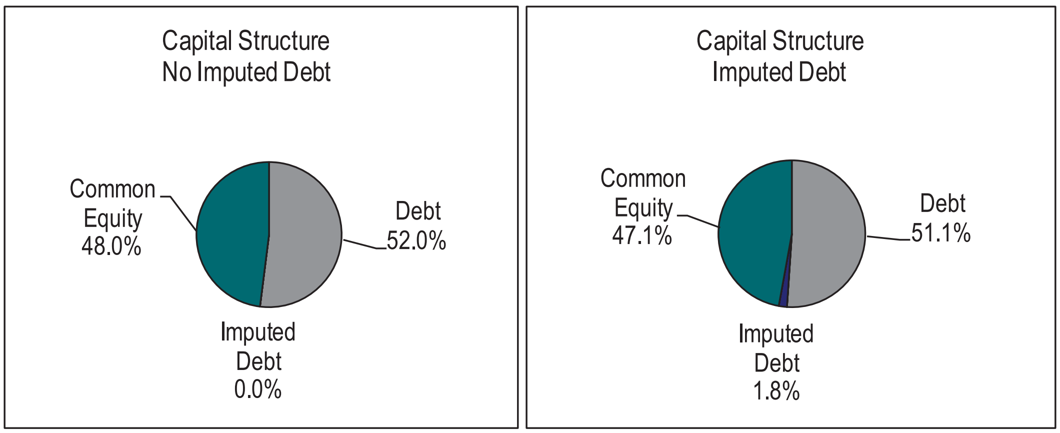
The cost impact of imputed debt on PPAs varies with the term of the contract, the proportion of the PPA associated with demand payment, and with the escalation of the PPA rate or demand payments. Assuming a flat, un-escalated PPA rate and PSE's allowed cost of capital, the imputed debt cost will increase the levelized cost of the PPA by approximately 1 percent on a 3-year PPA, 2 percent on a 5-year PPA, 3 percent on a 10-year PPA and 5 percent on a 20-year PPA.

APPENDIX F – FINANCIAL CONSIDERATIONS

Imputed debt's effect on capital structure

Figure F-2 shows that the capital structure with imputed debt is eroding PSE's financial strength as measured by the credit rating agencies. The percentage mix of debt and equity is as allowed in the May 2012 General Rate Case order from the Washington Utilities and Transportation Commission (WUTC) in DOCKETS UE-111048 and UG-111049 (consolidated). The level of imputed debt shown in the 2011 IRP was about $266 million or 3.9%. Based on the total capitalization forecast for the year-end 2012, the 2013 IRP imputed debt is about $139 million or 1.8% and reflects the roll-off, or shorter remaining term, of several large PPAs.

Figure F-2
Capital Structure with and without Imputed Debt



3. Other Financial Considerations

Discount rate

PSE uses a discount rate to calculate the present value of the various portfolio costs in this plan, and the same discount rate to evaluate the present value of portfolio costs and benefits of alternative resources. PSE uses its allowed regulatory return on rate base as the discount rate.

DSR financial considerations

Slow economic recovery and the elimination of federal tax incentives and economic stimulus funding may impact PSE's ability to acquire demand-side resources. Lower growth and lower use per customer means less demand-side potential, and lower incomes may reduce the willingness of customers to invest in energy efficiency resources. Also, as a result of the energy efficiency tax credits and grants, PSE experienced increases in customer demand for certain energy efficiency equipment. Now that most federal stimulus funds have been allocated, and the recently extended energy efficiency federal tax credits end on December 31, 2013, the increased demand for these measures may prove to have been temporary. This could mean that PSE may have to increase incentives, customer education, and promotional efforts to achieve energy efficiency goals. While the increase in energy savings may reduce costs over the long run, customers will continue to face increased rate pressure from higher program costs in the short run. The reduction of revenues due to reduced energy sales from conservation also creates pressure on PSE's financial performance.

Operational Flexibility

Contents

1. Introduction

System flexibility discussions have often focused on wind integration due to the historic increases in wind capacity in the Pacific Northwest, however the need for flexibility is actually more complex. Load fluctuations, Balancing Authority obligations to integrate scheduled interchanges, and unexpected events like forced outages all place demands on system flexibility. So does the need to maintain contingency reserves to assist other balancing authorities that may have sudden needs for help balancing loads.

This IRP endeavors to examine the issue of operational flexibility in a holistic manner that takes into account the full range of demands that impact system balancing. This examination looks at the need for balancing reserve capacity, the supply of this capacity available from PSE resources, and the deployment of that capacity each hour to maintain load-resource balance. The process has resulted in better understanding of the operational flexibility needs. It has also established a starting point for better understanding the cost implications associated with maintaining sufficient flexibility in the system, although further work in this area needs to be done.

APPENDIX G – OPERATIONAL FLEXIBILITY

This appendix is divided into five sections.

System Balancing discusses the role of balancing capacity, the Control Performance Standard 2 (CPS2) metric used to gauge PSE's ability to reliably balance the system, and how PSE defines variability and uncertainty as they relate to balancing.

Flexibility Supply and Demand covers how PSE evaluates the availability of balancing capacity from PSE resources in light of the demands placed on the system for that capacity, and discusses how that capacity is procured and deployed.

Modeling Methodology reviews two models used to assess how PSE will meet its balancing obligations in 2018. The first model determines how best to set aside balancing reserves prior to an operating hour; the second simulates deployment of those reserves at 10-minute intervals.

Finally, we present the **Results** from the analysis, and offer a **Conclusion and Next Steps**.

Four 2018 resource scenarios were analyzed. The first used the lowest reasonable cost portfolio identified in the analysis for the 2013 IRP Base Scenario; then, each of the incremental scenarios added one unique gas-fired resource capable of providing balancing services to the portfolio.

While additional work needs to be done, given the assumptions made for this study, the analysis indicates PSE has sufficient capacity and flexibility in the Base Scenario portfolio to effectively meet its known Balancing Authority demands in 2018 across both hour-ahead and intra-hour time frames. Balancing-related cost savings in the incremental portfolios ranged from $300,000 to $1,000,000 annually depending on the gas-fired resource analyzed, compared to the Base Scenario portfolio of resources.

2. System Balancing

The PSE Balancing Authority

A Balancing Authority (BA) is an entity that manages generation, transmission, and load; it maintains load-interchange-generation balance within a geographic or electrically interconnected Balancing Authority area, and it supports frequency in real time. The responsibility of the PSE Balancing Authority is to maintain frequency on its system and support frequency on the greater interconnection. To accomplish this, the PSE BA must balance load with generation on the system at all times. When load is greater than generation, a negative frequency error occurs. When generation is greater than load, a positive frequency error occurs. Small positive or negative frequency deviations are acceptable and occur commonly during the course of normal operations, but moderate to high deviations require corrective action by the BA. Large frequency deviations can severely damage electrical generating equipment and ultimately result in large-scale cascading power outages. Therefore, the primary responsibility of the BA is to do everything it can to maintain frequency so that load will be served reliably.

The Area Control Error (ACE) metric has been used for many years to track the ability of a BA to meet its reliability obligation. ACE is the instantaneous difference between actual and scheduled interchange, taking into account the effects of frequency. It reflects the balance of generation, load, and interchange. Balancing Authority ACE determines how much a BA needs to move its regulating generation units (both manually and automatically) to meet mandatory control performance standard requirements.

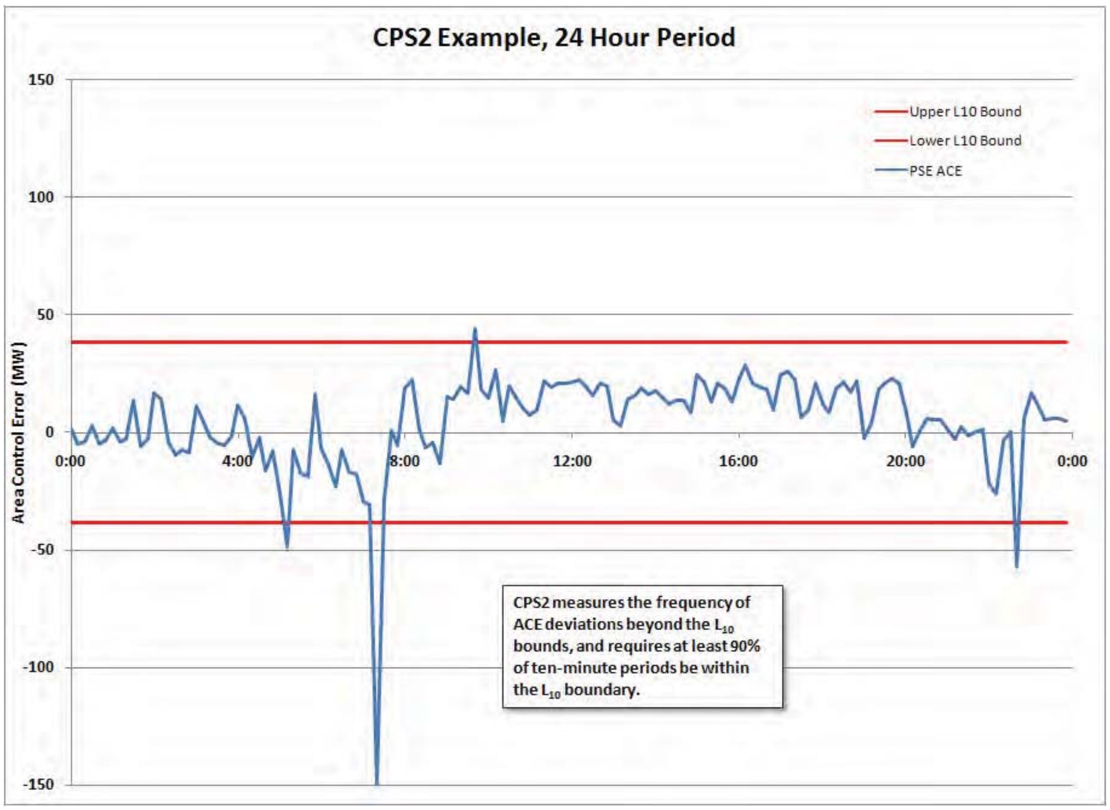
By properly managing its ACE, PSE meets several key objectives: it reliably serves its customers, it maintains regulatory compliance, and it minimizes frequency excursions originating within its own BA that could impact other BAs or Transmission Operators (TOP) within the interconnection. PSE's CPS2 metric sets a requirement for how far and often its system can stray from load and generation being in balance. CPS2 measures whether the average ACE stays within a given boundary over a 10-minute period; this is the L10 value. At least 90 percent of the 10-minute periods in each month must be within the +/- L10 boundary to meet the CPS2 requirement. The L10 value is provided to PSE by the North American Electric Reliability Corporation (NERC). The PSE system responds to ACE every four seconds to ensure that PSE's average CPS2 score exceeds the required 90 percent for compliance. CPS2 is a concrete benchmark for assessing

APPENDIX G – OPERATIONAL FLEXIBILITY

system reliability, and it is one of the metrics used to determine the adequacy of PSE's portfolio in this analysis.

Balancing reserves refer to capacity held back on the PSE system to respond to negative and positive frequency errors. These can be incremental (INC) or decremental (DEC). Incremental capacity adds energy to the grid, decremental capacity reduces power to the grid. Contingency reserves are also required in addition to balancing reserves; these are capacity reserved in spinning and non-spinning forms for managing a large negative frequency event such as a sudden loss of generation in PSE's BA or a neighboring BA. Contingency reserves are used for the first hour of the event only.

Figure G-1
Example of Control Performance Standard 2



Impact of variability and uncertainty on system volatility

Variability is the moment-to-moment, natural fluctuations in loads and generating resources and is always present on the electric system. Uncertainty is the inability to perfectly predict the hourly values for loads and generating resources. Volatility refers to the collective variability and uncertainty observed system-wide.

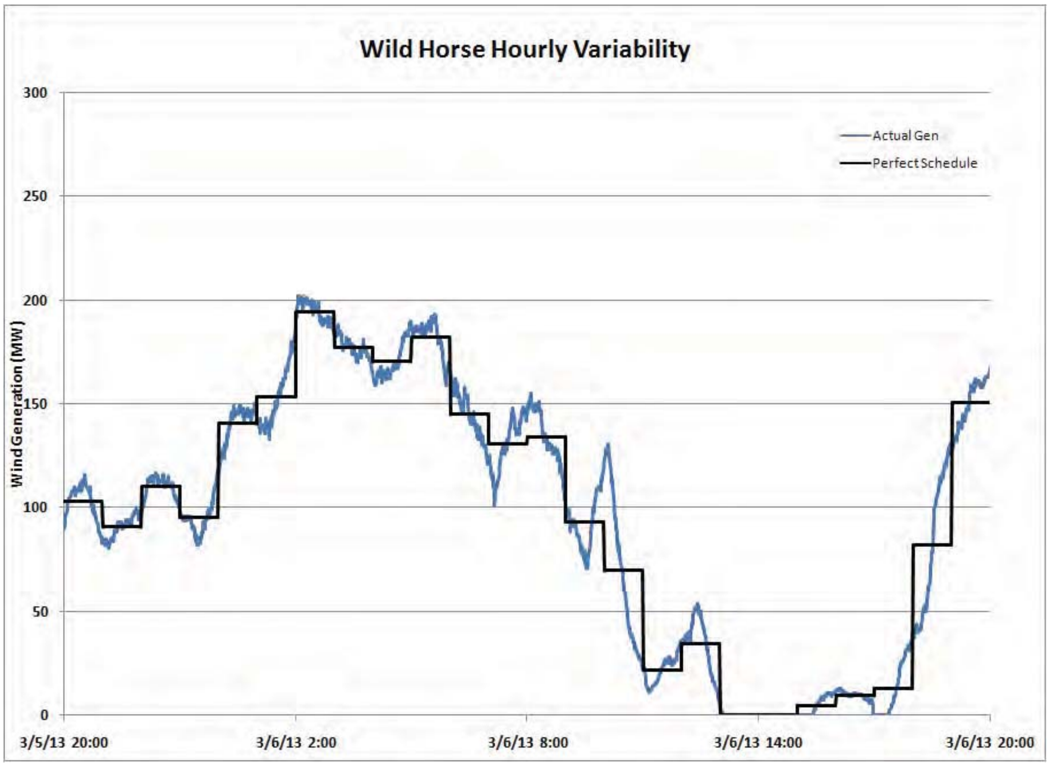
Understanding the distinction between variability and uncertainty is essential when discussing ways to manage and potentially reduce volatility across the entire PSE system. Variability is a smaller component of volatility than uncertainty. It is largely uncontrollable, since it is caused by random changes in loads, generating resource power output, and fuel availability (such as wind). Uncertainty is the larger component of system volatility, but there are tools that can be used to reduce this uncertainty. For example, improvements in load and wind forecasting can increase the accuracy of load and wind generation schedules, reducing the need to provide balancing energy. Also, shortening scheduling windows can reduce the impact of both variability and uncertainty on system volatility. Currently the PSE BA must manage system volatility over 60-minute scheduling periods. If shorter scheduling windows are ultimately implemented in the region, it would reduce the magnitude of scheduling errors and the length of time PSE has to manage system volatility with generating resources internal to its system. Shorter scheduling windows would also allow PSE to use market transactions more frequently as a tool to address deviations in system conditions.

Figures G-2 through G-4 use a 24-hour period at the Wild Horse Wind Facility to illustrate examples of variability, uncertainty, and volatility. In Figure G-2, the variability of Wild Horse is shown as the moment-to-moment generation relative to a perfect hourly schedule (a perfect hourly schedule equals the hourly average actual generation). It shows that even equipped with a perfect schedule, PSE must still manage fluctuations in wind generation within the hour, along with other deviations on the system.

APPENDIX G – OPERATIONAL FLEXIBILITY

Figure G-2

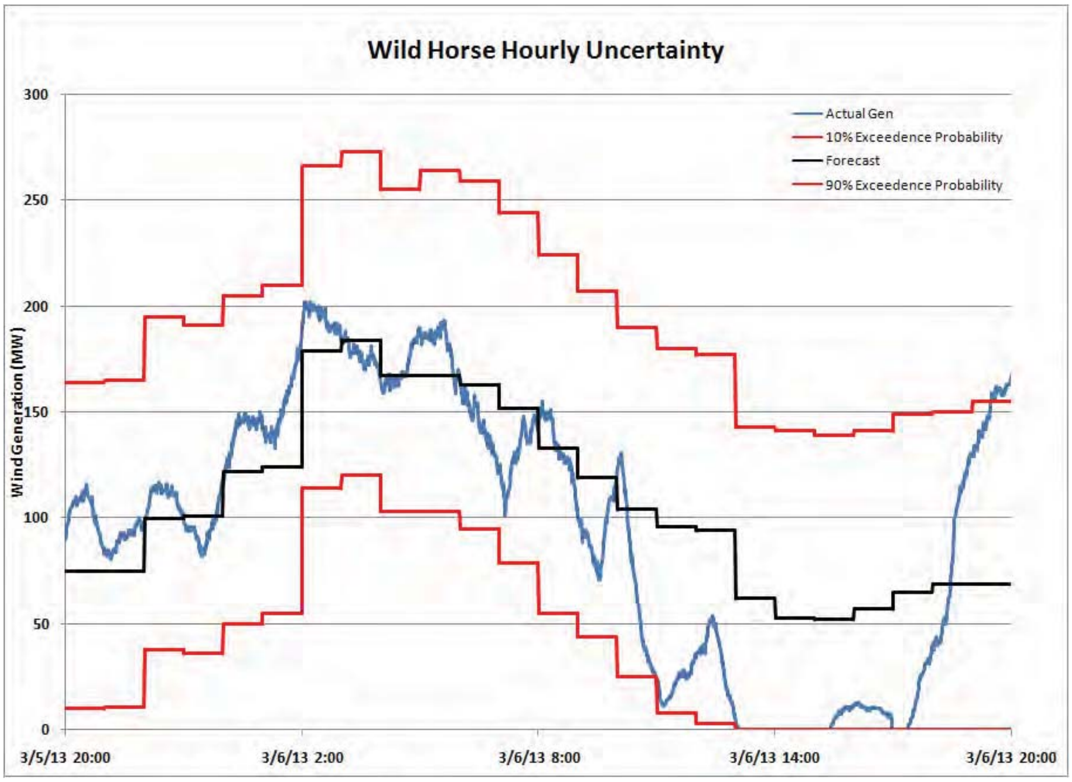
Hourly Variability in Wind Generation



In reality, perfect foresight of wind generation or load for each upcoming operating hour is not possible. As shown in Figure G-3, future wind generation is presented as an expected forecast for the next several hours, along with two additional forecasts that provide the probability of wind generation exceeding those values. At the 10% Exceedence forecast, we would expect actual wind generation to be above this value only 10 percent of the time, whereas at the 90% Exceedence forecast we would expect actual wind generation to be above this value 90 percent of the time. Actual wind generation may come in above or below the forecast, or as is the case in HE 20 of March 6, 2013, it can exceed the forecasted bounds.

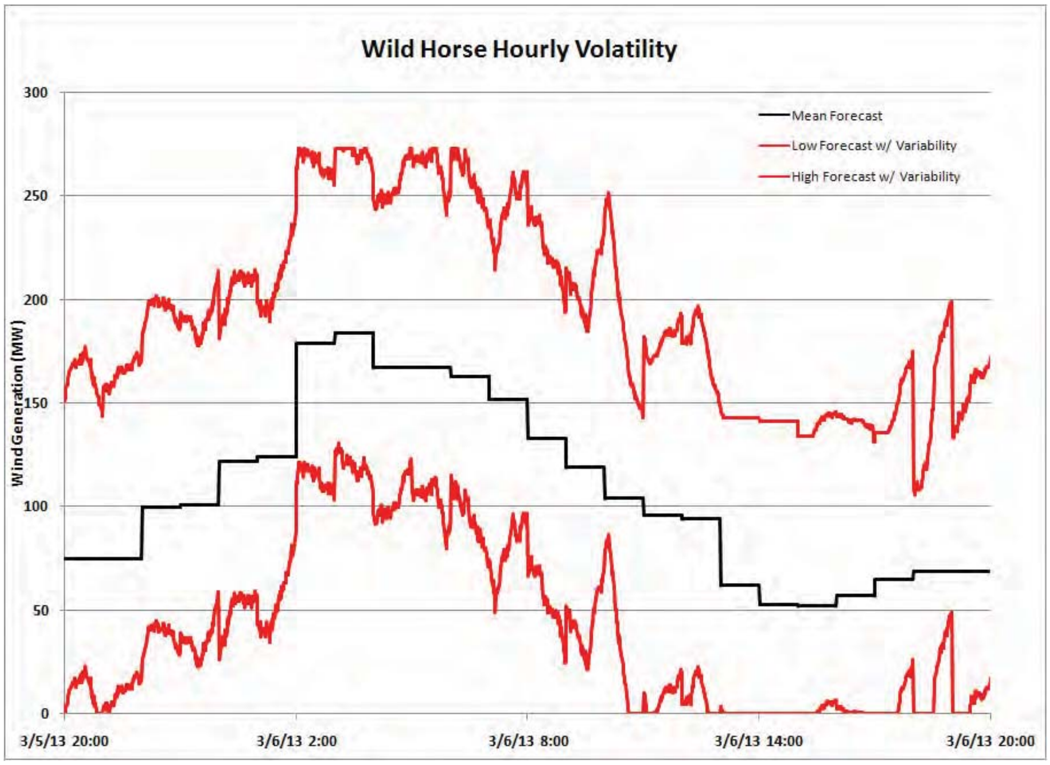
APPENDIX G – OPERATIONAL FLEXIBILITY

Figure G-3
Hourly Uncertainty in Wind Generation



APPENDIX G – OPERATIONAL FLEXIBILITY

Figure G-4
Hourly Volatility in Wind Generation



The variability and uncertainty at Wild Horse are combined in Figure G-4 to illustrate the volatility that may be expected each hour. The actual variability observed around each perfect hour in Figure G-2 is imposed on the upper and lower probability forecasts from Figure G-3. It shows how PSE must balance potentially large blocks of energy related to forecast error (uncertainty) while simultaneously balancing within-hour fluctuations (volatility) in order to maintain system reliability. Addressing volatility from sources other than wind requires similar action on PSE's part.

Managing volatility

System volatility (variability and uncertainty) is managed with balancing reserves. Balancing reserves are generating capacity available to respond to changes in system conditions by either increasing generation (INC capacity) or decreasing generation (DEC capacity). The amount of balancing reserve capacity at PSE is determined by examining historical balancing capacity needs, and then establishing the amount of reserves necessary to cover 95 percent of the historical deviations in net load. This amount of balancing capacity is referred to as a 95 percent Confidence Interval level (95% CI) of reserves.

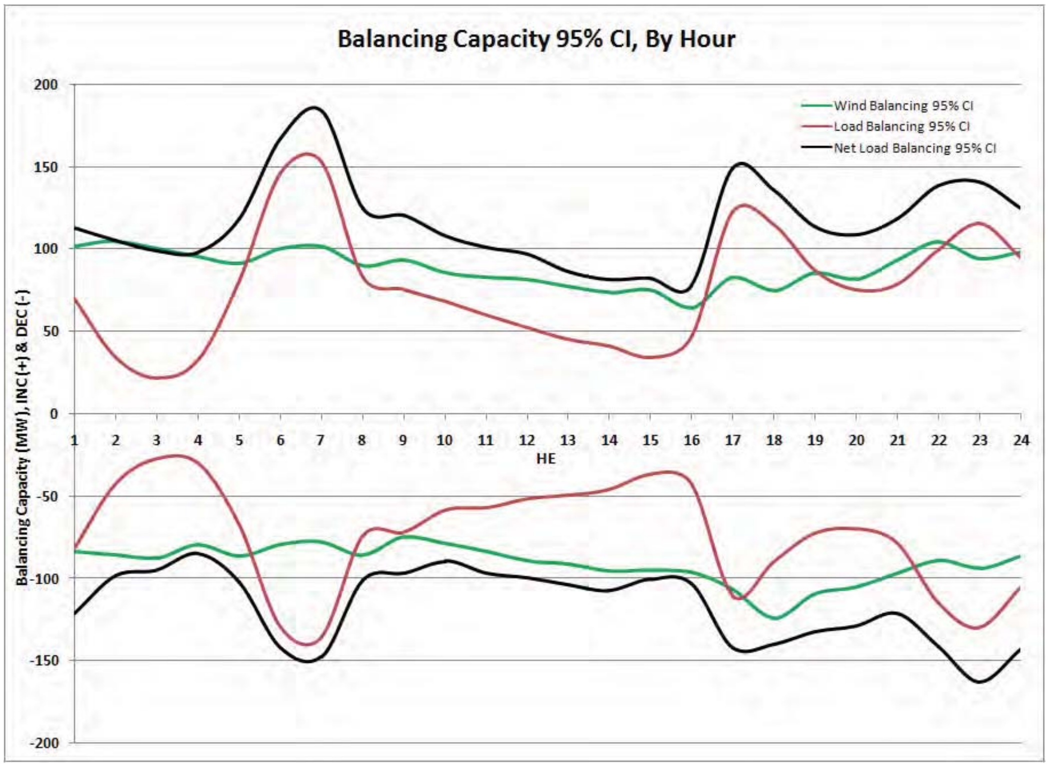
An overall 95% CI can be calculated that covers all time periods, but developing multiple 95% CIs can provide greater insight into balancing capacity needs. PSE develops 24 distinct 95% CIs for the entire day's operation. As Figure G-5 shows, the hourly 95% CI values can vary a great deal through the day for both load and wind resources. For load, large amounts of balancing capacity can be needed to manage strong load ramps to meet the 95% CI during morning and evening peaks.

For PSE wind resources, the 95% CI is more constant throughout the day, with a slight transition to more DEC capacity required in the evening and more INC capacity in the morning hours. The fixed range of potential wind generation, from 0 MW to full capacity, suggests the wind forecast can be a criterion for developing additional 95% CI. Taking the extremes, at a 0 MW wind forecast the only potential forecast error (forecast generation minus actual generation) PSE would need to balance is a negative error (forecast is less than actual generation), which would only require DEC capacity reserves. Conversely, when wind generation is forecast at full output, PSE would only need to manage positive forecast errors where the forecasted generation is greater than actual generation. In this case, INC capacity reserves are required.

APPENDIX G – OPERATIONAL FLEXIBILITY

Figure G-5

Hourly PSE Balancing Capacity at a 95% Confidence Interval



It is important to note that contingency reserves are accounted for separate from balancing reserves. Contingency reserves are dedicated to addressing short-term reliability in the event of forced outages; they cannot be deployed to address hourly system volatility unless a qualifying event occurs, such as a unit tripping off-line.

3. Flexibility Supply and Demand

System flexibility is the capability of PSE resources to manage system volatility over varying time periods, rates of change, and overall magnitude. Flexibility is supplied by PSE generating resources, primarily PSE's share of the Mid-Columbia hydroelectric generating facilities (Mid-C), but also PSE's fleet of simple- and combined-cycle gas-fired units. Flexibility demand is created by the volatility observed in load, generation, and transmission curtailments, and the uncertainty inherent in predicting loads, wind generation, and unexpected events. Load and wind volatility are the two primary drivers of the demand for flexibility on the PSE system. Regional consensus on flexibility metrics is still developing, but PSE has begun to try to quantify the flexibility supply it has available to meet demand.

Flexibility supply

All resources provide some measure of flexibility; however, the ability of a resource to supply flexibility is constrained by unit-specific characteristics including availability, operational or environmental limitations, range, and ramp rate. These characteristics, coupled with economic dispatch generation set points, affect PSE's total supply of system flexibility.

Availability depends on whether the resource is online, the speed with which it can be dispatched if off-line, and whether it is out of service due to planned maintenance or unplanned outage.

In terms of **operational limitations**, the speed with which a resource can transition from off-line to generating and synced to the system is a distinguishing feature of the resources needed to supply flexibility. Resources that take several hours to properly prepare for dispatch, like combined-cycled units, are limited in their availability to respond to short-term system balancing needs.

Resource range refers to the physical and environmental (temperature) constraints that dictate the maximum and minimum levels at which a resource can generate. For any given resource, the difference between this maximum and minimum at any given time is referred to as its operating range. For conventional thermal resources, this range remains fairly constant, but the range for hydro resources changes dramatically during certain times of the year. A portion of PSE's capacity share of the Mid-C is available to meet PSE flexibility needs for most of the year, but during the spring runoff, high stream flows on the Columbia River reduce the available operating range on the Mid-C. At these times, hydro projects must generate at or near full capacity to avoid flowing excess water over spillways to meet water quality requirements. PSE's supply of flexibility is severely reduced at this time of year.

Resource ramp rates describe the speed at which a unit can increase or decrease its generation. The ramp rate determines the ability of a resource to respond to all, some, or none of the system's deviations. Slow ramp rates effectively limit the balancing capacity of a resource during a given time increment. A resource with a large operating range but very slow ramp rate may be insufficient to address sudden changes in load and wind generation, while a resource with a small operating range and faster ramp rate can quickly respond to system needs but may not be able to sustain such a rate for an extended period, so multiple resources may need to respond simultaneously.

Flexibility demand

The demand for flexibility is created primarily by system volatility, the need to manage the scheduled interchange ramp period between hours, and potential system contingencies.

Volatility. Continuous demands for flexibility are placed on the system by volatility – the variability of loads and generating resources that fluctuate from moment-to-moment combined with the uncertainty inherent in forecasting load and wind resources hour by hour.

PSE addresses the demand placed by all system loads and resources simultaneously, rather than responding to each deviation individually. The relationship between load and wind is especially important. Because wind generation serves system load, load and wind scheduling errors in the same direction offset each other. The BA does not need to respond to an increase in load if there is an equal increase in wind generation. Load and wind schedule deviations in opposite directions create greater demands on system balancing resources. On a probabilistic basis, the fact that PSE load and wind may often move in the same direction or at the same rate places a smaller total demand for flexibility on PSE than if each were measured individually and then added together.

APPENDIX G – OPERATIONAL FLEXIBILITY

Scheduled interchange. In addition to managing loads and resources throughout each operating hour, PSE's BA must integrate hourly imports and exports. This is known as a scheduled interchange. Little volatility is associated with scheduled interchanges (they are generally a flat, hourly amount of energy), but the magnitude of scheduled interchanges can vary each hour, often by several hundred megawatts. To accommodate these large changes, resources are ramped in over a 20-minute period beginning 10 minutes prior to the start of the operating hour and ending 10 minutes after. Even with planned ramps, integrating such large changes in power can be demanding, both in the range required of resources and the speed with which they must respond.

System contingencies. Forced outages place significant demands for flexibility on the system because they create an immediate need for large increases in energy to replace the resource lost to the outage. Forced outages occur when a generating unit, transmission line, or other facility becomes unavailable for unforeseen mechanical or reliability reasons.

PSE also faces forced outage-type events as other BAs manage their own system volatility. For example, all wind resources within the BPA BA, of which PSE has 500 MW, are subject to dispatcher instructions meant to address BPA's need for system flexibility at times when its system reserve capacity is exhausted. One notable BPA business practice is Dispatch Standing Order 216 (DSO-216). DSO-216 states that if wind plants are under-generating and BPA is supplying INC balancing reserves, BPA will have the ability to curtail transmission schedules for each plant, relative to the plant's actual generation. A schedule cut within the hour is like a forced outage in that the PSE BA must respond instantaneously to a potentially large loss of energy. In addition to wind schedule cuts, PSE's thermal resources located outside the company's BA can also be cut due to regional transmission congestion and maintenance requirements. Transmission congestion can mean within-hour schedule cuts of several hundreds of megawatts.

Procuring and deploying balancing reserve capacity

The balancing reserves required to manage system operations within every operating hour can be thought of in two phases:

- the procurement of balancing reserve capacity ahead of the operating hour; and
- the deployment of reserves as balancing energy within the hour.

Procuring balancing capacity ideally consists of positioning hydro assets to allow sufficient room to increase generation (INC capacity) or decrease generation (DEC capacity) as needed within the operating hour. Thermal resources (gas and coal) can also be dispatched to provide balancing capacity. It should be noted that procurement of the needed balancing reserve capacity does not always guarantee sufficient flexibility is available to meet actual net load deviations on the system in real time. Meeting the demand for flexibility also requires unit ramp rates that can effectively deploy the capacity procured.

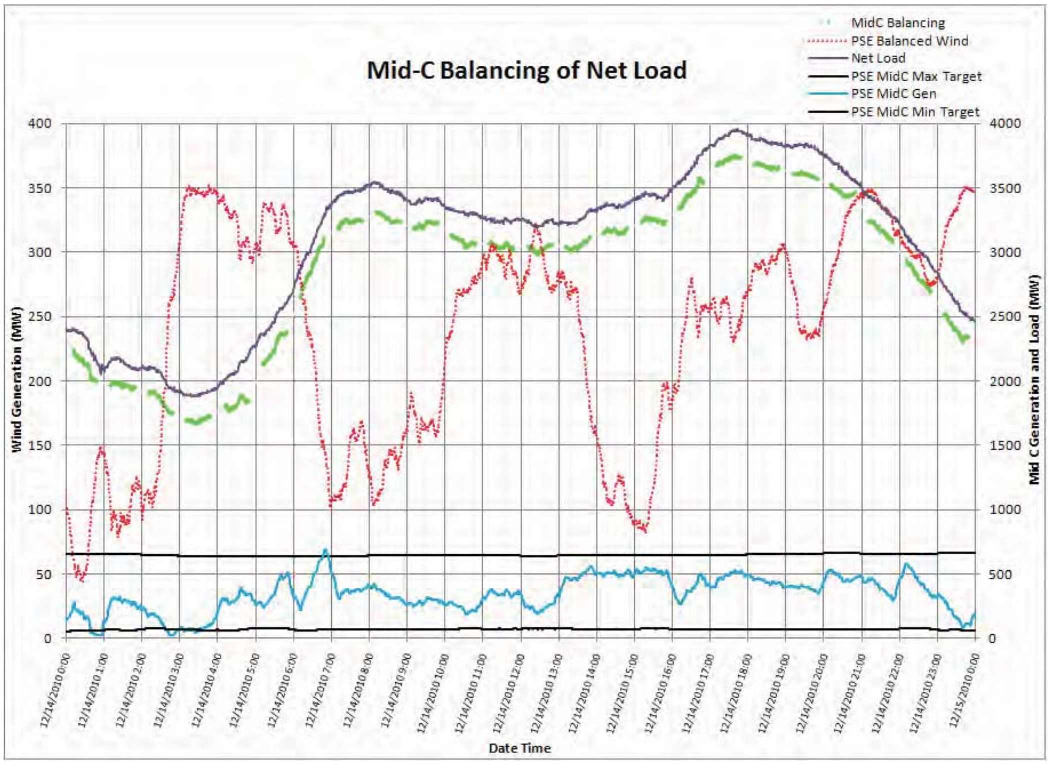
Figure G-6 depicts all aspects considered for balancing capacity and addressing system flexibility. In this 24-hour example, PSE's Mid-C generation is the source of balancing capacity. The moment-to-moment changes in net load (load minus wind generation) are represented by the purple trace. The blue line representing Mid-C generation is bounded by black minimum and maximum generation targets.

The green trace labeled "Mid-C Balancing" represents the slope, or rate of change in Mid-C generation for each hour. It is presented just below the net load trace in order to highlight how the Mid-C generation is changing within the hour relative to the change in net load. The trace shows that during each hour, the Mid-C is responding in unison with changes in net load. The flexibility of the Mid-C is most evident during the 6:00 to 7:00 a.m. period as it manages an extreme load ramp of nearly 500 MW (over 8 MW per minute through the entire hour).

APPENDIX G – OPERATIONAL FLEXIBILITY

Figure G-6

Balancing of Net Load with Mid-C Generation



Note how the Mid-C reacts during the 20-minute schedule interchange period, from 5:50 to 6:10 am and from 6:50 to 7:10 am. During these periods Mid-C generation is being pushed down to accommodate new imports and to provide incremental balancing services for the next hour. In these instances, Mid-C frequently changes generation levels by 500 MWs over a 20-minute period (25MW per minute ramp rate). No other resource in PSE's fleet is capable of this combination of speed and range. This is why Mid-C hydro is such an important flexibility resource in PSE's portfolio.

4. Modeling Methodology

This analysis focuses on whether PSE has enough flexibility supply to meet system demands and ancillary obligations, and how the costs of meeting those demands can be quantified.

The cost of supplying flexibility takes three forms.

- First is reliability. Uncertainty about the levels of generation and load can result in more frequent deployment of contingency reserves or a reduction in PSE's CPS2 score.
- Second is market opportunity cost. Procuring reserves can constrain PSE's operations, because flexibility demands may require PSE to adjust the amount of available PSE-owned dispatchable generation in a manner contrary to market signals.
- Third is the physical wear and tear on units. Ramping up generating units to take advantage of their operational range rather than operating them at their most efficient generating point tends to shorten maintenance timetables. Maintenance costs are difficult to estimate on a pro forma basis, however, and are not included in this analysis. As we collect more cost data related to system flexibility requirements, maintenance costs may become possible to model.

Hour-ahead model methodology

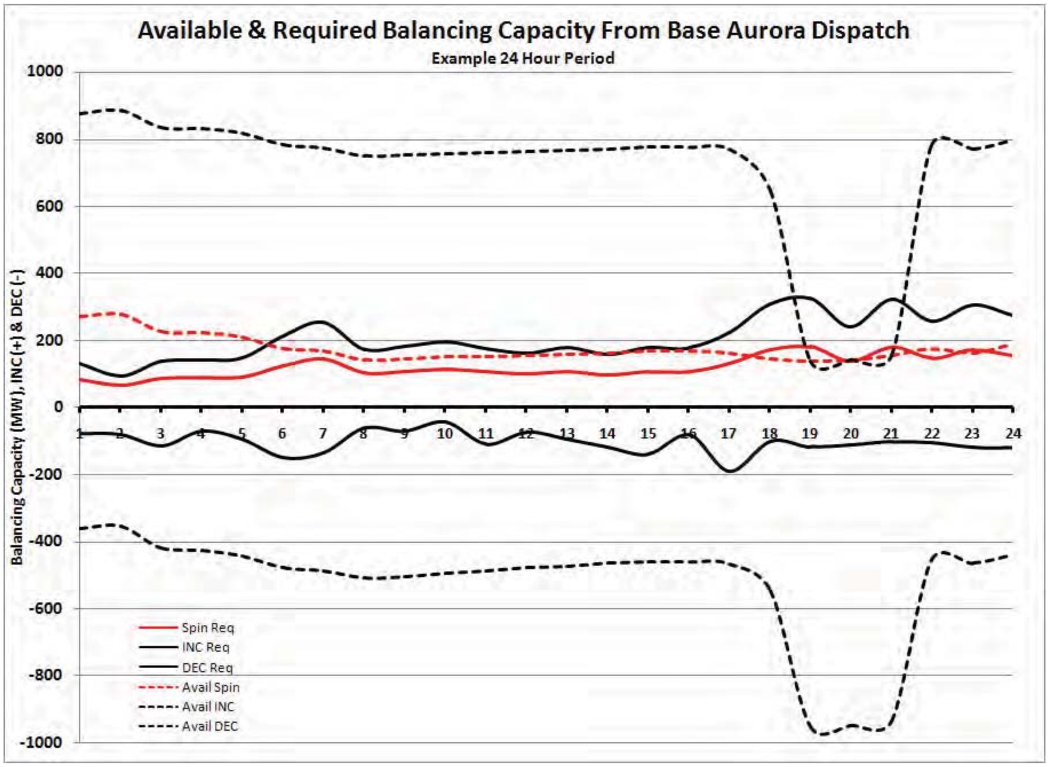
The Aurora® production cost model used in the IRP does not feature the ability to set reserve capacity constraints on the PSE system. As a result, the hourly dispatch of generation produced by Aurora does not necessarily provide adequate balancing capacity each hour to meet the demands experienced by PSE. For this reason, the procurement of hour-ahead reserve capacity is modeled outside of Aurora.

Figure G-7 shows an Aurora dispatch in which there is inadequate spinning capacity during HE18 – HE21 and inadequate INC balancing capacity during HE19 – HE21. Adjustments to the dispatch must be made outside the Aurora model to provide sufficient balancing capacity, because Aurora does not take into account PSE-specific balancing capacity requirements in its optimization.

APPENDIX G – OPERATIONAL FLEXIBILITY

Figure G-7

PSE Balancing Capacity, Based on Aurora Economic Dispatch



Based on historical deviations in load and hourly wind in PSE's balancing authority, a 95% CI of INC and DEC balancing capacity was determined for each hour of the Aurora dispatch, and for the contingency reserve requirement. Setting aside this amount of balancing capacity every hour, PSE would expect to capture 95 percent of deviations in load and wind.

Once balancing reserve capacity requirements were set for each hour, the Aurora economic unit dispatch and price simulations were fed through a mixed-integer linear program in SAS-OR. This model adjusted the dispatch of PSE's Mid-C hydro generation and 13 gas-fired resources to provide the required balancing capacity over a 24-hour period. Net changes to internal PSE dispatch were offset by market transactions to maintain hourly load-resource balance.

Once adjustments were completed, economic costs were tabulated based on the hourly changes to PSE's market position for power and the fuel costs associated with dispatching off-line gas-fired units or re-dispatching those units to less efficient points on their heat-rate curves. Statistics on unit operations can be gathered from the adjusted dispatch. Finally, if the stack of PSE resources was unable to procure balancing capacity to fulfill the 95% CI in any hour, the hour was flagged and the balancing capacity shortfall was recorded.

Intra-hour modeling methodology

To model intra-hour deployment of balancing capacity, the adjusted unit dispatch from the hour-ahead model was converted into 10-minute dispatch increments. Aurora's hourly wind and load values were then treated as hourly schedules, and 10-minute profiles were simulated based on the historical behavior of PSE load and wind resources. The simulated profiles represent deviations from the hourly schedules that require generation to be dispatched to return the system to equilibrium. The hour-ahead resources identified in the previous step were eligible to respond to the net change in load and wind. This also ensured that balancing capacity was held to meet PSE's contingency reserve obligations.

The intra-hour model also uses a mixed-integer linear program in SAS-OR. Redispatch of internal generation was guided by unit economics and operating characteristics. Each unit was constrained by its ramp rate, minimum and maximum generation points, minimum runtime, minimum downtime, and any forced outages modeled by Aurora. The optimization horizon was limited to 3 hours to reflect the limited foresight system operators have when making within-hour unit decisions. The output from the model was a record of unit deployment for PSE's dispatchable generation that quantified how each unit contributes to system balancing, pinpointed periods of stress, and identifies periods when the model could not balance the system.

Modeling assumptions and limitations

Some key assumptions made in these modeling efforts should be noted. These relate to Aurora and the Mid-C data used in the analysis.

Relying on Aurora unit dispatch and price information as inputs to the model allows for continuity between the primary production cost calculation and the subsequent modeling of system balancing, but it also assumes the Aurora dispatch reflects a realistic portrayal of hour-by-hour unit dispatch and system conditions and this is not certain.

The uncertainty arises partly from the Mid-C hydro dispatch profiles used in Aurora, which are based on 70 years of historical hydro generation beginning in 1929. These profiles reflect conditions that prevailed many decades ago, but that may not exist today, or may not accurately mirror the current demands on PSE's system. As discussed previously, hydro dispatch (accessed through Mid-C contracts) is a primary flexibility resource for PSE because it is already synchronized to the system, it has enormous range, it responds instantaneously, and it ramps quickly. Therefore, any inputs that overstate or overly constrain Mid-C availability can have a dramatic impact on the results.

The current models do not make net MWh changes to the Aurora hydro dispatch; generation may be moved between hours but daily, monthly, and annual MWh Mid-C generation is constant between the initial Aurora dispatch and the resulting Mid-C generation profile from the model.

5. Results

For this analysis, a fifty-simulation subset of the 250 Aurora IRP simulations were analyzed, limited to the year 2018. The results are divided into two sections: The first looks at the hour-ahead availability and procurement of balancing capacity, and the second looks at intra-hour deployment of those reserves. The hour-ahead supply of capacity is expressed as the contribution of PSE resources to the total balancing capacity available, while intra-hour demand is input as hourly 95% CI. Once the portfolio is positioned hour-ahead, meeting the system's flexibility demands was simulated with intra-hour load and wind deviations, hourly scheduled interchanges, and forced outages modeled by Aurora.

The analysis first assessed the ability of the lowest reasonable cost portfolio identified in the analysis for the 2013 IRP Base Scenario to balance these deviations. Then, three additional portfolios were analyzed. Each introduced one additional resource to this portfolio: a CCCT resource, a frame CT resource, and a reciprocating engine CT. Basic operational characteristics of the units are identified in Figure G-8. By comparing these three portfolios to the Base Scenario's least-cost portfolio, PSE can assess potential benefits to system reliability and reductions in portfolio balancing costs associated with the added resource.

Figure G-8
Overview of Resource Additions Analyzed

Unit	Capacity (MW)	Min Generation (MW)	Heat Rate (Btu/kW)*	10-Minute Ready
CCCT**	343	189	6,682	No
Frame CT	221	133	10,324	Yes
Recip CT	18	9	8,370	Yes

*Heat rates based on IRP assumptions for 2017
**Duct-firing portion excluded from analysis

Demand for hour-ahead balancing capacity

Figure G-9, below, translates the hourly 95% CI levels (the balancing capacity PSE should carry to manage 95 percent of load and wind deviations) into a monthly average. These values reflect PSE balancing obligations based on the study assumptions for 2018, and they act as input constraints on the PSE system during the modeling phases. Capacity requirements are expressed as monthly amounts of spinning capacity, INC capacity, and DEC capacity required to meet the total 95% CI. Spinning capacity is a specific type of INC capacity for which resources must already be online and synchronized to the system. The remainder of INC requirements can be met with capacity from off-line, 10-minute-ready resources, or spinning capacity in excess of the minimum spin requirement. In Figure G-9, the spinning and INC capacity requirements include the capacity necessary to meet the contingency reserve obligation.

Figure G-9

Average Hourly Balancing Capacity Requirements (MW) for 2018

Month	Avg. Spin Capacity Required	Avg. INC Capacity Required	Avg. DEC Capacity Required
1	112	188	113
2	103	171	104
3	107	178	114
4	100	165	101
5	85	135	100
6	86	137	97
7	93	150	94
8	99	164	101
9	96	158	90
10	103	171	100
11	110	185	115
12	109	183	114

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Supply of hour-ahead balancing capacity

To benchmark the initial state of the PSE system, available balancing capacity from the unaltered Aurora dispatch is tabulated by asset class for the Base Scenario's least-cost portfolio for the year 2018. These values are presented as average hourly amounts of balancing capacity available in Figure G-10. (In reality, however, each individual hour's available balancing capacity can vary widely as market conditions dictate unit dispatch and therefore the actual balancing capacity available.)

Figure G-10
Base Portfolio, Average Hourly Balancing Capacity Available,
Initial Aurora Dispatch (MW)

Month	Mid-C Spin	Mid-C DEC	CT Spin	CT INC	CT DEC	CCCT Spin	CCCT INC	CCCT DEC
1	141	280	0	587	39	10	10	135
2	230	225	0	544	64	6	6	179
3	214	201	0	524	58	5	5	163
4	162	189	0	417	71	3	3	148
5	137	124	0	416	42	5	5	63
6	66	95	0	511	17	10	10	70
7	150	158	0	521	45	16	16	146
8	217	168	0	474	81	17	17	200
9	315	89	0	433	106	7	7	215
10	229	129	0	534	46	11	11	200
11	244	187	0	569	41	16	16	167
12	266	217	0	542	71	7	7	177

At this level of granularity, the Aurora dispatch reflects the importance of the Mid-C hydro contracts by illustrating that for the least-cost portfolio in the Base Scenario, this single resource is sufficient to meet balancing capacity requirements during most of the year. No spinning capacity is provided by the CT fleet (8 units); the Aurora dispatch will commit those resources to their maximum generation. However, when dispatched, the CT resources provide their full operating range as DEC capacity. The CCCT fleet is similar to the CTs. Typically they are dispatched to their maximum generation and rarely provide spinning capacity. At times they may be dispatched to their minimum generation point during brief uneconomic periods of a much longer economic dispatch, at which time they are able to provide some spinning capacity.

APPENDIX G – OPERATIONAL FLEXIBILITY

The reduced availability of balancing capacity from May through July is due to a confluence of system conditions. Hydro runoff conditions can severely limit the availability of balancing capacity of the Mid-C projects as spring stream flows must pass through turbines to avoid violating environmental constraints related to excessive spill. The abundant hydro generation depresses market prices, reducing the economic commitment of gas-fired units. And finally, due to the predictability of these hydro and market conditions, annual maintenance for CT and CCCT resources is typically scheduled during this time to align their outages with periods of unlikely dispatch.

To address any hours where there is insufficient balancing capacity, unit dispatch is adjusted until the capacity requirements are met. In Figure G-11, the average hourly available balancing capacity is presented after hourly adjustments are made to the unit dispatch of the Base Scenario portfolio in 2018.

Figure G-11

Average Hourly Balancing Capacity Available, Adjusted 2018 Base Portfolio (MW)

Month	Mid-C Spin	Mid-C DEC	CT Spin	CT INC	CT DEC	CCCT Spin	CCCT INC	CCCT DEC
1	141	280	26	570	49	16	16	129
2	230	225	8	525	78	6	6	179
3	214	201	10	515	64	4	4	164
4	162	189	17	409	75	9	9	142
5	137	124	25	406	48	3	3	64
6	66	95	43	477	40	17	17	62
7	150	158	14	508	54	19	19	142
8	217	168	8	458	92	14	14	202
9	315	89	0	415	119	8	8	214
10	229	129	0	525	53	11	11	201
11	244	187	1	563	44	8	8	175
12	266	217	1	537	73	7	7	177

APPENDIX G – OPERATIONAL FLEXIBILITY

The static nature of Mid-C availability is due to a pond constraint imposed on the model, and the level at which these values are presented. If the Mid-C generation is increased by 1 MW in a given hour, this results in a 1 MW addition to DEC capacity and a 1 MW decline in available spin capacity. However to maintain pond balance, this extra 1 MW of generation must be offset by a 1 MW decrease in generation in another hour, which will also lead to inverse changes in the available spin and DEC capacity. At an hourly level the available capacity on the Mid-C is changing, yet the arithmetic for the monthly averages does not show this change.

Only small changes in the available capacity on the CCCT fleet are present. Since these resources are not capable of being ready to dispatch in 10 minutes, they are normally called on only when the resource is already online. In actual practice, CT units are frequently called on more often than in the initial Aurora dispatch, especially during the first half of the year, because of the increased availability of their spinning capacity and DEC capacity. In the fall, there is no change in spin capacity, however CT resources are being dispatched at maximum generation more frequently to support DEC capacity needs.

Hourly results from the four portfolios show that PSE has adequate hour-ahead balancing capacity (Figure G-5). Across the 50 simulations, approximately two hours of unmet balancing capacity were expected over the entire study year; this primarily involved DEC capacity shortfalls. The shortfalls do not necessarily indicate a failure to balance the PSE system; rather, they indicate hours when PSE is unable to fully meet the 95% CI set aside of balancing reserves, which may or may not be needed in that hour. However, the contingency reserve portion of the spinning capacity and INC capacity are requirements that PSE must meet every hour. Investigation of the hours with either unmet spin or unmet INC capacity reveals that none of the shortfalls impact our ability to meet contingency reserve obligations.

Figure G-12

Summary Hour-Ahead Balancing Results, 50 Simulations

Portfolio	Avg. Unmet Spin Capacity (Hrs)	Avg. Unmet INC Capacity (Hrs)	Avg. Unmet DEC Capacity (Hrs)	Avg. Unmet Spin Capacity (aMW)	Avg. Unmet INC Capacity (aMW)	Avg. Unmet DEC Capacity (aMW)
2018 Base	0.1	0.3	1.9	0.5	9.1	17.3
2018 Base + CCCT	0.1	0.3	1.7	0.5	9.1	15.7
2018 Base + Frame CT	0.0	0.0	0.2	0.0	0.0	0.0
2018 Base + Recip CT	0.2	0.3	1.2	0.1	8.5	10.5

Intra-hour flexibility adequacy results

Once balancing capacity has been set aside in the hour-ahead time frame, the simulated 10-minute level wind and load deviations were introduced, along with the need to balance hourly shifts in scheduled interchange. Then the portfolios were assessed on their ability to respond.

The modeled deployment of PSE balancing resources revealed that PSE can maintain a high degree of reliability; in all portfolios, the expected proxy CPS2 score is 97 percent, well above the requirement of 90 percent. (This does not include frequency bias.) The score reflects a very aggressive constraint in the model, which is set to balance load and resources exactly every 10 minutes. The times when load and generation are not in balance fall into two categories, unserved energy and excess energy. Unserved energy is when the system load is greater than the amount of energy provided by PSE resources, while excess energy is when resources are over-generating relative to demand. While the model solves to have no imbalances, in actual operations small differences in system demand and net resources are permissible over short periods of time, as reflected in the CPS1 and CPS2 metrics. The magnitude of these violations is usually small. Periods of unserved energy average an imbalance of 6 MW, periods of excess energy average a 12 MW deviation.

PSE must also maintain spinning capacity to meet its contingency reserve obligation. Each portfolio has only a handful of 10-minute periods with insufficient spinning capacity, and during those periods the average capacity shortfall is 2 MW.

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Figure G-13
Summary Results from Flexibility Analysis, 50 Simulations

Portfolio	CPS2 Score Proxy (%)*	Spin Capacity Shortfall (%)	Spin Capacity Shortfall (aMW)	Unserved Energy (aMW)	Excess Energy (aMW)	Expected Annual Balancing Savings ($)	Expected Annual Bal. Savings ($/kW Capacity)
2018 Base	97%	0.1%	2.0	5.9	12.5	--	--
2018 Base + CCCT	97%	0.1%	1.8	5.7	12.2	$800,000	$2.33
2018 Base + Frame CT	97%	0.1%	1.9	5.9	12.1	$1,037,000	$4.69
2018 Base + Recip CT	97%	0.1%	1.8	5.9	12.1	$328,000	$18.23

*NERC CPS2 metric requires a score of 90% or greater

As the Base Scenario portfolio's set of balancing resources are flexible enough to balance the PSE system, the addition of another resource to the portfolio does not have much room to further improve these reliability metrics. However, this result should not diminish the value of these resources to improve system reliability and flexibility. In addition to the flexibility attributes they bring to the portfolios, they also lower the cost of providing and deploying balancing capacity. Adding a new balancing resource to the portfolio may provide a lower-cost means to meet system reliability than previously existed, although further cost analysis is required.

The annual savings in Figure-13 for each resource addition is the expected reduction in annual production costs compared to the Base Scenario portfolio as measured by fuel consumption, market purchases, and sales associated with providing and deploying balancing capacity. As this value only considers production costs, it is worth noting the savings may be larger or smaller when secondary effects are considered, such as changes in maintenance needs or availability factors.

The expected benefit from adding the CCCT resources is $800,000. As the CCCT is not 10-minute ready it can only contribute to balancing capacity and adjust to meet load and wind deviations if it has already been economically dispatched by Aurora. The unit's efficient heat rate sees it dispatched 57 percent of the time in the simulations analyzed, and the unit's large operating range can manage in-hour changes that may otherwise have required multiple units to move. With respect to the two CT resources, the expected annual benefit is $1 million for the frame CT and $328,000 for the reciprocating engine CT. They are dispatched by Aurora less frequently than the CCCT resources, 30 percent of the time for the frame and 32 percent of the time for the reciprocating engine. However, their 10-minute ready status means they can be dispatched as necessary during the hour. On a benefit-per-capacity basis, the reciprocating engine CT represents the highest value at $18.23 per kW, followed by the frame CT at $4.69 per kW, and finally the CCCT at $2.33 per kW.

What distinguishes the two CT units is their relative size. While the frame CT has a large operating range, its minimum generating level is relatively high. Dispatching this unit from an off-line state when there is a small incremental energy need (less than the 133 MW minimum operating level for the unit) may not be beneficial as it could trigger an excess energy situation unless another unit was available to offset it with decremental capacity. On the other hand, the reciprocating engine's smaller nameplate capacity, operating range, and low minimum generation level make it an ideal resource when there is a marginal energy or spinning capacity need.

6. Conclusion and Next Steps

While additional work needs to be done, given the assumptions made for this study, the analysis indicates PSE has sufficient capacity and flexibility in the Base Scenario portfolio to effectively manage its known system flexibility demands in 2018 across both hour-ahead and intra-hour time frames. Comparing three different additions to that portfolio indicates potential production cost savings of $300,000 to $1,000,000 annually, and provides insight into how differing unit characteristics can alter potential balancing benefits.

Perhaps most valuable has been the change in perspective to a more comprehensive view of operational flexibility needs and costs. Efforts to expand on this work are already underway. Further exploration of the maintenance stresses placed on the system by balancing needs, the operational complexity associated with rapid deployment of multiple resources, and the capabilities of different types of resources are primary areas of interest to PSE. The current models use stringent constraints to maintain load-resource balance and will utilize all resources, if necessary. Understanding how increased resource use potentially changes a resource's operational abilities will help us carry out even more rigorous assessments of operational flexibility needs in the future.

Demand Forecasts

Contents

Demand forecasts are an estimate of how much energy customers will use in the future. When demand forecasts are compared with an assessment of the company's existing resources, the gap between the two identifies "resource need."

1. Overview

The F2012 IRP Base Demand Forecast for electric loads shows lower load levels throughout the forecast horizon than the demand forecasts used in the 2011 IRP. This is due to the loss of Jefferson County in 2013, lagging economic, housing, and employment recoveries, and higher short-term unemployment rates.

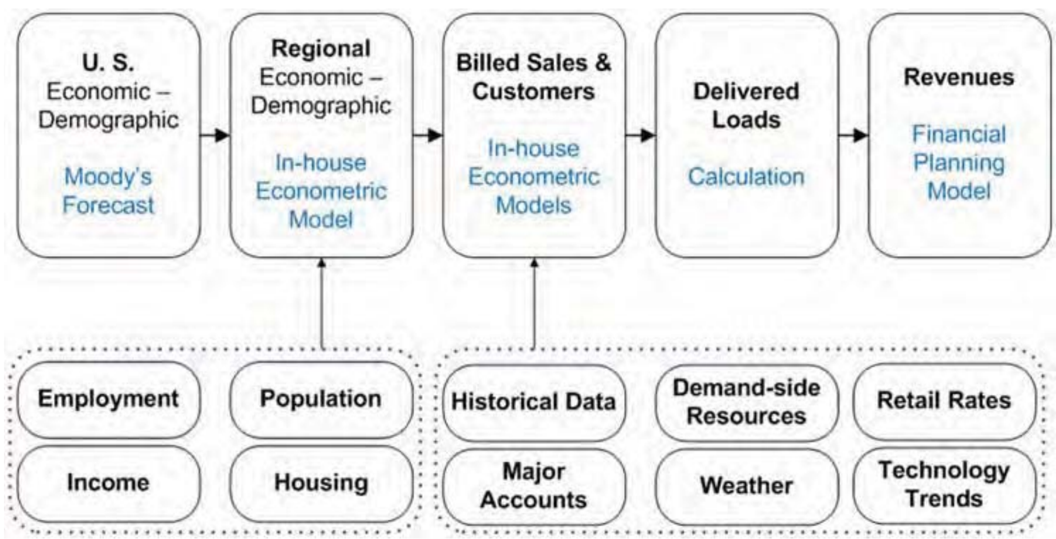
The F2012 Base Demand Forecast for gas also has lower load levels for most of the forecast period than those used in the 2011 IRP, catching up only in the last few years. This is also due to lagging recovery in the single-family housing market and sluggish labor market recovery. Since gas load is primarily heat-based, it is relatively less affected by economic conditions and exhibited slightly greater resilience between forecasts than the electric load.

NOTE: The load forecasts that appear in the IRP often do not match the load forecasts presented in rate cases or during acquisition discussions. There are two reasons for this. First, the IRP analysis takes 12 to 18 months to complete, and load forecasts are so central to the analysis that they are one of the first inputs we need to develop. By the time the IRP is completed, PSE will have updated the load forecast, and the most current forecast will always be used in rate cases or when making acquisitions. Second, the IRP demand forecast does not include an off-set for demand-side resources (since the IRP is used to determine cost-effective levels of these resources), and most other load forecasts published by PSE do include DSR.

2. Methodology

The demand forecast PSE develops for the IRP is an estimate of energy sales, customer counts, and peak demand over a 20-year period. These estimates are designed for use in long-term planning for resources and delivery systems. The 20-year horizon helps us anticipate needs so we can develop timely responses. Updates based on the most current information are used in developing near-term annual revenue forecasts and operational plans.

Figure H-1
PSE Load Forecasting Process: Electric and Gas



Source of Local Data: Washington State Employment Security Department, Bureau of Economic Analysis, Bureau of Labor Statistics, Office of Financial Management (Washington). The Puget Sound Economic Forecaster, Washington State Economic and Revenue Forecast Council

In the forecast models, electricity and gas are assumed as inputs into the production of various economic activities. For residential customers, typical energy uses include space heating, water heating, lighting, cooking, refrigeration, dish washing, laundry washing, televisions, computers, and various other plug loads. Commercial and industrial customers use energy for production processes, space heating, ventilation, and air conditioning (HVAC), lighting, computers, and other office equipment.

To forecast energy sales and customer counts, customers are divided into classes and service levels that use energy for similar purposes and at comparable retail rates. The different classes are modeled separately using variables specific to their usage patterns.

- Electric customer classes include residential, commercial, industrial, streetlights, resale, and transportation.
- Gas customer classes include firm (residential, commercial, industrial, commercial large volume, and industrial large volume), interruptible (commercial and industrial), and transportation (commercial firm, commercial interruptible, industrial firm, and industrial interruptible).

The following section provides a more detailed technical description of the four econometric methodologies used to forecast (a) billed energy sales and customer counts, (b) hourly distribution of electric loads, and (c) system peak loads for electricity and natural gas.

For the 2012 load forecast used in this IRP, the company updated our key forecast driver assumptions and re-estimated the main equations.

APPENDIX H – DEMAND FORECASTS

Electric and gas billed sales and customer counts

PSE estimated the following use-per-customer (UPC) and customer count equations using varied sample dates from within a historical monthly data series from January 1989 to December 2011, depending on sector or class and fuel type. The billed sales forecast is based on the estimated equations, normal weather assumptions, rate forecasts, and forecasts of various economic and demographic inputs.

The UPC and customer count equations are defined as follows:

$$UPC_{c,t} = f(UPC_{c,t(k)}, RR_{c,t(k)}, W_{c,t}, ED_{c,t(k)}, MD_m)$$

$$CC_{c,t} = f(CC_{c,t(k)}, ED_{c,t(k)}, MD_m)$$

$$MD_i = \begin{cases} 1, Month = i \\ 0, Month \neq i \end{cases} \quad i \in \{1,2,\square\ 12\}$$

$$t \in \{1,2,\square\ 12\}$$

$UPC_{c,t}$ = use (billed sales) per customer for class “c”, month “t”

$CC_{c,t}$ = customer counts for class “c”, month “t”

$\_\_{t(k)}$ = the subscript $t(k)$ denotes either a lag of “k” periods from “t” or a polynomial distributed lag form in “k” periods from month “t”

$RR_{c,t(k)}$ = effective real retail rates for class “c”

$W_{c,t}$ = class-appropriate weather variable; cycle-adjusted HDD/CDD using base temperatures of 65, 60, 45, 35 for HDD and 65 and 75 for CDD; cycle-adjusted HDDs/CDDs are created to fit consumption period implied by the class billing cycles

$ED_{c,t(k)}$ = class-appropriate economic and demographic variables; variables include income, household size, population, employment levels or growth, and building permits

MD_i = monthly dummy variable that is 1 when the month is equal to “i”, and zero otherwise for “i” from 1 to 12

APPENDIX H – DEMAND FORECASTS

UPC is forecast at a class level using several explanatory variables including weather, retail rates, monthly effects, and various economic and demographic variables such as income, household size, and employment levels. Some of the variables, such as retail rates and economic variables, are added to the equation in a lagged, or polynomial lagged form to account for both short-term and long-term effects of changes in these variables on energy consumption. Finally, we use a lagged form of the dependent variable in many of the UPC equations. This lagged form could be as simple as a one month lag, or could be a more sophisticated time-series model, such as an ARIMA(p,q) model. This imposes a realistic covariant structure to the forecast equation.

Similar to UPC, PSE forecasts the customer count equations on a class level using several explanatory variables such as household population, total employment, manufacturing employment, or the retail rate. Some of the variables are also implemented in a lagged or polynomial distributed lag form to allow the impact of the variable to vary with time. Many of the customer equations use monthly growth as the dependent variable, rather than totals, to more accurately measure the impact of economic and demographic variables on growth, and to allow the forecast to grow from the last recorded actual value.

We generate customer forecasts by county by estimating an equation relating customer counts by class and county to population or employment levels in that county. Once the customer counts for each county are estimated, adjustments are made proportionally so that the total of all customer counts is scaled to the original service area forecast.

The billed sales forecast for each customer class is the product of the class UPC forecast and the forecasted number of customers in that class, as defined below.

$$Billed\ Sales_{c,t} = UPC_{c,t} \times CC_{c,t}$$

The billed sales and customer forecast is adjusted for discrete additions and subtractions not accounted for in the forecast equations, such as major changes in energy usage by large customers. These adjustments may also include fuel and schedule switching by large customers. Total billed sales in a given month are calculated as the sum of the billed sales across all customer classes:

$$Total\ Billed\ Sales_t = \sum_c Billed\ Sales_{c,t}$$

APPENDIX H – DEMAND FORECASTS

PSE estimates total system delivered loads by distributing monthly billed sales into each billing cycle for the month, then allocating the billing cycle sales into the appropriate calendar months using degree days as weights, and adjusting each delivered sales for losses from transmission and distribution. This approach also enables computation of the unbilled sales each month.

Hourly electric demand profile

Because temporarily storing large amounts of electricity is costly, the minute-by-minute interaction between electricity production and consumption is very important. For this reason, and for purposes of analyzing the effectiveness of different electric generating resources, an hourly profile of PSE electric demand is required.

We use our hourly (8,760 hours) load profile of electric demand for the IRP, for our power cost calculation, and for other AURORA analyses. The estimated hourly distribution is built using statistical models relating actual observed temperatures, recent load data, and the latest customer counts.

Data

PSE developed a representative distribution of hourly temperatures based on data from Jan. 1, 1950 to Dec. 31, 2011. Actual hourly delivered electric loads between Jan. 1, 1994 and Dec. 31, 2011 were used to develop the statistical relationship between temperatures and loads for estimating hourly electric demand based on a representative distribution of hourly temperatures.

Methodology for distribution of hourly temperatures

The above temperature data were sorted and ranked to provide two separate data sets:
For each year, a ranking of hourly temperatures by month, coldest to warmest, over 60 years was used to calculate average monthly temperature. A ranking of the times when these temperatures occurred, by month, coldest to warmest, was averaged to provide an expected time of occurrence. Next PSE found the hours most likely to have the coldest temperatures (based on observed averages of coldest-to-warmest hour times) and matched them with average coldest-to-warmest temperatures by month. Sorting this information into a traditional time series then provided a representative hourly profile of temperature.

APPENDIX H – DEMAND FORECASTS

Methodology for hourly distribution of load

For the time period Jan. 1, 1994 to Dec. 31, 2011, PSE used the statistical hourly regression equation:

$$\hat{L}_h = \vec{\beta}_{1,d} \cdot DD_d + \alpha_1 L_{h-1} + \alpha_2 \left(\frac{L_{h-2} + L_{h-3} + L_{h-4}}{3} \right) + \left(\vec{\alpha}_{3,m} T_h + \vec{\alpha}_{4,m} T_h^2 \right) + \vec{\beta}_{2,d} Hol + \alpha_5 P^{(1)}(h)$$

for h from one to 24 to calculate load shape from the representative hourly temperature profile. This means that a separate equation is estimated for each hour of the day.

$\hat{L}_h =$ Estimated hourly load at hour “h”

L_h = Load at hour “h”

L_{h-k} = Load “k” hours before hour “h”

T_h = Temperature at time “h”

T_h^2 = Squared hourly temperature at time “h”

$P^{(1)}(h)$ = 1st degree polynomial

Hol = NERC holiday dummy variables

All Greek letters again denote coefficient vectors.

Peak load forecasting

Peak load forecasts are developed using econometric equations that relate observed monthly peak loads to weather-sensitive delivered loads for both residential and nonresidential sectors. They account for deviations of actual peak hour temperature from normal peak temperature for the month, day of the week effects, and unique weather events such as a cold snap or an El Nino season.

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Electric peak hour load forecast

Based on the forecast delivered loads, we use hourly regressions to estimate a set of monthly peak loads for the system based on three specific design temperatures: "Normal," "Power Supply Operations" (PSO), and "Extreme." The "Normal" peak is based on the average temperature at the monthly peak during a historical time period, currently 30 years. The winter peaks are set at the highest Normal peak, which is currently the December peak of 23 degrees Fahrenheit. We estimated the PSO peak design temperatures to have a 1-in-20 year probability of occurring. These temperatures were established by examining the minimum temperature of each winter month. A function relating the monthly minimum temperature and the return probability was established. The analysis revealed the following design temperatures: 15 degrees Fahrenheit for January and February, 17 degrees Fahrenheit for November, and 13 degrees Fahrenheit for December. Finally, the "Extreme" peak design temperatures are estimated at 13 degrees Fahrenheit for all winter months.

Weather dependent loads are accounted for by the major peak load forecast explanatory variable, the difference between actual peak hour temperature and the average monthly temperature multiplied by system loads. The equations allow the impact of peak design temperature on peak loads to vary by month. This permits the weather-dependent effects of system delivered loads on peak demand to vary by season. The sample period for this forecast utilized monthly data from January 1991 to December 2011.

In addition to the effect of temperature, the peak load is estimated by accounting for the effects of several other variables. A variable is used to account for the portion of monthly system delivered loads which are non-weather dependent and affect the peak load. The peak forecast also depends on a number of other variables such as a dummy variable accounting for large customer changes, a day of the week variable, and a cold snap variable to account for when the peak day occurs following several cold days. The functional form of the electric peak hour equation is

$$PkMW_t = \alpha_{1,m} S_t + \alpha_{2,m} \chi_1 \cdot \Delta T \cdot S_t + \beta_{1,d} DD_d + \alpha_{3,m} CSnp + \delta_1 \cdot LT_t$$

where:

$$\chi_1 = \begin{cases} 1, & Month \neq 7,8 \\ 0, & Month = 7,8 \end{cases}$$

$$\chi_2 = \begin{cases} 1, & Month = 7,8 \\ 0, & Month \neq 7,8 \end{cases}$$

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$PkMW_t$ = monthly system peak hour load in MW

S_t = system delivered loads in the month in aMW

ΔT = deviation of actual peak hour temperature from monthly normal temperature

DD_d = day of the week dummy

$CSnp$ = 1 if the minimum temperature the day before peak day is less than 32 degrees Fahrenheit

LT_d = late hour of peak dummy

χ_1, χ_2 = dummy variables used to put special emphasis on summer months to reflect growing summer peaks.

To clarify the equation above, when forecasting we allow the coefficients for loads to vary by month to reflect the seasonal pattern of usage. However, in order to conserve space, we have employed vector notation. The Greek letters α_m, β_d, and δ_d are used to denote coefficient vectors; α_m denotes a monthly coefficient vector (12 coefficients) , β_d denotes a coefficient for the day of the week (seven coefficients), and δ_d denotes a coefficient for morning or evening peak. The difference between α_m and α_m is that all values in α_m are constant, whereas α_m can have unique values by month. That is to say, all "January" months will have the same coefficient. There are also two indicator variables that account for air conditioning load, to reflect the growing summer usage caused by increased saturation of air conditioning.

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Gas peak day load forecast

Similar to the electric peaks, the gas peak day is assumed to be a function of weather-sensitive delivered sales, the deviation of actual peak day average temperature from monthly normal average temperature, and other weather events. The following equation used monthly data from October 1993 to June 2011 to represent peak day firm requirements:

$$PkDThm_t = \alpha_{1,m} Fr_t + \alpha_{2,m} \Delta T_g \cdot Fr_t + \alpha_{3,m} EN + \alpha_{4,m} M_t + \alpha_{5,m} Sum + \alpha_{6,m} Csnp$$

where:

$$Win = \begin{cases} 1, & Month = 1,2,11,12 \\ 0, & Month \neq 1,2,11,12 \end{cases}$$

$$Smr = \begin{cases} 1, & Month = 6,7,8,9 \\ 0, & Month \neq 6,7,8,9 \end{cases}$$

$PkDThm_t$ = monthly system gas peak day load in dekatherms

Fr_t = monthly delivered loads by firm customers

ΔT_g = deviation of actual gas peak day average daily temperature from monthly normal temperature

EN = dummy for when El Nino is present during the winter

M_t = dummy variable for month of the year

$CSnp$ = indicator variable for when the peak occurred within a cold snap period lasting more than one day, multiplied by the minimum temperatures for the day

As before, the Greek letters are coefficient vectors as defined in the Electric Peak section above.

This formula uses forecasted billed sales as an explanatory variable, and the estimated model weighs this variable heavily in terms of significance. Therefore, the peak-day equation will follow a similar trend as that of the billed sales forecast with minor deviations based on the impact of other explanatory variables. An advantage of this process is the ability to account for the effects of conservation on peak loads by using billed sales with conservation included as the forecast variable. It also helps estimate the contribution of distinct customer classes to peak loads.

The design peak day used in the gas peak day forecast is a 52 heating degree day (13 degrees Fahrenheit average temperature for the day), based on the costs and benefits of meeting a higher or lower design day temperature. In the 2003 LCP, PSE changed the gas supply peak day planning standard from 55 heating degree days (HDD), which is equivalent to 10 degrees Fahrenheit or a coldest day on record standard, to 51 HDD, which is equivalent to 14 degrees Fahrenheit or a coldest day in 20 years standard. The Washington Utilities and Transportation Commission (WUTC) responded to the 2003 plan with an acceptance letter directing PSE to "analyze" the benefits and costs of this change and to "defend" the new planning standard in the 2005 LCP.

As discussed in Appendix I of the 2005 LCP, PSE completed a detailed, stochastic cost-benefit analysis that considered both the value customers place on reliability of service and the incremental costs of the resources necessary to provide that reliability at various temperatures. This analysis determined that it would be appropriate to increase our planning standard from 51 HDD (14 degrees Fahrenheit) to 52 HDD (13 degrees Fahrenheit). PSE's gas planning standard relies on the value our natural gas customers attribute to reliability and covers 98 percent of historical peak events. As such, it is unique to our customer base, our service territory, and the chosen form of energy. Thus, we use projected delivered loads by class and this design temperature to estimate gas peak day load.

3. Key Assumptions

Economic activity has a significant effect on energy demand. During this 2-year planning cycle, it has been particularly challenging to develop assumptions about national and regional economic trends due to continued uncertainty throughout the period. While the economy continued to slowly recover through this period, "false starts" in 2010 and 2011, as well as downside risks from the "fiscal cliff," European recession, and Asian slowdown in 2012 had a dampening effect on confidence and growth.

Economic growth

Because the Puget Sound region is a major commercial and manufacturing center with strong links to the national and state economies, the performance of these economies has a direct affect on the industries in our service territory and the businesses that support them. For this reason, PSE's service area forecast begins with assumptions about what is happening in the broader U.S. economy. PSE relies on Moody's Analytics U.S. Macroeconomic Forecast, a long-term forecast of the U.S. economy, for this information. Ultimately, PSE forecasts economic and demographic conditions for each county in the service territory using a system of econometric equations that relates national to regional economic conditions.

National economic outlook

For the purpose of creating the baseline load forecast used in this IRP, PSE used the February 2012 Moody's Analytics U.S. Macroeconomic Forecast. Moody's pushed out its expectations for recovery and predicted that it would gain strong ground only by 2014, when real GDP was expected to be rising at nearly 4 percent and unemployment would finally be below 7% and on a sustainable path downward. At the time Moody's expected the Federal Reserve to begin tightening monetary policy in late 2013 and normalize it by 2015 with inflation near its target level.

Risks to this economic forecast were the deepening of the European financial crisis with adverse impacts on U.S. exports; spending cuts and expiration of the payroll tax holiday and unemployment insurance benefits; corrosion of purchasing power due to elevated oil prices with further increases possible due to tensions in the Middle East; and an uncertain housing market recovery due to shadow inventory; and spending cuts by both state and local governments. Some of these risks have abated since this forecast was created. The housing recovery has gained traction, the fiscal cliff has been avoided in the short term, and Middle East issues have not precipitated an oil price crisis. However, fiscal challenges in the near- and long-term future remain. Europe's financial problems are still not over and a potential breakup of the European Union is still a downside risk, and U.S. – Iran tensions have the potential to create upward pressure on oil prices in the future.

Globally, the dollar was expected to strengthen against the euro and yen in the near term, and to depreciate against the yuan but not without resistance from China. In the long term, the dollar was expected to depreciate only slightly due to the lack of better investment alternatives.

Regional economic outlook

PSE's regional economic and demographic forecast is prepared internally using econometric models whose primary input is a macroeconomic forecast of the United States and historical economic data of counties in PSE's service area. Although the Puget Sound region has its own economic and demographic characteristics, it is part of a national and global economy and its pattern of growth is highly correlated with that of the rest of the nation. As mentioned above, the baseline analysis in the current IRP is drawn from a regional economic forecast derived using the February 2012 Moody's Analytics U.S. Macroeconomic Forecast, with other regional sources providing input and context where appropriate. The assumptions from this regional forecast were used to create the forecast scenario identified as the 2013 IRP Base Demand Forecast.

According to PSE's regional forecast model base case, the projected employment in the electric service territory is expected to grow at an annual rate of 1.4 percent between 2012 and 2033, compared to the prior 20-year historical rate of 1.1 percent. The main factor contributing to the slightly faster long-term growth in employment is recovery from the effects of the latest recession that is built into the forecast sample. Overall long-term regional growth is driven by existence of a diversified group of employers such as Microsoft, REI, Boeing, Starbucks and the like, but is moderated by expectations that the Boeing Company's strong historical employment growth will not necessarily persist into the future. While manufacturing employment showed a greater than expected improvement in the short run due to the strong performance of the aerospace industry, it is expected on average to decline annually by 0.4 percent between 2012 and 2033 in this scenario due to increases in productivity through capital investment in this sector. The base case forecast projects that local employers will create more than 596,000 jobs between 2012 and 2033 and that an

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inflow of more than 1 million new residents will increase the population of PSE's electric service territory to almost 4.8 million by 2033.

Multiple alternate scenarios were developed for the analysis, six based on business cycle variations ("Cyclical" Alternate Lows and Highs) and two based on population growth variations ("Structural" Alternate Low and High). The "Structural" Alternate Low is also referred to as the 2013 IRP Low Demand Forecast. Similarly, the "Structural" Alternate High is also known as the 2013 IRP High Demand Forecast.

The "Cyclical" Alternate Low and High scenarios were developed using varied assumptions provided by Moody's Analytics. "Cyclical" is used as a descriptor in this case because Moody's alternative scenarios are based in large part on assumptions about near-term business cycles in the national economy. To derive the Cyclical Low 1 assumptions, PSE calculated the ratio between Moody's baseline and pessimistic outlooks for each major national economic variable (such as total U.S. employment). These ratios were then used to scale down the equivalent regional variable (such as regional employment). Then these sets of revised variables were used to calculate the Cyclical Low 1 load forecast scenario. A similar approach was taken to calculate the Cyclical High 1 load forecast scenarios, with a ratio calculated between Moody's optimistic and baseline projections for each economic variable. The other scenarios, all of which followed the same development structure, include Cyclical Low 2, Cyclical Low 3, Cyclical Low 4, and Cyclical Low 5, and are essentially variations on the base case that consider delayed economic recovery in some form.

"Structural" Alternate Low and High scenarios were developed using variations on long-term population growth provided by the Washington state Office of Financial Management (OFM). "Structural" is used in this case as a descriptor to indicate that the scenarios are based on alternative assumptions of long-term regional population growth, rather than business cycles. The methodology used to derive these scenarios was to calculate the high and low to base population ratios for the OFM data; the ratios were then used to scale PSE's long-term forecast of population derived from the in-house economic-demographic models.
Other economic variables such as total employment, unemployment rate, etc., were also appropriately scaled, maintaining their relative relationship to the population in the base case. The final set of variables related to both the high and low population estimates were then used to calculate the Structural Low load forecast and the Structural High load forecast.

Energy prices

Retail energy prices – what customers pay for energy – are included as explanatory variables in the demand forecast models because they affect the efficiency level of newly acquired appliances, their frequency and level of use, and the type of energy source used to power them. The energy price forecasts draw on information obtained from internal and external sources.

Electricity

PSE projects that between 2012 and 2033, nominal retail electric rates will experience on average a compounded annual growth rate of 3.2 percent with a range of 0.4 to 4.4 percent in the forecast period. In the near term, the retail price forecast assumes rate increases resulting from PSE's General Rate Cases and from Power Cost Only Rate Cases. For long-term retail rates, each usage class's annual retail rate growth is estimated using sources such as EIA's Annual Energy Outlook, NWPPC's Power Plan and Seattle's consumer price index based on PSE's regional economic and demographic forecast. In addition, Puget Sound Energy recognizes that forecasting from within a business cycle has inherent risks, and that the prevailing trend, whether growth or decline, should be moderated in the long-run portion of the forecast. This can be accomplished by understanding which aspects of the load forecast parameters are most anomalous and modifying those aspects appropriately for the long-run forecast.

Natural gas

PSE expects the rise in nominal retail gas rates to be slightly higher than the long-term rate of inflation, approximately 2.4 percent per year over the next 20 years. Two components make up gas retail rates: the cost of gas and the cost of distribution, known as the distribution margin. The near-term forecast of gas rates includes PSE's purchased gas adjustment and General Rate Case considerations. Forecasted gas costs reflect Kiodex gas prices for the 2012-2016 period and inflation projections beyond that. The distribution margin is based on PSE's projection for the near term and inflation projections for the longer term.

Other assumptions

Weather

The billed sales forecast is based on normal weather, defined as the average monthly weather using a historical time period of 30 years, ending in 2011.

Loss factors

Based on updated analysis, the electric loss factor was adjusted from 6.8 to 6.9, while the gas loss factor remains at 0.8 percent.

Major accounts

The 2013 IRP Base Forecast took into account major load additions and declines beyond typical economic change, using information from account executives covering major customers. The overall impact was approximately 5-10 aMW over the next 10 years.

4. Electric and Gas Demand Forecasts

Demand forecasts starting in 2012 serve as the basis for establishing resource need in this IRP. The charts and tables included here incorporate demand-side resources implemented through December 2013 (primarily energy efficiency), but do not include anticipated additional demand-side resources thereafter. PSE analyzed the scenarios described below in order to capture a range of possible economic futures.

2013 IRP Base Demand Forecast. This scenario assumes that the U.S. economy grows over time at an average annual real GDP growth rate of 2.3 percent from 2012 to 2033, with no major shocks or disruptions. It projects employment in the electric service territory to grow at an annual rate of 1.4 percent, and manufacturing employment growth to decline by an annual rate of 0.4 percent. With a faster rate of growth than the 15-year historical rate of 0.8 percent, it projects that local employers will create more than 596,000 jobs between 2012 and 2033, and that the inflow of more than 1,050,000 new residents will increase the population of our service territory to almost 4.8 million.

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2013 IRP Low Demand Forecast. This scenario assumes lower long-term population growth and determines the subsequent effect on customer growth and other parameters. Final population in 2033 is approximately 9 percent lower than the 2013 IRP Base Demand Forecast, leading to substantially reduced levels of employment and total personal income.

2013 IRP High Demand Forecast. This scenario assumes higher long-term population growth and determines the subsequent effect on customer growth and other parameters. Final population in 2033 is just over 10 percent higher than the 2013 IRP Base Demand Forecast, leading to substantially increased levels of employment and total personal income.

Figure H-2

Forecast of Electric Service Area Household Growth Rates

Forecast of Electric Service Area Household Growth Rates							
Scenario	2014	2015	2016	2017	2018	2019	2020
2013 IRP Base Demand Forecast	1.3%	1.2%	1.1%	1.2%	1.4%	1.4%	1.4%
2013 IRP High Demand Forecast	2.6%	2.9%	2.0%	1.4%	1.9%	1.8%	1.9%
2013 IRP Low Demand Forecast	1.1%	-0.7%	0.4%	1.2%	0.6%	1.1%	1.0%

Figure H-3

Forecast of Electric Service Area Unemployment rates

Forecast of Electric Service Area Unemployment Rates							
Scenario	2014	2015	2016	2017	2018	2019	2020
2013 IRP Base Demand Forecast	6.2%	5.3%	4.7%	4.6%	4.5%	4.4%	4.2%
2013 IRP High Demand Forecast	6.0%	5.1%	4.5%	4.3%	4.3%	4.1%	4.0%
2013 IRP Low Demand Forecast	6.5%	5.5%	5.0%	4.8%	4.7%	4.6%	4.5%

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Electric forecasts

Figures H-4 and H-5 show electric load and peak growth forecasts for all three scenarios over the first 10 years of the planning horizon. Highlights with reference to the 2013 IRP Base Demand Forecast are discussed on the following pages.

Figure H-4
Electric Load Growth for Three Scenarios
Load (MWh), Gross of Losses, Net of Station Service, 2012-2013 DSR Only

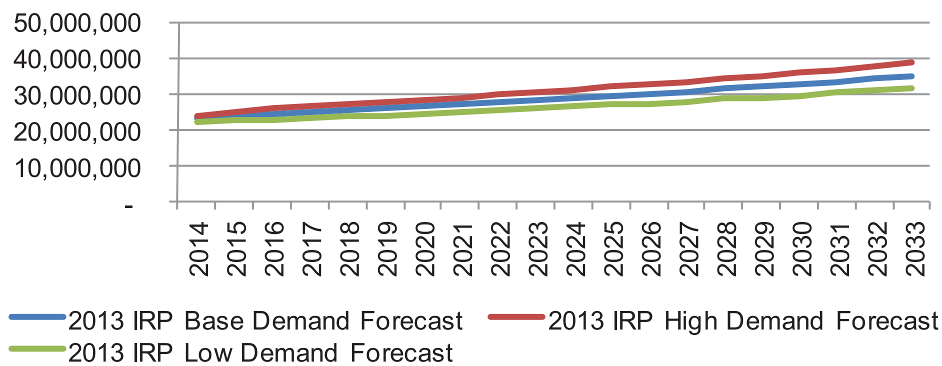
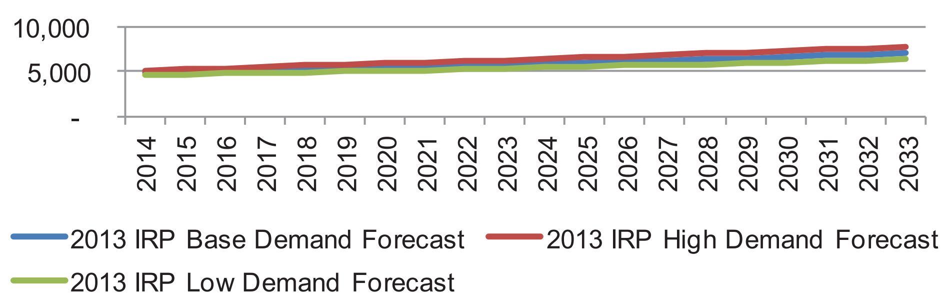


Figure H-5
Electric Peak Load Growth for Three Scenarios
Hourly Annual Peak (23 Degrees, MWh), Gross of Losses, Net of Station Service, 2012 -2013 DSR Only



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Electric forecast highlights – 2013 IRP Base Demand Forecast

1. System. Average electric firm loads are expected to grow at an average annual rate of 2 percent per year, from 2,437 aMW in 2012 to 3,719 aMW by 2033.

The average annual growth rate is projected to be approximately 1.7 percent between 2012 and 2016 due to reduced near-term economic growth with higher short-term unemployment rates and a lagging housing recovery. The long-term growth rate of sales returns to slightly above 2 percent per year for the remainder of the period, 2017-2033.

2. Residential. Residential load as a percentage of firm load is expected to decline from 51 percent in 2012 to 46 percent in 2033.

Slower growth in residential loads is caused by several factors: a projected increase in the rate of construction of multifamily housing, which uses less energy per customer compared to single-family housing; the use of more efficient appliances; and the expectation that new single-family homes are likely to use gas for space and water heating. These factors are expected to combine to create a relatively flat average residential use per customer during the forecast period. In terms of customer growth, the residential sector is expected to see a lower percentage growth compared to the commercial sector. However, the absolute number of customer additions would still be the largest in the residential sector in the forecast period. Multi-family residential housing units, which have a lower number of persons per household than single-family units, are expected to be constructed at a higher rate in the future. Since multi-family units tend to have a lower average number of persons per household, this leads to a customer growth rate that is higher than the population growth rate.

3. Commercial and industrial. Commercial loads are expected to increase as a percentage of firm load from 43 percent in 2012 to 50 percent in 2033. This is partly due to the shifts in residential energy use described above, but it is also due to the way the commercial sector tends to adopt of energy efficient technologies early. Most conservation is captured in early years, leaving less savings available for capture in later years, so the load grows. The commercial sector is expected to experience the strongest average customer growth among major customer classes in the forecast period, however, in absolute terms, it will add fewer customers than the residential sector. Industrial loads are forecasted to

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decline as a percentage of firm load from 6 percent in 2012 to 3 percent in 2033, in line with expectations for declining average customer growth of about 0.4 percent in the period.

4. Peak. Peak hourly loads for electric are expected to grow by 1.9 percent per year between 2012 to 2033 to 7,113 MW from 4,837 MW, nearly keeping pace with the growth in billed energy.

Peak load growth in this forecast tracks closer to energy load growth than it did in the 2011 IRP due to a change in methodology. The 2011 IRP forecast used percentages of customer classes to model peak growth, while this IRP forecast uses the total load. This resulted in patterns of overall energy load growth being closer to peak load growth.

In general, the 2013 IRP Base Forecast of energy load is lower than the 2011 IRP forecast by about 349 aMW by 2033. This is because the 2012 forecast begins with a lower starting point due to the impacts of the recession.

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The following tables summarize electric demand forecast results.

Figure H-6

Electric Load Forecast Scenarios

Load (aMW)								
Scenario	2014	2015	2016	2017	2023	2028	2033	AARG
2013 IRP Base Demand Forecast	2,644	2,718	2,796	2,849	3,210	3,587	3,995	2.2%
2013 IRP High Demand Forecast	2,734	2,856	2,955	3,023	3,468	3,920	4,409	2.5%
2013 IRP Low Demand Forecast	2,554	2,571	2,628	2,671	2,955	3,264	3,592	1.8%

Figure H-7

Electric Load by Class, 2013 IRP Base Demand Forecast

Load (aMW) by class from 2013 IRP Base Demand Forecast								
	2014	2015	2016	2017	2023	2028	2033	AARG
Total	2,644	2,718	2,796	2,849	3,210	3,587	3,995	2.2%
Residential	1,228	1,263	1,299	1,321	1,469	1,605	1,726	1.8%
Commercial	1,078	1,112	1,150	1,180	1,376	1,593	1,855	2.9%
Industrial	144	144	142	140	130	126	121	-0.9%
Other	12	12	12	12	14	15	17	2.0%
Losses	182	188	193	197	221	247	276	2.2%

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Figure H-8

Electric Average Annual Customers by Class, 2013 IRP Base Demand Forecast

Average Annual Customers by Class from 2013 IRP Base Demand Forecast								
	2014	2015	2016	2017	2023	2028	2033	AARG
Total	1,102,073	1,123,497	1,145,710	1,167,667	1,295,135	1,404,168	1,515,902	1.7%
Residential	974,424	993,636	1,013,383	1,032,760	1,143,994	1,237,431	1,331,928	1.7%
Commercial	120,498	122,619	124,989	127,453	142,872	157,705	174,059	2.0%
Industrial	3,518	3,507	3,496	3,484	3,401	3,329	3,257	-0.4%
Other	3,633	3,734	3,842	3,971	4,868	5,703	6,658	3.2%

Figure H-9

Annual Electric Peak (MW), 2013 IRP Base Demand Forecast

Annual Electric Peak (MW) from 2013 IRP Base Demand Forecast								
	2014	2015	2016	2017	2023	2028	2033	AARG
Normal	4,922	5,039	5,150	5,244	5,846	6,439	7,113	2.0%
Extreme	5,419	5,549	5,672	5,776	6,444	7,102	7,849	2.0%

Figure H-10

Electric Use per Customer, 2013 IRP Base Demand Forecast

Use Per Customer (MWh) from 2013 IRP Base Demand Forecast								
	2014	2015	2016	2017	2023	2028	2033	AARG
Residential	11.040	11.134	11.229	11.201	11.247	11.362	11.349	0.1%
Commercial	78.342	79.427	80.595	81.081	84.365	88.498	93.353	0.9%
Industrial	358.604	359.182	355.486	351.575	334.014	330.669	326.514	-0.5%

Gas forecasts

Figures H-11 and H-12 map the gas forecasts for all three scenarios to show load and peak day forecasts, excluding demand-side resources, for the first 10 years of the planning horizon. Highlights are discussed on the following pages.

Figure H-11
Annual Gas Load Forecast Scenarios, 2010-2019
Load (Therms), Gross of Losses, 2012-2013 DSR Only

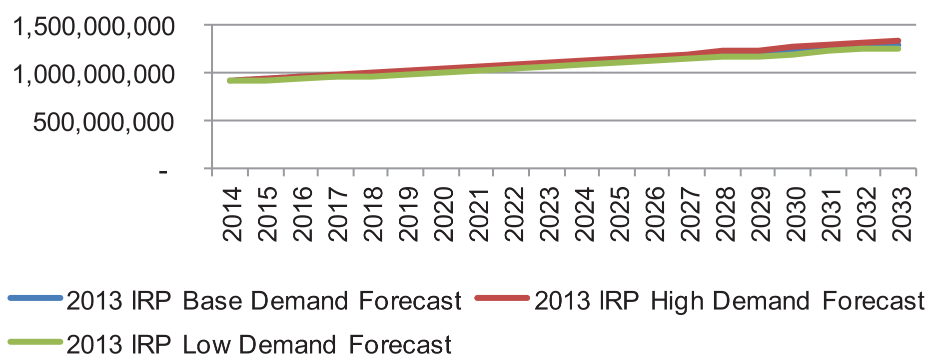
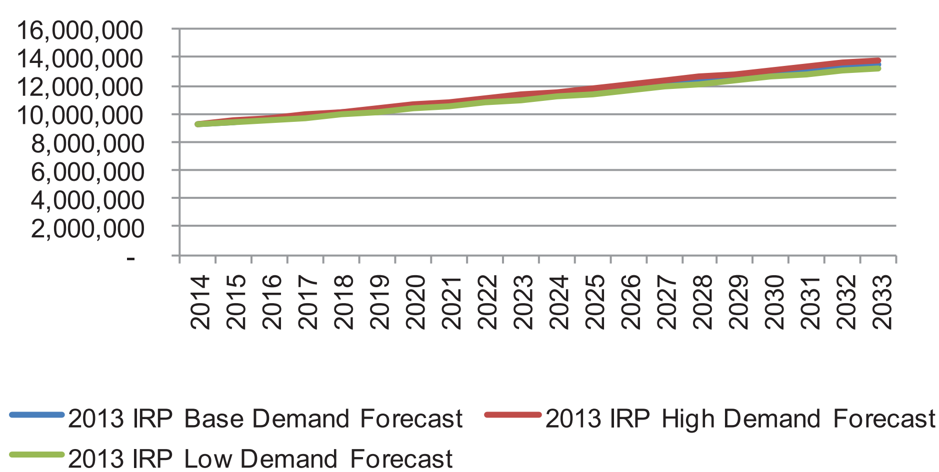


Figure H-12
Firm Gas Peak-Day Forecast Scenarios 2010-2019
Daily Annual Peak (13 Degrees, Therms), Gross of Losses, 2012-2013 DSR Only



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Gas forecast highlights – 2013 IRP Base Demand Forecast

1. System. Natural gas load is expected to grow at an average rate of 1.4 percent per year between 2012 and 2033, from 1.1 billion therms in 2012 to just under 1.5 billion therms in 2033.

For 2012-2016, we expect a slightly lower growth rate in gas load of 1.3 percent due to lower household formation stemming from high unemployment and a weak housing market in the near term; recovery begins to pick up pace starting 2016. Given persistently lower natural gas prices which translate into lower gas retail rates in the forecast period, along with normalized economic conditions, load is expected to grow at a long-term rate of 2.3 percent per year.

While overall sales volume will increase over the long term, some sectors (industrial, interruptible, and transportation) are expected to decline slightly, continuing more than a decade-long trend of slowing manufacturing employment. The gas customer count is expected to increase at a rate of 2.2 percent per year between 2012 and 2033, reaching approximately 1.2 million by the end of the forecast period.

2. Residential. Residential accounts are expected to increase at a rate of approximately 2.2 percent per year from 2012 to 2033, and to represent 93.3 percent of our total customer base in 2033, up 0.8 percent from 92.6 percent in 2012.

In the residential class, a slight decline in use per customer caused by more efficient equipment, a projected increase in multi-family housing and energy efficiency is expected to be offset by a steady increase in the number of customers due to population growth and conversion from electric to gas.

While the number of potential conversion customers is expected to decline, this is expected to be partially offset by increasing penetration of gas into multi-family buildings (townhomes and condominiums) and new single-family homes.

3. Commercial and industrial. Commercial sector accounts are expected to grow at an average annual rate of approximately 1.8 percent per year during the next two decades, and to account for roughly 6.5 percent of the overall customer base in 2033. Similar to the electric side, industrial gas customers also decline over the forecast period on account of a declining manufacturing base. Over approximately a 20-year period, the industrial load's share of the system load declines form 0.3 percent to 0.2 percent.

4. Peak. Peak day firm gas requirements are expected to increase at an average rate of 1.9 percent per year over approximately the next 20 years, from 8.9 million therms in 2012 to 13.5 million therms in 2033.

Gas peak-day growth rates are slightly higher than those for total load because faster growth is predicted for the weather-sensitive residential and commercial sectors. The primary drivers of peak growth across all sectors are an expanding customer base and changes in use per customer. Rising base-loads are contributing to peak demand because gas is increasingly being used for purposes other than heating (such as cooking, clothes drying, and fireplaces). This effect is slightly offset by higher appliance and home efficiencies, and by the increasing use of gas in multi-family housing, where per-customer use is lower.

Compared to the gas peak day forecast from the 2011 IRP, this forecast is lower during the 20-year forecast. A reduced customer growth forecast, as well as a slightly lower use per customer due to weaker economic conditions resulted in a lower residential billed sales forecast, which is the primary driver of the peak-day forecast.

The following tables summarize gas demand forecast results.

Figure H-13

Gas Load without Transport

Load (1,000 Therms), without Transport								
Scenario	2014	2015	2016	2017	2023	2028	2033	AARG
2013 IRP Base Demand Forecast	917,389	932,182	952,010	965,135	1,080,673	1,191,601	1,290,187	1.8%
2013 IRP High Demand Forecast	924,845	944,627	966,838	981,529	1,105,637	1,223,056	1,326,689	1.9%
2013 IRP Low Demand Forecast	910,019	920,668	938,743	950,448	1,058,047	1,162,713	1,255,926	1.7%

APPENDIX H – DEMAND FORECASTS

Figure H-14

Gas Customers by Class, 2013 IRP Base Demand Forecast

Load (1,000 Therms) by Class from 2013 IRP Base Demand Forecast								
	2014	2015	2016	2017	2023	2028	2033	AARG
Total	1,159,749	1,173,254	1,192,823	1,204,464	1,313,113	1,418,811	1,510,884	1.4%
Residential	563,388	574,100	588,485	598,716	682,779	759,150	835,260	2.1%
Commercial	258,670	263,151	269,046	273,097	307,981	344,073	370,634	1.9%
Industrial	29,248	28,902	28,588	28,022	25,794	24,198	20,153	-1.9%
Interruptible	58,743	58,571	58,275	57,579	55,474	54,648	53,819	-0.5%
Transport	240,421	239,143	238,887	237,415	230,580	225,392	218,932	-0.5%
Losses	9,278	9,386	9,543	9,636	10,505	11,350	12,087	1.4%

Figure H-15

Average Annual Gas Customers by Class, 2013 IRP Base Demand Forecast

Average Annual Gas Customers by Class from 2013 IRP Base Demand Forecast								
	2014	2015	2016	2017	2023	2028	2033	AARG
Total	786,664	802,457	820,369	839,644	968,499	1,083,751	1,206,349	2.3%
Residential	728,257	743,186	760,156	778479.0068	901041.3326	1010157.819	1125945.399	2.3%
Commercial	55494.42474	56388.09293	57359.46489	58340.11168	64786.20821	71034.72225	77947.7624	1.8%
Industrial	2378.567337	2360.247851	2341.990724	2323.901217	2218.166903	2133.686582	2052.2899	-0.8%
Interruptible	331.8497874	319.7952523	308.6304672	298.344579	250.218944	222.1483774	200.9786862	-2.6%
Transport	203	203	203	203	203	203	203	0.0%

Figure H-16

Gas Use per Customer, 2013 IRP Base Demand Forecast

Use Per Customer (Therms) from 2013 IRP Base Demand Forecast								
	2014	2015	2016	2017	2023	2028	2033	AARG
Residential	774	772	774	769	758	752	742	-0.2%
Commercial	4,661	4,667	4,691	4,681	4,754	4,844	4,755	0.1%
Industrial	12,296	12,245	12,207	12,058	11,629	11,341	9,820	-1.2%

Pacific Northwest Power Supply Adequacy Assessment for 2017

Final Report

November 21, 2012

Council document 2012-12

Executive Summary

In 2010, as a part of its Sixth Power Plan, the Northwest Power and Conservation Council reported that the region's power supply was on the cusp of becoming inadequate by 2015. Based on an assessment prepared by the Resource Adequacy Forum, the plan noted that relying only on existing resources and targeted energy efficiency savings would result in a 5 percent likelihood of a shortfall, which is right at the limit the Council adopted in 2008. This result is consistent with the plan's finding that energy efficiency could meet most but not all forecasted load growth.

In this updated assessment, the forum concludes that the likelihood of a shortfall in 2017 has increased to 6.6 percent. This means that the region will have to acquire additional resources in order to maintain an adequate power supply, a finding that supports acquisition actions currently being taken by regional utilities.

Between 2015 and 2017, regional electricity demands, net of planned energy efficiency savings, are expected to grow by about 300 average megawatts. Since the last assessment, 114 megawatts of new thermal capacity, about 1,200 megawatts of new wind capacity and about 250 megawatts of small hydro and hydro upgrades have been added to the analysis. Also, a Northwest utility has contracted to purchase 380 megawatts of capacity from an independent power producer, which shifts this in-region generation from the market supply to firm resource status. Meanwhile, availability of the winter California market is assumed to decrease from 3,200 to 1,700 megawatts, mainly due to the retirement of coastal water-cooled thermal power plants.

The majority of potential future problems are short-term capacity shortfalls. The most critical months are January and February and, to a lesser extent, August. This is a different result from the 2015 assessment, which indicated that August was the most critical month. The major reason for this shift is the use of an updated streamflow record, which contains 10 more years of historical flows, new irrigation withdrawal amounts and various updates to reservoir operations both in the U.S. and Canada. The net result yields a higher average streamflow in August, thus improving summer adequacy.

The forum analyzed two different approaches to lowering the likelihood of a shortfall in 2017 back down to the 5 percent limit. Results show that adding 350 megawatts of additional dispatchable generation capacity or lowering the 2017 annual load by 300 average megawatts would bring the likelihood of a shortfall back down to the 5 percent limit. Demand response may also be a viable option but was not analyzed.

It should be noted that this assessment is not a substitute for a comprehensive resource acquisition plan. The optimal amount and mix of new resources needed to provide an adequate, efficient, economic and reliable regional power system is determined by the Council's power plan. This assessment also does not fully reflect constraints and needs of individual utilities within the region. Thus, these results should be viewed as a conservatively lower bound on regional needs for new resource capacity.

The Resource Adequacy Standard and What it Means

In 2008, the Northwest Power and Conservation Council adopted a regional power supply adequacy standard to "provide an early warning should resource development fail to keep pace with demand growth." The standard, developed by the Northwest Resource Adequacy Forum, deems the power supply to be inadequate should the likelihood of curtailment five years in the future be higher than 5 percent. The forum uses probabilistic analysis to assess that likelihood, most often referred to as the loss of load probability.

The assessment only counts existing resources and those expected to be operational. It also includes targeted energy efficiency savings from the Council's Sixth Power Plan. When the likelihood of curtailment exceeds the 5 percent limit, a separate analysis is made to quantify the minimum amount of new generation capacity or load reduction needed to bring the loss of load probability back down to 5 percent.

2017 Resource Adequacy Assessment

The last official adequacy assessment was adopted as part of the Sixth power plan. That assessment indicated the region's power supply for 2015 was on the cusp of becoming inadequate -- the implied loss of load probability was 5 percent.

Between 2015 and 2017, the region's electricity loads, net of planned energy efficiency savings, are expected to grow by about 300 average megawatts or about a 0.7 percent annual rate. Since the last assessment, 114 megawatts of new thermal capacity and about 1,200 megawatts of new wind capacity have been added along with about 250 megawatts of small hydro and hydro upgrades. The recent acquisition of 380 megawatts of a regional independent power resource has been included and the in-region market supply has correspondingly decreased.

California is expected to retire a substantial amount of its coastal water-cooled thermal power plants. It is also uncertain whether two units at the San Onofre Nuclear Generating Station will be operational in 2017. As a result, the forum reduced its assumption for the availability of California winter on-peak market supply from 3,200 to 1,700 megawatts.

Taking all of these changes into account, the expected loss of load probability for the 2017 power supply is 6.6 percent, indicating an inadequate supply if no additional resources are acquired. Types of potential problems the region could face range from energy shortfalls that could last for several days to peak curtailments that last several hours. Results show that the majority of simulated shortfalls are four hours or less in duration and over 40 percent are two hours or less.

To minimize cost and risk, new resource additions should be tailored to specifically address the expected types of shortfalls, that is, peak-hour shortages. This suggests that capacity resources such as simple-cycle combustion turbines or demand response programs or winter-peaking energy efficiency measures should be considered. It should be noted again, however, that the scope of this assessment is only to provide a gauge of the relative adequacy of the power supply. The determination of the quantity and mix of new resource capacity needed make the power supply adequate is left to more comprehensive integrated resource planning processes.

With that being said, the forum analyzed two different approaches to lowering the likelihood of a shortfall in 2017 back down to the 5 percent limit. First it examined how much additional dispatchable generating capacity would be needed to reduce the likelihood to 5 percent and secondly, it examined how much of an annual load reduction would accomplish the same objective. The results show that adding 350 megawatts of new dispatchable generation capacity would lower the 6.6 percent likelihood down to 5 percent. The same level of adequacy can be achieved by lowering the 2017 annual load by 300 average megawatts. Demand response is another alternative but the forum did not examine how much would be needed.

The findings for 2017 are consistent with assessments made by regional utilities indicating a need for new resources. It is also consistent with the plan, which concluded that energy efficiency alone will not be sufficient to offset all future load growth. In aggregate, utility planned resources far exceed the 350 megawatt gap.

In the analysis for 2017, the most critical months are January and February and, to a lesser extent, August. This is a different result from the last official assessment, which indicated that August was the most critical month. The major reason for this shift is the use of an updated streamflow record. The new record contains;

- 80 years of historical streamflow data (the old record had 70 years)
- New irrigation withdrawal amounts
- More current Canadian system operation (both for treaty and non-treaty storage)
- Updated operating requirements at Grand Coulee
- More accurate representation of the operation of Snake River Basin dams
- Other miscellaneous adjustments at various hydroelectric projects

These changes, in aggregate, result in an overall shift in streamflows across the months of the year. In particular, the average August streamflow is expected to increase by about 10,000 cubic feet per second, which translates into about 650 megawatts of additional power for the regional system.

Dependence on the Market

The methodology used to assess the adequacy of the Northwest power supply assumes a certain amount of reliance on market power supplies, both from within the region and from California. A significant part of the Northwest market is made up of independent power producer resources. The full capability of these resources, about 3,450 megawatts, is assumed to be available for Northwest use during winter months. However, during summer months, due to competition with

California utilities, the Northwest market availability for Northwest use is limited to 1,000 megawatts.

The California market is broken into on-peak and off-peak availabilities. The off-peak availability is assumed to be 3,000 megawatts year round. Energy from the off-peak market is purchased during light-load hours prior to periods of potential shortfalls and is often referred to as a purchase-ahead resource. The on-peak availability is assumed to be 1,700 megawatts during winter and not available at all during summer.

Northwest utilities routinely rely on market resources to maintain an adequate power supply. The amount of market resources used depends on a number of conditions, with the biggest factors being stream flow levels, outages of utility-owned resources, and temperature-driven load variations. For 2017, assuming only existing resources and targeted energy efficiency, the analysis shows the region would purchase an average of 1,170 megawatt-months of market supplied energy in December representing about 18 percent of the total available energy (6,450 megawatts-months). In August the region is would purchase an average of 400 megawatt-months of market supplied energy or approximately 10 percent of the total available energy (4,000 megawatts-months).

However, averages can be misleading and a more important statistic is how much market supplied energy is needed during extreme events when the regional load-resource balance tightens. Ten percent of the time, market purchases would exceed 2,200 megawatt-months in December (34 percent of the total) and 820 megawatt-months in August (21 percent of the total). The full amount of market supplied energy would be needed in less than 1 percent of all hours.

Uncertainties

The forum's analytical tools account for uncertainties in stream flows, wind generation, temperature-driven demand variations, and generating resource availability. However, there are additional uncertainties that are not explicitly modeled. Two of the more significant uncertainties are economic load growth and the availability of the California energy market. The expected 6.6 percent loss of load probability assumes the Council's medium load forecast and 1,700 megawatts of expected California on-peak winter market supply.

To investigate the potential impacts of different combinations of economic load growth and California market availability, scenario analyses were performed. In the worst case, with high load growth and no California market, the loss of load probability would be 16.8 percent. The good news is that this scenario is very unlikely. In the best case, with low load growth and 3,200 megawatts of California market, the loss of load probability drops to 2.8 percent, well within the Council's limit.

While the current assessment provides the best estimate for the probability of a power supply shortage, the loss of load probability could be larger or smaller depending on load and market conditions in 2017. And, because the uncertainty surrounding these particular variables is not well defined, it is difficult to develop a range of likely loss of load probability values. What is clear is that there is a relatively high chance that the region will need some level of new resource development by 2017 in order to maintain an adequate supply.

Future Assessments

The Resource Adequacy Forum will continue to annually assess the adequacy of the power supply. However, this task is becoming more difficult because the power supply has become more complex in recent years. The increase in variable generation resources, combined with changing patterns for electricity demand, is forcing utility planners and operators to more carefully assess what resources are needed in reserve to ensure that demand can be met minute to minute. The current adequacy assessment incorporates a certain amount of minute-to-minute reserves, but it is not certain that they will be sufficient. Regional planners are evaluating various methods to quantify and plan for these flexibility needs.

Another emerging concern is the lack of access for some utilities to market supplies due to insufficient transmission or other factors. For the current adequacy assessment, the Northwest region is split into two subsections and only the major East-West transmission lines are modeled. Similarly, only the major Canadian-US and Northwest-Southwest interties are modeled. It may be necessary to divide the Northwest region into more subsections to better address the effects of transmission congestion on power supply adequacy.

Resource adequacy continues to be a concern in the Northwest. The forum's results are consistent with regional utility integrated resource planning, which supports the need for additional capacity. The Council and forum will continue to improve methods used to assess the power supply adequacy.

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Northwest Power and Conservation Council

January 8, 2013

MEMORANDUM

TO: Power Committee

FROM: John Fazio, Senior Systems Analyst

SUBJECT: Briefing on Resource Adequacy after Coal Plant Retirements

At the November Council meeting, during the discussion of power supply adequacy, staff was asked to assess the adequacy of the regional supply after the expected retirements of Boardman and Centralia Unit 1 coal plants in 2020. The combined generating capacity of those two plants is about 1,330 megawatts.

In 2021, assuming anticipated load growth, 6th Plan energy efficiency savings, and sited and licensed new resources, the loss of load probability (LOLP) is 15.3 percent without Boardman and Centralia 1 and 8.3 percent with those plants remaining in service. The Council's adequacy standard limits the LOLP to a maximum of 5 percent - meaning that in both cases, the 2021 supply would be inadequate without additional actions.

For the coal retirement case, it would take about 2,000 megawatts of additional dispatchable resource capacity to bring the 15.3 percent LOLP down to the 5 percent limit. This amount is approximately 1,300 megawatts more than would be required if the coal units are not retired.

For comparison, recall that the recent adequacy assessment for 2017 indicated that the LOLP for that year is expected to be 6.6 percent and that it would take about 350 megawatts of additional capacity to make the system adequate.

While these results are the most likely, it should be noted that they are subject to change, either up or down, depending on how the future unfolds.

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Staff has identified over 3,000 megawatts of planned resources that were not counted in the analysis but could be developed by 2021 if the need arises. These planned resources were not counted because they have not yet been sited and licensed.

Announced Coal Unit Retirements: Effect on Regional Resource Adequacy

Boardman

Centralia

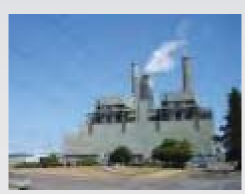
Power Committee Meeting
January 15, 2013
Portland, Oregon

1

Assignment

At the October Council meeting, Member Rockefeller asked:

'How will the announced closure of coal units at Boardman and Centralia in 2020 affect regional resource adequacy?'



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Analysis Performed

1. Assessed regional resource adequacy in 2021 after Boardman and Centralia 1 are closed
2. Estimated how much additional dispatchable resource capacity is needed to make the regional power system adequate[1]

[1]The Council's adequacy standard sets a maximum limit of 5 percent for the power supply's loss of load probability.

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Summary of Results for 2021

1. Adequacy: **15.3% LOLP**
2. Needed Resource[1]: **2,000 megawatts**

[1]Additional dispatchable resource capacity needed to bring the LOLP down to 5%

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Step-by-Step Analysis

1. Assess adequacy (LOLP) for 2021
   - Use forecasted loads, net of 6th plan energy efficiency
   - Add resources expected to be operational by 2021
   - Add additional resources (wind) to meet state RPS
2. Remove Boardman and Centralia 1 and reassess LOLP for 2021
3. Add sufficient additional dispatchable resource capacity to bring LOLP down to 5%

Northwest Power and Conservation Council

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Summary of Projected Changes From 2013 to 2021

Changes that Increase Need	Notes
Load Growth	1,210 MWa[1] net of EE (0.6% growth rate)
Boardman Retires	510 MWa[2] (601 MW nameplate)
Centralia 1 Retires	620 MWa[2] (730 MW nameplate)

[1]EE savings from 2013 to 2021 are targeted to be 2,900 MW.
[2]Assuming an 85% availability factor for coal-fired plants.

Northwest Power and Conservation Council

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Summary of Projected Changes From 2013 to 2021

Changes that Reduce Need	Notes
Hydro Upgrades	350 MWa
Thermal Resources	115 MWa[1] (124 MW nameplate)
RPS Resources	1,200 MWa (4,000 MW nameplate)

[1]Assuming a 92% availability factor for gas-fired turbines.

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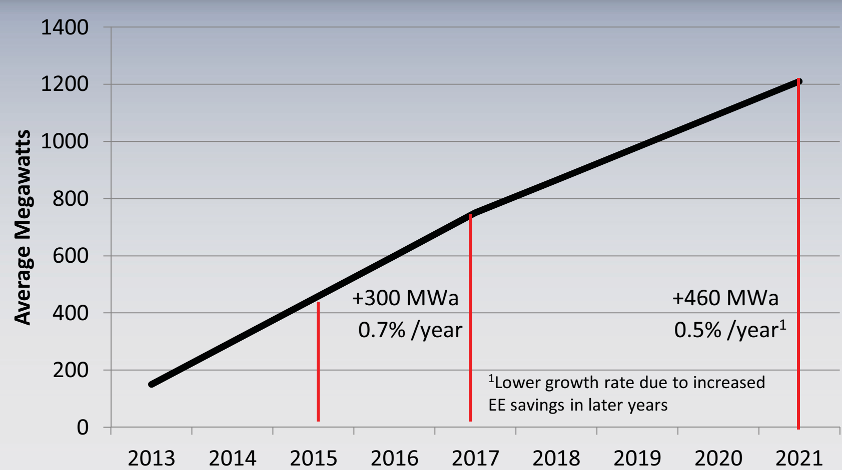
Load Growth Net of Energy Efficiency Savings



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1/8/2013

Sixth Plan Target Efficiency Levels

Year	Incremental Savings (MWa)	Cumulative Savings from 2010 (MWa)	Cumulative Savings from 2013 (MWa)
2010	200	200	
2011	220	420	
2012	240	660	
2013	260	920	260
2014	280	1,200[1]	540
2015	300		840
2016	320		1,160
2017	340		1,500
2018	350[2]		1,850
2019	350		2,200
2020	350		2,550
2021	350		2,900

[1]Council's target for 2014 is 1,200 MWa.
[2]EE savings past 2017 are limited by assumed ramp rates.

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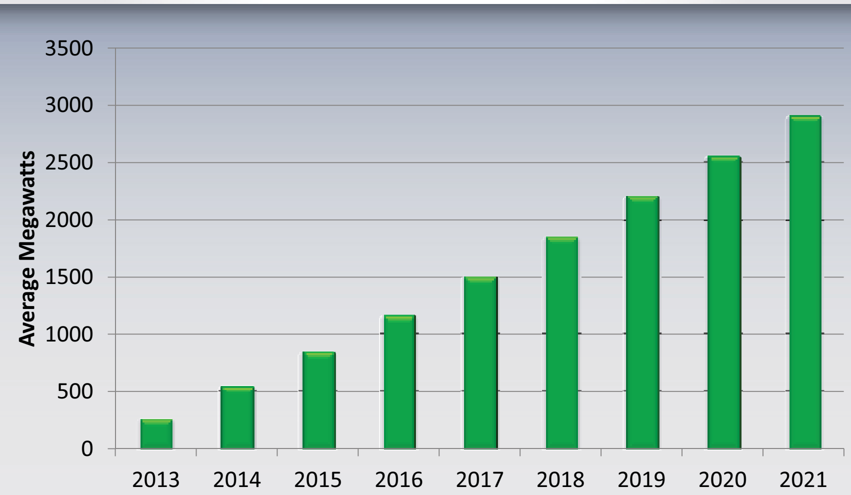
Energy Efficiency (cumulative)



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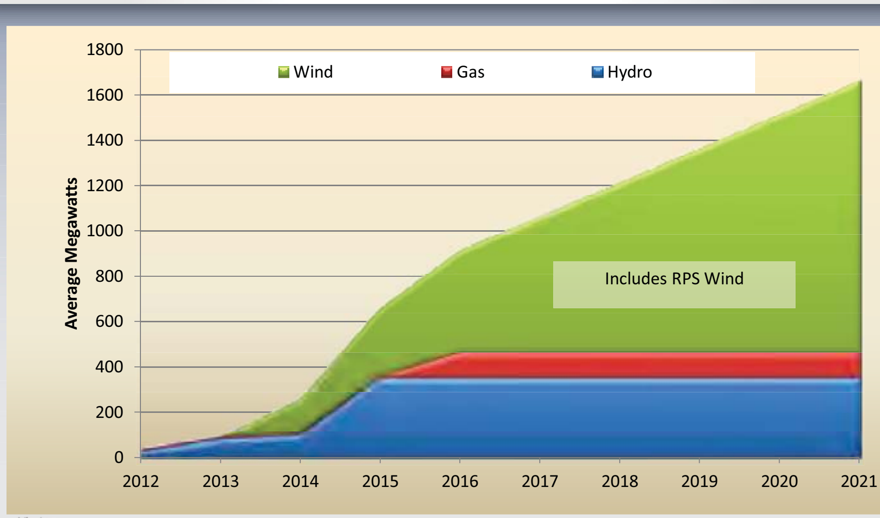
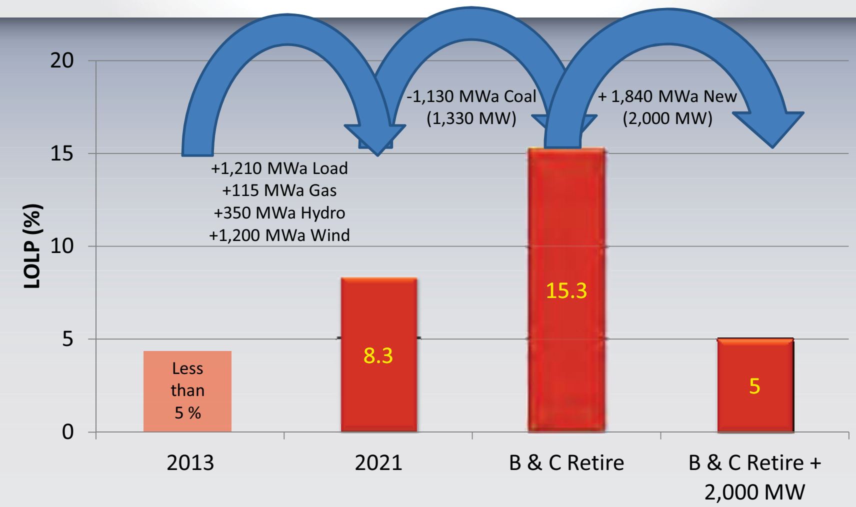
Generating Resource Additions (Cumulative)



Results

Step	Description	LOLP
0	2017 LOLP	6.6%
1	2021 LOLP with Boardman and Centralia	8.3%
2	2021 Without Boardman and Centralia	15.3%
3	2021 Without Boardman and Centralia With 2,000 MW new dispatchable capacity	5.0%

Loss of Load Probability



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Resource Classification

- Existing: Included
- Under construction: Included
- Sited and licensed: Included
- RPS resources:
  - This analysis Included
  - Forum Assessment Not included
- Planned: Not included

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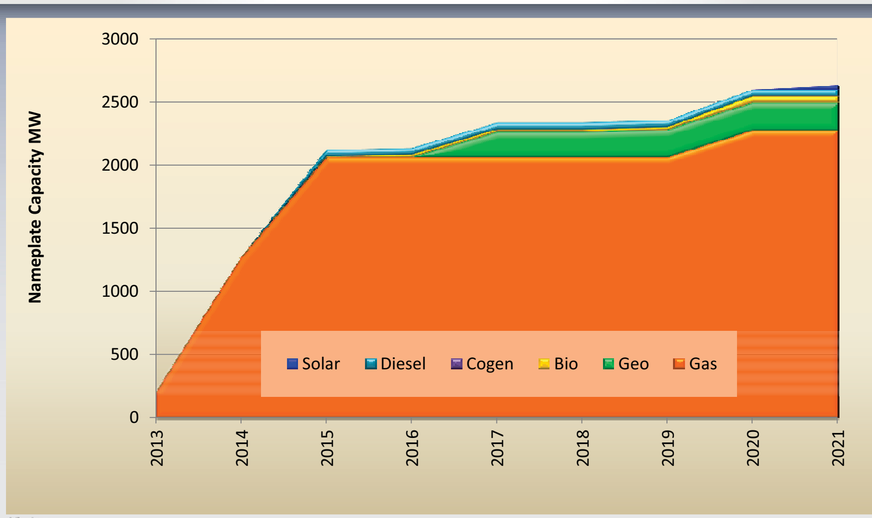
1/8/2013

Planned Generating Resources (Cumulative)



Source: PNUCC

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APPENDIX J

Colstrip

Contents

This appendix describes the Colstrip generating plant, its ownership structure, governance agreements, and the history of the site. It explains plant operations and describes the measures the plant employs to minimize environmental impacts. Finally, it summarizes the rules and regulations that may impact the plant's future operation, and describes four environmental compliance cost cases PSE developed to test the economic viability of the resource under varying regulatory conditions.[1]

1. Facility Description

The Colstrip generating plant supplies PSE customers with reliable, low-cost electric power. It also contributes diversity to the electric resource portfolio. Currently the facility supplies 18 to 20 percent of the baseload energy that serves PSE demand. Among U.S. coal-fired generators, Colstrip is a relatively new plant. It operates more cleanly and efficiently than older plants. It also operates "ahead" of compliance in many respects, because it began service with modern environmental controls and has continuously invested in upgrading them.

[1] *Potential future CO_2 regulation is incorporated in the overall scenarios for the IRP since it impacts all thermal resources. Since Colstrip is included among these, CO_2 is not treated separately here.*

APPENDIX J – COLSTRIP

The plant consists of four coal-fired steam electric plant units located in eastern Montana about 120 miles southeast of Billings. It was built in two phases.

- Units 1 & 2 began operation in 1975 and 1976, respectively. Each produces up to 307 MW net. PSE and PPL Montana each own a 50 percent undivided interest in both units.
- Units 3 & 4 began operation in 1984 and 1986, respectively. Each produces up to 740 MW net. Six companies participate in the ownership of Units 3 & 4. PSE owns 25 percent each of Units 3 & 4, Portland General Electric owns 20 percent of both units, Avista owns 15 percent of both units and PacifiCorp owns 10 percent of both. PPL Montana owns 30 percent of Unit 3 and NorthWestern Energy owns 30 percent of Unit 4.

Figure J-1 summarizes ownership of the Colstrip plant.

Figure J-1
Colstrip Ownership Share by Unit and Owner

		Unit 1	Unit 2	Unit 3	Unit 4	Ownership Total, MW	% of Total Plant
Puget Sound Energy	% MW	50% 153.5	50% 153.5	25% 185	25% 185	677	32.3%
PPL Montana-Plant Operator		50% 153.5	50% 153.5	30% 222		529	25.3%
North Western Energy					30% 222	222	10.6%
Portland GE				20% 148	20% 148	296	14.1%
Avista				15% 111	15% 111	222	10.6%
PacifiCorp				10% 74	10% 74	148	7.1%
Total		307	307	740	740	2094	100.0%

APPENDIX J – COLSTRIP

The Colstrip Transmission System was built at the same time as Units 3 & 4. This double circuit, 500 kV transmission line runs from the plant to an interconnection with the Bonneville Power Administration (BPA) in Townsend, Montana. It is owned by the five regulated utility owners of the power plant: PSE, Northwestern Energy, Portland GE, Avista, and PacifiCorp.

Governance

Colstrip owners are governed by two ownership agreements, the Units 1 & 2 Construction and Ownership Agreement executed in 1971, and the Colstrip Units 3 & 4 Ownership and Operations Agreement executed in 1981. There is a separate Operating Agreement for Units 1 & 2.

Each agreement establishes an Owners Committee to guide operating decisions, and the agreements set forth several key conditions.

- Ownership is as “tenants in common,” without a right of partition, and the obligations of each owner are several and not joint.
- Assignment and ownership transfer to third parties is limited, with a right of first refusal for an existing owner to acquire any ownership offered for sale.
- The term of the agreements continues for as long as the units are used and useful or to the end of the period permitted by law.
- Each owner must provide enough fuel to operate its share of the units at minimum load.
- Failing to pay its share of project costs or failing to provide adequate fuel constitutes a default on the part of the owner.
- An owner must continue to pay its share of operating costs and coal costs until it has transferred its ownership to another entity.
- The ownership contracts do not establish a “put” right for any owner.

The Operating and Ownership Agreement for Units 3 & 4 specifies a voting structure to be used by the Owners Committee for approving annual budgets and other operating decisions. Both ownership agreements provide that the Owners Committee may not amend the agreement. A separate agreement governs ownership and operation of the Colstrip Transmission System.

Requirements after operations cease

Potential plant remediation obligations

The Ownership Agreements for both Units 1 & 2 and Units 3 & 4 are silent about a definite date for shut-down of the units. They address decommissioning or remediation costs only to the extent that costs remaining after equipment salvage are to be distributed based on ownership share. Currently there are no plans or cost estimates for decommissioning of the facility.

Potential mine reclamation and obligations

Mining permits held by Western Energy Company (WECo), the coal supplier, require development of reclamation plans and cost estimates for all areas disturbed by mining, and WECo has provided surety bonds to the State of Montana to ensure that reclamation will occur. Plant owners reimburse WECo for the cost of mine reclamation, including final reclamation work after coal deliveries cease, as part of the current costs paid for each ton of coal supplied.

Wastewater remediation

In August 2012, PPL-Montana and the Montana Department of Environmental Quality (MDEQ) signed an Administrative Order of Consent Regarding Impacts of Wastewater Facilities (AOC). The AOC sets up a comprehensive program for investigation, interim response, remediation and closure of the holding ponds and any related impacts to area groundwater. The AOC provides for preparation of a Site Report for identified areas of the plant site where spills or wastewater leakage have occurred. The Site Report will include a description of investigations performed to date, results of modeling, details of pond construction and recommendations for additional characterization. After the Site Report is complete, a Site Characterization Work Plan, a Cleanup Criteria and Risk Assessment, a Remedy Evaluation Report, and, if required, a Final Remediation Action Report and a Facility Closure Plan will be completed and approved by the MDEQ. The AOC provides for public notice and comment on each report, and response by MDEQ to substantive comments. Initial Proposed Facility Closure Plans shall be prepared and submitted by July 2017, and updated at least every five years, sooner if major changes or modifications are made to the facility. Most of the remediation work to be identified will be completed during facility operations before the facility ceases operation. The facility closure plans will cover all waste water facilities identified in the AOC, but may not include plans and costs for removal of power production equipment and structures.

The history of Colstrip

The Northern Pacific Railway established the town of Colstrip in 1924 at the northern end of the Powder River Basin to provide coal for its steam locomotives. The Powder River Basin is the single largest source of coal in the United States and is one of the largest deposits of coal in the world. At Colstrip, coal is mined from the Rosebud seam of the Fort Union Formation. The railroad shut down the mine in 1958 when it switched to diesel locomotives, and the Montana Power Company purchased the rights to the mine and the town in 1959. They resumed mining operations in the 1970s with plans to build coal-fired electrical plants.

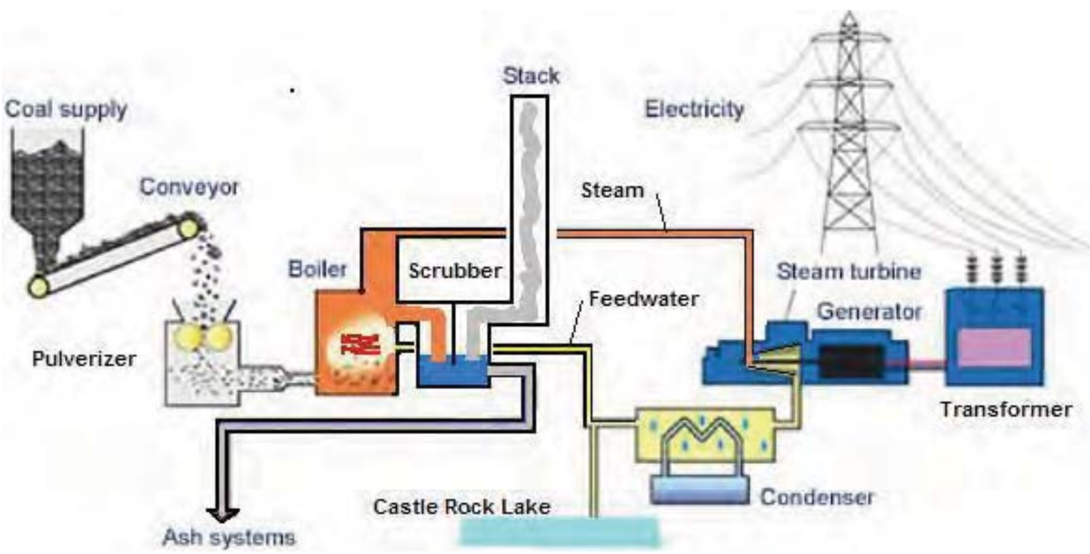
In the 1960s, the Bonneville Power Administration (BPA) forecast that available base-load hydroelectric power would be fully subscribed by its statutory preference customers, leaving none available for sale to PSE and other investor-owned utilities. Faced with this situation, PSE had to develop or contract for other sources of baseload energy. Developing a coal-fired generating plant at Colstrip, Montana was the result. The adjacent Rosebud mine offered plentiful coal reserves that could be delivered to the generating plant without the need for costly rail facilities. Sharing the ownership and output of a two-unit plant with Montana Power Company (whose generating plants were later acquired by PPL Montana) made construction and operation more economical, and sharing the output of two units increased reliability compared to owning a single unit of similar size or a larger, single-unit plant.

In the early 1970s, under the same forecast that the region’s investor-owned utilities would soon lose access to BPA base-load hydro power, PSE and Montana Power Company began planning for Units 3 & 4 together with three other utilities. Construction of the two units began, but delays in obtaining the required Montana Major Facility Siting Act Certificate postponed their opening until 1984 and 1986 respectively. The 500 kV Colstrip Transmission System was constructed in tandem with Units 3 & 4.

The power plant and mine dominate the economies of Colstrip and Rosebud County, although ranching is also an important source of jobs and income. A 2010 study by University of Montana economists estimated that the plant and mine support more than 3,700 jobs, $360 million of personal income and over $100 million of annual tax payments to the State of Montana and county and local governments.

Plant operations

Each Colstrip unit consists of a fuel supply system, a coal-fired boiler, a steam turbine-generator, a cooling tower, step-up transformers, piping, and electric distribution and auxiliary equipment.



How Colstrip generates electricity

Coal from the Rosebud Mine is crushed into 3-inch chunks and transported to the generating plant on overland conveyors or in trucks where it is stored in piles at the plant site before being moved to silos in the boiler buildings. Finally, the coal travels through a pulverizer that grinds it to the consistency of talcum powder; then it is mixed with air and blown into the boiler.

Inside the boiler the coal and air mixture burns, releasing hot gases that convert water in boiler tubes to steam. The steam powers turbines connected to electric generators, which transform the mechanical energy from the turbine into electric energy.

Afterwards, the hot gases are drawn into the scrubbers, where they are cleaned before being exhausted through the stack. Bottom ash, the heavier of the two residuals, sinks to the bottom of the boiler where it is collected for treatment and storage. The lighter fly ash is pulled into the scrubbers with the flue gases, where it is captured for treatment and storage. The scrubbers also capture sulfur and mercury emitted from the coal during combustion.

Water for plant operations comes from the Yellowstone River about 30 miles north. A 30-day supply is maintained in Castle Rock Lake, a man-made lake constructed as part of the plant facilities. As water enters the plant it is divided into two streams. The largest flows to the cooling towers where it replaces water lost from evaporation, the smaller flow is used for various processes including equipment cooling and scrubber system make-up. Water used in the boilers is demineralized before entering a closed-loop system that passes through the boiler and turbine system.

Environmental impact measures

Nearly every step of the process includes measures to reduce environmental impacts.

NO_X. Coal and air leaving the pulverizers passes though burner systems and over-fire air systems that cool the flame temperature and reduce the formation of nitrogen oxides (NO_X). Units 1 & 2 use a second-generation low-NO_X combustion system with a close-coupled over-fire air injection. The newer Units 3 & 4 use a third-generation combustion system with separated over-fire air injection. Digital control systems recently installed on all four units further enhance NO_X emissions control.

Mercury. Coal contains mercury. To oxidize the mercury and enhance its capture, the coal is treated with a bromine solution before entering the boiler. Then, flue gases are treated with powdered activated carbon to capture the mercury before the gases enter the scrubbers; there, the activated carbon and mercury are removed along with other particulate matter.

SO_2. Permit specifications limit the amount of sulfur in the coal fuel. Additionally, all four units remove sulfur dioxide from flue gases using wet alkali scrubbers. These scrubbers use the alkalinity of flyash to capture SO_2; then a water spray collects the fly ash and the mercury for further processing. Units 1 & 2 capture more than 70% of SO_2 emissions; Units 3 & 4 add hydrated lime to the scrubber spray to achieve more than 90% SO_2 removal.

Coal combustion residuals (CCR). Two types of ash are produced by coal combustion. Bottom ash makes up 30 percent to 35 percent of the total. Flyash makes up the remainder. The larger and heavier bottom ash falls into a water-filled trough in the bottom of the boiler; from there it is pumped to settling ponds on the plant site and then to permanent storage ponds. Some bottom ash is used as a construction material.

The smaller and lighter flyash and other particulate matter (PM) passes into the scrubbers with the flue gases. The scrubbers use the flyash's alkalinity to capture SO_2 gases, and a water spray removes the flyash and other PM. The resulting scrubber slurry is piped to storage ponds. Before final placement in the storage ponds, paste plants remove most of the water; the paste, which begins the process at about 65 percent solids, sets up like low-grade concrete after several days.

The original ash holding ponds at Colstrip were designed with highly impermeable clay liners to prevent slurry components from seeping into the groundwater. These conformed to the requirements of the Montana Major Facility Siting Act Certificate. Monitoring wells, installed prior to the start of operations, monitor the groundwater for any sign of possible contamination (pond water seepage), and capture wells pump impacted ground water back to the ponds.

Since 2000, the six Colstrip owners have spent $97 million to control ash pond leakage, reduce migration of affected groundwater, and to upgrade plant wastewater systems to allow increased recycling of water.

History of ash holding pond seepage

Several years after the first slurry was placed into the stage one pond for Units 1 & 2 some of the monitoring wells began to show increases in groundwater constituents, such as dissolved salts, which could indicate that some of the ash constituents were migrating through the clay lining. In consultation with the Montana Department of Environmental

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Quality (MDEQ), Colstrip plant operators installed capture wells to capture affected groundwater and pump it back to the ponds to prevent affected water from leaving plant property, as well as additional monitoring wells. Colstrip is a “zero discharge” facility so it is not permitted to discharge liquid wastes off the plant property, including precipitation that falls on plant property. In addition to capture wells, existing ponds have been continually modified and additional storage cells have been installed over time utilizing newer, state-of-the-art lining methods including polymer liners, geo membranes, and leak detection/collection systems.

In the late 1990s, pond seepage was indentified off plant property for the first time in a shallow groundwater well at the Colstrip Moose Lodge. The MDEQ was notified, a meeting was held with residents and businesses near the Moose Lodge to discuss the issue, and the plant provided a replacement well at a much great depth. In 2003, a group of Colstrip residents filed suit against the Colstrip owners claiming (1) homes had been damaged by settlement caused by the filling of Castle Rock Lake[2] and (2) that leakage from a Unit 1 & 2 ash pond had impacted shallow groundwater under private property. This lawsuit was settled and although no impact to drinking water wells was identified, the plant connected the property owners with the municipal water supply as a precaution.

In 2007, two ranch owners filed a second lawsuit alleging groundwater contamination from the Units 3 & 4 effluent holding ponds. That lawsuit was also settled.

[2] *Due to naturally occurring ash deposits, some of the soil in the area is susceptible to collapse when initially saturated with groundwater, such as when Castle Lake was filled to serve as the facility’s water reservoir and town’s drinking water supply. These 2003 claims were repeat claims of earlier lawsuits in the 1990s that also addressed construction methods (although the collapse potential was known, it was alleged that houses were not constructed with appropriate foundations, etc.).*

2. Rules and Proposed Rules

During the next five years, the Colstrip units will become subject to several recently enacted regulations, changes in existing regulations and a proposed rule governing coal combustion residuals (CCR). For Colstrip, CCR includes flyash, bottom ash and scrubber slurry.

The Mercury and Air Toxics (MATS) Rule

Promulgated in December 2011, this technology-based rule governs emissions of mercury, acid gases and heavy metals. Particulate matter (PM) emissions may be used as a surrogate for heavy metal emissions. Compliance is required by April 2015. The mercury control system installed at Colstrip to meet a previous Montana mercury rule will also meet the MATS requirements for mercury capture and removal. The existing scrubbers on all four units adequately remove acid gases covered by the rule. Some investments for additional PM control by the Unit 1 & 2 scrubbers are anticipated in the environmental compliance cost cases developed for the IRP to comply with the heavy metals requirements of the MATS Rule. The Unit 3 & 4 scrubbers already remove the required level of PM.

See http://www.epa.gov/mats/actions.html for more information on the MATS Rule.

The Regional Haze Rule

Adopted in 1998, the goal of this rule is to improve visibility in mandatory Class I areas (National Parks, National Forests, and Wilderness Areas); it is not a health-based rule. It requires each state to prepare an analysis of visibility impairments to Class I areas and develop plans to eliminate man-made impairment by 2064. Major sources that began construction before 1977 (this includes Colstrip Units 1 & 2) must also bring emission controls to Best Available Retrofit Technology (BART) standards during the initial review cycle. “Reasonable Progress” requirements call for an updated analysis of impacts every five years. The State of Montana declined to prepare the necessary studies, so the requirement defaulted to the Environmental Protection Agency (EPA). The EPA published its Final Implementation Plan (EPA FIP) for Colstrip, covering both the BART and Reasonable Progress requirements in September 2012 with implementation required within five years. The EPA FIP requirements have been appealed to the U.S. Court of Appeals for the 9th Circuit. This analysis will be updated every five years.

See http://www.epa.gov/region8/air/FinalActonMTRegionaHazeFIPAug2012.pdf for more information on the EPA FIP.

For the Draft Federal Implementation Plan containing EPA's analyses and cost estimates, see https://federalregister.gov/a/2012-8367.

The Coal Combustion Residuals (CCR) Rule

In 2010, the EPA published proposed revisions to the Resource and Conservation Recovery Act (RCRA) for the handling and permanent disposal of coal combustion residuals: bottom ash, flyash, scrubber slurry and boiler slag. The proposed EPA rule considered three options.

Subtitle C "Special Waste" Option Designate CCR as a "*special waste*" under RCRA Subtitle C (Hazardous Wastes) requirements. This would include the phase out of impoundments within five years.

Subtitle D Option. Composite liners required for all existing and future CCR impoundments and for new landfills. State regulations would continue to apply to the construction and operation of existing CCR storage facilities. The EPA would develop minimum standards for state rules governing CCR disposal and maintain oversight authority. There would be no new regulatory controls for any CCR landfills and impoundments that closed before the effective date. Also, all new surface impoundments and existing facilities that continued to operate would need to have composite liners within five years of the effective date.

Subtitle "D prime" Option. Composite liners required only for new impoundments and landfills. This approach would be the same as the Subtitle D option above, except that existing impoundments would not be required to retrofit and install a composite liner, or close.

The EPA has not announced when it expects to issue the final rule or its effective date.

History of the CCR Rule. The EPA has reviewed CCR toxicity to identify any hazardous characteristics in 1993 and most recently in 2000. In both instances EPA determined that CCRs were not hazardous, and should not be regulated as a Hazardous

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Waste under Subtitle C. CCRs typically contain a broad range of metals, including arsenic, selenium, and cadmium; however, using EPA's Toxicity Characteristic Leaching Procedure (TCLP), these metals do not leach at sufficient levels to classify as RCRA-characteristic hazardous waste. The proposed rule was triggered in part by the failure of an ash impoundment dam at a plant operated by the Tennessee Valley Authority. After that event, the EPA examined Colstrip’s ash management practices and the integrity of the dams and abutments at the facility’s ponds; no changes in design or management were requested or required. See http://www.epa.gov/osw/nonhaz/industrial/special/fossil/surveys2/index.htm.

For more information on the proposed CCR rules, go to http://www.epa.gov/wastes/nonhaz/industrial/special/fossil/ccr-rule/index.

The CCR disposal costs used for this IRP analysis are based on EPA estimates. For more information, go to: http://www.regulations.gov/#!documentDetail;D=EPA-HQ-RCRA-2009-0640-0003.

Clean Water Act

Proposed changes to Section 316(b) issued under the Act will apply to power plants as well as other industrial facilities. These changes will affect cooling water intake structures to prevent fish mortality due to impingement and entrainment. They require facilities to utilize “best technology available.” The EPA expects to finalize power plant standards by June 2013. See: http://water.epa.gov/lawsregs/lawsguidance/cwa/316b/phase2/index.cfm.

Effluent guidelines are to be reviewed biennially, and changes may be proposed for various types of facilities. See: http://water.epa.gov/scitech/wastetech/guide/steam_index.cfm.

Colstrip’s water intake structure and cooling towers already meet the best technology available requirement contained in the proposed change to Section 316(b), and effluent guideline changes will not affect the plant since it is a “zero discharge” facility and does not discharge any liquid wastes.

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National Ambient Air Quality Standards (NAAQS)

A fundamental requirement of the Clean Air Act, the NAAQS set allowable ambient levels of several pollutants. These ambient level standards apply uniformly throughout the states. The Clean Air Act required EPA to set NAAQS for widespread pollutants from numerous and diverse sources considered harmful to public health and the environment. EPA has set NAAQS for six "criteria" pollutants. Two types of national air quality standards are established by The Clean Air Act. Primary standards set limits to protect public health, including the health of "sensitive" populations such as asthmatics, children, and the elderly. Secondary standards set limits to protect public welfare, including protection against visibility impairment, damage to animals, crops, vegetation, and buildings. The Clean Air Act requires periodic review of the science upon which the standards are based and the standards themselves. With each revised NAAQS the states must evaluate whether any parts of the state exceed the standard (are “non-attainment” areas). If a state contains any non-attainment areas, the state must propose a plan and schedule to reduce emissions to achieve attainment for approval by the EPA. Currently the Colstrip area of Montana is in attainment for all criteria pollutants. Reductions in Colstrip emissions for SO_2, NO_X and PM to meet the MATS Rule and the EPA FIP are expected to keep the area in attainment with any NAAQS revisions with no further actions required. For more information, go to: http://www.epa.gov/air/criteria.html.

The Cross State Air Pollution Rule (CSAPR)

CSAPR and the prior Clean Air Interstate Rule (CAIR) would not have applied to Colstrip but only to plants in certain eastern states. Both rules were vacated by the Court of Appeals for the D.C. Circuit. See http://www.epa.gov/airtransport/basic.html .

3. Four Environmental Compliance Cost Cases

PSE developed four environmental compliance cost cases for Units 1 & 2 and Units 3 & 4. All are based on plans for achieving compliance with the rules by the required date (or by the expected compliance date for proposed rules). The cases for Units 1 & 2 differ from those for Units 3 & 4 because the former units are older, so the Reasonable Progress and BART requirements of EPA's Regional Haze FIP affect them differently. All cases start with the same forecast for continuing variable and fixed operating and maintenance costs, and the cost of expected capital additions now required for continuing operation; then they add the assumed costs of compliance.

Case 1 – Low Cost Estimated additional costs are based on achieving compliance using existing, installed equipment with a minimum of modifications or additions to meet the MATS Rule and the BART requirements of EPA's Regional Haze FIP. This case and Case 2 assume that coal combustion residuals continue to be classified as non-hazardous.	**Case 2 – Mid Cost** This case includes all the costs from Case 1, plus costs for adding additional equipment that may be needed to assure compliance. It is largely based on EPA estimates for equipment intended to bring Units 1 & 2 into compliance with the BART requirements of EPA's Regional Haze FIP.
Case 3 – High Cost Case 3 assumes the Case 2 costs, plus additional costs for equipment needed to meet potential new requirements. It reflects a scenario in which (1) coal combustion residuals are defined as hazardous waste and therefore are more costly to dispose of, and (2) the Reasonable Progress requirements of the Regional Haze program require the addition of Selective Catalytic Reduction (SCR) technology on all units by 2027.	**Case 4 – Very High Cost** Case 4 assumes all Case 2 costs, plus it accelerates the effective date for installation of SCR technology to 2022. It also increases the estimated cost of SCR technology on Units 1 & 2, and it triples the cost of hazardous waste disposal for CCR included in Case 3.

Compliance costs added for each case

The specific compliance costs included in each case are described in detail below, and the matrices at the end of this appendix identify the capital and operating costs assumed for each case.

Case 1 - Low Cost

FOR UNITS 1 & 2
To achieve greater particulate matter (PM) control to comply with the MATS Rule, costs have been included for modification of the scrubber vessels' internals.

To improve control of SO_2 to meet the EPA Regional Haze FIP, costs are included for a system to inject lime into the scrubbers.

To meet the NO_X removal requirement of the EPA Regional Haze FIP, costs for installation of a new system of Low NO_X burners and Separated Over-fire Air (SOFA) systems are included.

FOR UNITS 3 & 4
Only normal operating and capital costs are included in Case 1, because testing has shown that existing equipment can meet the requirements of the MATS Rule, and because the initial Regional Haze FIP does not require any emissions reduction for Units 3 & 4.

FOR ALL FOUR UNITS
Case 1 assumes that CCR will continue to be regulated as a non-hazardous waste, but that dry disposal will be required. Case 1 includes costs to add and operate equipment to further dry the ash paste currently being disposed.

Case 2 - Mid Cost

FOR UNITS 1 & 2
Case 2 assumes the cost of all the equipment additions in Case 1.

To increase particulate control to meet the MATS Rule, a wet electrostatic precipitator (Wet ESP) is added in series with each scrubber.

For improved SO_2 control to comply with EPA's Regional Haze FIP a fourth scrubber is added to each unit, with the cost from EPA's estimates.

For NO_X control to comply with the EPA's Regional Haze FIP, post-combustion selective non-catalytic reduction (SNCR) equipment is added, using cost estimates currently contained in Colstrip capital expenditure forecasts.

FOR UNITS 3 & 4
No additional equipment or costs are required immediately for the MATS rule or the EPA Regional Haze FIP, but Case 2 assumes that the Reasonable Progress requirement of the Regional Haze Rule will require the addition of a selective catalytic reduction (SCR) system on each unit by 2027.

FOR ALL FOUR UNITS
As in the Case 1, the Mid Cost Case assumes that CCR will continue to be regulated as a non-hazardous waste, but that dry disposal will be required. Like Case 1, Case 2 includes costs to add and operate equipment to further dry the ash paste currently being disposed of.

Case 3 - High Cost

Case 3 assumes significant equipment changes and additions, at significant cost, to remain in compliance. It includes all of the costs identified for Case 2, plus the following changes and additions.

FOR UNITS 1 & 2
To control particulate matter to meet the MATS Rule, the higher cost of a fabric filter (baghouse) is assumed rather than the cost of the wet ESP.

The cost of the additional scrubber vessels for EPA Regional Haze FIP compliance is increased to twice the EPA-estimated cost.
Selective catalytic reduction (SCR) equipment is added in 2027 at the EPA-estimated cost.

FOR UNITS 3 & 4
No additional equipment or costs are required immediately for the MAT Rule or the EPA Regional Haze FIP, but it is assumed that the Reasonable Progress requirement will necessitate the addition of an SCR system to each unit by 2027.

FOR ALL FOUR UNITS
Case 3 assumes that CCR will be regulated as a hazardous waste requiring off-site disposal in a permitted hazardous waste landfill. It includes an $8/MWh additional variable operating cost to account for the cost of off-site disposal.*

Case 4 – Very High Cost

Case 4 assumes all costs in Case 3 with the following additions and modifications:

The installation of SCR equipment on all four units is advanced to 2022 from 2027

The estimated cost of adding SCR on Units 1 & 2 is substantially increased.

The variable cost included to cover off-site disposal* of CCR in hazardous waste landfills triples to $24 per MWh.

**NOTE: The assumption that coal combustion residuals will need to be disposed of off-site as hazardous waste is a significant cost driver for Cases 3 and 4; however, depending on how potential regulations develop in the future, Colstrip may be able to store CCR waste on-site, given the quality of its current containment methods. If so, compliance costs for both cases would be substantially lower.*

4. Modeling Assumptions

The tables below detail the costs included in each of the Colstrip environmental cost cases for Units 1 & 2 and Units 3 & 4.

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Case 1 - Low Cost

Assumed Technology Employed and Estimated Costs to PSE (Costs in $ millions unless otherwise noted)

Colstrip 1 & 2	National Ambient Air Quality Standards (Compliance Dates Vary)				Mercury & Air Toxics (April 2015)			CSAPR *Note 14*	Montana Regional Haze FIP (Sept 2017) *Note 4*			Coal Combustion Residuals (expect 2018 compliance)		Clean Water Act	
	Ozone	SO_2	$PM_{2.5}$	NO_2	Mercury	Acid Gases	Other Metals		SO_2	NOx	PM	Non-Hazardous	Hazardous	Part 316(b)	Effluent Guidelines
	Expect that NOx, SO_2 and PM reductions required to meet other rules will maintain plant compliance				Complies *Note 2*	Complies *Note 2*	Additional Particulate Control	Not Applicable	Reduce emissions to 0.08 LB/MMBtu	Reduce emissions to 0.15 LB/MMBtu	0.10 LB/MMBtu	Onsite Dry Ash *Note 8*		Complies *Note 2*	No liquid waste discharges
Technology *Note 3*	None				Existing Mercury Control System	Existing Wet Scrubber System	Upgrade to Existing Scrubber System *Note 5*	None	Upgrade to Scrubber and Lime Injection *Notes 5 & 6*	Upgrade Low NOx Burners & SOFA *Note 7*	Complies *Note 2*			None	None
Variable Operating, $/MWH	$0				$0	$0	$0.0	$0	$0.5	$0.5	$0	$0.2		$0	$0
Annual Fixed Operating Cost	$0				$0	$0	$0.1	$0	$0.5	$0.4	$0	$0.5		$0	$0
Total Capital Cost	$0				$0	$0	$9.1	$0	$1.5	$6.3	$0	$7.0		$0	$0

Assumed Technology Employed and Estimated Costs to PSE (Costs in $ millions unless otherwise noted)

Colstrip 3 & 4	National Ambient Air Quality Standards (Compliance Dates Vary)				Mercury & Air Toxics (April 2015)			CSAPR	Montana Regional Haze FIP (Sept 2017) *Note 4*			Coal Combustion Residuals (expect 2018 compliance)		Clean Water Act	
	Ozone	SO_2	$PM_{2.5}$	NO_2	Mercury	Acid Gases	Other Metals		SO_2	NOx	PM	Non-Hazardous	Hazardous	Part 316(b)	Effluent Guidelines
	Expect that NOx, SO_2 and PM reductions required to meet other rules will maintain plant compliance				Complies *Note 2*	Complies *Note 2*	Complies *Note 2*	Not Applicable	None	None	None	Onsite Dry Ash *Note 8*		Complies *Note 2*	No liquid waste discharges
Technology *Note 3*	None				Existing Mercury Control System	Existing Wet Scrubber System	Existing Wet Scrubber System	None	Existing Wet Scrubber System	Existing Low NOx Burners & SOFA	None			None	None
Variable Operating, $/MWH	$0				$0	$0	$0	$0	$0	$0.0	$0	$0.2		$0	$0
Annual Fixed Operating Cost	$0				$0	$0	$0	$0	$0	$0.0	$0	$0.5		$0	$0
Total Capital Cost	$0				$0	$0	$0	$0	$0	$0.0	$0	$7.0		$0	$0

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Case 2 - Mid Cost

Colstrip 1 & 2	Assumed Technology Employed and Estimated Costs to PSE (Costs in $ millions unless otherwise noted)														
	National Ambient Air Quality Standards (Compliance Dates Vary)				Mercury & Air Toxics (April 2015)			CSAPR ***Note 14***	Montana Regional Haze FIP (Sept 2017) ***Note 4***			Coal Combustion Residuals (expect 2018 compliance)		Clean Water Act	
	Ozone	SO_2	$PM_{2.5}$	NO_2	Mercury	Acid Gases	Other Metals		SO_2	NOx	PM	Non-Hazardous	Hazardous	Part 316(b)	Effluent Guidelines
	Expect that NOx, SO_2 and PM reductions required to meet other rules will maintain plant compliance				Complies ***Note 2***	Complies ***Note 2***	Additional Particulate Control	Not Applicable	Reduce emissions to 0.08 LB/MMBtu	Reduce emissions to 0.15 LB/MMBtu	0.10 LB/MMBtu	Onsite Dry Ash ***Note 8***		Complies ***Note 2***	No liquid waste discharges
Technology ***Note 3***	none				Existing Mercury Control System	Existing Wet Scrubber System	Upgrade to Existing Scrubbers and Wet ESP ***Notes 5 & 9***	none	Additional Scrubber and Lime Injection ***Notes 6 & 10***	Upgrade Low NOx Burners, add SOFA and SNCR ***Notes 7 & 11***	Complies ***Note 2***			none	none
Variable Operating, $/MWH	$0				$0	$0	$0.1	$0	$0.5	$0.8	$0	$0.2		$0	$0
Annual Fixed Operating Cost	$0				$0	$0	$0.1	$0	$0.6	$0.4	$0	$0.5		$0	$0
Total Capital Cost	$0				$0	$0	$24.1	$0	$27.5	$11.1	$0	$7.0		$0	$0

Colstrip 3 & 4	Assumed Technology Employed and Estimated Costs to PSE (Costs in $ millions unless otherwise noted)														
	National Ambient Air Quality Standards (Compliance Dates Vary)				Mercury & Air Toxics (April 2015)			CSAPR ***Note 14***	Montana Regional Haze FIP (Sept 2017) ***Note 4***			Coal Combustion Residuals (expect 2018 compliance)		Clean Water Act	
	Ozone	SO_2	$PM_{2.5}$	NO_2	Mercury	Acid Gases	Other Metals		SO_2	NOx	PM	Non-Hazardous	Hazardous	Part 316(b)	Effluent Guidelines
	Expect that NOx, SO_2 and PM reductions required to meet other rules will maintain plant compliance				Complies ***Note 2***	Complies ***Note 2***	Complies ***Note 2***	Not Applicable	none	none in 2017 Assume SCR in 2027	none	Onsite Dry Ash ***Note 8***		Complies ***Note 2***	No liquid waste discharges
Technology ***Note 3***	none				Existing Mercury Control System	Existing Wet Scrubber System	Existing Wet Scrubber System	none	Existing Wet Scrubber System	Add Selective Catalytic Reduction in 2027 ***Note 12***	none			none	none
Variable Operating, $/MWH	$0				$0	$0	$0	$0	$0	$1.0	$0	$0.2		$0	$0
Annual Fixed Operating Cost	$0				$0	$0	$0	$0	$0	$0.1	$0	$0.5		$0	$0
Total Capital Cost (SCR added by 2027)	$0				$0	$0	$0	$0	$0	$190.0	$0	$7.0		$0	$0

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Case 3 - High Cost

Colstrip 1 & 2	National Ambient Air Quality Standards (Compliance Dates Vary)	Mercury & Air Toxics (April 2015)			CSAPR ***Note 14***	Montana Regional Haze FIP (Sept 2017) ***Note 4***			Coal Combustion Residuals (expect 2018 compliance)		Clean Water Act	
	Ozone / SO_2 / $PM_{2.5}$ / NO_2	Mercury	Acid Gases	Other Metals		SO_2	NOx	PM	Non-Hazardous	Hazardous	Part 316(b)	Effluent Guidelines
	Expect that NOx, SO_2 and PM reductions required to meet other rules will maintain plant compliance	Complies ***Note 2***	Complies ***Note 2***	Additional Particulate Control	Not Applicable	Reduce emissions to 0.08 LB/MMBtu	Reduce emissions to 0.15 LB/MMBtu	0.10 LB/MMBtu		Hazardous Waste Landfill	Complies ***Note 2***	No liquid waste discharges
Technology ***Note 3***	none	Existing Mercury Control System	Existing Wet Scrubber System	Upgrade to existing Scrubbers and New Fabric Filters (Baghouses)	none	Additional Scrubber and Lime Injection ***Notes 6 & 13***	Upgrade Low NOx Burners & SOFA, add SNCR. Assume SCR by 2027 ***Notes 7, 11 & 12***	Complies ***Note 2***		Hazardous Waste Landfill ***Note 16***	none	none
Variable Operating, $/MWH	$0	$0	$0	$0.0	$0	$0.5	$0.8	$0		8.0	$0	$0
Annual Fixed Operating Cost	$0	$0	$0	$0.1	$0	$0.6	$0.4	$0		0.2	$0	$0
Total Capital Cost (2014-2018) (SCR added by 2027)	$0	$0	$0	$130.0	$0	$54.0	$11.1 $78.0	$0		6.0	$0	$0

Assumed Technology Employed and Estimated Costs to PSE (Costs in $ millions unless otherwise noted)

Colstrip 3 & 4	National Ambient Air Quality Standards (Compliance Dates Vary)	Mercury & Air Toxics (April 2015)			CSAPR	Montana Regional Haze FIP (Sept 2017) ***Note 4***			Coal Combustion Residuals (expect 2018 compliance)		Clean Water Act	
	Ozone / SO_2 / $PM_{2.5}$ / NO_2	Mercury	Acid Gases	Other Metals		SO_2	NOx	PM	Non-Hazardous	Hazardous	Part 316(b)	Effluent Guidelines
	Expect that NOx, SO_2 and PM reductions required to meet other rules will maintain plant compliance	Complies ***Note 2***	Complies ***Note 2***	Complies ***Note 2***	Not Applicable	none	none in 2017 Assume SCR in 2027	none		Hazardous Waste Landfill	Complies ***Note 2***	No liquid waste discharges
Technology ***Note 3***	none	Existing Mercury Control System	Existing Wet Scrubber System	Existing Wet Scrubber System	none	Existing Wet Scrubber System	Assume Selective Catalytic Reduction by 2027	none		Hazardous Waste Landfill ***Note 16***	none	none
Variable Operating, $/MWH	$0	$0	$0	$0	$0	$0	$1.0	$0		$8.0	$0	$0
Annual Fixed Operating Cost	$0	$0	$0	$0	$0	$0	$0.1	$0		$0.2	$0	$0
Total Capital Cost (SCR added by 2027)	$0	$0	$0	$0	$0	$0	$190.0	$0		$9.8	$0	$0

Assumed Technology Employed and Estimated Costs to PSE (Costs in $ millions unless otherwise noted)

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Case 4 – Very High Cost

	Assumed Technology Employed and Estimated Costs to PSE (Costs in $ millions unless otherwise noted)														
Colstrip 1 & 2	National Ambient Air Quality Standards (Compliance Dates Vary)				Mercury & Air Toxics (April 2015)			CSAPR *Note 14*	Montana Regional Haze FIP (Sept 2017) *Note 4*			Coal Combustion Residuals (expect 2018 compliance)		Clean Water Act	
	Ozone	SO_2	$PM_{2.5}$	NO_2	Mercury	Acid Gases	Other Metals		SO_2	NOx	PM	Non-Hazardous	Hazardous	Part 316(b)	Effluent Guidelines
	Expect that NOx, SO_2 and PM reductions required to meet other rules will maintain plant compliance				Complies *Note 2*	Complies *Note 2*	Additional Particulate Control	Not Applicable	Reduce emissions to 0.08 LB/MMBtu	Reduce emissions to 0.15 LB/MMBtu	0.10 LB/MMBtu		Hazardous Waste Landfill	Complies *Note 2*	No liquid waste discharges
Technology *Note 3*	none				Existing Mercury Control System	Existing Wet Scrubber System	New Fabric Filters (Baghouses) *Note 15*	none	Additional Scrubber and Lime Injection *Notes 6 & 13*	Low NOx Burners, add SOFA and SNCR. Assume SCR added by 2022 *Notes 7, 11 & 17*	Complies *Note 2*		Hazardous Waste Landfill *Note 18*	none	none
Variable Operating, $/MWH	$0				$0	$0	$0.0	$0	$0.5	$0.8	$0		24.0	$0	$0
Annual Fixed Operating Cost	$0				$0	$0	$0.1	$0	$0.6	$0.4	$0		0.2	$0	$0
Total Capital Cost (2014-2018)	$0				$0	$0	$130.0	$0	$54.0	$11.1	$0		6.0	$0	$0
Total Capital Cost (SCR added by 2022)										$190.0					

	Assumed Technology Employed and Estimated Costs to PSE (Costs in $ millions unless otherwise noted)														
Colstrip 3 & 4	National Ambient Air Quality Standards (Compliance Dates Vary)				Mercury & Air Toxics (April 2015)			CSAPR	Montana Regional Haze FIP (Sept 2017) *Note 4*			Coal Combustion Residuals (expect 2018 compliance)		Clean Water Act	
	Ozone	SO_2	$PM_{2.5}$	NO_2	Mercury	Acid Gases	Other Metals		SO_2	NOx	PM	Non-Hazardous	Hazardous	Part 316(b)	Effluent Guidelines
	Expect that NOx, SO_2 and PM reductions required to meet other rules will maintain plant compliance				Complies *Note 2*	Complies *Note 2*	Complies *Note 2*	Not Applicable	none	none in 2017 Assume SCR in 2022	none		Hazardous Waste Landfill	Complies *Note 2*	No liquid waste discharges
Technology *Note 3*	none				Existing Mercury Control System	Existing Wet Scrubber System	Existing Wet Scrubber System	none	Existing Wet Scrubber System	Assume Selective Catalytic Reduction by 2022	none		Hazardous Waste Landfill *Note 18*	none	none
Variable Operating, $/MWH	$0				$0	$0	$0	$0	$0	$1.0	$0		$24.0	$0	$0
Annual Fixed Operating Cost	$0				$0	$0	$0	$0	$0	$0.1	$0		$0.2	$0	$0
Total Capital Cost (SCR added by 2022)	$0				$0	$0	$0	$0	$0	$190.0	$0		$9.8	$0	$0

Table notes

1. The cost estimates shown have been developed by PSE based on budget forecasts, EPA studies, industry information, and engineering judgment. Case 2 costs for Regional Haze compliance are based on costs included in EPA's draft Federal Implementation Plan for Montana (draft FIP). Costs shown are for PSE's 50 percent interest in Units 1 & 2 and 25 percent interest in Units 3 & 4. The costs of each case are not additive.

2. "Complies" means that existing unit equipment has been shown, by testing or other means, to meet the requirements of the rule or proposed rule.

3. "Technology" means the type of equipment modifications or additions expected to meet the requirements of the rule for that emission. Levels of technology and their costs vary among the four cases.

4. Limits for sulfur dioxide (SO_2), nitrogen oxides (NO_X) and particulate matter (PM) are from the EPA's State of Montana, Regional Haze Federal Implementation Plan (September 2012).

5. "Scrubber upgrade" means internal modifications to the existing scrubbers to improve PM and SO_2 capture. Cost estimate is from confidential vendor information.

6. "Lime Injection" means the addition of a system for injection of lime into the slurry mixture of each scrubber. Cost is based on draft FIP and vendor information.

7. "Low NO_X burners and add SOFA" means replacement of the existing coal burner systems and addition of a separated over-fire air (SOFA) system from the boiler windbox. Cost is based on draft FIP and vendor information.

8. "On-site Dry Ash" means the addition of a system to dry the ash/slurry paste to the limits needed to meet the Subtitle D (non-hazardous) requirements of EPA's proposed Coal Combustion Residuals Rule. Costs were developed by PSE using the Regulatory Impact Analysis for EPA's Proposed Regulation of Coal Combustion Residuals (April 2010).

9. "Upgrade to Existing Scrubber System & Wet ESP" means scrubber modifications in Note 5, plus the addition of wet electro-static precipitators (Wet ESP). Cost is from vendor information.

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10. "Additional Scrubber and Lime Injection" means addition of equipment in Notes 5 and 6 plus an additional scrubber vessel installed on each unit. The installation cost of the new scrubber vessels in estimated to be $25 million per unit based on the draft FIP.

11. "Low NO_X Burners & SOFA and SNCR" means the addition of equipment in Note 7, plus the addition of selective non-catalytic reduction (SNCR) equipment to each boiler. Cost is based on draft FIP and vendor information.

12. "Assume SCR in 2027" means an assumption that subsequent Regional Haze Reasonable Progress Requirements will call for the addition of Selective Catalytic Reduction (SCR) equipment by the year 2027. Cost is based on draft FIP.

13. "Additional Scrubber and Lime Injection" means addition of equipment in Notes 5 and 6, plus an additional scrubber vessel installed on each unit. The installation cost of each additional scrubber vessel is estimated to be $50 million per unit (two times the draft FIP cost).

14. CSAPR is the Cross State Air Pollution Rule, which applied only to plants in the eastern U.S. It has been vacated by the Court of Appeals for the D.C. Circuit.

15. "New Fabric Filters (Baghouses)" means the addition of fabric filters to meet particulate emissions limits. Cost based on PPL-M estimate submitted to EPA.

16. "Hazardous Waste Landfill" means the shipment of the ash/slurry paste to a landfill meeting the Subtitle C (hazardous) requirements of EPA's proposed Coal Combustion Residuals Rule. Alternatively, a Hazardous Waste Landfill could be permitted, constructed and operated adjacent to the plant site by plant owners. Costs are based on Regulatory Impact Analysis for EPA's Proposed RCRA Regulation of Coal Combustion Residuals (April 2010).

17. "Assume SCR in 2022" means an assumption that subsequent Regional Haze Reasonable Progress Requirements calls for the addition of Selective Catalytic Reduction (SCR) equipment by the year 2022. Added at request of Sierra Club.

18. "Hazardous Waste Landfill" means the shipment of the ash/slurry paste to a landfill meeting the Subtitle C (hazardous) requirements of EPA's proposed Coal Combustion Residuals Rule. Alternatively, a Hazardous Waste Landfill could be permitted, constructed and operated adjacent to the plant site by plant owners. Cost based on disposal cost of $300 per ton of ash. Added at request of Sierra Club.

APPENDIX K

Electric Analysis

Contents

This appendix presents details of the methods and models employed in PSE's electric resource analysis, and the data produced by that analysis.

1. Methods

2013 IRP process diagram

PSE uses three models for electric integrated resource planning: AURORAxmp®, a Stochastic Model, and the Portfolio Screening Model III (PSM III). AURORA analyzes the western power market to produce hourly electricity price forecasts of potential future market conditions and resource dispatch. The stochastic model is used to create draws and distributions for various variables. PSM III creates optimal portfolios and tests these portfolios to evaluate PSE's long-term revenue requirements for the incremental portfolio and risk of each portfolio. The following diagram shows the methods used to quantitatively evaluate the lowest reasonable cost portfolio.

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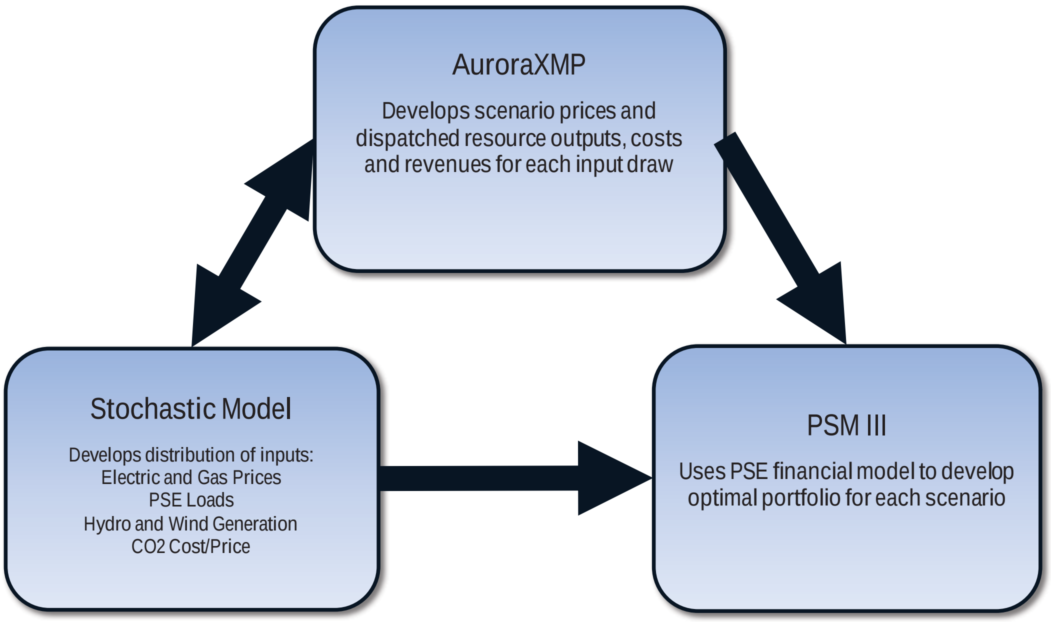
Figure K-1
Electric Analysis Methodology



Risk analysis

PSE performs risk assessment of its portfolio options using both a scenario approach and a probabilistic approach. Scenario analysis considers the impacts of known input factors in a deterministic model, while the probabilistic approach allows for the calculation of risks based on the distribution of input factors.

Scenarios

A description of the scenarios and sensitivities developed for this IRP can be found in Chapter 4. The monthly price output from these scenarios can be found in Section 2 of this appendix. An optimal portfolio was found for each scenario and sensitivity described in Chapter 4. The optimal portfolio for each scenario is the lowest-cost combination of supply- and demand-side resources that meets PSE's needs. More details on these portfolios can also be found in Section 2 of this appendix.

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Probabilistic analysis of risk factors

In addition to using scenarios to assess risk, this 2013 IRP continues to assess portfolio uncertainty through probabilistic Monte Carlo modeling in PSM III. It relies on Monte Carlo simulations of six uncertainty factors: natural gas prices, power prices, CO_2 cost/prices, weather and economic-demographic variability for load, wind generation variability, and hydroelectric generation availability. The simulations are based on assumptions about correlations and volatilities between the risk variables and also across time, based on the Stochastic model. This model and its assumptions are further described later in this appendix.

Risk measures

The results of the risk simulation allow PSE to calculate portfolio risk. Risk is calculated as the average value of the worst 10 percent of outcomes (called TailVar90). This risk measure is the same as the risk measure used by the Northwest Power Planning and Conservation Council (NWPCC) in its power plans. Additionally, PSE looked at annual volatility by calculating the standard deviation of the year-to-year percent changes in revenue requirements. A summary measure of volatility is the average of the standard deviations across the simulations, but this can be described by its own distribution as well. It is important to recognize that this does not reflect actual expected rate volatility. The revenue requirement used for portfolio analysis does not include rate base and fixed-cost recovery for existing assets.

2. Models

The AURORA dispatch model

Overview

PSE uses the AURORA model to estimate the regional wholesale market price of power used to serve our core customer load. The model is described below in general terms to explain how it operates, with further discussion of significant inputs and assumptions.

The following text was provided by EPIS, Inc. and edited by PSE.

> AURORA is a fundamentals-based program, meaning that it relies on factors such as the performance characteristics of supply resources, and regional demand for power and transmission to drive the electric energy market using the logic of a production costing model. AURORA models the competitive electric market, using the following modeling logic and approach to simulate the markets: Prices are determined from the clearing price of marginal resources. Marginal resources are determined by “dispatching” all of the resources in the system to meet loads in a least-cost manner subject to transmission constraints. This process occurs for each hour that resources are dispatched. Resulting monthly or annual hourly prices are derived from that hourly dispatch.
>
> AURORA uses information to build an economic dispatch of generating resources for the market. Units are dispatched according to variable cost, subject to non-cycling and minimum-run constraints until hourly demand is met in each area. Transmission constraints, losses, wheeling costs, and unit start-up costs are reflected in the dispatch. The market-clearing price is then determined by observing the cost of meeting an incremental increase in demand in each area. All operating units in an area receive the hourly market-clearing price for the power they generate.

AURORA estimates all market-clearing prices for the entire WECC, but the market-clearing price used in PSE’s modeling is the Middle Columbia hub, or Mid-C prices.

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Long-run optimization

AURORA also has the capability to simulate the addition of new generation resources and the economic retirement of existing units through its long-term optimization studies. This optimization process simulates what happens in a competitive marketplace and produces a set of future resources that have the most value in the marketplace. New units are chosen from a set of available supply alternatives with technology and cost characteristics that can be specified through time. New resources are built only when the combination of hourly prices and frequency of operation for a resource generate enough revenue to make construction profitable, unless reserve margin targets are selected. (That is, when investors can recover fixed and variable costs with an acceptable return on investment.) AURORA uses an iterative technique in these long-term planning studies to solve the interdependencies between prices and changes in resource schedules.

Use of reserve margin targets

During the summer of 2006, EPIS, Inc. released a new version of AURORAxmp, along with an input database that included the necessary inputs to perform long-term studies using planning reserve margin targets. The model builds resources to meet target reserve margins and estimates the "capacity price payments necessary to support the marginal entrants supplying capacity to the system."[1]

PSE uses reserve margin targets at the pool level, which consists of the Northwest Power Pool territory. The overall pool reserve margin target is 15 percent. PSE tested capacity pool reserve margins at 0 percent, 5 percent, and 15 percent. A pool reserve margin of 15 percent best mitigated summer price spreads without increasing average prices unreasonably. Many U.S. regions plan for at least a 15 percent reserve margin.

Existing units that cannot generate enough revenue to cover their variable and fixed operating costs over time are identified and become candidates for economic retirement. To reflect the timing of transition to competition across all areas, the rate at which existing units can be retired for economic reasons is constrained in these studies for a number of years.

---

[1] *EPIS, Inc., "Long-Term Studies Using Reserve Margins," from AURORAxmp electronic documentation, December 2005.*

Stochastic model

Overview

The goal of the stochastic modeling process is to understand the risks of alternative portfolios in terms of costs and revenue requirements. This process involves identifying and characterizing the likelihood of bad events and the likely adverse impacts of their occurrence for any given portfolio. The stochastic modeling process used to develop the stochastic inputs is Monte Carlo approach. Monte Carlo draws of inputs are used to generate a distribution of resource outputs (dispatched to prices and must take), costs and revenues from AURORAxmp. These distributions of outputs, costs, and revenues are then used to perform risk simulations in the PSMIII model where risk metrics for portfolio costs and revenue requirements are computed to evaluate alternative portfolios. The stochastic inputs considered in this IRP are Mid-C power price, gas prices for Sumas and AECO hubs, PSE loads, hydropower generation, wind generation, and risk of CO_2 cost/price regimes. This section describes how PSE developed these stochastic inputs, and the updates that were made from the 2011 IRP.

Development of Monte Carlo draws for the stochastic variables

A key goal in the stochastic model is to be able to capture the relationships of major drivers of risks with the stochastic variables in a systematic way. One of these relationships, for example, is that variations in Mid-C power prices should be correlated with variations in Sumas gas prices, contemporaneously or with a lag. Another important aspect in the development of the stochastic variables is the imposition of consistency across draws and key scenarios. This required ensuring, for example, that the same temperature conditions prevail for a load draw and for a power price draw. Figure K-2 shows the key drivers in developing these stochastic inputs. In essence, weather variables, long-term economic conditions and energy markets, and regulation determine the variability in the stochastic variables. Furthermore, two distinct approaches were used to develop the 250 Monte Carlo draws for the inputs: a) loads and prices were developed using econometric analysis given their connection to weather variables (temperature and water conditions), key economic assumptions, and the risks of CO_2 cost/price policy, and b) temperature, hydro, and wind variability were based directly on historical information assumed to be uniformly distributed, while the risks of a CO_2cost/price policy were based on probability weights.

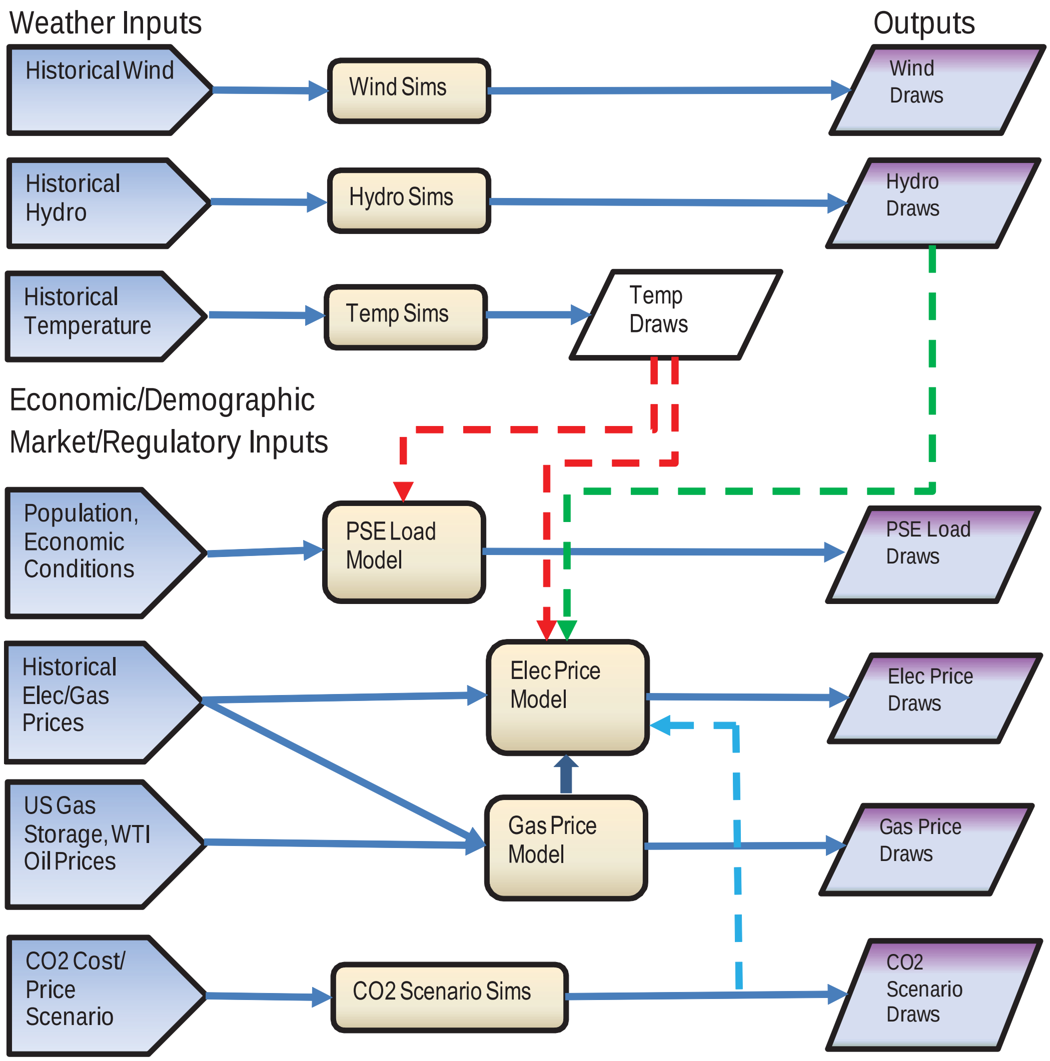
APPENDIX K – ELECTRIC ANALYSIS RESULTS

The econometric equations estimated using regression analysis provide the best fit between the individual explanatory values and maximize the predictive value of each explanatory variable to the dependent variable. However, there exist several components of uncertainty in each equation, including: i) uncertainty in the coefficient estimate, ii) uncertainty in the residual error term, iii) the covariate relationship between the uncertainty in the coefficients and the residual error, and iv) uncertainty in the relationship between equations that are simultaneously estimated. Monte Carlo draws utilizing these econometric equations capture these elements of uncertainty.

By preserving the covariate relationships between the coefficients and the residual error, we are able to maintain the relationship of the original data structure as we propagate results through time. For a system of equations, correlation effects between equations are captured through the residual error term. The logic of the linked physical and market relationships needs to be supported with solid benchmark results demonstrating the statistical match of the input values to the simulated data.

APPENDIX K – ELECTRIC ANALYSIS RESULTS

Figure K-2
Stochastic Model Diagram



APPENDIX K – ELECTRIC ANALYSIS RESULTS

Summary of updates for the 2013 IRP

- Consistent set of inputs for each draw, across models (Loss of Load Probability model and the stochastic model)
  - This ensured that the same weather draws were used for both models.
- Added AECO gas price simulations
  - Simulations for AECO gas price were added because this IRP also considered generic gas plants located in eastern Washington/Oregon, which would have to purchase its fuel using AECO gas price as an index.
- Raised electric daily price cap from $300/MWH to $750/MWH
  - Raising the daily price cap for electric implied a larger upside variation in power price draws, also consistent with FERC's order to increase the hourly price cap in WECC from about $400/mwh to $1,000/mwh.
- Included most recent available data from 2010
  - The historical data set used to estimate the price equations or to draw the weather variables was updated to include up to June 2012 for the price data, up to December 2011 for the temperature and wind data.
- Updated the econometric equations for power and gas prices
  - One change is accounting for effects of fracking technology on gas price trends.
- Temperature, hydro, and wind draws vary from year to year
  - Previously, the same set of weather draws were applied each year in the 20-year planning period. Varying the draws from year to year implied more variations due to weather, and that different weather patterns occurred each year.
- New CO_2 simulation approach
  - Given the changes in legislative agenda in the last couple of years, the simulation approach used in this IRP was revised to reflect the risks that a CO2 cost/price policy might occur in the future, and also to be consistent with the CO2/price forecasts shown in the deterministic scenario analysis. The approach used in this IRP assigns probability weights to each of the CO2 cost/price forecasts developed for each of the deterministic scenarios. The implication is that when the probability weights are assigned, and draws are made based on these weights, there is a risk that a CO2 cost/price policy at a given level will be implemented in the future.

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PSE load forecast. PSE developed a set of 250 Monte Carlo load forecast draws by allowing two sets of variable inputs to vary for each draw: 1) weather, and 2) economic-demographic conditions. The load forecast draws were created in three steps. First, PSE created 250 unique annual temperature profiles to use in the place of "normal" weather. Second, we created nine separate long-term economic-demographic scenarios using economic-demographic growth assumptions from Moody's Analytics and Washington's state Office of Financial Management (OFM). In the final step, for each of the 250 load forecast draws, a load scenario was created by selecting a unique weather pattern from the first step, plus an economic-demographic scenario selected probabilistically from the second step.

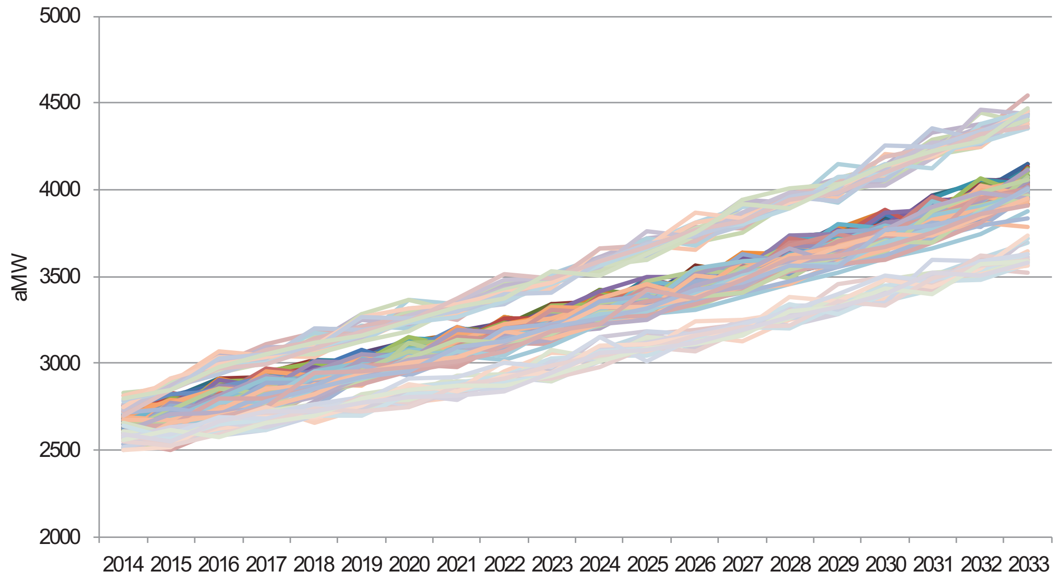
The 250 unique annual temperature profiles were created synthetically. For each temperature profile, an annual hourly temperature shape was selected randomly from the 62 years worth of hourly shapes at Sea-Tac Airport (1950 to 2011). Each annual hourly temperature shape was adjusted in an additive process to fit an annual average temperature selected according to a probabilistic distribution of historical annual average temperatures, also from Sea-Tac (1950-2011). By this process, PSE is able to create an infinite amount of unique temperature profiles to test possible load outcomes. For the current IRP, 250 annual temperature profiles were generated.

The nine economic-demographic scenarios used in the analysis are the ones underlying the following load forecast scenarios: " 2013 IRP Base Demand Forecast," "2013 IRP High Demand Forecast," "2013 IRP Low Demand Forecast," "2013 IRP Cyclical H1 Forecast," "2013 IRP Cyclical L1 Forecast," "2013 IRP Cyclical L2 Forecast," "2013 IRP Cyclical L3 Forecast," "2013 IRP Cyclical L4 Forecast," and "2013 IRP Cyclical L5 Forecast." The scenarios described as "Cyclical" are based on Moody's Analytics forecasts of short-term business cycle activity and generally converge to the Base Scenario in the long run. Alternatively, the "High Demand" and "Low Demand" scenarios are based upon the OFM's long-term population growth scenarios that imply a long-run structural change. Additional information about the economic-demographic conditions forecast for these scenarios is available in Appendix H

Figure K-3. depicts a graphical representation of the load forecast draws. In the short term, the Base Scenario draws merge with the low case draws due to the various near-term cyclical scenarios.

APPENDIX K – ELECTRIC ANALYSIS RESULTS

Figure K-3.
Load Forecast Draws (Base, Structural, Cyclical Scenarios)



For the Monte Carlo draws, the following probabilities shown in Figure K-4 were assigned to the selection of economic scenarios.

Figure K-4.
Economic-Demographic Scenario Probabilities

oad Scenarios	Description	Pro a ility
Base Scenario	Base	52.00%
Cyclical High 1	Stronger Near-Term Rebound	8.00%
Cyclical Low 1	Mild Second Recession	12.00%
Cyclical Low 2	Deeper Second Recession	2.40%
Cyclical Low 3	Protracted Slump	1.60%
Cyclical Low 4	Below-Trend Long-Term Growth	1.60%
Cyclical Low 5	Oil Price Increase, Dollar Crash Inflation	2.40%
High	OFM Structural High Population Growth	10.00%
Low	OFM Structural Low Population Growth	10.00%
Total		100.00%

For each of the 250 Monte Carlo load forecast draws, a temperature profile was selected sequentially from the 250 pre-created weather scenarios detailed above, ensuring that each profile was used once and not repeated. For each draw, an economic scenario was selected according to the probabilities listed above. In each draw, the selected weather and economic inputs were used in the econometric load models to forecast a unique load scenario. For more details on the econometric load forecast models, see Appendix H.

Gas and power prices. The econometric relationship between prices and their explanatory variables is shown in the equations below:

Sumas Gas Price = f(US Gas Storage Deviation fr. 5 Yr Avg, Oil Price, Lagged Oil Price, Time Trend,Fracking Effects)

AECO Gas Price = f(Sumas Gas Price)

Mid-C Power Price = f(Sumas Gas Price, Regional Temperature Deviation from Normal, Mid-C Hydro Generation, Day of Week, Holidays)

A semi-log functional form is used for each equation. These equations are estimated simultaneously with one period autocorrelation using historical daily data from January 2003 to June 2012. The Fracking Effects in the Sumas gas price equation accounted for the impacts of fracking technology on the historical gas price series starting in 2010.

Monte Carlo draws were obtained based on the error distributions of the estimated equations, oil price draws, temperature draws, and hydro condition draws. The temperature draws are consistent with those drawn for the load forecast, while the hydro draws are consistent with those drawn directly from the 70-year historical hydro data as described below. Gas price draws were further adjusted so that the 5th percentile, 10th percentile, 90th percentile and 95th percentiles correspond to the very low, low, high and very high gas price scenarios, respectively, based on the rank levelized price of each draw. The price draws were calibrated to ensure that the means of adjusted distributions are equal to the base case prices. Hourly power prices were then obtained using the hourly shape for the base case from AURORAxmp. Mid-C power price draws in the presence of risks of CO_2 cost/price policies were adjusted based on the observed changes in power price forecasts from AURORAxmp model runs when CO_2 costs/prices were imposed at different levels. Mid-C power prices are generally higher when CO_2 costs/prices are included.

Figure K-5 shows the historical trends in daily Mid-C power price and Sumas gas price from 2000 to 2010 including the price spikes in late 2000 to early 2001 due to the

APPENDIX K – ELECTRIC ANALYSIS RESULTS

California crisis, while Figure K-6 compares the distribution of historical daily Mid-C power prices to the simulated daily prices for 2014. As expected, the distribution is skewed positively or right-skewed, implying that there is a higher probability of realizing high prices relative to the mean compared to low prices. The difference in the distribution can be attributable to the higher gas prices in the historical period compared to the gas price forecast for 2014. The correlation coefficient between gas and power prices for the draws in the winter months of 2014 is about .70.

Figure K-5
Historical Daily Mid-C Power Price and Sumas Gas Price

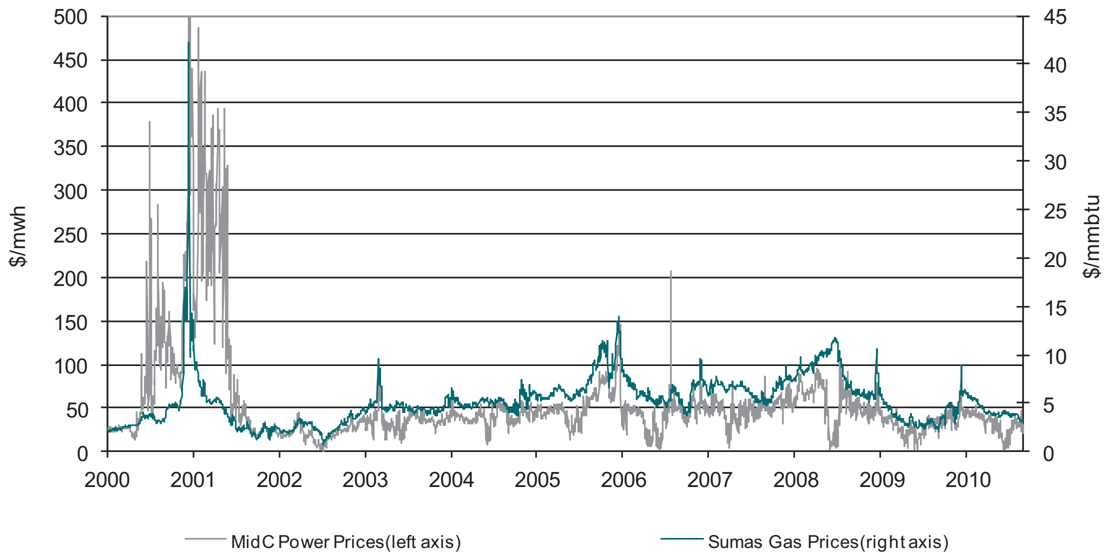


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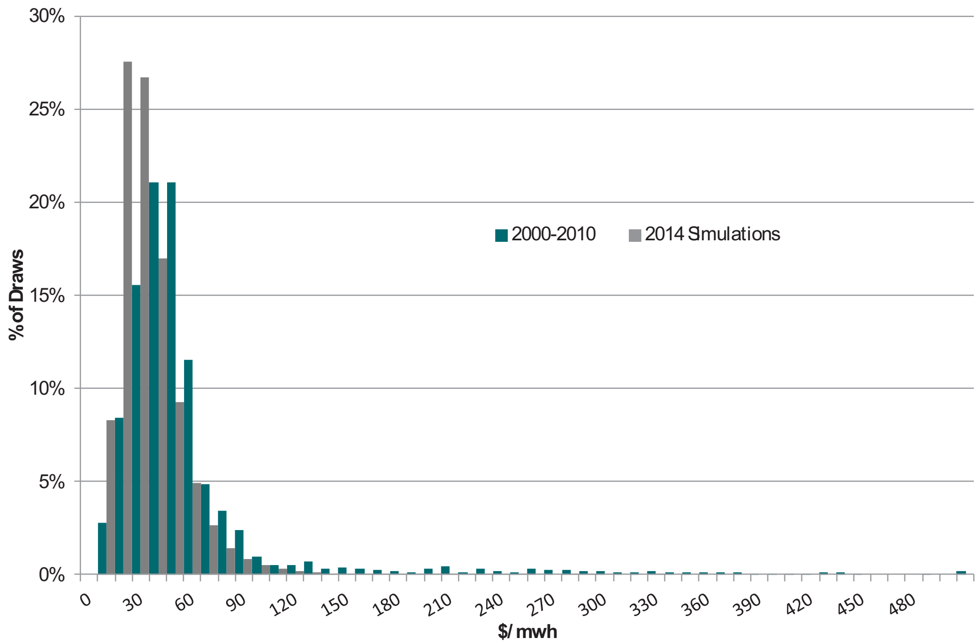
Figure K-6
Distribution of Mid-C Power Prices – Historical versus 2014 Simulations



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The annual Sumas and AECO gas price draws are shown in Figures K-7 and K-8, respectively.

Figure K-7
Annual Sumas Price Draws

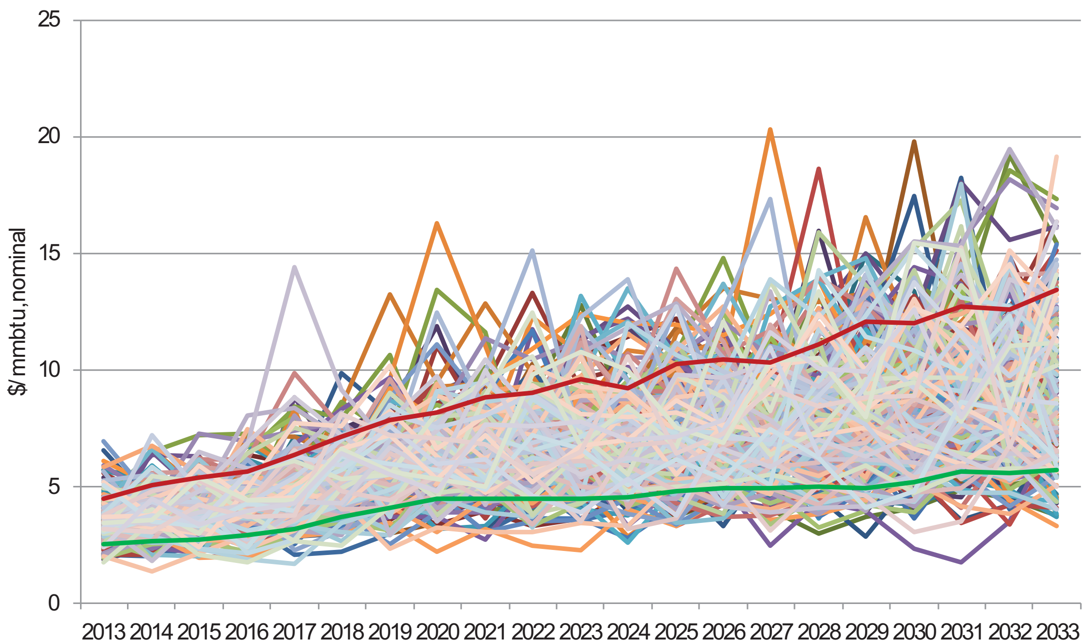
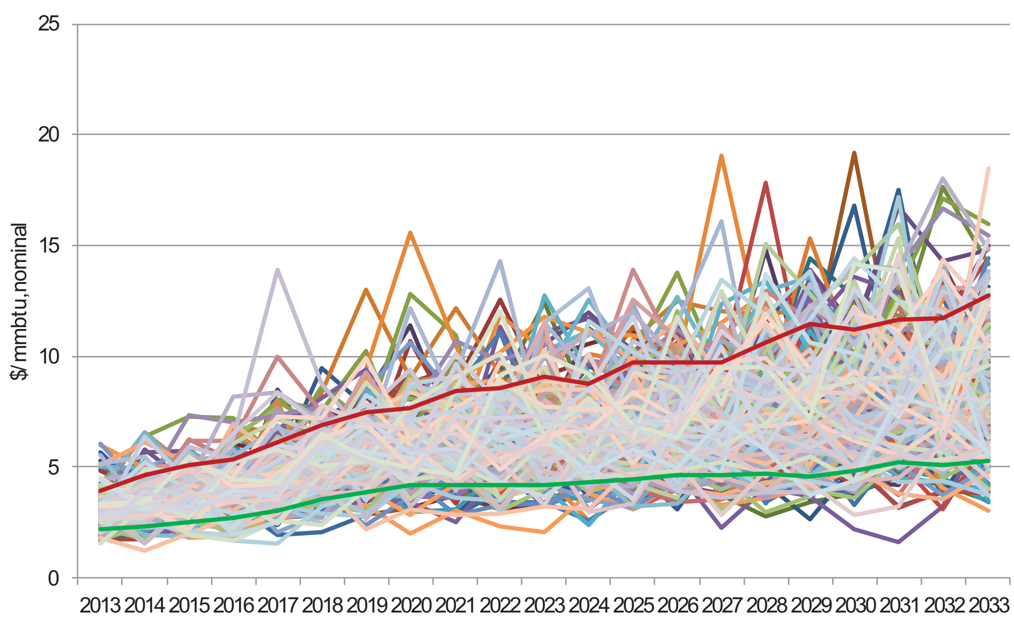


Figure K-8
Annual AECO Price Draws



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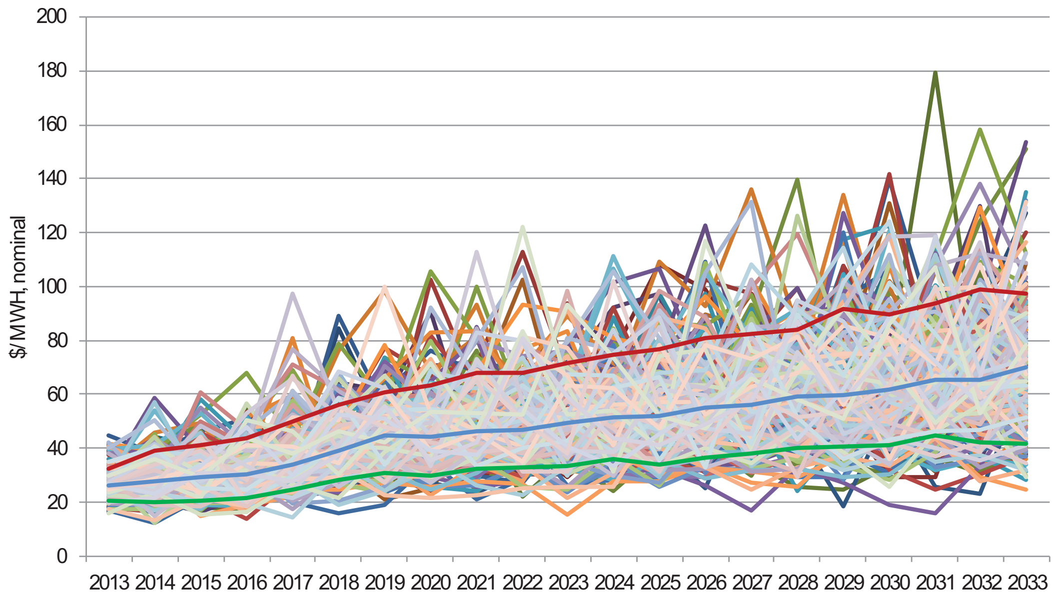
The annual Mid-C power price draws is shown in Figure K-9.

Figure K-9
Annual Mid-C Price Draws with no Risks of CO_2 Cost/Price Policy



Risks of CO_2 cost/price policy. Because of the changes in legislative agenda in the last 2-3 years, there was greater uncertainty of whether a CO_2 policy would be implemented in the future. As a result, the risk of a CO_2 policy was modeled differently in this IRP. Given the possible range of CO_2 cost/price per ton assumed in the deterministic scenarios as described in Chapter 4, subjective probabilities were assigned to each of these costs/price scenarios representing their likelihood of being implemented. The four scenarios and their respective probabilities are No CO_2 – 33.3 percent, Low CO_2 – 33.3 percent, High CO_2 – 33.3 percent, and Very High CO_2 – 0.0 percent. The Very High CO_2 cost/price starts at about $80/ton in 2017 and rises to about $180/ton by 2033, hence, its probability of being adopted is highly unlikely also. The assigned probabilities still imply that there is greater than 50 percent chance of a positive CO_2 cost/price being imposed in the future for this risk study. Figure K-10 shows the annual CO_2 cost/price draws with the weighted average of all draws.

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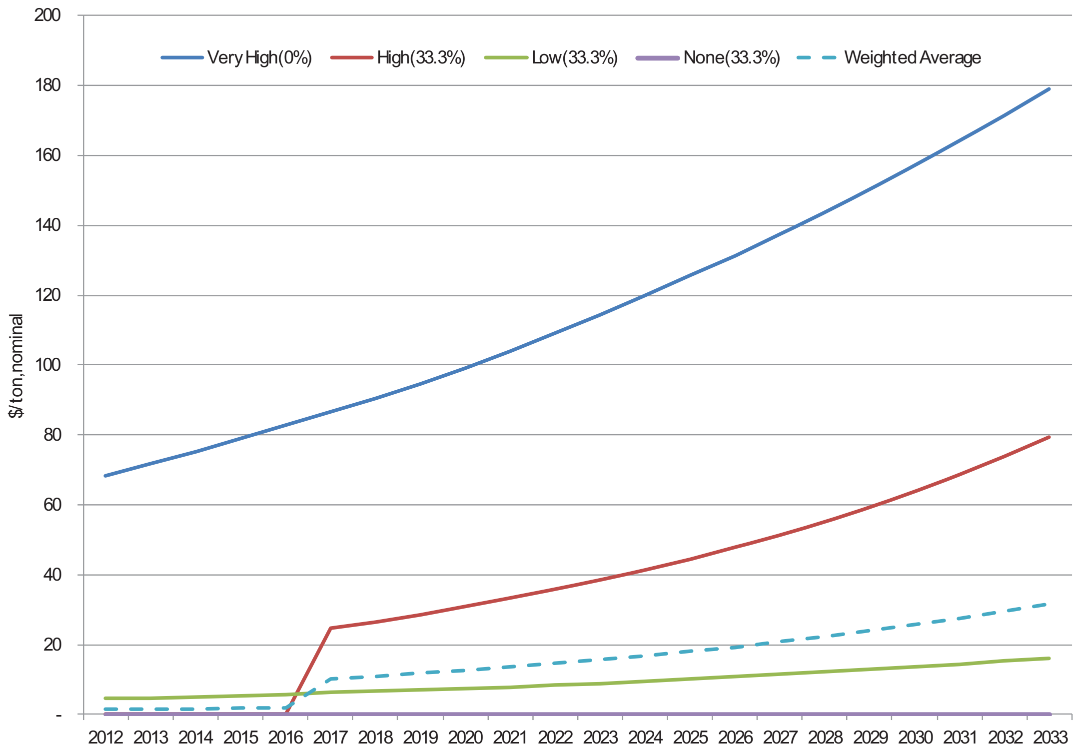
Figure K-10
Annual CO_2 Cost/Price Draws



The Mid-C power price draws in the presence of risks of CO_2 policy are shown in Figure K-11. Note that these power price draws are higher than those power price draws without the risk of CO_2 policy.

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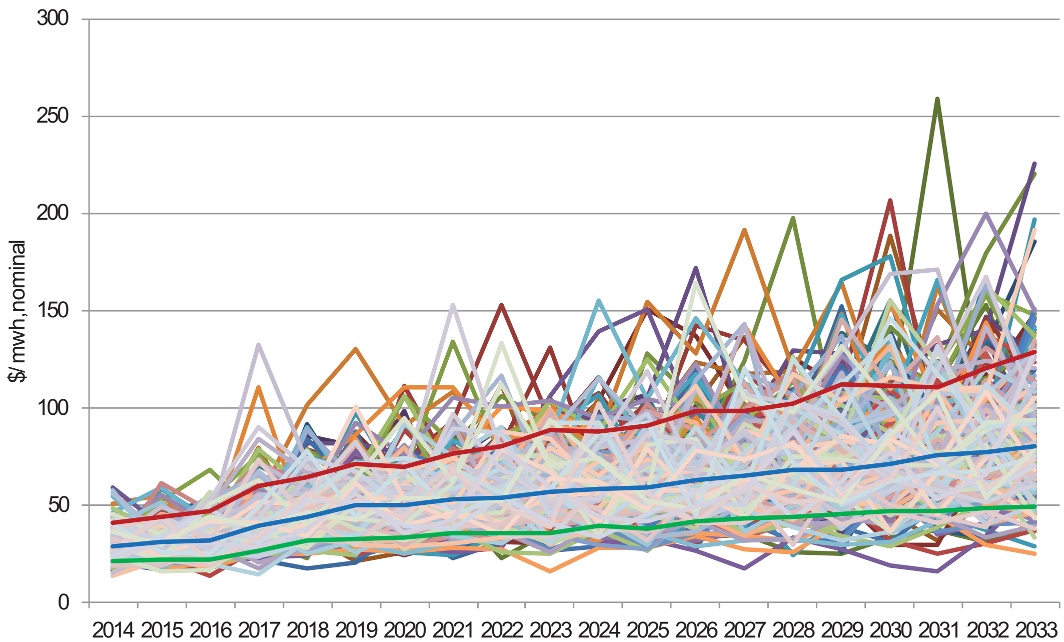
Figure K-11
Annual Mid-C Power Price Draws with Risks of CO_2 Cost/Price Policy



Hydro generation. Monte Carlo draws for each of PSE's hydro projects were obtained using the 70-year historical Pacific Northwest Coordination Agreement Hydro Regulation data (1929-1978). Each hydro year is assumed to have an equal probability of being drawn in any given calendar year in the planning horizon. Capacity factors and monthly allocations are drawn as a set for each of the 250 draws. A different set of 250 hydro draws is applied for each year in the planning horizon. Figure K-12 shows the first 5 draws for the total annual hydro output, while Figure K-13 shows the monthly outputs for these first 5 draws.

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Figure K-12
Annual Outputs from 5 Mid-C Hydro Projects

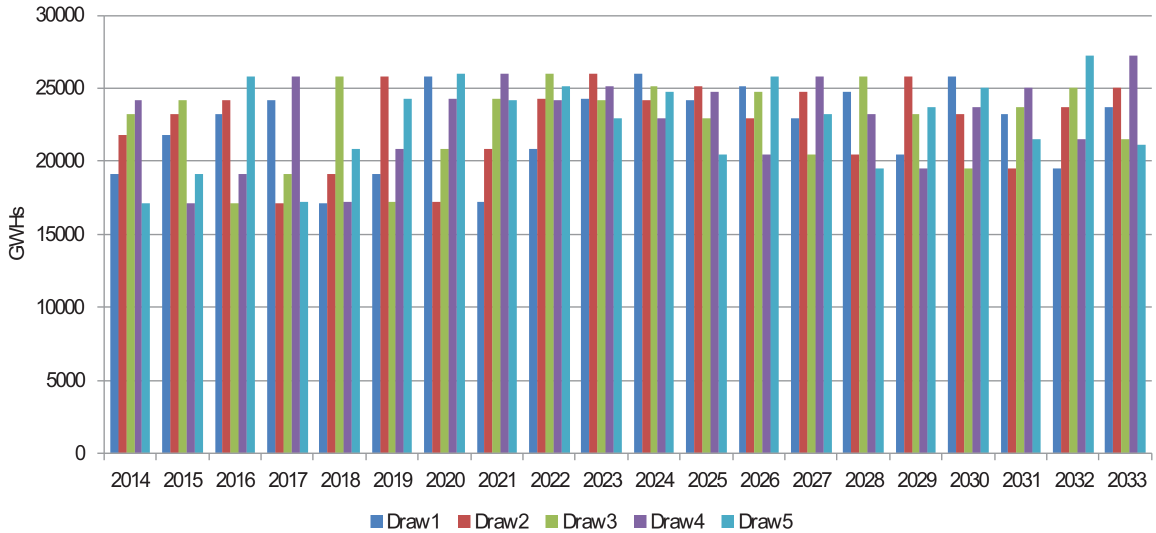
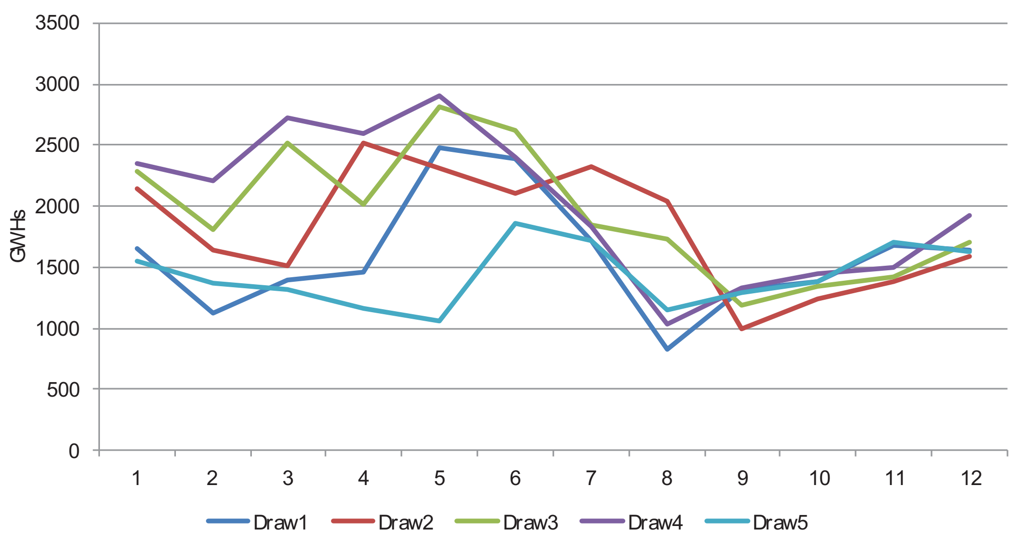


Figure K-13
2014 Monthly Hydro Outputs for 5 Mid-C Hydro Projects

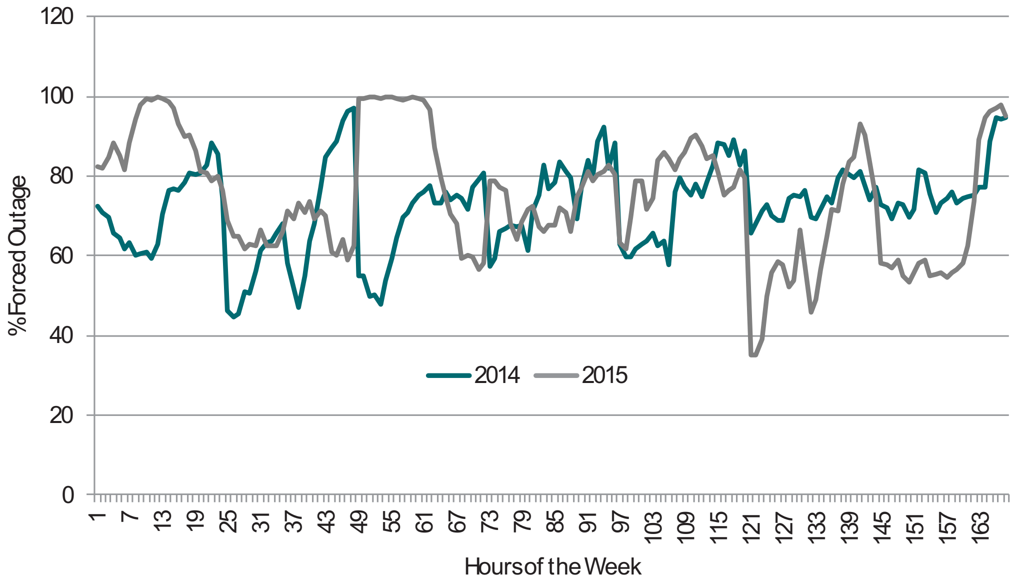


APPENDIX K – ELECTRIC ANALYSIS RESULTS

Wind generation. Since wind is an intermittent resource, one of the goals in developing the generation profile for each wind project considered in this IRP is to ensure that this intermittency is preserved. The other goals are to ensure that correlations across wind farms and the seasonality of wind generation are reflected. The wind distributions were derived from 5 years of historical data from Hopkins Ridge and Wild Horse. Given the limited historical data that is available to generate the 250 hourly wind profiles, draws of daily 24-hour wind profiles are made each month with each day having an equal probability of being chosen until all days in the month are populated. Since draws for each month are based only on daily profiles within each month, the seasonality of wind generation is also preserved. Finally, draws across wind farms are synchronized on a daily basis to preserve any correlations that may exist between Hopkins Ridge and Wild Horse. The Lower Snake River wind farm, which does not have a long historical data record yet, is assumed to have the same wind profile as Hopkins Ridge, with a lag since it is located near Hopkins Ridge, and scaled to its nameplate capacity and pro-forma capacity factor. Finally, the generic wind farm is assumed to have a wind profile distribution similar to that of Hopkins Ridge, scaled to a 100 MW capacity. Again, a different set of 250 draws is used for each of the calendar years in the planning horizon to ensure that there is also weather variation across years. The intermittency of wind generation is modeled as an hourly forced outage rate in AURORAxmp, hence the need to translate the hourly wind generation outputs into forced outage rate [Hourly Forced Outage Rate = 100 percent*(1 – Hourly Generation/Capacity)]. Figure K-14 below shows the hourly forced outage rate draw of a typical week in January for 2014 and 2015. The hourly draw in January 2014 is different from the draw in January 2015 because of the year-to-year variation in weather draws.

APPENDIX K – ELECTRIC ANALYSIS RESULTS

Figure K-14
Example of a Draw of Wind Hourly Forced Outage Rate for a Typical Week in January



Aurora risk modeling of PSE portfolios

The economic dispatch and unit commitment capabilities of AURORAxmp are utilized to generate the variable costs, outputs, and revenues of any given portfolio and input draws. The main advantage of using AURORAxmp is its fast hourly dispatch algorithm for 20 years, a feature that is well known by the majority of Northwest utilities. It also calculates market sales and purchases automatically, and produces other reports such as fuel usage and generation by plant for any time slice. Instead of defining the distributions of the risk variables within AURORAxmp, however, the set of 250 draws for all of the risk variables (power prices, gas prices, CO_2 costs/prices, PSE loads, hydro generation, and wind generation) are fed into the AURORAxmp model. Given each of these input draws, AURORAxmp then dispatches PSE's existing portfolio and all generic resources to market price. The results are then saved and passed on to the PSM III model where the dispatch energy, costs, and revenues for each draw are utilized to obtain the distribution of revenue requirements for each set of generic portfolio builds.

Risk simulation in PSM III

In order to perform risk simulation of any given portfolio in PSM III, the distribution of the stochastic variables must be incorporated into the model. The base case 250 draws of dispatched outputs, costs, and revenues for PSE's existing and generic resources were fed into PSM III from AURORAxmp and the stochastic model as described above. Note that these AURORAxmp outputs have already incorporated the variability in gas and power prices, CO_2 price, PSE's loads, hydro, and wind generation from the stochastic model. Frontline System's Risk Solver Platform Excel Add-On allows for the automatic creation of distributions of energy outputs, costs, and revenues based on the 250 draws that PSM III can utilize for the simulation analysis. In addition, peak load distribution, consistent with the energy load distribution, was incorporated into the PSM III. Given these distributions, the risk simulation function in the Risk Solver Platform allowed for drawing 1,000 trials to obtain the expected present value of revenue requirements, TailVar90, and the volatility index for any given portfolio. In addition to computing the risk metrics for the present value of revenue requirements, risk metrics are also computed for annual revenue requirements and market purchased power costs. The results of the risk simulation are presented in Chapter 5 and in Section 2 of this appendix.

Portfolio Screening Model III

Overview

The risk model used for this IRP combines the strengths of the stochastic model in generating the Monte Carlo draws for the risk variables with the dispatch algorithm in AURORAxmp, plus the financial modeling detail of the portfolio screening model. Given each draw from the stochastic model, the Aurora model generates the variable costs of dispatched generation from existing/new resources and market purchases/sales for all 250 trials. These outputs are then used as inputs into the Portfolio Screening Model, which combines other costs and financial data to generate the revenue requirements. Below is a description of the various models.

APPENDIX K – ELECTRIC ANALYSIS RESULTS

Portfolio Screening Model III

The Portfolio Screening Model III (PSM III for version 3) is a spreadsheet-based capacity expansion model that the company developed to evaluate incremental costs and risks of a wide variety of resource alternatives and portfolio strategies. The model produces the optimal mix of resources using the linear programming dual simplex method that minimizes the present value of portfolio costs subject to planning margin and renewable portfolio standard constraints. Incremental cost includes: (i) the variable fuel cost and emissions for PSE's existing fleet, (ii) the variable cost of fuel emissions and operations and maintenance for new resources, (iii) the fixed depreciation and capital cost of investments in new resources, (iv) the booked cost and offsetting market benefit remaining at the end of the 20-year model horizon or end effects, and (v) the market purchases or sales in hours when resource-dispatched outputs are deficient or surplus to meet PSE's need.

The primary input assumptions to the PSM are:

a) PSE's peak and energy demand forecasts,
b) PSE's existing and generic resources, their capacities and outage rates,
c) expected dispatched energy (MWh), variable cost ($000) and revenue ($000) from AURORAxmp for existing contracts, existing and generic resources,
d) capital and fixed-cost assumptions of generic resources,
e) financial assumptions such as cost of capital, taxes, depreciation, and escalation rates,
f) capacity contributions and planning margin constraints,
g) renewable portfolio targets.

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Mathematical representation of PSM III. The purpose of the optimization model is to create an optimal mix of new generic resources that minimizes the 20-year net present value of the revenue requirement plus end effects (or total costs) given that the portfolio meets the planning margin (PM) and the renewable portfolio standard (RPS), and subject to other various non-negativity constraints for the decision variables. The decision variables are the annual integer number of units to add for each type of generic resources being considered in the model. We may add one or two more constraints later on. The revenue requirement is the incremental portfolio cost for the 20-year forecast.

Let:

gn, gr – index for generic non-renewable and renewable resource at time t, respectively;
xn, xr – index for existing non-renewable and renewable resource at time t, respectively;
d(gn) – index for decision variable for generic non-renewable resource at time t;
d(gr) - index for decision variable for generic renewable resource at time t;

AnnCapCost = annual capital costs at time t for each type of resource (the components are defined more fully in the excel model);
VarCost = annual variable costs at time t for each type of resource (the components are defined more fully in the excel model);
EndEff = end effects at T, end of planning horizon, for each type of generic resource only (the components are defined more fully in the excel model);
ContractCost = annual cost of known power contracts;
DSRCost = annual costs of a given demand side resources;
NetMktCost = Market Purchases less market sales of power at time t;
RECSales = Sales of excess over RPS required renewable energy at time t
Cap = capacities of generic and existing resources, and DSR resources;
PM = planning margin to be met each t;
MWH = energy production from any resource type gn,gx,xn,xr at time t;
RPS = percent RPS requirement at time t;
PkLd = expected peak load forecast for PSE at time t;
EnLd = forecasted Energy Load for PSE at generator without conservation at time t;
LnLs = line loss associated with transmission to meet load at meter;
DSR = demand side resource energy savings at time t;
r = discount rate.

Annual revenue requirement (for any time t) is defined as:

APPENDIX K – ELECTRIC ANALYSIS RESULTS

$$RR_t = \sum_{gn} d(gn)*[AnnCapCost(gn) + VarCost(gn)] + \sum_{gr} d(gr)*[AnnCapCost(gr) + VarCost(gr)] + \sum_{xn} VarCost(xn) + \sum_{xr} VarCost(xr) + ContractCost + DSRCost + NetMktCost - RECSales.$$

a) The objective function for the model is the present value of RR to be minimized. This function is non-linear with integer decision variables.

$$PVRR = \sum_{t=1}^{T} RR_t *[1/(1+r)^t]+ [1/(1+r)^{20}]*[\sum_{gn} d(gn)*EndEff(gn) + \sum_{gr} d(gr)*EndEff(gr)].$$

b) The objective function is subject to two constraints

a. The planning margin was found using the loss of load probability (LOLP) approach. Details about the planning margin can be found later in this appendix. In the model, the planning margin is expressed as a percent, and is used as a lower bound on the constraint. That is, the model must minimize the objective function while maintaining a minimum of this planning margin percent capacity above the load in any given year. Below is the mathematical representation of how the planning margin is used as a constraint for the optimization.

$$\sum_{gn} d(gn)*Cap(gn) + \sum_{gr} d(gr)*Cap(gr) + \sum_{xr} Cap(xr) + \sum_{xn} Cap(xn) \geq PkLd + PM \text{ for all } t;$$

b. PSE is subject to the Washington state renewable target as stated in RCW 19.285. The load input for PSM is the load at generator, so that the company generates enough power to account for line loss and still meet customer needs. The RPS target is set to the average of the previous two years' load at meter less DSR. The model must minimize the objective function while maintaining a minimum of the total RECs need to meet the state RPS. Below is the mathematical representation of how the RPS is used as a constraint for the optimization.

APPENDIX K – ELECTRIC ANALYSIS RESULTS

$$\sum_{gr} d(gr)*MWH(gr) + \sum_{xr} MWH(xr) \geq RPS*\frac{\sum_{t-2}^{t-1}(EnLd*(1-LnLs)-DSR)}{2} \quad \text{for all t;}$$

d(gn), d(gr) ≥ 0, and are integer values for all t,

Other restrictions include total build limits. For example, for the generic wind, 5 plants may be built in a year, for a total of 10 plants over the 20-year time horizon. In the comparison between east and west builds (relative to the Cascade mountain range), the westside natural gas plants were limited to a total of 1,000 MW over the 20 years for both peakers and CCCT.

The model is solved using Frontline System's Risk Solver Platform software that provides various linear, quadratic, and nonlinear programming solver engines in Excel environments. Frontline System is the developer of the Solver function that comes standard with Excel. The software solves this non-linear objective function typically in less than a minute. It also provides a simulation tool to calculate the expected costs and risk metrics for any given portfolio.

End effects

The 2013 IRP calculation of end effects includes the following: 1) A revenue requirement calculation is made for the life of the plant, and 2) replacement costs are added for plants that retire during end effects to put all proposals on equal footing in terms of service level.

Revenue requirement. Revenue requirement for end effects is based on the operational characteristics of the 20th year in the dispatch model and an estimate of dispatch, based on the last 5 years of AURORA dispatch. The revenue requirement calculation takes into account the return on ratebase, operating expenses, book depreciation, and market value of the output from the plant. The operating expenses and market revenues are escalated at standard escalation rate using an average of the last 5 years of AURORA dispatch as the starting point.

Replacement costs on an equivalent life basis. To account for the differences in lives of projects the model includes a replacement resource at the end of the project life in the end effects period. Capacity resources are replaced with an equivalent type and amount of generic capacity resource, while renewable resources are replaced by an equivalent generic wind plant on a REC basis. The fixed capital cost of the replacement resource is added based on the estimated generic resource cost in the year of replacement on a level annual basis – equal annual costs until the end of the end-effects period. The variable cost, market revenue, and fixed operations cost are included based on an estimate of the costs using the standard inflation factor and the dispatch from the last 5 years of AURORA dispatch. By adding replacements in end effects on a levelized cost basis, the model is creating equivalent lives for all the resources. The end-effects period extends 34 years beyond the initial 20-year planning horizon.

Monte Carlo draws for the risk simulation

PSE utilized the 250 draws from the stochastic model as the basis for the 1,000 simulated risk trials. For each of the 1,000 trials, a draw was chosen at random from the 250 draws and the revenue requirement for the portfolio was calculated using all the outputs associated with that draw (Mid-C power price, CO_2 cost/price, Sumas and AECO natural gas prices, hydro generation, wind generation, and PSE load).

3. Key Inputs and Assumptions

Aurora inputs

Numerous assumptions are made to establish the parameters that define the optimization process. The first parameter is the geographic size of the market. In reality, the continental United States is divided into three regions, and electricity is not traded between these regions. The western-most region, called the Western Electricity Coordinating Council (WECC), includes the states of Washington, Oregon, California, Nevada, Arizona, Utah, Idaho, Wyoming, Colorado, and most of New Mexico and Montana. The WECC also includes British Columbia and Alberta, Canada, and the northern part of Baja California, Mexico. Electric energy is traded and transported to and from these foreign areas, but is not traded with Texas, for example.

For modeling purposes, the WECC is divided into 16 areas primarily by state and province, except for California which has three areas, Nevada which has two areas, and Oregon, Washington, Idaho and Montana, which combined have three areas. These areas approximate the actual economic areas in terms of market activity and transmission. The databases are organized by these areas and the economics of each area is determined uniquely.

All generating resources are included in the resource database, along with characteristics of each resource, such as its area, capacity, fuel type, efficiency, and expected outages (both forced and unforced). The resource database assumptions are based on EPIS's 2012.01 version produced in January 2012 with updates to include coal plant retirements, new WECC builds not included in the database and the California Once-Through (OTC) plant retirements. See following sections for more details.

Many states in the WECC have passed statutes requiring Renewable Portfolio Standards (RPS) to support the development of renewable resources. Typically, an RPS state has a specific percentage of energy consumed that must come from renewable resources by a certain date (e.g., 10 percent by 2015). While these states have demonstrated clear intent for policy to support renewable energy development, they also provide pathways to avoid such strict requirements. Further details of these assumptions are discussed in the Section titled "Renewable portfolio standard (WECC)," below.

APPENDIX K – ELECTRIC ANALYSIS RESULTS

Water availability greatly influences the price of electric power in the Northwest. PSE assumes that hydropower generation is based on the average stream flows for the 70 historical years of 1929 to 1998. While there is also much hydropower produced in California and the Southwest (e.g., Hoover Dam), it does not drive the prices in those areas as it does in the Northwest. In those areas, the normal expected rainfall and hence, the average power production, is assumed for the model. For sensitivity analysis, PSE can vary the hydropower availability, or combine a past year's water flow to a future year's needs.

Electric power is transported between areas on high voltage transmission lines. When the price in one area is higher than it is in another, electricity will flow from the low priced market to the high priced market (up to the maximum capacity of the transmission system), which will move the prices closer together. The model takes into account two important factors that contribute to the price: First, there is a cost to transport energy from one area to another, which limits how much energy is moved; and second, there are physical constraints on how much energy can be shipped between areas. The limited availability of high voltage transportation between areas allows prices to differ greatly between adjacent areas. EPIS updates the model to include known upgrades (e.g., Path 15 in California) but the model does not add new transmission "as needed."

Regional Load Forecast

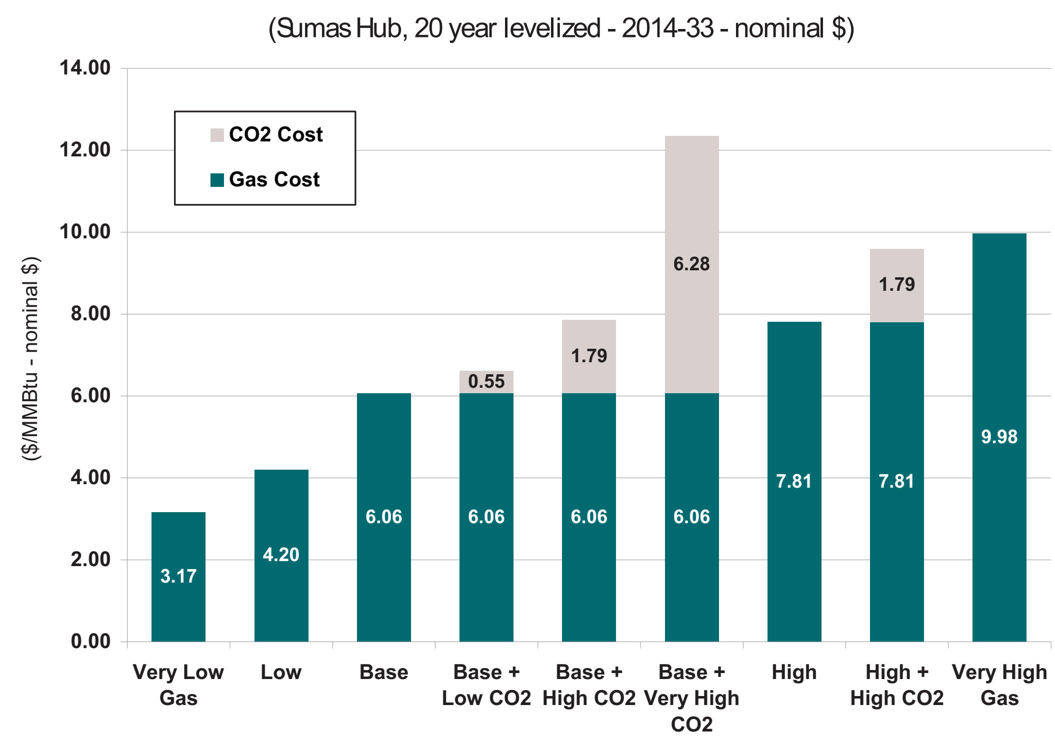
Load forecasts are created for each area. These forecasts include the base-year load forecast and an annual average growth rate. Since the demand for electricity changes over the year and during the day, monthly load shape factors and hourly load shape factors are included as well. All of these inputs vary by area: For example, the monthly load shape would show that California has a summer peak demand and the Northwest has a winter peak. For the 2013 IRP, load forecasts for Oregon, Washington, Montana, and Idaho were based on the Northwest Power and Conservation Council (NPCC) 6thPower Plan preliminary update load forecast, net of conservation.

APPENDIX K – ELECTRIC ANALYSIS RESULTS

Natural Gas Prices

Gas price assumptions for the Base Scenario are a combination of forward market prices and fundamental forecasts acquired in July 2012 from Wood Mackenzie, a well known macroeconomic and energy forecasting consultancy. Wood Mackenzie's gas market analysis includes regional, North American, and international factors, as well as Canadian markets and LNG exports. The full range of gas price assumptions was derived by calculating the relative difference between the Base Scenario gas prices and the very low, low, high, and very high forecasts in the 2011 IRP, and applying those ratios to the 2012 Wood Mackenzie fundamental forecast. Figure K-15, below, illustrates the range of 20-year levelized gas prices and associated CO_2 costs used in these IRP analyses.

Figure K-15
Levelized Gas Prices by Scenario



APPENDIX K – ELECTRIC ANALYSIS RESULTS

CO_2 Price

To capture a range of uncertainty around CO_2 costs, PSE developed the following estimates as inputs.

Base CO_2 Cost. $0 per ton. This estimate is based on existing Washington law RCW 80.70, which applies to new fossil fuel-fired thermal generation built within the state. The law's cost can be reflected on a per ton basis or as a one-time expense included in the facility's construction cost. The 2011 IRP tracked the cost at $0.32 per ton; to simplify modeling, this IRP incorporates the cost as a one-time expense. Base CO_2 cost was modeled in all scenarios except the four that specify Low, High, or Very High CO_2 cost in their names.

Low CO_2 Cost. $6 per ton in 2014 to $20 per ton in 2033. This estimate is based on the lowest cost estimate in the *Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis under Executive Order 12866*.[2] This cost was used as an internal CO_2 penalty that affects fossil fuel costs and dispatch. Low CO_2 cost was modeled in the Base + Low CO_2 Cost scenario.

High CO_2 Cost. $25 per ton in 2017 to $80 per ton in 2033. This estimate was developed using the CO_2 prices modeled and published by the Environmental Protection Agency (EPA) in their analysis of the Kerry-Lieberman "American Power Act" cap-and-trade scheme. In this environment, CO_2 costs are reflected in gas prices and power prices. High CO_2 cost was included in the Base + High CO_2 Cost and High (load & gas price) + High CO_2 Cost scenarios.

Very High CO_2 Cost. $75 per ton in 2014 to $179 per ton in 2033. This estimate is based on the highest cost estimate in the *Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis under Executive Order 12866*.[3] This cost was used as an internal CO_2 penalty that affects fossil fuel costs and dispatch. Very High CO_2 cost was modeled in the Base + Very High CO_2 Cost scenario.

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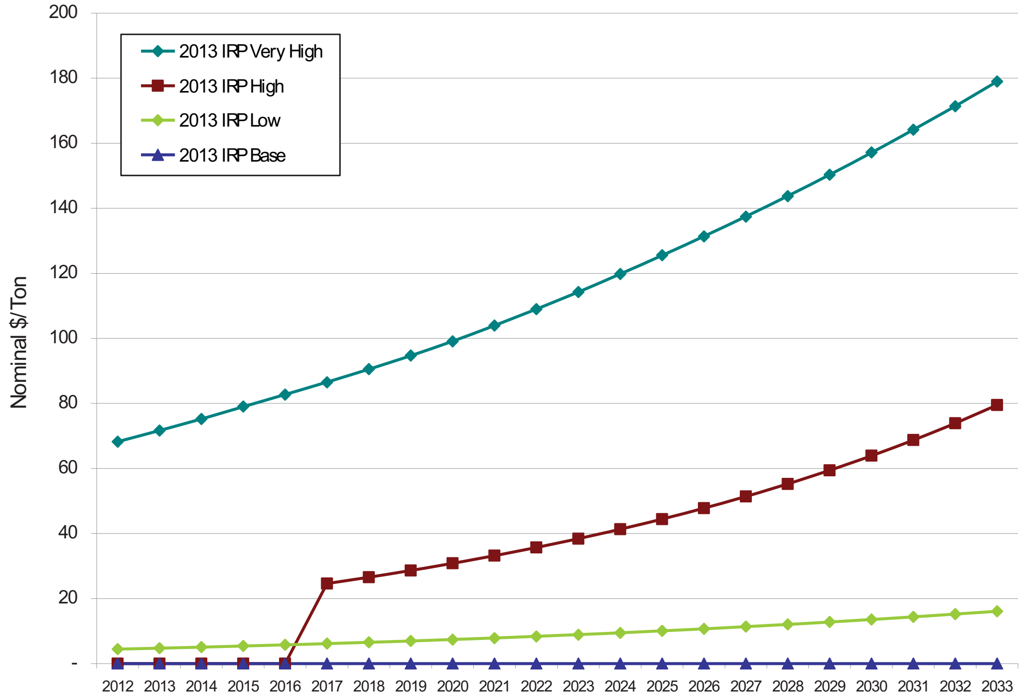
[2] *The study can be found on the Environmental Protection Agency's website.*
[3] *Ibid*

APPENDIX K – ELECTRIC ANALYSIS RESULTS

The range of CO_2 costs used in the IRP is illustrated below in Figure K-16.

Figure K-16.
CO_2 Costs Used in the Analysis



APPENDIX K – ELECTRIC ANALYSIS RESULTS

Annual CO_2 Costs (Nominal $/Ton)

	Base	Low	High	Very High
2014	-	5.10	-	75.24
2015	-	5.44	-	79.02
2016	-	5.80	-	82.69
2017	-	6.19	24.64	86.52
2018	-	6.57	26.56	90.53
2019	-	6.98	28.64	94.72
2020	-	7.41	30.88	99.11
2021	-	7.87	33.21	103.92
2022	-	8.35	35.71	108.97
2023	-	8.89	38.41	114.25
2024	-	9.46	41.31	119.80
2025	-	10.06	44.42	125.61
2026	-	10.71	47.78	131.38
2027	-	11.39	51.38	137.41
2028	-	12.08	55.26	143.72
2029	-	12.80	59.43	150.31
2030	-	13.57	63.91	157.21
2031	-	14.39	68.74	164.15
2032	-	15.25	73.92	171.40
2033	-	16.09	79.50	178.97

Emission standards / coal retirements

PSE added constraints on coal technologies to the AURORA model in order to reflect current political and regulatory trends. Specifically, no new coal builds were allowed in any state in the WECC. In addition, all the coal plants in the WECC must meet the National Ambient Air Quality Standards (NAAQS) and the Mercury and Air Toxics Standards (MATS). Any plant that did not meet these standards and did not have plans to retrofit was assumed to retire. All data came from the National Electric Energy Data System (NEEDS) v4.10.

APPENDIX K – ELECTRIC ANALYSIS RESULTS

Figure K-17

Total Coal Retirement	MW
Planned Retirement (2014 – 2025)	3,567
Assumed Retirement (2014)	1,123
Total	4 690

California OTC

On May 4, 2010, the State Water Resources Board of California adopted a statewide water quality control policy on the use of Once-Through-Cooling (OTC) power plants (nuclear and non-nuclear facilities). This policy establishes requirements for the implementation of the Clean Water Act Section 316 (b), using best professional judgment in determining best technology available (BTA) for cooling intake structures at existing coastal and estuarine plants. For the 2013 IRP we followed the retirement/replacement schedule from the WECC Transmission Expansion Planning Policy Committee (TEPPC) 2022 Common Case and Los Angeles Department of Water and Power (LADWP) Implementation Plan April 2011.

Figure K-18
California OTC Impacts on Plant Retirements and Replacements

MW Nameplate	2013 2017	2018 2023	2024 2030
Retirement	(6,217)	(6,568)	(1,124)
Replacement	1,150		
Cumulative Total	(5 067)	(11 635)	(12 761)

WECC builds assumptions

For the 2013 IRP we used the 2012.01 AURORAxmp database, but updated the resources table to include the latest builds with known commercial online dates, including renewable resources to meet the states' RPS requirements, and retirements in the

APPENDIX K – ELECTRIC ANALYSIS RESULTS

WECC. All data came from the SNL energy database[4] as of July 2012. Figure K-19 provides the build assumptions for each of the WECC areas.

Figure K-19

MW Nameplate	California	Pacific North est	South est	Rocky Mountain	Total
Solar	2,981	2	769	5	3,757
Other Renewable	103	126	80	22	331
Wind	1,298	1,867	152	36	3,353
Thermal	*5,930	319	87	1,330	7,665
Total	10,313	2,313	1,088	1,392	15,106

*Includes OTC replacement

Production Tax Credit assumptions

The Production Tax Credit (PTC) is a subsidy identified in the American Recovery and Reinvestment Act of 2009 (ARRA) for production of renewable energy. In January 2013, the American Taxpayer Relief Act of 2012 (H.R. 6, Sec. 407) removed the "placed in service dates" for eligibility and replaced this language with "begins construction in 2013." Currently, the PTC amounts to approximately $22 (in 2012 dollars) per MWh for 10 years of production after a project is placed into service. The PTC is indexed for inflation. The Base Scenario assumes no further PTCs are available for new resource development as of 2014.

Investment Tax Credit assumptions

The Investment Tax Credit (ITC) currently amounts to 30 percent of the eligible capital cost for renewable resources; it expires at the end of 2013. These scenarios assume no extension of ITCs.

[4] *SNL, which stands for Savings and Loan, is a company that collects and disseminates corporate, financial and market data on several industries including the energy sector (www.snl.com).*

APPENDIX K – ELECTRIC ANALYSIS RESULTS

Treasury Grant

The Treasury Grant (Grant) is subsidy that amounts to 30 percent of the eligible capital cost for renewable resources; it also expires at the end of 2013. For projects placed in service in 2013, construction must have started in 2009, 2010, or 2011 and the project must meet eligibility criteria. This subsidy differs from the previous two in that it is a cash payment from the federal government, versus a tax credit. No extension of the Treasury Grant is assumed.

Renewable portfolio standard (WECC)

Renewable portfolio standards (RPS) currently exist in 29 states and the District of Columbia, including most of the states in the WECC and British Columbia. They affect PSE because they increase competition for development of renewable resources. Each state and territory defines renewable energy sources differently, sets different timetables for implementation, and establishes different requirements for the percentage of load that must be supplied by renewable resources.

To model these varying laws, PSE first identifies the applicable load for each state in the model and the renewable benchmarks of each state's RPS (e.g. 3 percent in 2015, then 15 percent in 2020, etc.). Then we apply those requirements to each state's load. No retirement of existing WECC renewable resources is assumed, which perhaps underestimates the number of new resources that need to be constructed. After existing and "proposed" renewable energy resources are accounted for, "new" renewable energy resources are matched to the load to meet the applicable RPS. Following an internal and external review for reasonableness, these resources are created in the AURORA database. Technologies included wind, solar, biomass, and geothermal. Creation of RPS resources was guided by estimates of potential production by states that appear in the "Renewable Energy Atlas of the West," which can be found at www.dsireusa.gov. These vary considerably depending on local conditions; Arizona, for example, has little wind potential but great solar potential.

The table below includes a brief overview of the RPS for each state in the WECC that has one. The "Standard" column offers a summary of the law, as provided by the Lawrence Berkeley National Laboratory (LBNL), and the "Notes for AURORA Modeling" column includes a description of the new renewable resources created to meet the law.

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Figure K-20
RPS Requirements for States in WECC

State	Standard (BN)	Notes for AUR RA Modeling
Arizona	New Proposed RPS: 1.25% in 2006, increasing by 0.25% each year to 2% in 2009, then increasing by 0.5% a year to 5% in 2015, and increasing 1% a year to 14% in 2024, and 15% thereafter. Of that, 5% must come from distributed renewables in 2006, increasing by 5% each year to 30% by 2011 and thereafter. Half of distributed solar requirement must be from residential application; the other half from non-residential non-utility applications. No more than 10% can come from RECs, derived from non-utility generators that sell wholesale power to a utility.	Very little potential wind generation is available. Most of the requirement is met with central solar plants. The distributed solar (30%) is accounted for by assuming central renewable energy.
British Columbia	Clean renewable energy sources will continue to account for at least 90% of generation. 50% of new resource needs through 2020 will be met by conservation.	The assumption is that a majority of this need will be met by hydropower and wind.
California	IOUs must increase their renewable supplies by at least 1% per year starting January 1, 2003, until renewables make up 20% of their supply portfolios. The target now is to meet 20% level by 2010, with potential goal of 33% by 2020. IOUs do not need to make annual RPS purchases until they are creditworthy. CPUC can order transmission additions for meeting RPS under certain conditions.	The California Energy Commission created an outline of the necessary new resources by technology that could meet the 20% by 2010 goal. Technologies include wind, biomass, solar and geothermal in different areas of the state The renewable energy resources identified in the outline were incorporated into the model.
Colorado	HB 1281 -Expands the definition of "qualifying retail utility" to include providers of retail electric services, other than municipally owned utilities, that serve 40,000 customers or less. Raises the renewable energy standard for electrical generation by qualifying retail utilities other than cooperative electric associations and municipally owned utilities that serve more than 40,000 customers to 5% by 2008, 10% by 2011, 15% by 2015, and 20% by 2020. Establishes a renewable energy standard for cooperative electric associations and municipally owned utilities that serve more than 40,000 customers of 1% by 2008, 3% by 2011, 6% by 2015, and 10% by 2020. Defines "eligible energy resources" to include recycled energy and renewable energy resources.	The primary resource for Colorado is wind. The 4% solar requirement is modeled as central power only.

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State	Standard (BN)	Notes for AUR RA Modeling
Montana	5% of sales (net of line losses) to retail customers in 2008 and 2009; 10% from 2010 to 2014; and 15% in 2015 and thereafter. At least 50 MW must come from community renewable energy projects during 2010 to 2014, increasing to 75 MW from 2015 onward. Utilities are to conduct RFPs for renewable energy or RECs and after contracts of at least 10 years in length, unless the utility can prove to the PSC the shorter-term contracts will provide lower RPS compliance costs over the long-term. Preference is to be given to projects that offer in-state employees or wages.	The primary source for Montana is wind. The community renewable resources are modeled as solar units of 50 MW then 25 MW.
Nevada	6% in 2005 and 2006 and increasing to 9% by 2007 and 2008, 12% by 2009 and 2010, 15% by 2011 and 2012, 18% by 2013 and 2012, ending at 20% in 2015 and thereafter. At least 5% of the RPS standard must be from solar (PV, solar thermal electric, or solar that offsets electricity, and perhaps even natural gas or propane) and not more than 25% of the required standard can be based on energy efficiency measures.	The Renewable Energy Atlas shows that considerable geothermal energy and solar energy potential exists. For modeling the resources are located in the northern and southern part of the state respectively, with the remainder made up with wind.
New Mexico	Senate Bill 418 was signed into law in March 2007 and added new requirements to the state's Renewable Portfolio Standard, which formerly required utilities to get 10% of their electricity needs by 2011 from renewables. Under the new law, regulated electric utilities must have renewables meet 15% of their electricity needs by 2015 and 20% by 2020. Rural electric cooperatives must have renewable energy for 5$ of their electricity needs by 2015, increasing to 10% by 2020. Renewable energy can come from new hydropower facilities, from fuel cells that are not fossil-fueled, and from biomass, solar, wind, and geothermal resources.	New Mexico has a relatively large amount of wind generation currently for its small population. New resources are not required until 2015, at which time they are brought in as wind generation.
Oregon	Large utility targets: 5% in 2011, 15% in 2015, 20% in 2020 and 25% in 2025. Large utility sales represented 73% of total sales in 2002. Medium utilities 10% by 2025. Small utilities 5% by 2025.	We followed the the NWPCC 6th Power Plan assumption for REC banking in the state of Oregon.
Utah	Utah enacted The Energy Resource and Carbon Emission Reduction Initiative (S.B. 202) in March 2008. While this law contains some provisions similar to those found in renewable portfolio standards (RPSs) adopted by other states, certain other provisions in S.B. 202 indicate that this law is more accurately described as a renewable portfolio goal (RPG). Specifically, the law requires that utilities only need to pursue renewable energy to the extent that it is "cost-effective" to do so. Investor-owned utilities, municipal utilities and cooperative utilities must meet 20% of their 2025 adjusted retail electric sales.	

State	Standard (BN)	Notes for AUR RA Modeling
Washington	Washington state RPS: 3% by 2012, 9% by 2016, 15% by 2020. Eligible resources include wind, solar, geothermal, biomass, tidal. Oregon officials have been discussing the need for an RPS.	Assumed any new generic renewables will meet the criteria for the extra 20% REC credit.

Renewable portfolio standard (PSE)

The current PSE resources that meet the Washington state RPS include Hopkins Ridge, Wild Horse, Klondike III, Snoqualmie Upgrades, Lower Snake River I, and Lower Baker Upgrades. The Washington state RPS also gives an extra 20 percent credit to renewable resources that use apprenticeship labor. That is, with the adder a resource can contribute 120 percent to RCW 19.285. The PSE resources that can claim the extra 20 percent are Wild Horse Expansion, Lower Snake River I, and Lower Baker Upgrades. For modeling purposes, we assume that the generic wind receives the extra 20 percent.

Generic resource costs and characteristics

Figure K-21
Generic Resource Costs and Characteristics

2012 $	Units	CCCT	Frame Peaker / il	Frame Peaker /o il	Recip Engine	Wind
Capacity	MW	377	221	221	18	100
Capital Cost	$/KW	$1,540	$915	$879	$2,186	$2,019
O&M Fixed	$/KW-yr	$22.06	$19.91	$10.99	$40.57	$23.16
O&M Variable	$/MWh	$0.42	$0.44	$0.44	$1.80	$3.00
Forced Outage Rate	%	3%	3%	3%	3%	
Wind Capacity Factor	%					30%
Capacity Credit	%	100%	100%	100%	100%	4%
Operating Reserves	%	7%	7%	7%	7%	5%
Heat Rate – GT	Btu/KWh	6,822	10,231	10,231	8,370	
Heat Rate – DF	Btu/KWh	8,972				
Westside	Location	West of Cascades	West of Cascades	West of Cascades	West of Cascades	
Fixed Gas Transport	$/KW-yr	$43.23	$0.00	$66.94	$54.77	
Variable Gas Transport	$/MWh	$0.04	$0.24	$0.04	$0.04	
Fixed Transmission	$/KW-yr	$0.00	$0.00	$0.00	$0.00	
Variable Transmission	$/MWh	$0.00	$0.00	$0.00	$0.00	
Eastside	Location	East of Cascades	East of Cascades	East of Cascades	East of Cascades	East of Cascades
Fixed Gas Transport	$/KW-yr	$27.86	$0.00	$43.13	$35.29	
Variable Gas Transport	$/MWh	$0.01	$0.05	$0.01	$0.01	
Fixed Transmission	$/KW-yr	$17.47	$17.47	$17.47	$17.47	$31.79
Variable Transmission	$/MWh	$0.00	$0.00	$0.00	$0.00	$1.99
Emissions:						
SO_2	lbs/MMBtu	0.010	0.010	0.010	0.010	
NO_x	lbs/MMBtu	0.007	0.009	0.009	0.009	
CO_2	lbs/MMBtu	115.9	115.9	115.9	115.9	
First Year Available		2018	2016	2016	2016	2016

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The generic combined-cycle combustion turbine (CCCT) is assumed to be an F class frame gas turbine 1x1 facility with a wet-cooled condenser. The frame peaker is also assumed to be the same F class frame gas turbine as the CCCT.

Figure K-22
Gas Transport for Power Generation

Westside CCCT & Peakers – 100% Sumas on NWP + 50% Station 2 on Westcoast

	Fixed Demand ($/Dth/day)	Variable Commodity ($/Dth)	ACA Charge ($/Dth)	Fuel Use (%)	Utility Taxes (%)
NWP Expansion (1)	0.500	0.030	0.0018	1.90%	
Westcoast @ 50%	0.210	0.010		1.60%	
Storage (@ 20% of Demand) (2)	0.037	0.000		2.00%	
Total	0.747	0.040	0.0018	5.50%	3.852%

Eastside CCCT & Peakers – 100% AECO on GTN/Nova/Foothills

	Fixed Demand ($/Dth/day)	Variable Commodity ($/Dth)	ACA Charge ($/Dth)	Fuel Use (%)	Utility Taxes (%)
NOVA (TC-AB)	0.170	0.00		0%	
Foothills (TC-BC)	0.097	0.00		1.10%	
GTN to Stanfield	0.177	0.004	0.0018	1.39%	
Storage (@ 20% of Demand) (2)	0.037	0.000		2.00%	
Total	0.481	0.004	0.0018	4.49%	(3)

Westside Peakers without Oil Back-up – without Firm Gas Transport

	Fixed Demand ($/Dth/day)	Variable Commodity ($/Dth)	ACA Charge ($/Dth)	Fuel Use (%)	Utility Taxes (%)
NWP Expansion Demand (1)		0.238		-	
NWP Expansion Commodity (1)		-0.002	0.0018	0.00%	
Storage (@ 20% of Demand) (2)	0.000	0.000		0.00%	
Total	0.000	0.236	0.0018	0.00%	3.852%

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Eastside Peakers without Oil Back-up – without Firm Gas Transport

	Fixed Demand ($/Dth/day)	Variable Commodity ($/Dth)	ACA Charge ($/Dth)	Fuel Use (%)	Utility Taxes (%)
Nova + Foothills + GTN Demand		0.051		-	
Nova + Foothills + GTN Commodity		0.000	0.0018	0.00%	
Storage (@ 20% of Demand) (2)	0.000	0.000		0.00%	
Total	0.000	0.051	0.0018	0.00%	(3)

(1) Estimated NWP Sumas to PSE Expansion
(2) Storage requirements are based on current storage withdrawal capacity to peak plant demand for the gas for power portfolio (approximately 20%)
(3) Assume Eastside plants located in Oregon near Stanfield.

Peakers with oil back-up. The assumptions used to model the 2-day back-up as part of the total costs for PSE's generic peaker were based on cost estimates provided by Black & Veatch in 2010 along with market data for the price of fuel oil. Back-up fuel was included to model a scenario in which PSE's peaker would rely on a non-firm gas supply when available and then switch to the oil back-up when needed. The 2013 IRP assumed that non-firm gas supply would be unavailable 2 days a year and thus it assumed that a peaker would require continuous fuel oil back-up for the entire 48 hours over these 2 days. The proposed storage tank was assumed to hold 1 million gallons of Ultra Low Sulfur Diesel oil which is a sufficient quantity to run the peaker at full capacity for 48 hours. Black and Veatch estimated that the cost of the 1 million gallon above ground fuel storage tank along with all associated infrastructure needed to connect to the peaker was $3MM. The price of Ultra Low Sulfur Diesel oil was assumed to be $3/gallon based on market data, and thus the cost of a full 1 million gallon tank was modeled at $3MM.

Emissions performance standards. Generic peakers and CCCT units in the 2013 IRP were evaluated with regard to the new Emissions Performance Standards outlined by the EPA in 2012. During 2012, the EPA proposed a New Source Performance Standard (NSPS) under section 111 of the Clean Air Act to limit the CO_2 emissions for what it refers to as new Electric Utility Generating units (EGUs). The EPA defines an EGU as any steam electric generating unit or stationary combustion turbine that is constructed for the purpose of supplying more than one‐third of its potential electric output capacity and more than 25 MW net‐electrical output to any utility power distribution system for sale. The NSPS states that all new EGUs must meet a CO_2 Emissions requirement of 1,000 lbs/MWh to comply with the standard. The EPA states that simple-cycle units (peakers) are not subject to the NSPS since they are not intended to provide base-load capacity. All generic CCCT options evaluated in the 2013 IRP were in compliance with the NSPS. In addition, all costs for generic CCCT and peakers evaluated in the 2013 IRP included the cost of a selective catalytic reduction (SCR) system for reduction of NO_x emissions.

Financial assumptions

Discount rate

We used the pre-tax weighted average cost of capital (WACC) from the 2011 General Rate Case of 7.8 percent nominal or 6.7 percent after-tax.

REC price

The REC price starts at $3/MWh in 2014 and escalates to $14/MWh in 2033. The escalation rate is not uniform for the whole 20-year planning horizon. Major increases occur in 2016 and 2020 with an approximate 70 percent increase, corresponding to the RPS increase. All other years use a 2.5 percent escalation.

Inflation rate

The 2013 IRP uses a 2.5 percent escalation for all assumptions unless otherwise noted. This is the long-run average inflation rate that the AURORAxmp model uses.

Transmission inflation rate

In 1996, the BPA rate was $1.000/kW-yr and the estimated total rate in 2015 is $1.798/kW-yr. Using the compounded average growth rate (CAGR) of BPA Point-to-Point (PTP) transmission service (including fixed ancillary service Scheduling Control and

Dispatch) from 1996 to 2015, we estimated the nominal CAGR inflation rate to be 3.09 percent annually.

Gas transport inflation rate

Natural gas pipeline rates are not updated often and recent history indicates that the rates have been increasing at approximately 1.25 percent annually.

Planning standard

In the 2011 IRP, PSE adopted a planning margin of 15.7 percent for capacity plus relevant operating reserves. PSE's planning margin is net of operating reserves to allow for modeling different resource types which are required to carry different levels of operating reserves. For example, peakers must carry 7 percent contingency reserves, but demand-side resources have none. The modeling approach used to develop the planning margin is consistent with the Loss of Load Probability approach used by the NW Regional Resource Adequacy Forum [5] that is common in other parts of the country. PSE values the NW Regional Resource Adequacy Forum's work on resource adequacy. It is the best assessment of energy security available in the region and PSE actively participates on both the steering committee and technical committee.

Given the changes in PSE's existing portfolio and updates to the load forecasts, it is imperative that the planning margin is updated to determine if the existing planning margin is still applicable for the 2013 IRP. The following summarizes the updates made to the Loss of Load Probability (LOLP) model to derive the new planning margins for this IRP. We begin by reviewing the LOLP model, followed by a summary of the updates. Finally, we present the detailed results of the updates.

[5] *A description of the NW Regional Resource Adequacy Forum and the standards adopted can be found at: http://www.nwcouncil.org/energy/resource/Default.asp*

APPENDIX K – ELECTRIC ANALYSIS RESULTS

LOLP model overview

The primary objective of PSE's capacity planning standard analysis was to determine the appropriate level of planning margin for the utility. Planning margin for capacity is, in general, defined as the appropriate level of generation resource capacity reserves required to provide for a minimum acceptable level of system generation reliability.[6] This is one of the key constraints in any capacity expansion planning model, because it is important to maintain a uniform reliability standard throughout the planning period to obtain comparable capacity expansion plans. This planning margin is measured as:

Planning Margin = (Generation Capacity – Normal Peak Loads)/Normal Peak Loads.

The appropriate level of planning margin is typically identified in terms of its relationship with the loss of load probability (LOLP). LOLP is further defined as the probability of system loads greater than resource capability in any given hour, or

LOLP = Probability [-(Generation Capacity-Loads)>0].

Thus, as the reserve margin increases, one would expect that the LOLP also decreases. Because of uncertainties in loads due to extreme temperature events and resource capabilities due to outages and operating reserves, it is necessary to examine the probabilities using a Monte Carlo analysis. The LOLP approach is therefore a stochastic risk assessment framework to understand generation reliability given the risks in loads and resources. The framework provides reliability/risk metrics (likelihood, severity, and duration of outages) that can be used to develop capacity standards, and allows for understanding the relative contribution to peak reliability of different resource types (thermals, wind, energy storage, contracts, etc.).

The resources included in this analysis are Colstrip, Mid-Columbia and western Washington hydroelectric resources, several gas plants (simple- and combined-cycle units), purchased power contracts, several wind projects, and market purchases up to the available transmission capability. The following sources of variation were considered:

1. Forced Outage Rate for Thermal Units - modeled as a combination of an outage event and duration of an outage event (skewed beta distribution with

[6] *Details of LOLP approach can be found in* *http://pnucc.org/sites/default/files/ReservesinCapacityPlanningFinal.pdf*

fixed endpoints), subject to minimum up and down time conditions and total outage rate equal to GRC reported outage rate;

2. Hourly System Loads – modeled as an econometric function of hourly temperature for the month, and using the hourly temperature data for each year from 1950 to 2011 to preserve its chronological order;

3. Mid-Columbia and Baker Hydropower – modeled as a uniform distribution using the 70-year historical Pacific Northwest Coordination Agreement Hydro Regulation data, and further adjusted so that it is shaped to PSE load and to account for peak contributions for several sustained peaking periods (1-hour peak to 12-hour sustained peak);

4. Market Purchases – based on available transmission, which is a risk input because the available transmission is affected by Mid-Columbia hydro output and output from Wild Horse wind project;

5. Load Forecast Error – modeled as a discrete distribution so that load error is +/- 1 percent for 60 percent of the trials, with a range of +/-3.5 percent;

6. Wind – drawn randomly from historical hourly data for Wild Horse and Hopkins Ridge, but constrained for the following: a) draws of daily 24-hour wind profiles are made each month with each day having an equal probability of being chosen until all days in the month are populated to preserve seasonality; b) draws across wind farms are synchronized on a daily basis to preserve any correlations that may exist between Hopkins Ridge and Wild Horse; c) Lower Snake River wind farm, which has no long historical data record yet, is assumed to have the same wind profile as Hopkins Ridge, with a 10-minute lag since it is located near Hopkins Ridge, and is scaled to its nameplate capacity and pro-forma capacity factor.

As mentioned above, loss of load probability is defined as the number of trials where PSE observed a loss of load event over the total number of trials. An event is a trial or draw in which one or more hours show that resources are lower than load plus operating reserves. However, contingency reserves cover forced outage for the first hour, so this is not considered as an event for the LOLP calculation. 3,000 hourly trials/draws were conducted for the sample periods or seasons. Such a large number was chosen because at this level the resulting loss of load frequency becomes very stable. LOLP then is the

APPENDIX K – ELECTRIC ANALYSIS RESULTS

sum of events over the 3,000 trials/draws for each measurement period/season, or the frequency/likelihood of events. The simulation is done for all hours in the year so measurements can be taken for any defined period or season.

The goal of the simulation analysis for any hour is to run the simulation for the existing resource and load conditions, which imply an existing reserve margin. Loss of load probability associated with this reserve margin is then computed based on the 3,000 Monte Carlo draws of the risk variables. Generating capacity is then incremented using a CT plant as the "typical" peaking plant added which results in a higher reserve margin. Again, the loss of load probability associated with this higher reserve margin is computed based on the Monte Carlo simulation of the risk variables. The process is repeated until the loss of load probability is reduced to an industry standard level. PSE uses the 5 percent LOLP to define its capacity need/standard. This is consistent with the Northwest Power and Conservation Council's standard for the region (see footnote 4). Further, the LOLP metric is defined over the winter season since PSE is still a winter peaking utility.

Model updates for the 2013 IRP

Since the 2011 IRP, the following updates were made to the LOLP model:

- Weather-sensitive demand-side resources varied with the temperature draws;

- Mid-Columbia hydro was shaped to load, and its peak contribution was adjusted to account for sustained peaking;

- Wind profiles were updated to account for new historical data, plus the wind profile for the Klondike wind project was added;

- Monthly capacities for existing thermal plants were updated including their maintenance schedule, while the available Mid-C transmission was updated to reflect updates on all transmission contracts;

- A new thermal plant and a purchased power contract were added: Ferndale combined-cycle plant and the coal transition contract with TransAlta, respectively;

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- The latest load forecast, 2013 IRP Demand Forecast, was utilized for this study which includes new draws for hourly temperature profiles and updated hourly equations;

- The measurement period for the LOLP metric is the winter season (November to February) since LOLP events are likely to occur any time during the winter;

- Finally, we tested several winter seasons (Winter 2014-2015, Winter 2018-2019, and Winter 2023-2024) to ensure that changes in loads and resources are covered.

LOLP results

Figure K-23 illustrates the relationship between planning margin net of operating reserves and winter season LOLP for the two winter periods 2014-2015 and 2018-2019. LOLP declines as planning margin increases due to the addition of a peaking unit. For this two test periods, the 5 percent LOLP mark is reached when planning margin net of operating reserves is just below 15 percent.

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Figure K-23
LOLP versus Planning Margin

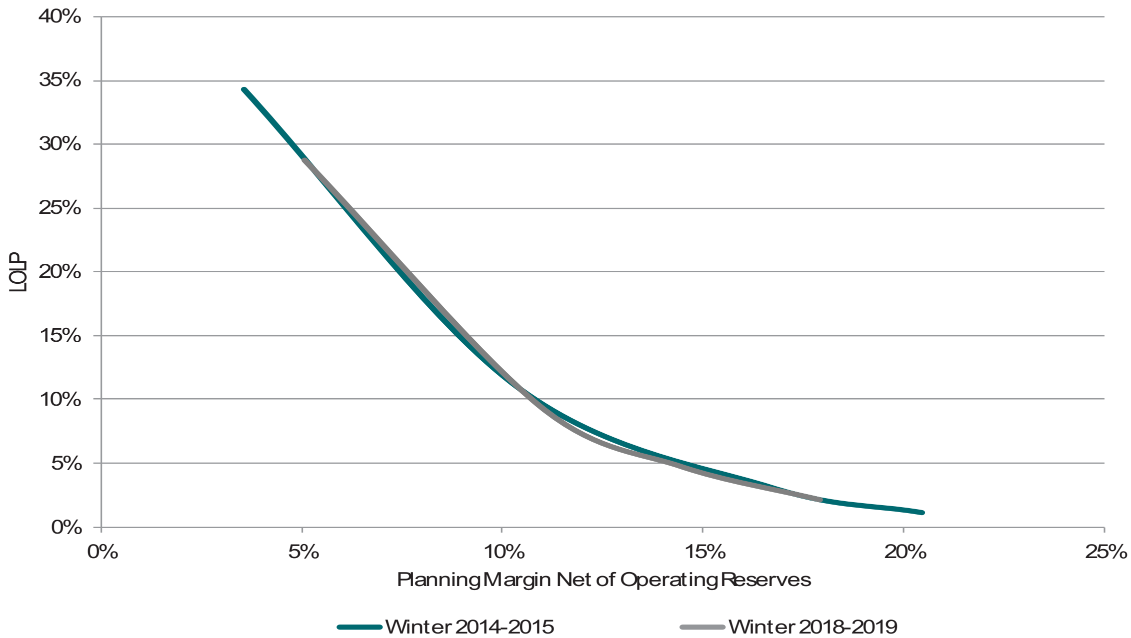

Table K-24 below shows a comparison of the 2013 IRP planning margins net of operating reserves at 5 percent LOLP for the test winter seasons. The lower margins near term are due to load forecast revisions and resource additions. It is worth noting that winter season margins capture more than 95 percent of the annual deficit events.

Table K-24

	Planning Margins Net of per Reserves 5% P		
	Winter 2014-2015	Winter 2018-2019	Winter 2023-2024
IRP2013-Winter Season	13.5%	14.0%	16.0%
IRP2011-Highest Need Month	15.7%	15.7%	15.7%

With the updated planning margins, the present value of revenue requirements is slightly higher as compared to the present value of revenue requirements using the 15.7 percent planning margin. Below is a table comparing the present value of revenue requirements of the old planning margin of 15.7 percent versus the updated planning margin for the 2013 IRP. The difference is a 0.07 percent increase in the revenue requirements because a lower level of DSR is needed.

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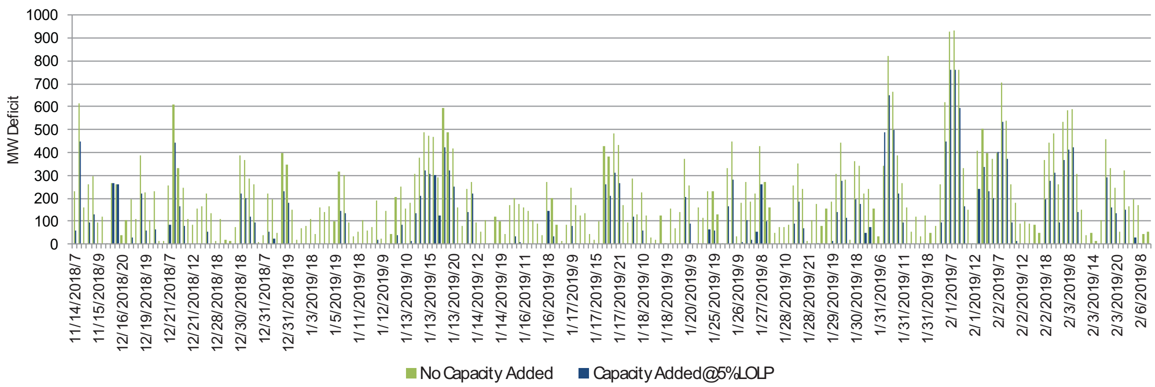
Table K-25

	Base Scenario Present alue of Revenue Requirements (illions)
Updated Planning Margin for 2013 IRP	$13.93
Planning Margin Used in 2011 IRP (15.7%)	$13.92

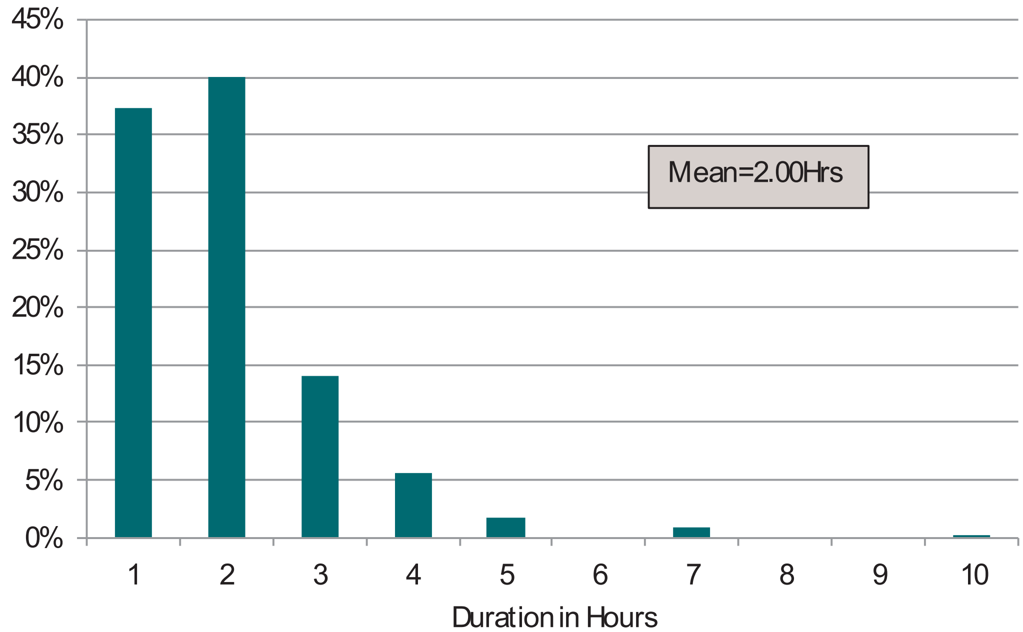
Figure K-26 below illustrates the severity of deficit events in Winter 2018-2019, measured in MWs, before and after adding peaking resources to reach the 5 percent LOLP. It shows that deficit events can occur any time within the winter period, and that remaining deficit events after adding peaking resources to meet the 5 percent LOLP could still be observed.

Figure K-26
Severity of Deficit Events in MWs



Finally, Figure K-27 below shows the distribution of event durations for winter 2018-2019 at the 5 percent LOLP level; that is, when enough peaking resources are added to reach the 5 percent likelihood that an event can still occur in 3,000 trials. Given an event (i.e., after the first hour which is covered by contingency reserves), the distribution of outage duration is right skewed with an expected value of 2 hours per event. However, event duration can range from 1 hour to 10 hours.

Figure K-27
Distribution of Deficit Event Duration at 5% LOLP



Incremental capacity equivalent

Methodology used

The incremental capacity credits for PSE's existing and prospective resources were developed by applying the incremental capacity equivalent (ICE) approach (similar to the equivalent load carrying capability [ELCC] approach) with our LOLP (loss of load probability) model. In essence, the ICE approach identifies the equivalent capacity of a gas peaker plant that would yield the same loss of load probability as the capacity of a different resource such as a wind farm, energy storage facility, or even a fixed purchased power contract. The ratio of the equivalent gas peaker capacity to the alternative resource capacity is the incremental capacity equivalent (ICE) or the capacity credit of the alternative resource. Section E provides a detailed description of the LOLP model.

For the 2013 IRP, ICE was calculated for existing and new wind projects, a battery, the Colstrip plant, and a fixed power purchase agreement. In order to implement the ICE approach for wind in the LOLP model, the distribution of wind hourly generation for each of the existing and prospective wind farms was developed. These are described in

APPENDIX K – ELECTRIC ANALYSIS RESULTS

Appendix K, in the Stochastic Model portion of the Methods and Models section, under the Wind Generation subheading. Given these distributions, the wind farms were incrementally added into the LOLP model to determine the reduction in peaker capacity to achieve the 5 percent loss of load probability. The ratio of the change in gas peaker capacity with and without the incremental wind capacity is that wind farm's capacity credit. The order in which the existing and prospective wind farms were added in the model follows the schedule when these wind farms were acquired or about to be acquired by PSE: Wild Horse, Hopkins Ridge, Klondike, Lower Snake River, then a generic wind resource expected to be located in southeast Washington close to the Lower Snake River project.

For the other resources, a battery is assumed to have a peak capacity of 100 MW, energy capacity of 400 MWHs, with a charge and discharge time of 4 hours. Once the battery is fully discharged, it needs 4 hours to re-charge to full capacity. The ICE for Colstrip coal plant (nameplate capacity or 657 MW) was also calculated, given that it has a higher forced outage rate compared to a generic gas peaking plant. Finally, the fixed power purchase contract was assumed to be a 200 MW contract available for 8,760 hours.

Results

The figure below shows the results of the ICE study.

Figure K-28
ICE Study Results

Incremental Capacity Equivalent 5% P	
Resource Type	Winter 2018-2019
** Natural Gas Peaker	100%
1) Existing Wind (Cumulative = 822MW)	10%
2) New Wind (SE Washington = 100MW)	4%
3) Battery (100MW, 400 MWhs Energy, Charge/Discharge Time=4Hrs)	57%
4) Colstrip (All Units =657MW)	90%
5) Fixed PPA (200MW, 8760Hours)	106%

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These results indicate that wind power's contribution to capacity is not as significant as other resources, such as thermal power. Although the capacity contribution of existing wind facilities is higher than the regional assumption of 5 percent, subsequent wind farms are likely to show lower capacity contribution because of the correlation of wind outputs with pre-existing farms. This result is consistent with those found in earlier studies.
The ICE for battery is higher than wind, but its availability is reduced during re-charge time so that its incremental capacity equivalent is still low. Colstrip is a coal plant with a forced outage rate of about 10 percent for the all of the units. The study results indicate that Colstrip's incremental capacity equivalent is about 90 percent relative to a natural gas peaker. Finally, a fixed power purchase agreement that is available all the time, i.e., no forced outage, actually has an incremental capacity equivalent of 106 percent. The above results are highly dependent on PSE's resource mix, load characteristics, and projected distribution of wind profiles.

The southeast Washington wind location was chosen as the generic wind for this IRP because good historical wind data exists for this site and PSE already owns development rights at the Lower Snake River site with existing transmission to the grid. In the 2011 IRP, PSE also examined the incremental capacity equivalent of a generic wind located in central Washington (Kittitas) which showed a slightly higher ICE, but PSE does not have existing development rights.

4. Outputs

AURORA electric prices and avoided costs

Below is a series of tables with the AURORA price forecasts for the different scenarios. Consistent with WAC 480-107-055, this schedule of estimated Mid-Columbia (Mid-C) power prices is intended to provide only general information to potential bidders about the avoided costs of power supply. It does not provide a guaranteed contract price for electricity.

Figure K-29
Monthly Flat Mid-C Prices (Nominal $/MWh)

Base

	1	2	3	4	5	6	7	8	9	10	11	12	Ave
2014	30.73	31.53	28.63	26.33	23.34	25.41	28.61	30.55	30.62	30.16	30.71	32.22	29.07
2015	33.26	33.14	30.18	27.57	24.77	26.19	29.29	31.34	31.51	31.52	31.63	33.44	30.32
2016	34.29	34.18	31.10	29.28	24.79	27.68	30.70	32.42	33.15	33.44	34.22	35.85	31.76
2017	38.15	38.71	35.60	32.22	28.23	31.69	35.35	37.22	38.39	37.84	38.18	40.52	36.01
2018	42.01	43.76	40.76	37.14	32.75	34.80	40.00	43.03	43.60	42.42	42.64	44.55	40.62
2019	46.24	48.44	44.98	41.12	34.87	38.51	44.87	49.04	49.00	48.13	48.66	49.18	45.25
2020	47.61	49.79	44.73	41.74	31.74	39.00	45.89	50.01	49.00	49.20	49.03	50.74	45.71
2021	51.80	52.75	48.11	45.94	36.40	41.91	49.49	53.17	51.24	51.92	51.35	53.70	48.98
2022	52.51	53.72	47.66	46.22	33.31	41.31	49.33	52.71	52.80	53.35	54.00	55.86	49.40
2023	53.89	55.80	51.10	46.95	35.08	43.75	52.46	55.54	55.44	55.07	55.99	58.28	51.61
2024	55.38	58.34	52.69	48.39	39.63	42.04	52.75	57.72	57.00	55.48	56.88	58.64	52.91
2025	57.77	60.26	54.10	49.96	37.55	44.10	54.67	60.07	59.29	58.38	60.59	61.10	54.82
2026	62.00	63.80	56.23	51.76	38.67	47.24	57.22	62.45	61.52	61.79	62.26	63.85	57.40
2027	64.10	65.58	57.24	54.81	43.39	49.20	58.68	63.01	61.96	62.68	62.82	66.12	59.13
2028	64.78	66.66	59.43	55.26	43.36	50.75	60.77	64.50	64.67	65.38	67.49	69.85	61.08
2029	65.81	70.47	62.91	55.86	44.74	50.14	62.26	67.77	67.26	66.26	67.32	70.75	62.63
2030	67.64	72.13	63.57	58.06	49.58	51.93	63.09	69.68	68.20	67.36	69.12	71.84	64.35
2031	70.79	74.42	64.99	59.74	49.49	55.01	66.02	72.40	71.16	70.89	73.38	75.32	66.97
2032	73.11	75.47	65.63	61.42	49.61	57.73	67.65	73.36	71.88	73.07	73.63	77.46	68.34
2033	74.68	77.03	67.76	65.04	55.72	59.91	69.77	74.63	73.55	74.20	75.20	80.10	70.63

APPENDIX K – ELECTRIC ANALYSIS RESULTS

Monthly Flat Mid-C Prices
(Nominal $/MWh)

Low

	1	2	3	4	5	6	7	8	9	10	11	12	Ave
2014	25.18	25.69	23.17	20.67	17.66	19.84	22.72	24.39	24.35	24.37	24.79	25.74	23.22
2015	26.28	26.67	24.05	21.13	18.48	20.16	23.02	24.59	24.75	25.08	25.09	26.17	23.79
2016	26.74	27.02	24.26	21.99	18.00	20.79	23.75	24.96	25.53	25.94	26.55	27.38	24.41
2017	28.43	29.33	26.78	24.20	20.05	23.68	26.46	27.57	28.11	28.06	28.13	29.74	26.71
2018	30.02	31.52	29.67	26.78	23.42	25.44	28.79	30.66	31.07	30.20	30.09	31.59	29.11
2019	32.39	34.08	31.77	29.18	25.34	27.77	31.42	34.05	34.19	33.42	33.91	34.09	31.80
2020	33.07	34.79	31.42	29.20	22.86	27.55	31.83	34.56	34.23	34.00	33.80	35.06	31.86
2021	35.64	36.79	33.01	31.37	25.60	29.05	33.95	36.60	35.62	35.69	35.41	37.06	33.82
2022	35.79	36.88	32.56	31.26	22.76	28.82	33.71	36.19	36.16	36.47	36.99	38.12	33.81
2023	36.42	37.74	34.54	31.64	23.96	30.11	35.42	37.87	37.49	37.30	37.76	39.46	34.98
2024	37.09	39.05	35.01	32.03	26.72	28.34	34.94	38.62	38.43	37.16	37.92	39.14	35.37
2025	38.11	39.60	35.73	32.63	24.37	29.23	36.19	39.90	39.67	39.01	40.22	40.47	36.26
2026	40.51	41.70	36.42	33.47	23.71	30.55	37.43	41.26	40.70	40.68	41.04	41.98	37.45
2027	41.69	42.73	36.97	35.03	26.51	31.70	38.03	41.43	40.60	40.96	40.80	42.85	38.28
2028	41.46	42.63	37.84	34.72	24.82	32.16	39.09	41.71	41.79	41.79	43.22	44.46	38.81
2029	41.89	44.91	39.86	35.19	25.80	31.04	39.50	43.54	43.45	42.40	43.00	45.03	39.63
2030	42.91	45.43	39.93	36.25	28.88	31.52	40.21	44.44	43.86	42.88	43.75	45.32	40.45
2031	44.35	46.32	40.53	36.93	26.78	32.72	41.36	45.86	45.54	44.88	46.34	46.67	41.52
2032	45.66	46.91	40.68	37.81	25.62	34.69	42.44	46.61	45.83	46.05	46.18	47.80	42.19
2033	46.70	47.93	41.78	39.91	29.80	36.21	43.87	47.35	47.18	46.84	46.92	49.88	43.70

APPENDIX K – ELECTRIC ANALYSIS RESULTS

Monthly Flat Mid-C Prices
(Nominal $/MWh)

High

	1	2	3	4	5	6	7	8	9	10	11	12	Ave
2014	37.43	37.91	34.64	30.89	28.45	30.56	34.81	37.30	37.08	36.42	37.36	38.83	35.14
2015	40.37	40.68	36.70	33.01	29.89	31.88	36.01	38.50	38.58	38.58	38.78	40.75	36.98
2016	42.25	42.21	37.95	35.22	29.74	33.60	37.74	39.67	40.56	40.85	41.86	43.73	38.78
2017	46.59	47.74	43.57	39.92	34.54	39.13	43.91	46.22	46.96	46.64	46.81	49.79	44.32
2018	51.73	54.75	50.19	45.84	41.01	43.31	50.89	54.11	54.47	52.58	52.30	55.48	50.56
2019	57.55	61.46	55.99	51.08	45.34	48.60	57.23	61.95	61.51	60.15	60.67	61.67	56.93
2020	59.41	63.09	56.10	52.24	41.73	49.57	58.96	63.75	62.21	61.77	61.73	64.90	57.95
2021	65.76	68.54	61.60	58.35	48.47	55.01	64.09	68.63	66.35	66.83	66.86	70.49	63.42
2022	67.66	70.41	61.51	59.38	46.33	54.90	64.85	68.97	68.22	69.20	71.33	73.45	64.68
2023	70.15	73.67	66.30	61.29	49.78	59.15	69.60	73.16	71.67	72.10	73.35	77.33	68.13
2024	72.14	77.04	67.77	62.57	54.54	57.04	70.01	75.17	74.34	72.05	74.06	77.48	69.52
2025	75.23	79.40	70.48	65.21	53.85	60.31	73.14	78.94	77.94	76.52	80.49	82.05	72.80
2026	80.27	83.32	73.03	67.81	55.98	64.24	74.83	81.69	78.51	80.30	81.86	84.29	75.51
2027	82.52	84.76	74.01	70.56	60.73	65.90	74.97	81.86	77.77	80.45	81.81	85.52	76.74
2028	83.47	85.98	76.35	71.00	61.94	67.69	77.65	82.04	81.25	83.32	87.34	89.38	78.95
2029	84.55	89.25	79.71	72.07	63.25	67.03	78.61	85.28	83.46	83.29	86.39	89.99	80.24
2030	87.11	91.86	80.77	75.05	68.05	68.93	80.16	87.70	84.73	84.97	88.79	91.91	82.50
2031	90.08	93.13	82.03	76.80	70.81	72.73	82.79	90.10	87.50	88.53	93.44	95.20	85.26
2032	91.53	93.00	82.45	77.81	71.35	75.38	83.49	90.09	86.43	90.12	93.41	96.62	85.97
2033	93.65	95.32	84.82	80.71	75.40	78.04	85.67	91.39	88.87	91.81	96.01	100.28	88.50

APPENDIX K – ELECTRIC ANALYSIS RESULTS

Monthly Flat Mid-C Prices
(Nominal $/MWh)

Base + Low CO_2

	1	2	3	4	5	6	7	8	9	10	11	12	Ave
2014	34.05	34.54	32.20	29.07	26.05	28.51	31.81	33.93	33.59	33.08	33.87	35.02	32.14
2015	36.06	36.66	33.67	30.45	27.76	29.33	32.83	34.91	34.82	34.57	35.00	36.62	33.56
2016	37.55	37.86	34.62	32.14	27.85	30.98	34.47	35.91	36.62	36.70	37.82	39.12	35.14
2017	41.35	42.16	38.66	35.82	31.75	35.45	38.40	40.17	41.33	40.89	41.34	43.72	39.25
2018	45.06	47.04	43.85	40.09	36.65	38.38	42.73	46.04	46.71	45.36	45.41	47.76	43.76
2019	49.53	51.70	48.36	44.02	39.67	42.23	47.98	51.94	51.87	51.25	51.66	52.40	48.55
2020	51.16	53.21	48.24	45.08	37.61	42.81	49.18	53.00	52.44	52.76	52.41	54.33	49.35
2021	55.37	56.38	51.59	49.27	41.58	45.77	52.89	56.15	54.76	55.52	54.92	57.34	52.63
2022	56.36	57.70	51.53	49.79	39.35	45.74	52.49	56.28	56.62	57.18	58.00	59.71	53.40
2023	58.09	59.88	55.19	51.12	41.58	48.27	56.31	59.45	59.60	59.19	60.09	62.52	55.94
2024	59.96	62.64	57.00	52.37	46.04	47.48	56.62	61.76	61.81	59.79	61.33	63.24	57.50
2025	62.54	64.75	59.06	54.28	44.92	49.84	59.04	64.63	64.11	62.87	65.30	66.12	59.79
2026	66.78	68.63	61.23	56.56	46.03	52.45	61.87	67.77	66.43	66.75	67.06	69.01	62.55
2027	69.22	70.83	62.25	59.87	50.22	54.07	63.55	68.57	67.37	68.30	68.14	71.18	64.46
2028	70.62	72.21	65.26	60.73	50.55	56.29	66.42	70.22	70.61	71.04	72.97	75.39	66.86
2029	71.99	76.60	69.42	61.79	52.56	56.18	68.10	73.96	73.47	72.37	73.25	76.93	68.89
2030	74.03	78.77	70.31	64.29	57.60	58.37	69.90	76.35	74.82	73.88	75.96	78.47	71.06
2031	77.67	81.18	72.43	66.40	57.59	61.59	72.33	79.17	78.06	77.67	80.34	82.20	73.89
2032	80.50	82.77	73.16	68.74	57.99	64.20	74.72	80.39	78.76	80.48	80.69	84.54	75.58
2033	82.50	84.67	75.05	72.50	62.95	66.54	76.62	81.62	80.66	82.07	83.09	87.56	77.98

APPENDIX K – ELECTRIC ANALYSIS RESULTS

Monthly Flat Mid-C Prices
(Nominal $/MWh)

Base + High CO_2

	1	2	3	4	5	6	7	8	9	10	11	12	Ave
2014	30.70	31.61	28.62	26.33	23.30	25.43	28.63	30.60	30.64	30.20	30.64	32.07	29.06
2015	33.18	33.20	30.24	27.68	24.76	26.24	29.25	31.30	31.40	31.55	31.71	33.51	30.34
2016	34.39	34.18	31.12	29.19	24.77	27.70	30.68	32.25	33.10	33.33	34.26	35.78	31.73
2017	52.79	52.15	47.74	44.17	39.28	44.07	48.61	50.73	51.33	50.86	51.53	54.08	48.95
2018	55.90	57.38	53.69	49.60	45.58	48.20	53.62	56.83	57.36	55.03	55.50	58.01	53.89
2019	60.13	62.62	58.88	54.10	50.34	53.02	58.39	62.47	62.80	61.12	61.88	62.81	59.05
2020	62.92	65.01	59.65	55.77	50.66	54.32	61.01	64.89	63.75	63.27	63.56	65.43	60.85
2021	67.83	69.18	62.72	60.10	54.17	57.81	65.13	69.22	66.96	66.91	67.13	69.36	64.71
2022	69.98	71.59	63.56	61.69	52.20	58.80	66.57	70.62	69.80	69.35	71.45	72.85	66.54
2023	72.32	74.69	68.04	64.46	56.28	62.57	71.55	74.81	73.62	72.68	73.83	76.94	70.15
2024	75.27	79.04	71.40	66.14	61.26	62.71	73.02	78.63	77.41	74.63	75.86	79.23	72.88
2025	79.08	82.07	74.66	68.95	61.92	66.07	76.58	82.99	81.33	79.05	82.10	83.60	76.53
2026	83.55	86.85	75.39	71.48	62.38	68.39	79.21	85.93	82.67	82.90	84.01	86.85	79.13
2027	87.63	90.34	77.48	75.38	66.92	71.09	81.99	87.58	84.52	85.95	86.37	90.24	82.12
2028	89.72	92.37	80.99	77.71	67.79	74.68	84.83	90.82	88.80	89.41	93.84	94.97	85.49
2029	92.05	97.97	85.86	79.89	71.26	74.65	89.36	95.48	93.21	91.29	93.21	97.51	88.48
2030	95.63	101.64	88.95	83.47	77.47	77.60	91.82	99.20	96.70	94.47	97.50	101.20	92.14
2031	100.24	104.54	91.09	86.76	79.15	81.84	94.46	103.44	99.48	98.91	103.87	105.68	95.79
2032	104.55	107.46	93.05	90.80	80.25	86.13	97.87	105.20	101.06	103.50	105.51	109.26	98.72
2033	108.15	110.74	97.12	95.86	86.85	90.26	100.62	108.28	105.00	106.30	109.48	114.09	102.73

APPENDIX K – ELECTRIC ANALYSIS RESULTS

Monthly Flat Mid-C Prices
(Nominal $/MWh)

Base + Very High CO_2

	1	2	3	4	5	6	7	8	9	10	11	12	Ave
2014	71.90	76.49	63.82	58.59	54.35	59.47	66.17	71.24	72.71	69.14	69.36	73.42	67.22
2015	75.10	79.29	66.68	60.98	57.61	61.68	68.78	73.75	74.44	71.22	71.24	75.94	69.73
2016	77.77	82.11	68.50	65.09	56.37	64.33	72.56	76.10	77.47	76.80	80.27	81.34	73.23
2017	84.78	89.69	75.25	70.58	62.72	71.75	80.04	83.88	84.96	84.47	84.84	88.78	80.15
2018	91.34	99.23	83.93	77.55	71.88	76.94	87.86	93.38	94.22	90.26	88.61	96.33	87.63
2019	99.10	106.65	90.88	83.83	77.70	83.25	95.32	101.85	103.09	100.58	102.29	104.79	95.78
2020	100.41	108.02	91.26	86.27	76.46	84.91	97.92	104.96	104.04	100.67	101.28	106.83	96.92
2021	106.25	111.86	95.35	91.74	82.60	89.68	103.45	110.51	107.08	103.55	105.11	111.14	101.53
2022	108.98	114.68	95.99	94.09	77.44	90.36	105.67	112.02	109.70	109.10	113.48	114.54	103.84
2023	112.41	118.87	101.71	97.53	83.02	94.36	111.81	117.13	113.62	113.38	115.08	119.97	108.24
2024	117.94	126.23	107.00	99.62	91.73	93.54	113.55	122.59	121.44	114.77	116.05	123.61	112.34
2025	122.94	131.31	111.56	103.72	90.26	98.35	118.41	128.89	127.33	121.85	127.60	130.31	117.71
2026	129.91	137.25	115.92	108.64	92.59	103.36	123.05	133.86	131.27	127.15	129.86	135.67	122.38
2027	136.13	142.68	119.26	113.88	100.28	108.02	127.60	137.34	134.62	131.07	133.65	140.91	127.12
2028	138.87	145.20	123.47	117.25	99.02	112.01	132.29	140.92	138.34	138.22	145.77	147.69	131.59
2029	143.36	153.51	131.15	121.00	104.61	110.92	136.51	147.80	144.90	140.52	141.43	151.74	135.62
2030	147.62	156.86	134.35	124.55	114.15	114.27	139.48	152.71	148.96	142.94	145.57	155.13	139.72
2031	154.00	162.34	138.80	128.94	114.14	121.26	145.30	158.55	154.75	151.18	158.32	163.28	145.91
2032	159.03	166.15	141.28	135.42	114.29	127.15	149.40	160.58	155.87	156.37	160.17	167.41	149.43
2033	163.70	170.22	145.35	140.86	124.84	132.31	153.75	164.65	159.47	159.88	163.94	173.71	154.39

APPENDIX K – ELECTRIC ANALYSIS RESULTS

Monthly Flat Mid-C Prices
(Nominal $/MWh)

High + High CO_2

	1	2	3	4	5	6	7	8	9	10	11	12	Ave
2014	37.45	37.86	34.63	30.96	28.55	30.59	34.73	37.45	37.15	36.47	37.37	38.98	35.18
2015	40.40	40.76	36.68	33.18	29.92	31.95	35.96	38.51	38.49	38.53	38.73	40.73	36.99
2016	42.24	42.24	37.85	35.07	29.67	33.56	37.50	39.43	40.34	40.63	41.77	43.58	38.66
2017	59.20	59.88	54.87	51.16	46.07	50.79	54.83	57.18	58.16	57.66	58.32	61.31	55.79
2018	64.07	67.54	61.70	57.56	53.43	56.02	61.28	65.81	66.12	64.07	63.95	67.23	62.40
2019	70.74	75.27	68.55	62.83	59.26	61.56	68.96	74.28	73.62	72.05	72.78	74.49	69.53
2020	73.33	77.61	69.46	65.08	59.46	63.63	71.63	76.75	75.53	74.71	75.03	78.08	71.69
2021	80.74	84.36	75.67	71.96	64.51	69.06	77.90	83.26	81.07	81.10	81.13	85.33	78.01
2022	83.55	87.03	76.71	74.23	64.37	70.33	80.09	85.88	83.97	84.56	87.07	89.46	80.60
2023	87.34	91.12	82.61	77.51	69.40	75.54	86.54	90.50	88.32	88.31	89.43	93.83	85.04
2024	90.61	96.08	85.85	79.34	74.58	75.00	86.72	94.65	92.46	89.91	92.04	96.17	87.78
2025	94.03	98.25	89.34	83.27	76.28	79.21	89.25	99.36	96.32	94.30	99.14	100.65	91.62
2026	100.87	103.99	91.12	87.41	79.70	83.47	93.73	103.14	98.36	99.22	102.10	105.04	95.68
2027	104.53	106.82	93.25	90.26	83.54	86.14	94.86	103.06	98.73	101.69	104.12	107.40	97.87
2028	107.11	108.79	96.77	92.84	84.90	90.03	99.96	105.63	102.73	105.05	111.60	113.11	101.54
2029	109.38	113.97	101.88	96.27	88.94	91.50	102.29	110.62	106.49	106.54	111.25	115.93	104.59
2030	113.74	117.70	104.40	99.27	94.12	94.93	104.37	114.12	109.37	110.08	116.06	119.45	108.13
2031	119.19	122.23	107.80	103.14	97.84	99.97	108.30	118.48	113.56	115.11	123.36	125.14	112.84
2032	122.33	123.59	110.56	106.45	101.15	103.52	111.73	119.85	114.96	118.60	124.46	128.05	115.44
2033	126.71	127.48	114.91	110.82	107.16	108.00	115.50	122.88	119.14	122.97	129.89	133.46	119.91

APPENDIX K – ELECTRIC ANALYSIS RESULTS

Monthly Flat Mid-C Prices
(Nominal $/MWh)

Very Low Gas

	1	2	3	4	5	6	7	8	9	10	11	12	Ave
2014	21.80	22.81	19.72	17.58	14.62	16.40	18.87	20.70	20.89	20.53	20.64	21.93	19.71
2015	21.76	22.64	19.68	17.29	14.34	16.00	18.21	20.14	20.74	20.50	20.46	21.92	19.47
2016	21.42	22.52	19.19	17.22	13.62	15.87	18.08	19.94	20.67	20.85	22.12	22.50	19.50
2017	22.50	23.91	20.55	18.16	14.88	17.46	19.93	21.80	22.12	22.55	22.30	23.57	20.81
2018	23.50	26.31	22.24	19.81	16.73	18.56	21.87	24.11	24.13	23.77	23.14	24.93	22.43
2019	25.39	28.06	23.65	21.31	17.95	20.04	23.75	25.96	26.14	26.02	26.27	26.74	24.27
2020	24.98	27.75	23.34	21.00	17.16	19.76	23.53	25.72	25.72	25.20	24.86	27.04	23.84
2021	25.83	27.96	23.80	21.82	17.97	20.50	24.35	26.56	25.97	25.47	25.91	27.52	24.47
2022	25.67	28.03	23.26	21.66	17.21	20.36	23.92	26.50	25.99	26.18	27.60	28.02	24.53
2023	26.36	28.67	24.48	21.93	17.95	21.39	25.17	27.62	26.58	26.97	27.25	28.86	25.27
2024	26.98	30.10	24.81	22.31	18.57	20.39	24.89	27.85	27.50	26.33	26.05	28.54	25.36
2025	26.99	30.08	24.82	22.66	17.92	20.58	25.23	28.18	27.90	26.83	28.07	29.45	25.73
2026	27.41	30.53	25.21	22.64	17.58	20.82	25.44	28.35	28.19	26.95	27.34	29.44	25.83
2027	27.84	31.12	24.85	22.66	17.87	21.02	25.47	28.27	28.00	27.11	27.79	30.04	26.00
2028	27.84	31.38	25.33	22.26	18.02	21.20	25.86	28.65	27.97	28.58	30.45	30.36	26.49
2029	28.54	32.48	25.97	22.67	17.78	20.42	25.99	29.40	28.42	27.87	27.60	30.72	26.49
2030	28.59	32.50	25.68	23.09	18.74	20.79	26.32	29.68	29.31	28.01	27.86	31.09	26.81
2031	29.46	33.21	26.16	23.58	18.91	21.76	27.03	30.09	30.37	28.84	30.65	32.64	27.72
2032	29.17	32.23	26.21	23.60	18.19	22.49	26.95	30.24	30.02	28.71	30.07	32.33	27.52
2033	29.59	32.89	26.20	24.05	19.61	23.00	27.29	30.65	30.09	29.37	30.58	32.52	27.99

APPENDIX K – ELECTRIC ANALYSIS RESULTS

Monthly Flat Mid-C Prices
(Nominal $/MWh)

Very High Gas

	1	2	3	4	5	6	7	8	9	10	11	12	Ave
2014	39.80	41.30	38.14	34.92	30.65	34.03	40.10	43.10	42.17	41.79	43.22	45.80	39.58
2015	45.41	46.23	42.53	40.48	33.68	38.29	44.49	47.95	46.88	46.87	47.00	49.99	44.15
2016	50.40	50.72	46.52	45.51	32.50	41.88	49.56	52.61	52.62	53.04	53.17	56.15	48.72
2017	54.71	56.19	51.86	48.56	35.60	46.29	54.64	57.88	58.10	57.64	58.08	61.32	53.41
2018	59.37	62.41	58.48	54.30	43.55	47.89	59.43	64.23	64.41	61.92	62.77	65.75	58.71
2019	64.58	67.87	63.29	58.29	42.73	51.40	64.66	70.34	70.00	68.43	69.33	70.47	63.45
2020	68.23	71.64	64.11	59.73	37.07	53.22	67.19	73.32	71.46	71.74	71.64	74.50	65.32
2021	76.06	78.04	70.64	67.80	47.33	59.76	74.36	80.29	76.35	77.46	77.05	80.99	72.18
2022	79.05	81.90	72.05	69.64	40.76	59.83	76.17	82.48	81.42	82.33	83.40	86.77	74.65
2023	84.12	87.64	79.25	72.21	43.82	65.10	82.92	88.19	86.96	86.36	88.02	91.89	79.71
2024	87.51	92.45	82.17	74.84	53.47	61.49	82.99	90.58	89.84	86.16	88.87	92.19	81.88
2025	90.31	94.53	83.76	77.44	46.10	64.66	86.66	94.57	93.32	90.53	94.71	96.00	84.38
2026	96.68	100.39	87.17	79.89	49.00	71.97	89.50	97.90	95.19	96.14	97.16	99.94	88.41
2027	99.68	103.07	88.85	84.51	60.03	74.55	91.08	98.19	95.48	97.32	97.50	102.65	91.08
2028	99.94	103.40	90.91	84.15	57.97	75.69	93.72	98.80	99.11	100.34	103.94	107.40	92.95
2029	101.85	109.11	96.54	85.31	60.80	74.14	96.54	103.28	103.74	102.07	104.19	109.76	95.61
2030	105.27	112.50	98.87	89.69	72.45	77.47	99.71	107.51	106.59	104.83	108.44	112.91	99.69
2031	110.53	115.81	100.91	93.40	68.79	82.97	103.91	112.24	110.88	110.77	115.32	118.34	103.65
2032	114.12	117.83	102.15	96.31	68.46	88.50	106.13	113.89	111.23	114.38	115.91	121.27	105.85
2033	117.25	120.65	105.43	100.73	81.36	92.01	108.89	115.84	114.43	116.17	118.72	125.80	109.77

APPENDIX K – ELECTRIC ANALYSIS RESULTS

Electric demand-side screening results

The results in the following tables were part of the bundles provided by Cadmus Group.

See Appendix N for a discussion of Cadmus' methodology and analysis.

Figure K-30
Annual Energy Savings (aMW)
Bundles A through H include Energy Efficiency, Fuel Conversion, and Distributed Generation and are incremental to the bundle before

	Bundle											
	A	A1	B	B1	C	D	E	F	G	H	DE	EISA
2014	7.6	0.8	0.7	0.4	2.0	0.4	0.5	0.3	0.6	3.3	0.3	9.3
2015	21.6	2.8	2.3	1.3	6.0	1.4	1.5	0.8	1.9	10.4	1.2	26.5
2016	32.7	5.0	3.9	2.2	10.0	2.7	2.6	1.4	3.4	17.8	1.9	39.4
2017	42.1	7.4	5.6	3.1	14.1	4.3	3.8	2.0	4.9	25.5	2.5	48.3
2018	51.0	10.0	7.3	4.1	18.2	6.5	5.0	2.6	6.5	33.4	3.1	55.6
2019	59.5	12.8	9.0	5.1	22.4	9.2	6.3	3.3	8.2	41.3	3.9	61.7
2020	67.5	15.8	10.6	6.2	26.5	11.9	7.6	3.9	9.9	49.5	4.8	79.1
2021	74.8	18.5	12.0	7.1	30.6	14.7	8.9	4.6	11.6	57.7	5.8	102.8
2022	82.7	21.1	13.5	8.1	35.1	17.6	10.0	5.2	13.4	66.1	6.7	117.1
2023	90.4	23.7	14.9	9.0	39.5	20.5	11.2	5.9	15.1	74.5	7.7	126.3
2024	98.0	26.5	16.3	10.0	44.0	23.6	12.5	6.6	16.9	83.2	8.7	133.8
2025	104.5	29.0	17.7	11.0	48.1	26.4	13.7	7.2	18.6	91.4	9.7	138.9
2026	111.3	31.7	19.1	11.9	52.4	29.4	14.9	7.8	20.3	99.9	10.7	143.6
2027	118.0	34.4	20.4	12.9	56.5	32.4	16.2	8.5	22.0	108.3	11.8	147.9
2028	125.0	37.1	21.8	13.8	60.7	35.4	17.4	9.1	23.7	116.7	12.9	152.2
2029	131.6	39.6	23.1	14.7	64.6	38.1	18.6	9.7	25.3	124.9	13.9	155.9
2030	138.3	42.3	24.4	15.6	68.6	40.6	19.9	10.3	26.9	133.3	15.0	159.7
2031	144.9	45.0	25.7	16.4	72.5	42.7	21.1	10.9	28.4	141.4	16.1	163.2
2032	151.8	47.8	27.2	17.2	76.7	45.0	22.5	11.6	30.1	150.4	17.3	167.0
2033	157.9	50.3	28.3	17.9	80.0	46.9	23.6	12.1	31.5	157.8	18.2	169.8

APPENDIX K – ELECTRIC ANALYSIS RESULTS

Figure K-31
Total December Peak Reduction (MW)
Bundles A through H includes Energy Efficiency, Fuel Conversion, and Distributed Generation and are incremental to the bundle before

	Bundle											
	A	A1	B	B1	C	D	E	F	G	H	DE	EISA
2014	19	2	3	1	8	2	2	1	2	11	1	24
2015	34	5	6	2	16	3	4	2	3	22	2	42
2016	46	9	9	4	24	5	6	3	5	35	3	55
2017	57	13	12	5	32	8	8	4	7	47	4	64
2018	67	18	15	6	41	10	11	6	9	60	5	72
2019	77	22	18	7	49	12	13	7	11	74	7	79
2020	86	28	21	9	58	15	16	8	14	88	8	115
2021	95	32	24	10	68	18	19	10	16	103	10	136
2022	104	37	27	11	77	20	21	11	18	117	11	150
2023	112	41	30	12	85	23	23	12	20	131	13	159
2024	120	45	32	13	94	25	25	13	22	143	14	166
2025	128	49	35	14	103	28	28	15	24	157	16	171
2026	136	53	38	16	112	31	30	16	26	172	18	177
2027	144	58	41	17	122	34	33	17	28	188	19	182
2028	152	62	44	18	131	36	35	18	30	201	21	187
2029	159	66	46	19	140	39	37	19	32	214	23	192
2030	167	70	48	20	148	41	39	21	34	228	24	196
2031	175	74	51	21	158	44	42	22	36	242	26	199
2032	183	79	54	23	169	47	45	23	38	258	28	204
2033	191	83	57	24	177	50	47	24	40	272	29	209

The DSR December peak reduction is based on the average of the very heavy load hours (VHLH). The VHLH method takes the average of the five-hour morning peak from hour ending 7 a.m. to hour ending 11 a.m. and the five-hour evening peak from hour ending 6 p.m. to hour ending 10 p.m. Monday through Friday.

Demand Response Programs were broken down into 5 categories that include:

1. ***Residential Direct Load Control (DLC) Space Heating and Water Heating***
2. ***Residential DLC Room Heating and Water Heating***
3. ***Residential Critical Peak Pricing (CPP)***
4. ***Commercial and Industrial Critical Peak Pricing***
5. ***Curtailment***

APPENDIX K – ELECTRIC ANALYSIS RESULTS

Figure K-32
Total December Peak Reduction (MW)
Demand Response Programs

	Program				
	1	2	3	4	5
2014	0	0	0	0	13
2015	0	0	0	0	26
2016	4	5	1	0	40
2017	4	5	1	0	55
2018	23	23	5	0	56
2019	23	24	6	0	57
2020	47	48	11	1	58
2021	48	49	11	1	60
2022	48	50	12	2	61
2023	49	51	12	2	63
2024	50	52	12	2	64
2025	51	53	12	2	66
2026	52	53	12	2	67
2027	52	54	13	2	69
2028	53	55	13	3	71
2029	54	56	13	3	72
2030	55	57	13	3	74
2031	56	58	13	3	76
2032	56	58	14	3	78
2033	57	59	14	3	80

APPENDIX K – ELECTRIC ANALYSIS RESULTS

Figure K-33
Annual Costs (Thousands $)
Bundles A through H includes Energy Efficiency, Fuel Conversion, Distributed Generation and are incremental costs to the bundle before.

EISA has no Cost and is considered a must-take bundle

	Bundle										
	A	A1	B	B1	C	D	E	F	G	H	DE
2014	$9,110	$6,046	$7,669	$5,738	$33,122	$8,831	$10,776	$7,045	$18,120	$357,960	$467
2015	$7,776	$7,011	$8,052	$5,354	$33,409	$8,692	$12,393	$7,478	$20,845	$386,968	$467
2016	$6,574	$7,791	$8,263	$4,980	$33,616	$9,920	$13,138	$7,729	$21,626	$407,772	$467
2017	$6,132	$8,445	$8,409	$4,672	$33,875	$10,587	$13,686	$7,943	$21,828	$416,627	$467
2018	$5,800	$9,006	$8,521	$4,430	$33,990	$11,170	$14,121	$8,113	$21,747	$419,354	$467
2019	$5,688	$9,578	$8,593	$4,311	$34,020	$11,760	$14,638	$8,303	$21,775	$424,791	$623
2020	$4,717	$10,145	$7,571	$4,266	$30,711	$12,369	$15,187	$8,497	$21,845	$431,187	$701
2021	$4,652	$8,856	$7,344	$3,960	$37,990	$14,024	$13,686	$8,614	$24,272	$494,467	$701
2022	$4,664	$8,889	$7,245	$3,859	$36,890	$14,081	$13,692	$8,481	$23,633	$487,412	$701
2023	$4,515	$8,907	$7,147	$3,794	$35,951	$14,147	$13,723	$8,372	$23,046	$481,998	$701
2024	$4,455	$8,984	$7,078	$3,789	$35,420	$14,236	$13,830	$8,312	$22,867	$481,657	$701
2025	$4,440	$9,005	$7,015	$3,794	$34,758	$14,327	$13,918	$8,246	$22,637	$479,161	$701
2026	$4,479	$8,999	$6,944	$3,784	$34,309	$14,389	$13,947	$8,182	$22,345	$474,641	$701
2027	$4,500	$8,996	$6,884	$3,806	$33,806	$14,457	$13,991	$8,121	$22,090	$470,937	$701
2028	$4,534	$8,989	$6,829	$3,828	$33,367	$14,521	$14,033	$8,068	$21,868	$467,764	$701
2029	$4,568	$9,075	$6,780	$3,850	$32,983	$14,575	$14,072	$8,021	$21,679	$465,094	$701
2030	$4,611	$9,001	$6,737	$3,875	$32,494	$14,625	$14,121	$7,982	$21,544	$463,084	$701
2031	$4,591	$9,038	$6,698	$3,899	$31,830	$14,664	$14,165	$7,937	$21,355	$460,779	$701
2032	$4,631	$9,074	$6,664	$3,925	$31,390	$14,681	$14,206	$7,906	$21,249	$459,187	$701
2033	$4,642	$9,115	$6,635	$3,923	$30,668	$14,179	$14,253	$8,015	$20,991	$450,538	$467

APPENDIX K – ELECTRIC ANALYSIS RESULTS

Figure K-34
Annual Costs (Thousands $)
Demand Response

	Program				
	1	2	3	4	5
2014	$0	$0	$400	$400	$1,054
2015	$59	$308	$149	$0	$2,222
2016	$2,339	$14,369	$2,787	$158	$3,523
2017	$511	$2,605	$752	$146	$4,933
2018	$10,460	$63,955	$12,256	$8	$5,172
2019	$1,706	$8,573	$1,411	$729	$5,411
2020	$15,272	$92,176	$17,064	$675	$5,688
2021	$2,935	$14,605	$1,131	$1,028	$5,955
2022	$3,050	$15,163	$1,166	$956	$6,251
2023	$3,169	$15,745	$1,204	$103	$6,559
2024	$3,294	$16,360	$1,246	$109	$6,902
2025	$3,425	$17,002	$1,290	$115	$7,233
2026	$3,559	$17,655	$1,333	$120	$7,592
2027	$3,698	$18,335	$1,378	$125	$7,961
2028	$3,841	$19,037	$1,425	$131	$8,387
2029	$3,989	$19,758	$1,472	$137	$8,790
2030	$4,145	$20,524	$1,525	$143	$9,236
2031	$4,305	$21,308	$1,577	$149	$9,704
2032	$4,467	$22,099	$1,627	$156	$10,200
2033	$4,633	$22,908	$1,679	$160	$10,729

APPENDIX K – ELECTRIC ANALYSIS RESULTS

Figure K-35
Optimal DSR Bundles and DR Programs.

All Scenarios Include Distribution Efficiency (DE)

Scenarios	Case 1		Case 2		Case 3	
	DSR Bundle	DR Program	DSR Bundle	DR Program	DSR Bundle	DR Program
Base	E	1 ,4 ,5	E	1 ,4 ,5	E	1 ,4 ,5
Low	E	1, 5	D	1, 5	D	1, 5
High	E	1, 5	E	1, 5	E	1, 5
Base + Low CO2	E	1, 4, 5	E	1, 4, 5	E	1, 3, 4, 5
Base + High CO2	E	1, 3, 4, 5	E	1, 3, 4, 5	E	1, 3, 4, 5
Base + Very High CO2	D	1, 5	D	1, 5	D	1, 5
High + High CO2	E	1, 5	E	1, 5	F	1, 3, 5
Very Low Gas	A1	1, 5	B	1, 5	B	1, 5
Very High Gas	E	1, 4, 5	E	1, 4, 5	E	1, 4, 5
Low + Base Load	E	1, 4, 5	E	1, 4, 5	E	1, 4, 5

APPENDIX K – ELECTRIC ANALYSIS RESULTS

Electric integrated portfolio results

This table summarizes the expected costs of the different portfolios.

Figure K-36
Revenue Requirements for Optimal Portfolio with Expected Inputs for the Scenario

Scenario	NP to 2014 ($Millions)								
	Expected Portfolio Cost	Net Market Purchases/ (Sales)	DSR Rev. Req.	Generic Rev. Req.	Generic End Effects	Colstrip & Tx Renewal Rev. Req.	Colstrip and Tx Renewal End Effects	Variable Cost of Existing	REC Revenue
Case 1									
Base	$13,783	$2,636	$1,142	$2,873	$1,613	$2,228	$550	$2,760	($18)
Low	$10,383	$1,677	$1,139	$1,280	$1,082	$2,220	$750	$2,258	($22)
High	$17,871	$4,363	$1,139	$4,706	$2,053	$2,230	$407	$2,993	($19)
Base + Low CO2	$14,954	$3,002	$1,142	$2,962	$1,610	$2,798	$652	$2,806	($18)
Base + High CO2	$17,548	$5,436	$1,172	$3,410	$1,685	$2,057	$746	$3,061	($18)
Base + Very High CO2	$22,601	$2,678	$973	$11,713	$876	$512	$519	$5,427	($96)
High + High CO2	$21,978	$7,039	$1,139	$4,037	$1,948	$3,949	$852	$3,034	($19)
Very High Gas	$16,175	$5,300	$1,142	$2,913	$1,483	$2,228	$247	$2,882	($18)
Very Low Gas	$11,446	$1,574	$280	$3,799	$1,911	$1,404	$692	$1,807	($20)
Low + Base Load	$11,826	$1,312	$1,142	$2,435	$1,727	$2,220	$750	$2,258	($18)
Case 2									
Base	$13,931	$2,636	$1,142	$2,873	$1,613	$2,343	$582	$2,760	($18)
Low	$10,519	$2,206	$973	$1,666	$1,325	$1,483	$632	$2,258	($23)
High	$18,019	$4,363	$1,139	$4,706	$2,053	$2,346	$439	$2,993	($19)
Base + Low CO2	$15,102	$3,003	$1,142	$2,962	$1,610	$2,913	$684	$2,806	($18)
Base + High CO2	$17,629	$5,436	$1,172	$3,410	$1,685	$2,109	$776	$3,061	($18)
Base + Very High CO2	$22,601	$2,678	$973	$11,713	$876	$512	$519	$5,427	($96)
High + High CO2	$22,125	$7,053	$1,139	$4,037	$1,948	$4,051	$883	$3,034	($19)
Very High Gas	$16,324	$5,300	$1,142	$2,913	$1,483	$2,343	$279	$2,882	($18)
Very Low Gas	$11,516	$1,798	$372	$4,367	$1,998	$701	$493	$1,807	($19)
Low + Base Load	$11,974	$1,313	$1,142	$2,435	$1,727	$2,335	$782	$2,258	($18)

APPENDIX K – ELECTRIC ANALYSIS RESULTS

Scenario	NP to 2014 ($Millions)								
	Expected Portfolio Cost	Net Market Purchases/ (Sales)	DSR Rev. Req.	Generic Rev. Req.	Generic End Effects	Colstrip & Tx Renewal Rev. Req.	Colstrip and Tx Renewal End Effects	Variable Cost of Existing	REC Revenue
Case 3									
Base	$14,471	$2,645	$1,142	$2,873	$1,613	$2,784	$673	$2,760	($18)
Low	$10,760	$2,244	$973	$1,666	$1,325	$1,617	$700	$2,258	($23)
High	$18,561	$4,367	$1,139	$4,706	$2,053	$2,793	$531	$2,993	($19)
Base + Low CO2	$15,591	$3,746	$1,172	$3,551	$1,717	$1,997	$622	$2,806	($18)
Base + High CO2	$17,744	$5,860	$1,172	$3,410	$1,685	$1,797	$778	$3,061	($18)
Base + Very High CO2	$22,601	$2,678	$973	$11,713	$876	$512	$519	$5,427	($96)
High + High CO2	$22,430	$8,378	$1,270	$4,551	$2,068	$2,397	$753	$3,034	($21)
Very High Gas	$16,864	$5,308	$1,142	$2,913	$1,483	$2,785	$370	$2,882	($18)
Very Low Gas	$11,516	$1,798	$372	$4,367	$1,998	$701	$493	$1,807	($19)
Low + Base Load	$12,271	$1,821	$1,172	$2,891	$1,830	$1,617	$700	$2,258	($18)
Case 4									
Base	$15,105	$3,482	$1,172	$3,444	$1,717	$1,877	$673	$2,760	($18)
Replacement Po er									
Base	$15,244	$4,086	$833	$4,445	$1,927	$711	$502	$2,760	($19)
Low	$10,889	$2,721	$973	$2,345	$1,409	$708	$498	$2,258	($23)
High	$20,089	$6,246	$976	$6,293	$2,392	$711	$499	$2,993	($21)
Base + Low CO2	$16,050	$4,600	$833	$4,583	$1,933	$811	$504	$2,806	($19)
Base + High CO2	$17,775	$6,110	$973	$4,486	$1,928	$729	$507	$3,061	($18)
Base + Very High CO2	$22,601	$2,678	$973	$11,713	$876	$512	$519	$5,427	($96)
High + High CO2	$22,634	$9,516	$973	$5,610	$2,296	$730	$499	$3,034	($24)
Very High Gas	$19,069	$7,697	$973	$4,493	$1,831	$711	$502	$2,882	($18)
Very Low Gas	$11,516	$1,798	$372	$4,367	$1,998	$701	$493	$1,807	($19)
Low + Base Load	$12,376	$2,361	$833	$3,696	$2,040	$708	$498	$2,258	($18)
Base + MT Wind 31% CF	$17,525	$2,577	$976	$7,849	$2,454	$711	$502	$2,760	($303)
Base + MT Wind 40% CF	$16,442	$2,502	$1,139	$6,907	$2,228	$711	$502	$2,760	($305)

APPENDIX K – ELECTRIC ANALYSIS RESULTS

Scenario	NP to 2014 ($Millions)								
	Expected Portfolio Cost	Net Market Purchases/ (Sales)	DSR Rev. Req.	Generic Rev. Req.	Generic End Effects	Colstrip & Tx Renewal Rev. Req.	Colstrip and Tx Renewal End Effects	Variable Cost of Existing	REC Revenue
Sensitivities (Case 2)									
Base w/o Oil Backup	$14,261	$2,636	$1,142	$3,072	$1,820	$2,343	$506	$2,760	($18)
Base West Only Builds	$14,009	$3,145	$1,142	$2,415	$1,641	$2,343	$582	$2,760	($18)
Base + No DSR	$15,350	$2,904	$0	$4,672	$2,110	$2,343	$582	$2,760	($21)
Base + 300 MW Wind	$14,410	$2,368	$1,003	$3,655	$1,771	$2,343	$582	$2,760	($72)
Base + 15.7% PM	$13,922	$2,630	$1,003	$3,018	$1,605	$2,343	$582	$2,760	($18)

APPENDIX K – ELECTRIC ANALYSIS RESULTS

Figure K-37
Annual Revenue Requirements for Optimal Portfolio with
Expected Inputs for the Scenario

Colstrip Case 1 ($Millions)

	Base	o	High	Base + o C 2	Base + High C 2	Base + ery High C 2	High + High C 2	ery High Gas	ery o Gas	o + Base oad
2014	$631	$537	$706	$695	$630	$1,274	$707	$752	$440	$538
2015	$685	$585	$779	$751	$683	$1,310	$779	$822	$492	$586
2016	$736	$632	$931	$802	$733	$1,364	$932	$892	$532	$633
2017	$842	$675	$1,003	$911	$1,114	$1,574	$1,261	$992	$652	$717
2018	$922	$732	$1,159	$994	$1,214	$1,678	$1,439	$1,086	$728	$772
2019	$970	$760	$1,236	$1,048	$1,269	$1,861	$1,542	$1,151	$759	$799
2020	$1,003	$790	$1,309	$1,088	$1,346	$1,911	$1,646	$1,197	$781	$829
2021	$1,022	$782	$1,402	$1,111	$1,364	$1,921	$1,754	$1,250	$815	$825
2022	$1,150	$878	$1,559	$1,242	$1,543	$2,033	$1,930	$1,392	$951	$952
2023	$1,211	$885	$1,645	$1,310	$1,593	$2,084	$2,052	$1,481	$1,010	$1,002
2024	$1,212	$838	$1,693	$1,319	$1,618	$2,161	$2,147	$1,504	$1,036	$999
2025	$1,311	$894	$1,819	$1,428	$1,758	$2,280	$2,310	$1,645	$1,072	$1,050
2026	$1,442	$955	$2,058	$1,584	$1,991	$2,622	$2,658	$1,886	$1,131	$1,107
2027	$1,525	$1,019	$2,177	$1,677	$2,159	$2,812	$2,831	$1,992	$1,166	$1,167
2028	$1,650	$1,119	$2,347	$1,814	$2,272	$2,937	$3,056	$2,147	$1,224	$1,265
2029	$1,781	$1,123	$2,429	$1,960	$2,458	$3,079	$3,204	$2,297	$1,233	$1,362
2030	$1,846	$1,255	$2,582	$2,037	$2,576	$3,321	$3,428	$2,410	$1,338	$1,389
2031	$2,001	$1,300	$2,775	$2,204	$2,782	$3,497	$3,692	$2,620	$1,423	$1,489
2032	$2,110	$1,391	$2,966	$2,329	$2,970	$3,730	$3,981	$2,758	$1,493	$1,578
2033	$2,233	$1,421	$3,052	$2,467	$3,154	$3,937	$4,152	$2,928	$1,511	$1,651
20-yr NPV	$11,620	$8,551	$15,411	$12,691	$15,117	$21,206	$19,178	$14,446	$8,844	$9,349
End Effects	$2,163	$1,832	$2,460	$2,263	$2,431	$1,395	$2,800	$1,729	$2,602	$2,477
Expected Cost	$13,783	$10,383	$17,871	$14,954	$17,548	$22,601	$21,978	$16,175	$11,446	$11,826

APPENDIX K – ELECTRIC ANALYSIS RESULTS

Colstrip Case 2 ($Millions)

	Base	o	High	Base + o C 2	Base + High C 2	Base + ery High C 2	High + High C 2	ery High Gas	ery o Gas	o + Base oad
2014	$633	$520	$708	$697	$630	$1,274	$709	$754	$449	$539
2015	$689	$565	$783	$755	$683	$1,310	$783	$826	$500	$590
2016	$742	$608	$938	$809	$733	$1,364	$938	$898	$538	$639
2017	$853	$653	$1,015	$922	$1,114	$1,574	$1,272	$1,004	$730	$728
2018	$929	$696	$1,166	$1,002	$1,214	$1,678	$1,447	$1,094	$762	$779
2019	$978	$725	$1,243	$1,055	$1,269	$1,861	$1,550	$1,159	$789	$807
2020	$1,010	$760	$1,316	$1,095	$1,346	$1,911	$1,653	$1,204	$807	$836
2021	$1,029	$748	$1,409	$1,118	$1,364	$1,921	$1,761	$1,257	$885	$832
2022	$1,157	$841	$1,566	$1,249	$1,543	$2,033	$1,936	$1,398	$968	$959
2023	$1,218	$903	$1,652	$1,317	$1,593	$2,084	$2,058	$1,487	$1,024	$1,009
2024	$1,218	$906	$1,699	$1,325	$1,618	$2,161	$2,153	$1,511	$1,049	$1,005
2025	$1,317	$908	$1,825	$1,434	$1,758	$2,280	$2,316	$1,651	$1,119	$1,056
2026	$1,457	$1,023	$2,073	$1,600	$2,000	$2,622	$2,673	$1,901	$1,124	$1,122
2027	$1,553	$1,098	$2,205	$1,705	$2,182	$2,812	$2,859	$2,020	$1,158	$1,195
2028	$1,682	$1,141	$2,379	$1,846	$2,298	$2,937	$3,088	$2,178	$1,205	$1,296
2029	$1,812	$1,248	$2,460	$1,991	$2,484	$3,079	$3,235	$2,328	$1,260	$1,392
2030	$1,875	$1,267	$2,611	$2,067	$2,600	$3,321	$3,457	$2,439	$1,268	$1,418
2031	$2,029	$1,368	$2,803	$2,232	$2,806	$3,497	$3,720	$2,649	$1,405	$1,517
2032	$2,137	$1,409	$2,993	$2,357	$2,992	$3,730	$4,008	$2,785	$1,470	$1,605
2033	$2,259	$1,493	$3,078	$2,493	$3,175	$3,937	$4,177	$2,954	$1,487	$1,677
20-yr NPV	$11,736	$8,563	$15,527	$12,807	$15,169	$21,206	$19,294	$14,562	$9,026	$9,465
End Effects	$2,195	$1,957	$2,492	$2,295	$2,460	$1,395	$2,831	$1,761	$2,490	$2,509
Expected Cost	$13,931	$10,519	$18,019	$15,102	$17,629	$22,601	$22,125	$16,324	$11,516	$11,974

APPENDIX K – ELECTRIC ANALYSIS RESULTS

Cosltrip Case 3 ($Millions)

	Base	o	High	Base + o C 2	Base + High C 2	Base + ery High C 2	High + High C 2	ery High Gas	ery o Gas	o + Base oad
2014	$631	$520	$706	$695	$630	$1,274	$717	$752	$449	$537
2015	$694	$565	$788	$749	$683	$1,310	$788	$831	$500	$583
2016	$757	$608	$953	$800	$734	$1,364	$941	$913	$538	$631
2017	$872	$653	$1,034	$959	$1,115	$1,574	$1,312	$1,023	$730	$755
2018	$988	$718	$1,226	$1,067	$1,232	$1,678	$1,515	$1,153	$762	$830
2019	$1,035	$747	$1,301	$1,113	$1,288	$1,861	$1,611	$1,216	$789	$847
2020	$1,069	$782	$1,375	$1,175	$1,365	$1,911	$1,734	$1,263	$807	$897
2021	$1,089	$773	$1,469	$1,177	$1,384	$1,921	$1,867	$1,317	$885	$871
2022	$1,215	$864	$1,624	$1,348	$1,561	$2,033	$1,982	$1,456	$968	$1,037
2023	$1,277	$927	$1,712	$1,378	$1,612	$2,084	$2,111	$1,547	$1,024	$1,047
2024	$1,279	$932	$1,760	$1,378	$1,636	$2,161	$2,185	$1,571	$1,049	$1,034
2025	$1,376	$932	$1,884	$1,482	$1,777	$2,280	$2,341	$1,710	$1,119	$1,080
2026	$1,518	$1,049	$2,135	$1,659	$2,017	$2,622	$2,704	$1,962	$1,124	$1,154
2027	$1,615	$1,125	$2,268	$1,806	$2,198	$2,812	$2,874	$2,082	$1,158	$1,270
2028	$1,743	$1,167	$2,441	$1,887	$2,313	$2,937	$3,068	$2,240	$1,205	$1,309
2029	$1,876	$1,275	$2,524	$2,042	$2,496	$3,079	$3,243	$2,392	$1,260	$1,412
2030	$1,940	$1,296	$2,677	$2,110	$2,611	$3,321	$3,449	$2,505	$1,268	$1,431
2031	$2,093	$1,396	$2,867	$2,275	$2,814	$3,497	$3,706	$2,712	$1,405	$1,528
2032	$2,203	$1,439	$3,060	$2,412	$2,996	$3,730	$3,990	$2,851	$1,470	$1,627
2033	$2,327	$1,525	$3,146	$2,543	$3,176	$3,937	$4,143	$3,021	$1,487	$1,695
20-yr NPV	$12,185	$8,735	$15,977	$13,253	$15,281	$21,206	$19,609	$15,011	$9,026	$9,741
End Effects	$2,286	$2,025	$2,583	$2,338	$2,462	$1,395	$2,821	$1,853	$2,490	$2,530
Expected Cost	$14,471	$10,760	$18,561	$15,591	$17,744	$22,601	$22,430	$16,864	$11,516	$12,271

APPENDIX K – ELECTRIC ANALYSIS RESULTS

Replacement Power for Colstrip ($Millions)

	Base	o	High	Base + o C 2	Base + High C 2	Base + ery High C 2	High + High C 2	ery High Gas	ery o Gas	o + Base oad
2014	$600	$518	$688	$665	$611	$1,274	$688	$733	$449	$507
2015	$650	$561	$755	$716	$661	$1,310	$755	$798	$500	$550
2016	$694	$604	$904	$762	$707	$1,364	$904	$864	$538	$591
2017	$930	$696	$1,182	$979	$1,127	$1,574	$1,369	$1,172	$730	$763
2018	$1,061	$784	$1,322	$1,107	$1,259	$1,678	$1,508	$1,337	$762	$850
2019	$1,115	$810	$1,456	$1,166	$1,323	$1,861	$1,664	$1,406	$789	$875
2020	$1,154	$842	$1,539	$1,210	$1,380	$1,911	$1,768	$1,468	$807	$904
2021	$1,185	$837	$1,655	$1,242	$1,422	$1,921	$1,889	$1,551	$885	$904
2022	$1,300	$920	$1,800	$1,360	$1,545	$2,033	$2,050	$1,687	$968	$1,019
2023	$1,377	$981	$1,910	$1,442	$1,644	$2,084	$2,181	$1,810	$1,024	$1,076
2024	$1,400	$938	$1,921	$1,470	$1,682	$2,161	$2,228	$1,850	$1,049	$1,088
2025	$1,489	$981	$2,091	$1,569	$1,815	$2,280	$2,427	$1,978	$1,119	$1,128
2026	$1,671	$1,086	$2,350	$1,771	$2,068	$2,622	$2,776	$2,272	$1,124	$1,230
2027	$1,766	$1,099	$2,442	$1,875	$2,152	$2,812	$2,921	$2,352	$1,158	$1,293
2028	$1,860	$1,180	$2,615	$1,978	$2,307	$2,937	$3,146	$2,486	$1,205	$1,358
2029	$1,968	$1,232	$2,712	$2,099	$2,489	$3,079	$3,283	$2,660	$1,260	$1,418
2030	$2,036	$1,313	$2,901	$2,177	$2,607	$3,321	$3,487	$2,787	$1,268	$1,441
2031	$2,190	$1,350	$3,083	$2,341	$2,804	$3,497	$3,735	$2,995	$1,405	$1,536
2032	$2,355	$1,449	$3,191	$2,515	$2,985	$3,730	$3,921	$3,159	$1,470	$1,679
2033	$2,442	$1,478	$3,347	$2,614	$3,169	$3,937	$4,143	$3,341	$1,487	$1,703
20-yr NPV	$12,815	$8,982	$17,198	$13,613	$15,340	$21,206	$19,839	$16,737	$9,026	$9,837
End Effects	$2,429	$1,907	$2,891	$2,437	$2,435	$1,395	$2,795	$2,332	$2,490	$2,538
Expected Cost	$15,244	$10,889	$20,089	$16,050	$17,775	$22,601	$22,634	$19,069	$11,516	$12,376

APPENDIX K – ELECTRIC ANALYSIS RESULTS

Colstrip Case 4 & Sensitivities ($Millions)

	Base Case 4	Base + 300 MW Wind	Base + 15.7% PM	Base + No DSR	Base /o oil ackup	Base + West nly Builds	Base + MT Wind 31% CF	Base + MT Wind 40% CF
2014	$630	$616	$616	$520	$633	$633	$612	$628
2015	$683	$672	$672	$582	$689	$689	$661	$679
2016	$733	$726	$766	$676	$742	$742	$707	$726
2017	$899	$924	$833	$797	$860	$853	$1,446	$1,345
2018	$1,048	$1,001	$921	$874	$936	$930	$1,509	$1,377
2019	$1,091	$1,026	$958	$987	$984	$978	$1,497	$1,373
2020	$1,157	$1,069	$1,006	$1,022	$1,017	$1,011	$1,503	$1,387
2021	$1,173	$1,067	$1,058	$1,180	$1,037	$1,030	$1,474	$1,358
2022	$1,342	$1,191	$1,185	$1,284	$1,164	$1,158	$1,475	$1,363
2023	$1,368	$1,250	$1,201	$1,362	$1,232	$1,220	$1,538	$1,428
2024	$1,363	$1,264	$1,216	$1,456	$1,240	$1,223	$1,546	$1,423
2025	$1,455	$1,360	$1,315	$1,595	$1,345	$1,323	$1,625	$1,503
2026	$1,601	$1,497	$1,490	$1,740	$1,500	$1,470	$1,760	$1,638
2027	$1,728	$1,642	$1,600	$1,892	$1,597	$1,566	$1,848	$1,728
2028	$1,792	$1,716	$1,676	$2,027	$1,734	$1,699	$1,897	$1,777
2029	$1,938	$1,845	$1,809	$2,074	$1,872	$1,831	$1,999	$1,880
2030	$1,998	$1,906	$1,873	$2,240	$1,936	$1,892	$2,059	$1,940
2031	$2,151	$2,057	$2,028	$2,405	$2,098	$2,048	$2,202	$2,083
2032	$2,278	$2,164	$2,138	$2,461	$2,214	$2,157	$2,320	$2,203
2033	$2,400	$2,284	$2,262	$2,615	$2,338	$2,280	$2,398	$2,281
20-yr NPV	$12,715	$12,058	$11,735	$12,657	$11,934	$11,786	$14,569	$13,712
End Effects	$2,390	$2,353	$2,186	$2,223	$2,326	$2,223	$2,956	$2,730
Expected Cost	$15,105	$14,410	$13,922	$14,880	$14,261	$14,009	$17,525	$16,442

APPENDIX K – ELECTRIC ANALYSIS RESULTS

Figure K-38
Annual Revenue Requirement Savings/(Cost) of Colstrip Case 2, all 4 units vs. Replacement Power ($Millions)

	Base	o	High	Base + o C 2	Base + High C 2	Base + ery High C 2	High + High C 2
2017	$77	$9	$168	$57	$29	($12)	$97
2018	$131	$45	$155	$105	$61	($92)	$61
2019	$138	$43	$212	$111	$60	($14)	$115
2020	$143	$44	$223	$115	$56	$0	$114
2021	$156	$48	$246	$124	$57	($22)	$128
2022	$143	$36	$235	$112	$43	$40	$114
2023	$159	$89	$258	$125	$45	($41)	$122
2024	$181	$94	$221	$144	$47	$33	$75
2025	$172	$81	$266	$135	$35	($58)	$111
2026	$214	$116	$277	$172	$48	($69)	$103
2027	$214	$52	$236	$170	($11)	($20)	$62
2028	$178	$29	$236	$133	($35)	($48)	$58
2029	$156	$78	$252	$108	($38)	($119)	$48
2030	$161	$28	$290	$110	($48)	($40)	$30
2031	$161	$22	$279	$109	($58)	($135)	$15
2032	$218	$31	$198	$159	($58)	($66)	($86)
2033	$183	$31	$269	$120	($64)	($67)	($34)

Figure K-39

Revenue Requirement with Input Simulations – 1,000 Trials

Expected Portfolio Cost ($Millions)	Risk Simulation - 1000 Trials				
	Base Case 1	Base Case 2	Base Case 3	Base Replacement Po er	Base + No DSR Case 2
No C 2 Policy Risk					
Minimum	$10,725	$10,872	$11,379	$11,394	$11,852
1st Quartile (P25)	$12,113	$12,259	$12,759	$13,016	$13,289
Mean	$12,755	$12,902	$13,410	$14,053	$14,094
Median (P50)	$12,687	$12,835	$13,358	$14,012	$14,031
3rd Quartile (P75)	$13,155	$13,303	$13,821	$14,796	$14,629
TVar90	$14,533	$14,681	$15,206	$16,452	$16,114
Maximum	$16,035	$16,183	$16,722	$18,545	$17,781
Annual Volatility	13.3%	13.2%	13.1%	17.4%	14.5%
With C 2 Policy Risk					
Minimum	$10,725	$10,872	$11,379	$11,394	$11,852
1st Quartile (P25)	$12,797	$12,944	$13,418	$13,795	$14,071
Mean	$13,931	$14,075	$14,500	$14,815	$15,394
Median (P50)	$13,694	$13,842	$14,311	$14,736	$15,206
3rd Quartile (P75)	$14,978	$15,125	$15,479	$15,681	$16,585
TVar90	$16,753	$16,895	$17,262	$17,722	$18,564
Maximum	$18,509	$18,651	$19,053	$19,787	$20,629
Annual Volatility	13.8%	13.8%	13.8%	17.6%	15.0%

APPENDIX K – ELECTRIC ANALYSIS RESULTS

Figure K-40
Incremental Portfolio Builds by Year (nameplate MW)

Base – Colstrip Cases 1, 2 & 3

	CCCT	Peaker	Wind	Transmission Rene al	DSR	Colstrip
2014	-	-	-	664	88	-
2015	-	-	-	(40)	82	-
2016	-	-	-	117	82	-
2017	-	221	-	400	76	657
2018	-	-	-	266	80	-
2019	-	-	-	-	64	-
2020	-	-	-	-	120	-
2021	-	-	-	-	77	-
2022	-	-	300	-	70	-
2023	-	221	-	-	62	-
2024	-	221	-	-	20	-
2025	-	221	-	-	21	-
2026	-	442	-	-	23	-
2027	-	-	100	-	23	-
2028	-	221	-	-	20	-
2029	-	221	100	-	18	-
2030	-	-	-	-	18	-
2031	-	221	-	160	19	-
2032	-	221	-	-	25	-
2033	-	-	100	-	20	-
Total	-	2,212	600	1,567	1,007	657

APPENDIX K – ELECTRIC ANALYSIS RESULTS

Incremental Portfolio Builds by Year (nameplate MW)

Base – Colstrip Case 4

	CCCT	Peaker	Wind	Transmission Rene al	DSR	Colstrip
2014	-	-	-	664	69	-
2015	-	-	-	(40)	82	-
2016	-	-	-	117	83	-
2017	-	442	-	400	76	359
2018	-	-	-	266	84	-
2019	-	-	-	-	64	-
2020	-	-	-	-	125	-
2021	-	-	-	-	78	-
2022	-	221	300	-	70	-
2023	-	-	-	-	62	-
2024	-	221	-	-	20	-
2025	-	221	-	-	21	-
2026	-	442	-	-	23	-
2027	-	221	100	-	24	-
2028	-	-	-	-	20	-
2029	-	221	100	-	18	-
2030	-	-	-	-	19	-
2031	-	221	-	160	19	-
2032	-	221	-	-	25	-
2033	-	-	100	-	20	-
Total	-	2,433	600	1,567	1,001	359

APPENDIX K – ELECTRIC ANALYSIS RESULTS

Incremental Portfolio Builds by Year (nameplate MW)

Base – Replacement Power for Colstrip

	CCCT	Peaker	Wind	Transmission Rene al	DSR	Colstrip
2014	-	-	-	664	83	-
2015	-	-	-	(40)	76	-
2016	-	-	-	117	75	-
2017	-	663	-	400	68	-
2018	-	221	-	266	72	-
2019	-	-	-	-	55	-
2020	-	-	-	-	110	-
2021	-	-	-	-	69	-
2022	-	-	300	-	62	-
2023	-	221	-	-	55	-
2024	-	221	-	-	18	-
2025	-	221	-	-	19	-
2026	-	442	100	-	20	-
2027	-	221	-	-	21	-
2028	-	-	100	-	18	-
2029	-	221	-	-	16	-
2030	-	-	-	-	17	-
2031	-	221	-	160	17	-
2032	-	221	100	-	21	-
2033	-	-	-	-	18	-
Total	-	2,875	600	1,567	910	-

APPENDIX K – ELECTRIC ANALYSIS RESULTS

Incremental Portfolio Builds by Year (nameplate MW)

Low – Colstrip Case 1

	CCCT	Peaker	Wind	Transmission Rene al	DSR	Colstrip
2014	-	-	-	664	88	-
2015	-	-	-	(40)	82	-
2016	-	-	-	117	82	-
2017	-	-	-	400	75	657
2018	-	-	-	266	80	-
2019	-	-	-	-	64	-
2020	-	-	-	-	119	-
2021	-	-	-	-	77	-
2022	-	-	200	-	69	-
2023	-	-	-	-	62	-
2024	-	-	-	-	19	-
2025	-	221	-	-	21	-
2026	-	442	-	-	23	-
2027	-	-	100	-	23	-
2028	-	221	-	-	20	-
2029	-	-	-	-	18	-
2030	-	221	100	-	18	-
2031	-	-	-	160	19	-
2032	-	221	-	-	25	-
2033	-	-	-	-	20	-
Total	-	1,327	400	1,567	1,004	657

APPENDIX K – ELECTRIC ANALYSIS RESULTS

Incremental Portfolio Builds by Year (nameplate MW)

Low – Colstrip Cases 2 & 3

	CCCT	Peaker	Wind	Transmission Rene al	DSR	Colstrip
2014	-	-	-	664	85	-
2015	-	-	-	(40)	79	-
2016	-	-	-	117	78	-
2017	-	-	-	400	72	359
2018	-	-	-	266	76	-
2019	-	-	-	-	59	-
2020	-	-	-	-	114	-
2021	-	-	-	-	74	-
2022	-	-	200	-	65	-
2023	-	221	-	-	59	-
2024	-	221	-	-	19	-
2025	-	-	-	-	20	-
2026	-	442	100	-	22	-
2027	-	221	-	-	22	-
2028	-	-	-	-	19	-
2029	-	221	100	-	17	-
2030	-	-	-	-	18	-
2031	-	221	-	160	18	-
2032	-	-	-	-	23	-
2033	-	221	-	-	19	-
Total	-	1,769	400	1,567	957	359

APPENDIX K – ELECTRIC ANALYSIS RESULTS

Incremental Portfolio Builds by Year (nameplate MW)

Low – Replacement Power for Colstrip

	CCCT	Peaker	Wind	Transmission Rene al	DSR	Colstrip
2014	-	-	-	664	85	-
2015	-	-	-	(40)	79	-
2016	-	-	-	117	78	-
2017	-	221	-	400	72	-
2018	-	221	-	266	76	-
2019	-	-	-	-	59	-
2020	-	-	-	-	114	-
2021	-	-	-	-	74	-
2022	-	-	200	-	65	-
2023	-	221	-	-	59	-
2024	-	-	-	-	19	-
2025	-	221	-	-	20	-
2026	-	442	100	-	22	-
2027	-	-	-	-	22	-
2028	-	221	-	-	19	-
2029	-	-	100	-	17	-
2030	-	221	-	-	18	-
2031	-	-	-	160	18	-
2032	-	221	-	-	23	-
2033	-	-	-	-	19	-
Total	-	1,990	400	1,567	957	-

APPENDIX K – ELECTRIC ANALYSIS RESULTS

Incremental Portfolio Builds by Year (nameplate MW)

High – Colstrip Cases 1, 2 & 3

	CCCT	Peaker	Wind	Transmission Rene al	DSR	Colstrip
2014	-	-	-	664	88	-
2015	-	-	-	(40)	82	-
2016	-	442	-	117	82	-
2017	-	-	-	400	75	657
2018	-	221	-	266	80	-
2019	-	-	-	-	64	-
2020	-	-	-	-	119	-
2021	-	-	200	-	77	-
2022	-	221	200	-	69	-
2023	-	221	-	-	62	-
2024	-	221	-	-	19	-
2025	-	221	-	-	21	-
2026	-	442	100	-	23	-
2027	-	221	-	-	23	-
2028	-	-	100	-	20	-
2029	-	221	-	-	18	-
2030	-	221	-	-	18	-
2031	-	221	-	160	19	-
2032	-	221	100	-	25	-
2033	-	-	-	-	20	-
Total	-	3096	700	1567	1004	657

APPENDIX K – ELECTRIC ANALYSIS RESULTS

Incremental Portfolio Builds by Year (nameplate MW)

High – Replacement Power for Colstrip

	CCCT	Peaker	Wind	Transmission Rene al	DSR	Colstrip
2014	-	-	-	664	85	-
2015	-	-	-	(40)	79	-
2016	-	442	-	117	78	-
2017	-	663	-	400	72	-
2018	-	-	-	266	76	-
2019	-	221	-	-	59	-
2020	-	-	-	-	115	-
2021	-	-	200	-	74	-
2022	-	221	200	-	66	-
2023	-	221	-	-	59	-
2024	-	-	-	-	19	-
2025	-	442	-	-	20	-
2026	-	442	100	-	22	-
2027	-	-	100	-	22	-
2028	-	221	-	-	19	-
2029	-	221	-	-	17	-
2030	-	221	100	-	18	-
2031	-	221	-	160	18	-
2032	-	-	-	-	23	-
2033	-	221	-	-	19	-
Total	-	3,760	700	1,567	960	-

APPENDIX K – ELECTRIC ANALYSIS RESULTS

Incremental Portfolio Builds by Year (nameplate MW)

Base + Low CO_2 – Colstrip Cases 1 & 2

	CCCT	Peaker	Wind	Transmission Rene al	DSR	Colstrip
2014	-	-	-	664	88	-
2015	-	-	-	(40)	82	-
2016	-	-	-	117	82	-
2017	-	221	-	400	76	657
2018	-	-	-	266	80	-
2019	-	-	-	-	64	-
2020	-	-	-	-	120	-
2021	-	-	-	-	77	-
2022	-	-	300	-	70	-
2023	-	221	-	-	62	-
2024	-	221	-	-	20	-
2025	-	221	-	-	21	-
2026	-	442	-	-	23	-
2027	-	-	100	-	23	-
2028	-	221	-	-	20	-
2029	-	221	100	-	18	-
2030	-	-	-	-	18	-
2031	-	221	-	160	19	-
2032	-	221	-	-	25	-
2033	-	-	100	-	20	-
Total	-	2,212	600	1,567	1,007	657

APPENDIX K – ELECTRIC ANALYSIS RESULTS

Incremental Portfolio Builds by Year (nameplate MW)

Base + Low CO_2 – Colstrip Case 3

	CCCT	Peaker	Wind	Transmission Rene al	DSR	Colstrip
2014	-	-	-	664	88	-
2015	-	-	-	(40)	82	-
2016	-	-	-	117	83	-
2017	-	442	-	400	76	359
2018	-	-	-	266	84	-
2019	-	-	-	-	64	-
2020	-	-	-	-	125	-
2021	-	-	-	-	78	-
2022	-	221	300	-	70	-
2023	-	-	-	-	62	-
2024	-	221	-	-	20	-
2025	-	221	-	-	21	-
2026	-	442	-	-	23	-
2027	-	221	100	-	24	-
2028	-	-	-	-	20	-
2029	-	221	100	-	18	-
2030	-	-	-	-	19	-
2031	-	221	-	160	19	-
2032	-	221	-	-	25	-
2033	-	-	100	-	20	-
Total	-	2,433	600	1,567	1,021	359

APPENDIX K – ELECTRIC ANALYSIS RESULTS

Incremental Portfolio Builds by Year (nameplate MW)

Base + Low CO_2 – Replacement Power for Colstrip

	CCCT	Peaker	Wind	Transmission Rene al	DSR	Colstrip
2014	-	-	-	664	83	-
2015	-	-	-	(40)	76	-
2016	-	-	-	117	75	-
2017	-	663	-	400	68	-
2018	-	221	-	266	72	-
2019	-	-	-	-	55	-
2020	-	-	-	-	110	-
2021	-	-	-	-	69	-
2022	-	-	300	-	62	-
2023	-	221	-	-	55	-
2024	-	221	-	-	18	-
2025	-	221	-	-	19	-
2026	-	442	100	-	20	-
2027	-	221	-	-	21	-
2028	-	-	100	-	18	-
2029	-	221	-	-	16	-
2030	-	-	-	-	17	-
2031	-	221	-	160	17	-
2032	-	221	100	-	21	-
2033	-	-	-	-	18	-
Total	-	2,875	600	1,567	910	-

APPENDIX K – ELECTRIC ANALYSIS RESULTS

Incremental Portfolio Builds by Year (nameplate MW)

Base + High CO_2 – Colstrip Casse 1, 2 & 3

	CCCT	Peaker	Wind	Transmission Rene al	DSR	Colstrip
2014	-	-	-	664	88	-
2015	-	-	-	(40)	82	-
2016	-	-	-	117	83	-
2017	-	442	-	400	76	359
2018	-	-	-	266	84	-
2019	-	-	-	-	64	-
2020	-	-	-	-	125	-
2021	-	-	-	-	78	-
2022	-	221	300	-	70	-
2023	-	-	-	-	62	-
2024	-	221	-	-	20	-
2025	-	221	-	-	21	-
2026	-	442	-	-	23	-
2027	-	221	100	-	24	-
2028	-	-	-	-	20	-
2029	-	221	100	-	18	-
2030	-	-	-	-	19	-
2031	-	221	-	160	19	-
2032	-	221	-	-	25	-
2033	-	-	100	-	20	-
Total	-	2433	600	1567	1021	359

APPENDIX K – ELECTRIC ANALYSIS RESULTS

Incremental Portfolio Builds by Year (nameplate MW)

Base + High CO_2 – Replacement Power for Colstrip

	CCCT	Peaker	Wind	Transmission Rene al	DSR	Colstrip
2014	-	-	-	664	85	-
2015	-	-	-	(40)	79	-
2016	-	-	-	117	78	-
2017	-	663	-	400	72	-
2018	-	221	-	266	76	-
2019	-	-	-	-	59	-
2020	-	-	-	-	114	-
2021	-	-	-	-	74	-
2022	-	-	300	-	65	-
2023	-	221	-	-	59	-
2024	-	221	-	-	19	-
2025	-	221	-	-	20	-
2026	-	442	100	-	22	-
2027	-	-	-	-	22	-
2028	-	221	-	-	19	-
2029	-	221	100	-	17	-
2030	-	-	-	-	18	-
2031	-	221	-	160	18	-
2032	-	221	-	-	23	-
2033	-	-	100	-	19	-
Total	-	2,875	600	1,567	957	-

APPENDIX K – ELECTRIC ANALYSIS RESULTS

Incremental Portfolio Builds by Year (nameplate MW)

Base + Very High CO_2 – Colstrip Cases 1, 2, 3 & Replacement Power

	CCCT	Peaker	Wind	Transmission Rene al	DSR	Colstrip
2014	-	-	-	664	85	-
2015	-	-	-	(40)	79	-
2016	-	-	-	117	78	-
2017	754	-	-	400	72	-
2018	-	-	-	266	76	-
2019	-	-	800	-	59	-
2020	-	-	-	-	114	-
2021	-	-	-	-	74	-
2022	377	-	-	-	65	-
2023	-	-	-	-	59	-
2024	377	-	-	-	19	-
2025	-	-	-	-	20	-
2026	377	-	-	-	22	-
2027	377	-	-	-	22	-
2028	-	-	-	-	19	-
2029	-	-	-	-	17	-
2030	377	-	-	-	18	-
2031	-	-	-	160	18	-
2032	-	221	-	-	23	-
2033	-	-	-	-	19	-
Total	2,640	221	800	1,567	957	-

APPENDIX K – ELECTRIC ANALYSIS RESULTS

Incremental Portfolio Builds by Year (nameplate MW)

High + High CO_2 – Colstrip Cases 1 & 2

	CCCT	Peaker	Wind	Transmission Rene al	DSR	Colstrip
2014	-	-	-	664	88	-
2015	-	-	-	(40)	82	-
2016	-	442	-	117	82	-
2017	-	-	-	400	75	657
2018	-	221	-	266	80	-
2019	-	-	-	-	64	-
2020	-	-	-	-	119	-
2021	-	-	200	-	77	-
2022	-	221	200	-	69	-
2023	-	221	-	-	62	-
2024	-	221	-	-	19	-
2025	-	221	-	-	21	-
2026	-	442	100	-	23	-
2027	-	221	-	-	23	-
2028	-	-	100	-	20	-
2029	-	221	-	-	18	-
2030	-	221	-	-	18	-
2031	-	221	-	160	19	-
2032	-	221	100	-	25	-
2033	-	-	-	-	20	-
Total	-	3,096	700	1,567	1,004	657

APPENDIX K – ELECTRIC ANALYSIS RESULTS

Incremental Portfolio Builds by Year (nameplate MW)

High + High CO_2 – Colstrip Case 3

	CCCT	Peaker	Wind	Transmission Rene al	DSR	Colstrip
2014	-	-	-	664	90	-
2015	-	-	-	(40)	84	-
2016	-	442	-	117	85	-
2017	-	221	-	400	77	359
2018	-	221	-	266	86	-
2019	-	-	-	-	66	-
2020	-	-	-	-	127	-
2021	-	-	400	-	80	-
2022	-	221	-	-	71	-
2023	-	221	-	-	64	-
2024	-	221	-	-	20	-
2025	-	221	-	-	22	-
2026	-	442	100	-	24	-
2027	-	221	-	-	24	-
2028	-	-	-	-	21	-
2029	-	221	100	-	18	-
2030	-	221	-	-	19	-
2031	-	221	-	160	20	-
2032	-	221	100	-	26	-
2033	-	-	-	-	20	-
Total	-	3,317	700	1,567	1,042	359

APPENDIX K – ELECTRIC ANALYSIS RESULTS

Incremental Portfolio Builds by Year (nameplate MW)

High + High CO_2 – Replacement Power for Colstrip

	CCCT	Peaker	Wind	Transmission Rene al	DSR	Colstrip
2014	-	-	-	664	85	-
2015	-	-	-	(40)	79	-
2016	-	442	-	117	78	-
2017	-	663	-	400	72	-
2018	-	-	-	266	76	-
2019	-	221	-	-	59	-
2020	-	-	-	-	114	-
2021	-	-	200	-	74	-
2022	-	221	200	-	65	-
2023	-	221	-	-	59	-
2024	-	-	-	-	19	-
2025	-	442	-	-	20	-
2026	-	442	100	-	22	-
2027	-	-	200	-	22	-
2028	-	221	-	-	19	-
2029	-	221	-	-	17	-
2030	-	221	-	-	18	-
2031	-	221	-	160	18	-
2032	-	-	-	-	23	-
2033	-	221	-	-	19	-
Total	-	3,760	700	1,567	957	-

APPENDIX K – ELECTRIC ANALYSIS RESULTS

Incremental Portfolio Builds by Year (nameplate MW)

Very High Gas – Colstrip Cases 1, 2 & 3

	CCCT	Peaker	Wind	Transmission Rene al	DSR	Colstrip
2014	-	-	-	664	88	-
2015	-	-	-	(40)	82	-
2016	-	-	-	117	82	-
2017	-	221	-	400	76	657
2018	-	-	-	266	80	-
2019	-	-	-	-	64	-
2020	-	-	-	-	120	-
2021	-	-	-	-	77	-
2022	-	-	300	-	70	-
2023	-	221	-	-	62	-
2024	-	221	-	-	20	-
2025	-	221	-	-	21	-
2026	-	442	-	-	23	-
2027	-	-	100	-	23	-
2028	-	221	-	-	20	-
2029	-	221	100	-	18	-
2030	-	-	-	-	18	-
2031	-	221	-	160	19	-
2032	-	221	-	-	25	-
2033	-	-	100	-	20	-
Total	-	2212	600	1567	1007	657

APPENDIX K – ELECTRIC ANALYSIS RESULTS

Incremental Portfolio Builds by Year (nameplate MW)

Very High Gas – Replacement Power for Colstrip

	CCCT	Peaker	Wind	Transmission Rene al	DSR	Colstrip
2014	-	-	-	664	85	-
2015	-	-	-	(40)	79	-
2016	-	-	-	117	78	-
2017	-	663	-	400	72	-
2018	-	221	-	266	76	-
2019	-	-	-	-	59	-
2020	-	-	-	-	114	-
2021	-	-	-	-	74	-
2022	-	-	300	-	65	-
2023	-	221	-	-	59	-
2024	-	221	-	-	19	-
2025	-	221	-	-	20	-
2026	-	442	100	-	22	-
2027	-	-	-	-	22	-
2028	-	221	-	-	19	-
2029	-	221	100	-	17	-
2030	-	-	-	-	18	-
2031	-	221	-	160	18	-
2032	-	221	-	-	23	-
2033	-	-	100	-	19	-
Total	-	2,875	600	1,567	957	-

APPENDIX K – ELECTRIC ANALYSIS RESULTS

Incremental Portfolio Builds by Year (nameplate MW)

Very Low Gas – Colstrip Case 1

	CCCT	Peaker	Wind	Transmission Rene al	DSR	Colstrip
2014	-	-	-	664	65	-
2015	-	-	-	(40)	58	-
2016	-	-	-	117	56	-
2017	-	442	-	400	48	359
2018	-	221	-	266	52	-
2019	-	-	-	-	35	-
2020	-	-	-	-	88	-
2021	-	-	100	-	48	-
2022	-	221	200	-	41	-
2023	-	221	-	-	35	-
2024	-	-	100	-	14	-
2025	-	221	-	-	12	-
2026	-	663	-	-	13	-
2027	-	-	100	-	13	-
2028	-	221	-	-	13	-
2029	-	-	-	-	11	-
2030	-	221	100	-	12	-
2031	-	221	-	160	10	-
2032	-	221	-	-	13	-
2033	-	-	-	-	12	-
Total	-	2875	600	1567	649	359

APPENDIX K – ELECTRIC ANALYSIS RESULTS

Incremental Portfolio Builds by Year (nameplate MW)

Very Low Gas – Colstrip Cases 2, 3 & Replacement Power

	CCCT	Peaker	Wind	Transmission Rene al	DSR	Colstrip
2014	-	-	-	664	69	-
2015	-	-	-	(40)	62	-
2016	-	-	-	117	60	-
2017	-	885	-	400	53	-
2018	-	-	-	266	56	-
2019	-	-	-	-	39	-
2020	-	-	-	-	93	-
2021	-	221	100	-	52	-
2022	-	-	200	-	45	-
2023	-	221	-	-	39	-
2024	-	221	-	-	15	-
2025	-	221	100	-	14	-
2026	-	442	-	-	15	-
2027	-	-	100	-	15	-
2028	-	221	-	-	14	-
2029	-	221	-	-	12	-
2030	-	-	-	-	13	-
2031	-	221	100	160	12	-
2032	-	221	-	-	15	-
2033	-	-	-	-	14	-
Total	-	3096	600	1567	706	-

APPENDIX K – ELECTRIC ANALYSIS RESULTS

Incremental Portfolio Builds by Year (nameplate MW)

Low + Base Load – Colstrip Cases 1 & 2

	CCCT	Peaker	Wind	Transmission Rene al	DSR	Colstrip
2014	-	-	-	664	88	-
2015	-	-	-	(40)	82	-
2016	-	-	-	117	82	-
2017	-	221	-	400	76	-
2018	-	-	-	266	80	657
2019	-	-	-	-	64	-
2020	-	-	-	-	120	-
2021	-	-	-	-	77	-
2022	-	-	300	-	70	-
2023	-	221	-	-	62	-
2024	-	221	-	-	20	-
2025	-	221	-	-	21	-
2026	-	442	-	-	23	-
2027	-	-	100	-	23	-
2028	-	221	-	-	20	-
2029	-	221	100	-	18	-
2030	-	-	-	-	18	-
2031	-	221	-	160	19	-
2032	-	221	-	-	25	-
2033	-	-	100	-	20	-
Total	-	2,212	600	1,567	1,007	657

APPENDIX K – ELECTRIC ANALYSIS RESULTS

Incremental Portfolio Builds by Year (nameplate MW)

Low + Base Load – Colstrip Case 3

	CCCT	Peaker	Wind	Transmission Rene al	DSR	Colstrip
2014	-	-	-	664	88	-
2015	-	-	-	(40)	82	-
2016	-	-	-	117	83	-
2017	-	442	-	400	76	359
2018	-	-	-	266	84	-
2019	-	-	-	-	64	-
2020	-	-	-	-	125	-
2021	-	-	-	-	78	-
2022	-	221	300	-	70	-
2023	-	-	-	-	62	-
2024	-	221	-	-	20	-
2025	-	221	-	-	21	-
2026	-	442	-	-	23	-
2027	-	221	100	-	24	-
2028	-	-	-	-	20	-
2029	-	221	100	-	18	-
2030	-	-	-	-	19	-
2031	-	221	-	160	19	-
2032	-	221	-	-	25	-
2033	-	-	100	-	20	-
Total	-	2,433	600	1,567	1,021	359

APPENDIX K – ELECTRIC ANALYSIS RESULTS

Incremental Portfolio Builds by Year (nameplate MW)

Low + Base Load – Replacement Power for Colstrip

	CCCT	Peaker	Wind	Transmission Rene al	DSR	Colstrip
2014	-	-	-	664	83	-
2015	-	-	-	(40)	76	-
2016	-	-	-	117	75	-
2017	-	663	-	400	68	-
2018	-	221	-	266	72	-
2019	-	-	-	-	55	-
2020	-	-	-	-	110	-
2021	-	-	-	-	69	-
2022	-	-	300	-	62	-
2023	-	221	-	-	55	-
2024	-	221	-	-	18	-
2025	-	221	-	-	19	-
2026	-	442	100	-	20	-
2027	-	221	-	-	21	-
2028	-	-	100	-	18	-
2029	-	221	-	-	16	-
2030	-	-	-	-	17	-
2031	-	221	-	160	17	-
2032	-	221	100	-	21	-
2033	-	-	-	-	18	-
Total	-	2875	600	1567	910	-

APPENDIX K – ELECTRIC ANALYSIS RESULTS

Incremental Portfolio Builds by Year (nameplate MW)

Base + No DSR – Colstrip Case 2

	CCCT	Peaker	Wind	Transmission Rene al	DSR	Colstrip
2014	-	-	-	664	-	-
2015	-	-	-	(40)	-	-
2016	-	221	-	117	-	-
2017	-	221	-	400	-	657
2018	-	-	-	266	-	-
2019	-	221	-	-	-	-
2020	-	-	-	-	-	-
2021	-	221	200	-	-	-
2022	-	-	200	-	-	-
2023	-	221	-	-	-	-
2024	-	221	-	-	-	-
2025	-	221	100	-	-	-
2026	-	442	-	-	-	-
2027	-	221	100	-	-	-
2028	-	221	-	-	-	-
2029	-	-	-	-	-	-
2030	-	221	100	-	-	-
2031	-	221	-	160	-	-
2032	-	-	-	-	-	-
2033	-	221	-	-	-	-
Total	-	3,096	700	1,567	-	657

APPENDIX K – ELECTRIC ANALYSIS RESULTS

Incremental Portfolio Builds by Year (nameplate MW)

Base + 15.7% Planning Margin – Colstrip Case 2

	CCCT	Peaker	Wind	Transmission Rene al	DSR	Colstrip
2014	-	-	-	664	85	-
2015	-	-	-	(40)	79	-
2016	-	221	-	117	79	-
2017	-	-	-	400	72	657
2018	-	-	-	266	80	-
2019	-	-	-	-	60	-
2020	-	-	-	-	120	-
2021	-	221	-	-	74	-
2022	-	-	300	-	66	-
2023	-	-	-	-	59	-
2024	-	221	-	-	19	-
2025	-	221	-	-	20	-
2026	-	442	100	-	22	-
2027	-	221	-	-	22	-
2028	-	-	-	-	19	-
2029	-	221	100	-	17	-
2030	-	-	-	-	18	-
2031	-	221	-	160	18	-
2032	-	221	-	-	23	-
2033	-	-	100	-	19	-
Total	-	2,212	600	1,567	971	657

Incremental cost of renewable resources to meet RCW 19.285 incremental cost alternative compliance

Overview

According to RCW 19.285, certain electric utilities in Washington must meet 15 percent of their retail electric load with eligible renewable resources by the calendar year 2020. The annual target for the calendar year 2012 is 3 percent of retail electric load. However, if the incremental cost of those renewable resources compared to an equivalent non-renewable is greater than 4 percent of its revenue requirement, then a utility will be considered in compliance with the annual renewable energy target in RCW 19.285. The law states it this way: "The incremental cost of an eligible renewable resource is calculated as the difference between the levelized delivered cost of the eligible renewable resource, regardless of ownership, compared to the levelized delivered cost of an equivalent amount of reasonably available substitute resources that do not qualify as eligible renewable resources".[7]

Analytic framework

This analysis compares the revenue requirement cost of each renewable resource with the projected market value and capacity value at the time of the renewable acquisition. There may be other approaches to calculating these costs – such as using variable costs from different kinds of thermal plants instead of market. However, PSE's approach is most reasonable because it most closely reflects how customers will experience costs; i.e., PSE would not dispatch a peaker or CCCT with the ramping up and down of a wind farm without regard to whether the unit is being economically dispatched. For example, a peaker will not be economically dispatched often at all, so capacity from the thermal plant and energy from market is the closest match to actual incremental costs – and that is the point of this provision in the law – a to ensure customers don't pay too much. This, "contemporaneous" with the decision-making aspect of PSE's approach, is important. Utilities should be able to assess whether they will exceed the cost cap before an acquisition, without having to worry about ex-post adjustments that could change compliance status. The analytical framework here reflects a close approximation of the

[7] *RCW 19.285.050 (1) (a) (b)*

portfolio analysis used by PSE in resource planning, as well as in the evaluation of bids received in response to the company's Request for Proposals (RFP).

Resources that meet RCW 19.285 definition of "eligible renewable resource"

Figure K-41
Resources that meet RCW 19.285 definition of Eligible Renewable Resource

	Nameplate (MW)	Annual Energy (aMW)	Commercial nline Date	Market Price/ Peaker Assumptions	Capacity Credit Assumption
Hopkins Ridge	149.4	53.3	Dec 2005	2004 RFP	20%
Wild Horse	228.6	73.4	Dec 2006	2006 RFP	17.2%
londike III	50	18.0	Dec 2007	2006 RFP	15.6%
Hopkins Infill	7.2	2.4	Dec 2007	2007 IRP	20%
Wild Horse Expansion	44	10.5	Dec 2009	2007 IRP	15%
o er Snake River I	342.7	102.5	Apr 2012	2010 Trends	5%
Snoqualmie Upgrades	6.1	3.9	Mar 2013	2009 Trends	95%
o er Baker Upgrades	30	12.5	May 2013	2011 IRP Base	95%
Generic Wind 2022	300	90	Jan 2022	2013 IRP Base	4%
Generic Wind 2027	100	30	Jan 2027	2013 IRP Base	4%
Generic Wind 2029	100	30	Jan 2029	2013 IRP Base	4%
Generic Wind 2033	100	30	Jan 2033	2013 IRP Base	4%

Equivalent non-renewable

The incremental cost of a renewable resource is defined as the difference between the levelized cost of the renewable resource compared to an equivalent non-renewable resource. An equivalent non-renewable is an energy resource that does not meet the definition of a renewable resource in RCW 19.285, but is equal to a renewable resource on an energy and capacity basis. For the purpose of this analysis, the cost of an equivalent non-renewable resource has three components:

1. Capacity Cost: There are two parts of capacity cost. First is the capacity in MW. This would be nameplate for a firm resource like biomass, or the assumed

capacity of a wind plant. Second is the $/kW cost, which we assumed to be equal to the cost of a peaker.

2. Energy Cost: This was calculated by taking the hourly generation shape of the resource, multiplied by the market price in each hour. This is the equivalent cost of purchasing the equivalent energy on the market.
3. Imputed Debt: The law states the non-renewable must be an "equivalent amount," which includes a time dimension. If PSE entered into a long-term contract for energy, there would be an element of imputed debt. Therefore, it is included in this analysis as a cost for the non-renewable equivalent.

For example, Hopkins Ridge produces 466,900 MWh annually. The equivalent non renewable is to purchase 466,900 MWh from the Mid-C market and then build a 30 MW (149.4*20 percent = 30) peaker plant for capacity only. With the example, the cost comparison includes the hourly Mid-C price plus the cost of building a peaker, plus the cost of the imputed debt. The total revenue requirement (fixed and variable costs) of the non-renewable is the cost stream – including end effects – discounted back to the first year. That net present value is then levelized over the life of the comparison renewable resource.

Cost of renewable resource

Levelized cost of the renewable resource is more direct. It is based on the proforma financial analysis performed at the time of the acquisition. The stream of revenue requirement (all fixed and variable costs, including integration costs) are discounted back to the first year – again, including end effects. That net present value is then levelized out over the life of the resource/contract. The levelized cost of the renewable resource is then compared with the levelized cost of the equivalent non-renewable resource to calculate the incremental cost.

APPENDIX K – ELECTRIC ANALYSIS RESULTS

Example

The following is a detailed example of how PSE calculated the incremental cost of Wild Horse. It is important to note that PSE's approach uses information contemporaneous with the decision making process, so this analysis will not reflect updated assumptions for capacity, capital cost, or integration costs, etc.

Eligible Renewable: Wild Horse Wind Facility
Capacity Contribution Assumption: 228.6 * 17.2% = 39 MW

1. Calculate Wild Horse revenue requirement

Figure K-42 is a sample of the annual revenue requirement calculations for the first few years of Wild Horse, along with the NPV of revenue requirement.

Figure K-42
Calculation of Wild Horse Revenue Requirement

($ Millions)	20-yr NPV	2007	2008	...	2025
Gross Plant		384	384	...	384
Accumulative depreciation (Avg.)		(10)	(29)		(355)
Accumulative deferred tax (EOP)		(20)	(56)		(7)
Rate base		354	299		22
After tax WACC		7.01%	7.01%		7.01%
After tax return		25	21		2
Grossed up return		38	32		2
PTC grossed up		(20)	(20)		-
Expenses		16	16		22
Book depreciation		19	19		19
Revenue required	370.9	53	48		44
End effects	4.6				
Total revenue requirement	375				

2. Calculate revenue requirement for equivalent non-renewable: Peaker capacity

Capacity = 39 MW

Capital Cost of Capacity: $462/KW

Figure K-43
Calculation of Peaker Revenue Requirement

($ Millions)	20-yr NPV	2007	2008	…	2025
Gross Plant		18	18		18
Accumulative depreciation (Avg.)		(0)	(1)		(10)
Accumulative deferred tax (EOP)		(0)	(0)		(3)
Rate base		18	17		5
After tax WACC		7.01%	7.01%		7.01%
After tax return		1	1		0
Grossed up return		2	2		0
Expenses		1	1		2
Book depreciation		1	1		1
Revenue required	32	4	4		3
End effects	2				
Total revenue requirement	34				

APPENDIX K – ELECTRIC ANALYSIS RESULTS

3. Calculate revenue requirement for equivalent non-renewable: Energy

Energy: 642,814 MWh

For the market purchase, we used the hourly power prices from the 2006 RFP plus a transmission adder of $1.65/MWh in 2007 and escalated at 2.5 percent.

Figure K-44
Calculation of Energy Revenue Requirement

Month	Day	Hour	20-yr NPV	2007	...	2025
1	1	1		49 MW * $59/MW = $2891	...	49 MW * $61/MW = $2989
1	1	2		92 MW * $60/MW = $5520	...	92 MW * $63/MW = $5796
...	....	...		...	...	...
12	31	24		13 MW * $59/MW = $767	...	13 MW * $65/MW = $845
($Millions)						
Cost of Market				36	...	41
Imputed Debt				1	...	0
Total Revenue Requirement			285	37	...	41

APPENDIX K – ELECTRIC ANALYSIS RESULTS

4. Incremental cost

The table below is the total cost of Wild Horse less the cost of the peaker and less the cost of the market purchases for the total 20-year incremental cost difference of the renewable to an equivalent non-renewable.

Figure K-45
20-yr Incremental Cost of Wild Horse

($ Millions)	20-yr NPV
Wild Horse	375
Peaker	34
Market	285
20-yr Incremental Cost of Wild Horse	56

We chose to spread the incremental cost over 25 years since that is the depreciable life of a wind project used by PSE. The payment of $56 Million over 25 years comes to $5.2 Million/Year using the 7.01 percent discount rate.

Summary results

Each renewable resource that counts towards meeting the renewable energy target was compared to an equivalent non-renewable resource starting in the same year and levelized over the book life of the plant: 25 years for wind power and 40 years for hydroelectric power. Figure K-46 presents results of this analysis for existing resources and projected resources. This demonstrates PSE expects to meet the physical targets under RCW 19.285 without being constrained by the cost cap. A negative cost difference means that the renewable was lower-cost than the equivalent non-renewable, while a positive cost means that the renewable was a higher cost.

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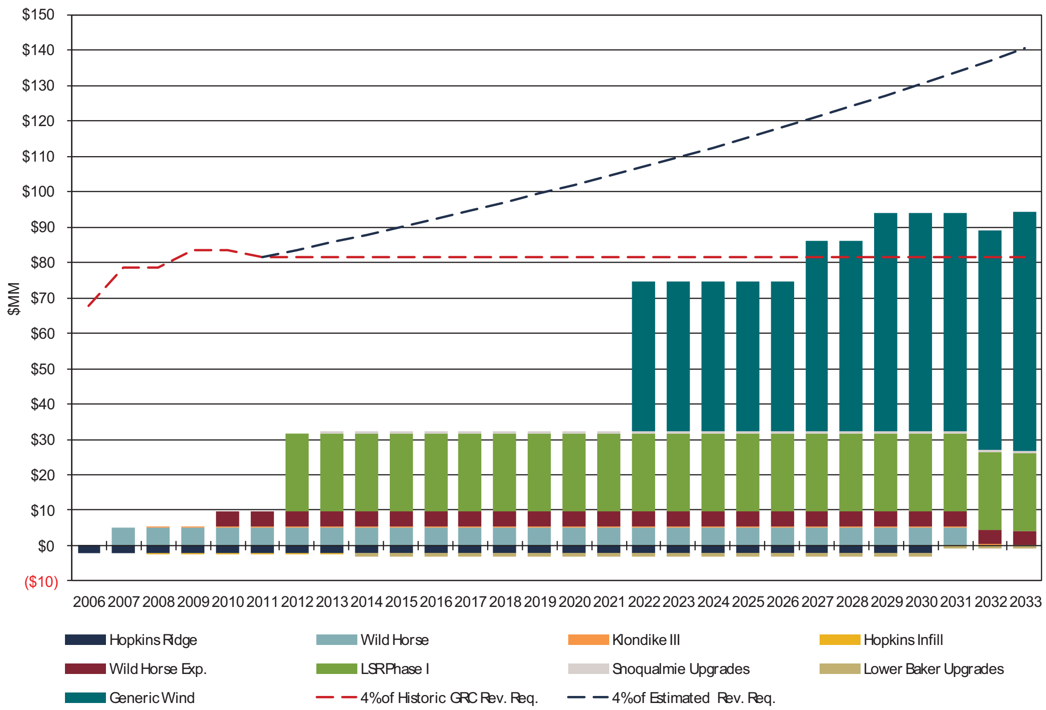
Figure K-46
Equivalent Non-renewable 20-year Levelized Cost Difference Compared to 4 Percent of 2011 GRC Revenue Requirement



As the chart reveals, even if the company's revenue requirement were to stay the same for the next 10 years, PSE would still not hit the 4 percent requirement. The estimated revenue requirement uses a 2.5 percent assumed escalation from the 2011 General Rate Case revenue requirement.

LOLP of the Base Scenario portfolio

To determine if the optimal portfolio in the Base Scenario is actually meeting the planning margin criteria for reliability at the 5 percent loss of load probability (LOLP), the capacity additions from this portfolio was included in the LOLP model. The goal is to perform an LOLP simulation using the same set of risks as those done to derive the updated planning margins, but using the capacity additions from the optimal portfolio in the Base Scenario. The test is performed for the Winter 2018-2019 since that was one of the test periods used in the LOLP analysis, and a period where a complete set of risk data is available.

The results showed that the LOLP for winter 2018-2019 using the capacity additions from the base case portfolio is 4.6 percent. This portfolio meets the requirement that the planning margin should be below the 5 percent LOLP standard used in the industry. It is worth noting that the actual LOLP is not too low, which would have implied that there is too much capacity added.

Gas Analysis

Contents

1. Analytical Models

PSE uses the SENDOUT® software model from Ventyx for long-term gas supply portfolio planning. SENDOUT is a widely used model that helps identify the long-term least-cost combination of resources to meet stated loads. Avista, Cascade Natural Gas, and Terasen all use the SENDOUT model as well. The current version of SENDOUT used by PSE (Version 12.5.5) incorporates a Monte Carlo capability allowing analysis of uncertainty about future prices and weather-driven loads. The following description of SENDOUT includes the Monte Carlo features.

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SENDOUT

SENDOUT is an integrated tool set for gas resource analysis that models the gas supply network and the portfolio of supply, storage, transportation, and demand-side resources (DSR) to meet demand requirements. The Monte Carlo capabilities allow simulation of uncertainties regarding weather and commodity prices. It then runs the SENDOUT portfolio over many draws to provide a probability distribution of results from which to make decisions.

SENDOUT can operate in two different modes: It can be used to determine the optimal set of resources (energy efficiency, supply, storage, and transport) to minimize costs over a defined planning period. Or, specific portfolios can be defined, and the model will determine the least-cost dispatch to meet demand requirements for each portfolio. SENDOUT solves both problems using a linear program (LP). It determines how a portfolio of resources (energy efficiency, supply, storage, and transport), including associated costs and contractual or physical constraints, should be added and dispatched to meet demand in a least-cost fashion. By using an LP, SENDOUT considers thousands of variables and evaluates tens of thousands of possible solutions in order to generate the least-cost solution. A standard dispatch considers the capacity level of all resources as given, and therefore performs a variable-cost dispatch. A resource-mix dispatch can look at a range of potential capacity and size resources, including their fixed and variable costs.

Energy efficiency

SENDOUT provides a comprehensive set of inputs to model a variety of energy efficiency programs. Costs can be modeled at an overall program level or broken down into a variety of detailed accounts. The impact of efficiency programs on load can be modeled at the same detail level as demand. SENDOUT has the ability to determine the most cost-effective size of energy efficiency programs on an integrated basis with supply-side alternatives in a long-run resource mix analysis.

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Supply

SENDOUT allows a system to be supplied by either flowing gas contracts or a spot market. Specific physical and contractual constraints can be modeled, such as maximum flow levels and minimum flow percentages, on a daily, monthly, seasonal, or annual basis. SENDOUT uses standard gas contract costs; the rates may be changed on a monthly or daily basis.

Storage

SENDOUT allows storage sources (either leased or company owned) to serve the system. Storage input data include the minimum or maximum inventory levels, minimum or maximum injection and withdrawal rates, injection and withdrawal fuel loss, *to* and *from* interconnects, and the period of activity (i.e., when the gas is available for injection or withdrawal). There is also the option to define and name volume-dependent injection and withdrawal percentage tables (ratchets), which can be applied to one or more storage sources.

Transportation

SENDOUT provides the means to model transportation segments to define flows, costs, and fuel loss. Flow values include minimum and maximum daily quantities available for sale to gas markets or for release. Cost values include standard fixed and variable transportation rates, as well as a per-unit cost generated for released capacity. Seasonal transportation contracts can also be modeled.

Demand

SENDOUT allows the user to define multiple demand areas, and it can compute a demand forecast by class based on weather.

Monte Carlo analysis

Monte Carlo simulation is a statistical modeling method used to imitate the many possibilities that exist within a real-life system. By describing the expectation, variability, behavior, and correlation among potential events, it is possible through repeated random draws to derive a numerical landscape of the many potential futures. The goal of Monte Carlo is for this quantitative landscape to reflect both the magnitude and the likelihood of these events, thereby providing a risk-based viewpoint from which to base decisions.

Traditional optimization is deterministic. That is, the inputs for a given scenario are fixed (one value to one cell), and there is a single solution for this set of assumptions. Monte Carlo simulation allows the user to generate the inputs for optimization with hundreds or thousands of values (draws) for weather and price possibilities. The SENDOUT network optimizer provides a detailed dispatch for each Monte Carlo draw.

Another application for Monte Carlo and optimization is to study the resource trade-off economics by optimally sizing the contract or asset level of various and competing resources for each draw. This can be especially helpful in determining the right resource mix that will lower expected costs. This mix of resources is difficult to identify using deterministic methods, since it is difficult to determine at which points various resources are better or worse.

Monte Carlo uncertainty inputs

Monte Carlo analysis provides helpful information to guide long-term resource planning as well as to support specific resource acquisitions. Monte Carlo analysis is performed by creating a large number of price and temperature (and thus demand) scenarios that are analyzed in SENDOUT. Creating hundreds or thousands of reasonable scenarios of prices at each relevant supply basin with different temperatures requires a new and significant set of data inputs that are not required for a single static optimization model run. The following discussion identifies the uncertainty factors included for Monte Carlo analyses and explains the analysis used to define each factor.

Below is a list of the inputs needed to create reasonable sets of scenarios followed by a brief description of each.

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- **Expected Monthly Heating Degree Days.** The expected summation of daily heating degree days (HDD) for each month is required. Daily heating degree days are calculated as 65 degrees F minus the average daily temperature.
- **Standard Deviation of Monthly HDD.** A measure of variability in total monthly HDD that can be assigned a different value for every month.
- **Daily HDD Pattern.** Daily HDD are derived by applying a historic daily HDD pattern to each monthly HDD draw. This daily pattern can be drawn independently from the monthly HDD level or can be set to reflect a different historic period in each month. Different months can have different daily pattern settings.
- **Expected Monthly Gas Price Draw.** The basis of determining prices each month.
- **Standard Deviation of Monthly Price Draw:** This is a measure of the variability of prices at each basin, such as at AECO. Standard deviation is expressed in dollars. A different standard deviation can be assigned to each month for the planning period.
- **Price-to-Price Correlations between Basins**. Ensures reasonable relationships for prices between each basin for the Monte Carlo scenarios.

Uncertainty factor descriptions

Expected Monthly HDD. PSE is using the average monthly HDD for each month based on temperature data going back over the most recent 30 years. This period was chosen because it includes the period during which PSE has hourly temperature data with which to calculate HDD, and because it is consistent with the period used to establish the company's gas peak day planning standard.

Standard Deviation of Monthly HDD. The standard deviation for each month was calculated using the monthly data above. That is, the standard deviation of monthly HDD totals was calculated.

Daily HDD Pattern. The daily HDD pattern for each month was prevented from varying randomly, independent of the monthly HDD draw. Preliminary analysis showed that randomly pairing monthly HDD levels with daily patterns can result in temperatures significantly colder than those recorded in history. To avoid overstating temperature variability, PSE applied the daily temperature pattern that best matches the monthly HDD.

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Expected Monthly Price Draw. The gas price forecast is used as the expected monthly price draw.

Standard Deviation of Monthly Price Draw. Historical data was used to establish the range of variability for each price basin. Selecting a consistent time period for all four basins provides a reasonably consistent basis for calculating the standard deviation.

Price Correlations between Basins. Similar to the price-to-weather correlations, price-to-price correlations were calculated seasonally. Price correlations between supply basins are strongly positive, which is to be expected given the infrastructure in the Pacific Northwest.

Alternative resource data

Resource costs and modeling assumptions for the pipeline alternatives considered in the IRP are summarized in Figure L-1. The resource costs and modeling assumptions for the storage alternatives are summarized in Figure L-2.

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Figure L-1

Prospective Pipeline Alternatives Available

Prospective Pipeline Alternatives Available

Alternative	From/To	Years Available	Maximum Capacity Available In Sendout (MDth)	Current Rates: Capacity Demand ($/Dth/day)	Current Rates: Variable Commodity ($/Dth)	Current Rates: Fuel Use (%)	Comments
Vintage NWP	Rockies and Sumas To PSE	-	Equal to existing contract amounts	0.41	0.03	1.4	No additional vintage NWP capacity is available
Expansion of NWP	Sumas to PSE	Oct. 2017, 2018, 2022,2026 & 2030	200	0.50	0.03	1.9	Prospective project, estimated costs
Additional Westcoast Capacity (T-South)	Station 2 to Sumas	Oct. 2014, 2018, 2022,2026 & 2030	200	0.42	0.01	1.6	Uncontracted firm capacity is available
Additional Westcoast Capacity (T-North)	Production field to Station 2	Oct. 2014, 2018, 2022,2026 & 2030	40	0.13	0.01	1	Needed in conjunction with Aitken Creek Storage. Assume capacity available equal to Aitken Storage withdrawal capacity. https://noms.weipipeline.com/regulatory/
Fortis BC KORP/Spectra Expansion	TransCanada BC to Sumas (Bi-directional)	Oct. 2017, 2018, 2022,2026 & 2030	50	0.44	0	0	Prospective project, estimated costs http://www.fortisbc.com/About/ProjectsPlanning/GasUtility/NewOngoingProjects/FortisBCKingsvale-OliverReinforcementProject/Pages/default.aspx, Prospective project, estimated costs
Added Capacity on TC-AB Pipeline	AECO to Alberta/BC border	Oct. 2014, 2018, 2022,2026 & 2030	100	0.17	0	0	NOVA Gas Transmission Ltd. (NGTL) For Southern Crossing and/or GTN Expansion www.transcanada.com/customerexpress/2766.html. Estimate that demand charge will increase to $.17 from $.16 for 2013.
Added Capacity on TC-BC Pipeline	BC Border to Kingsgate	Oct. 2014, 2018, 2022,2026 & 2030	100	0.097	0	1.1	www.transcanada.com/customerexpress/2766.html
Added Capacity on TC-GTN Pipeline	Kingsgate to Stanfield	Oct. 2014, 2018, 2022,2026 & 2030	100	0.177	0.004	1.4	Updated as of 9/27/12 - www.gastransmissionnw.com
Palomar/Blue Bridge Alternative	Stanfield to PSE City Gate	Oct. 2018, 2022,2026 & 2030	200	0.80	0.005	2.0	Prospective project, estimated costs
Ruby Pipeline	Rockies to Malin	Oct. 2014, 2018, 2022,2026 & 2030	100	1.14	0.01	2.0	Published tariff is $1.14 but discounted rates are expected to be available for several years.
GTN "Backhaul"	Malin to Stanfield	Oct. 2014, 2018, 2022,2026 & 2030	100	0.21	0.0054	0	www.gastransmissionnw.com

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Figure L-2

Prospective Storage Alternatives Available

Prospective Storage Alternatives Available

Alternative	Location	Years Expansion Available In SENDOUT	Maximum Storage Capacity Available (MDth)	Maximum Withdrawal Capacity (MDth/day)	Equivalent Days of Full Withdrawal (days)	Maximum Injection Capacity (MDth/day)	Rates: Storage Capacity Demand ($/Dth/mo)	Rates: Delivery Capacity Demand ($/Dth/mo)	Rates: Injection Rate ($/Dth)	Rates: Withdrawal Rate ($/Dth)	Rates: Fuel Use (%)	Comments
Recent Jackson Prairie Expansion	I-5 corridor, Western Washington	-	-	104	21	52	0.106	1.234	0	0	0.58	Data is for comparsion purposes only, no expansions of JP are planned at this time
PSE LNG Project (PSE portion)	I-5 corridor, Western Washington	Apr. 2016, 2018, 2022, 2026 & 2030	300	30	10	1.5	-	-	-	-	-	Prospective confidential project, estimated size and costs
LNG Peak Gas Supply	I-5 corridor, Western Washington	Conditional on the PSE LNG Project	100	20	5	-	-	-	-	-	-	Prospective confidential project, estimated size and costs
Mist Expansion	N.W. Oregon	Apr. 2017, 2018, 2022,2026 & 2030	1000	50	20	20	-	-	-	-	-	Confidential project, estimated size and costs
Swarr LP-Air Upgrade	PSE Service Territory	2018	128.4	30	4	-	-	-	-	-	-	Prospective confidential project, estimated size and costs
Clay Basin	N.E. Utah	Apr. 2018, 2022,2026 & 2030	4000	33	120	26	0.02378	2.85	0.01049	0.01781	1.9	Existing project, released capacity available in 2018
Ryckman Creek (Peregrine)	S.W. Wyoming	Not modeled	-	40	101	-	-	-	-	-	-	Confidential data, estimated size and costs, somewhat similar to Clay Basin
Aitken Creek	N.E. BC	Not modeled	-	40	150	-	-	-	-	-	-	Confidential data, estimated size and costs

2. Analytical Results

Eight planning scenarios were analyzed for the gas sales portfolio using the SENDOUT Model. As discussed in Chapter 4, the planning scenarios are:

1. Base
2. Low
3. High
4. Base + Low CO_2 Cost
5. Base + Very High CO_2 Cost
6. High + High CO_2 Cost
7. Very Low Gas Prices
8. Very High Gas Prices

Two sensitivity tests were done to determine the optimal resources in the event that the PSE LNG Peaking Project and/or the Swarr Upgrade project are not done. These senstitvities are:

1. Base Scenario without the PSE LNG Peaking Project
2. Base Scenario without the PSE LNG Peaking Project and the Swarr Upgrade project

Only the Base Scenario was analyzed for the gas-for-power portfolio.

Optimal Portfolio Results of Scenarios

The optimal portfolios of supply and energy efficiency resources for each of the scenarios and sensitivity cases were identified using SENDOUT. The resources added in each of the gas sales scenarios for the winter periods 2018-19, 2022-23, and 2032-33 are shown in Figures L-3, L-4, and L-5 respectively. Graphs of the resource additions are shown in Figures L-6 thru L-13.

APPENDIX L – GAS ANALYSIS

Figure L-3

Gas Sales Scenario Resource Additions for 2018-19 (MDth/day)

	Base	Low	High	Base + Low CO2	Base + Very High CO2	High + High CO2	Very Low Gas	Very High Gas
DSR	15	13	23	15	31	23	9	23
Westcoast/NWP Expansion	0	0	0	0	0	0	0	0
KORP/NWP Expansion	0	0	0	0	0	0	0	0
Palomar/Blue Bridge	0	0	0	0	0	0	0	0
Mist Storage Expansion	17	7	20	17	0	20	28	5
PSE LNG Project	50	50	50	50	50	50	50	50
Swarr Upgrade	30	30	30	30	30	30	30	30

Figure L-4

Gas Sales Scenario Resource Additions for 2022-23 (MDth/day)

	Base	Low	High	Base + Low CO2	Base + Very High CO2	High + High CO2	Very Low Gas	Very High Gas
DSR	28	24	42	28	57	42	16	42
Westcoast/NWP Expansion	41	28	43	41	19	42	68	118
KORP/NWP Expansion	0	0	0	0	0	0	0	0
Palomar/Blue Bridge	13	13	13	13	0	13	0	13
Mist Storage Expansion	50	50	50	50	50	50	50	50
PSE LNG Project	50	50	50	50	50	50	50	50
Swarr Upgrade	30	30	30	30	30	30	30	30

APPENDIX L – GAS ANALYSIS

Figure L-5

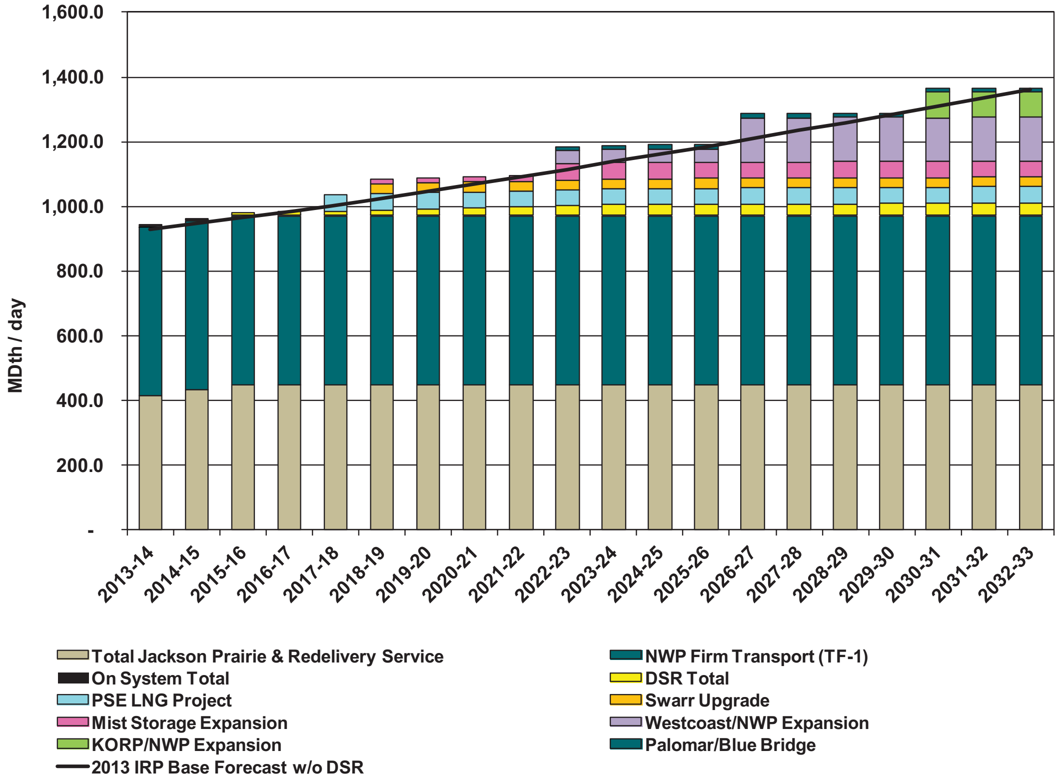
Gas Sales Scenario Resource Additions for 2032-33 (MDth/day)

	Base	Low	High	Base + Low CO2	Base + Very High CO2	High + High CO2	Very Low Gas	Very High Gas
DSR	37	32	58	37	77	58	21	58
Westcoast/NWP Expansion	135	119	138	135	173	137	239	114
KORP/NWP Expansion	78	76	79	78	0	79	0	77
Palomar/Blue Bridge	13	13	13	13	13	13	3	13
Mist Storage Expansion	50	50	50	50	50	50	50	50
PSE LNG Project	50	50	50	50	50	50	50	50
Swarr Upgrade	30	30	30	30	30	30	30	30

APPENDIX L – GAS ANALYSIS

Figure L-6

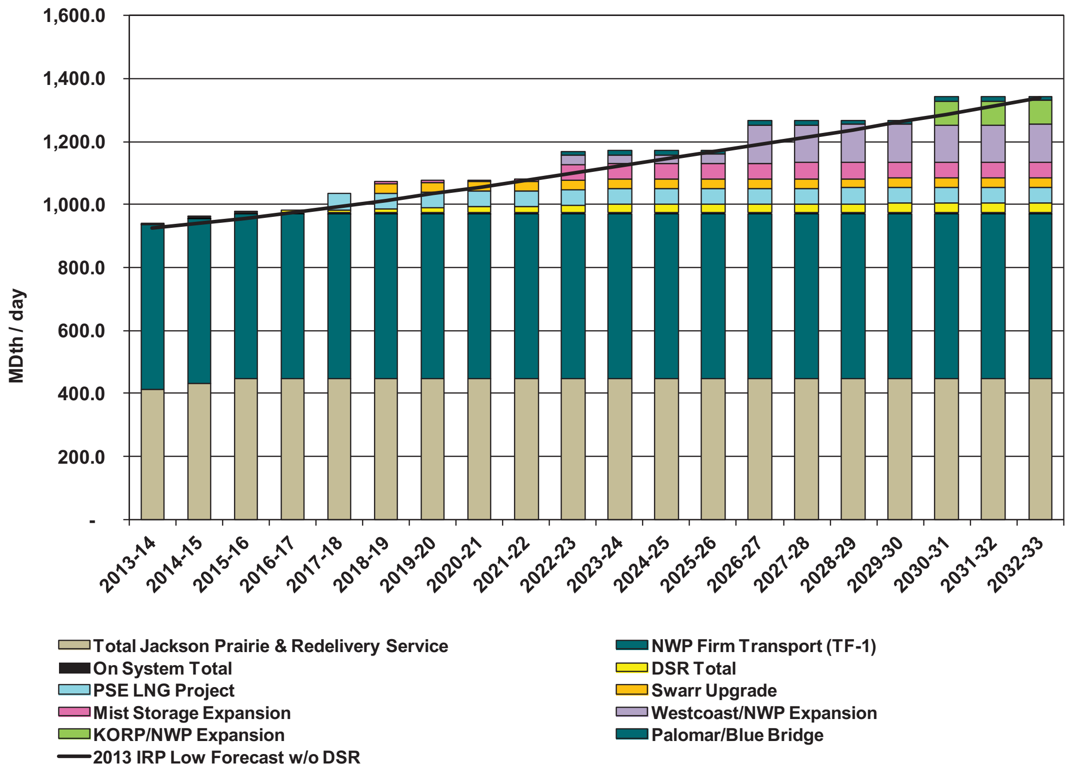
Base Scenario Optimal Portfolio – Gas Sales



APPENDIX L – GAS ANALYSIS

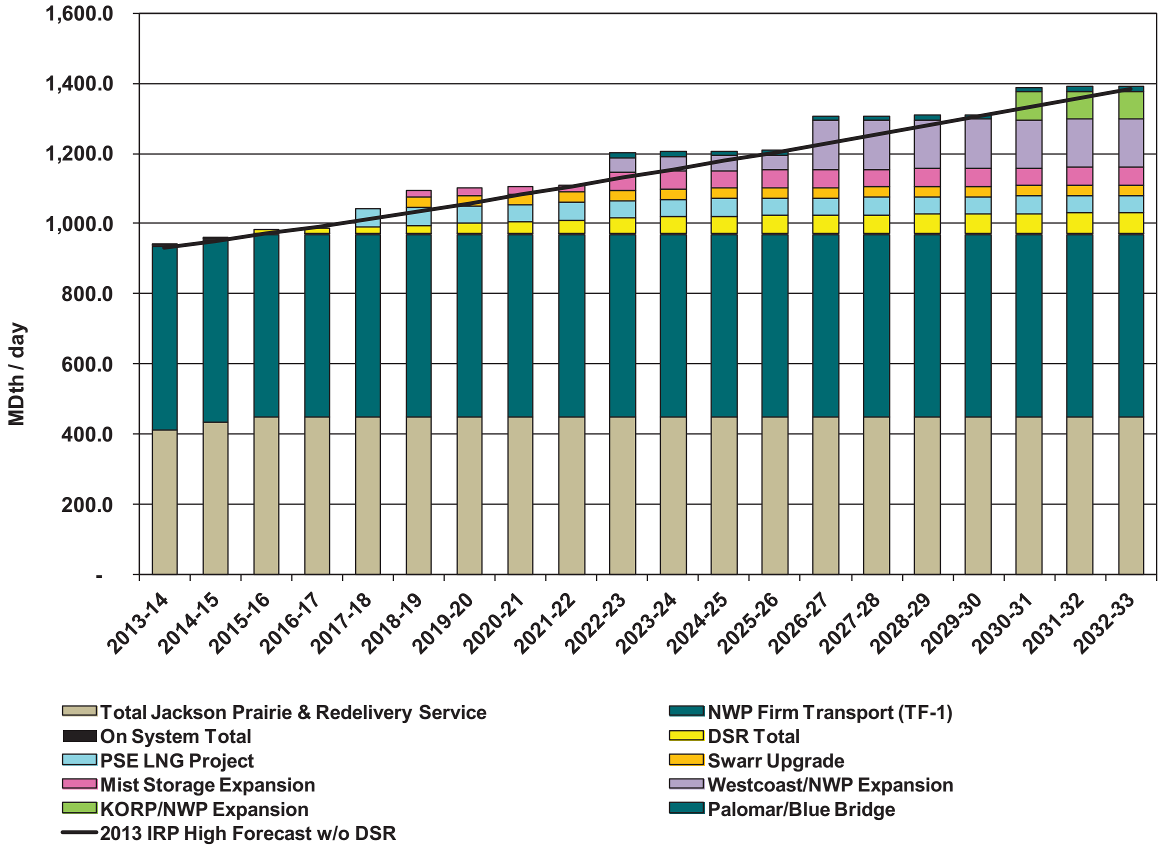
Figure L-7

Low Scenario Optimal Portfolio – Gas Sales



APPENDIX L – GAS ANALYSIS

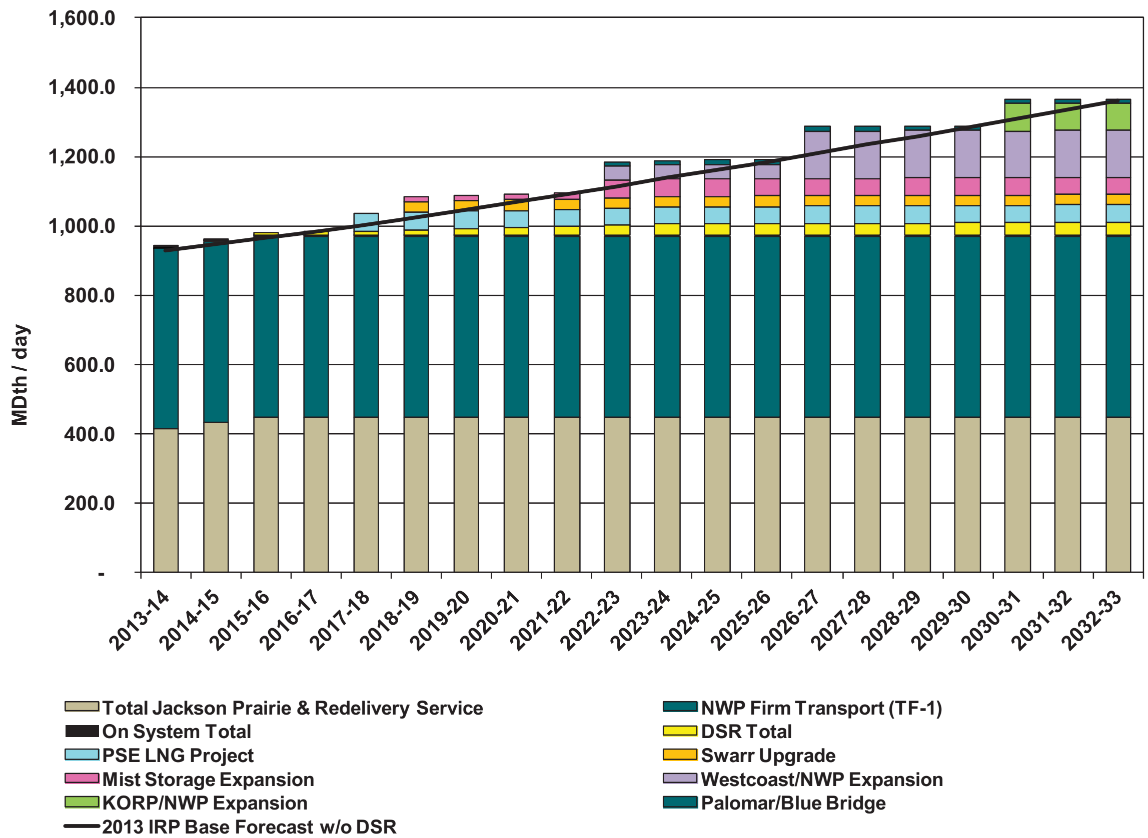
Figure L-8
High Scenario Optimal Portfolio – Gas Sales



APPENDIX L – GAS ANALYSIS

Figure L-9

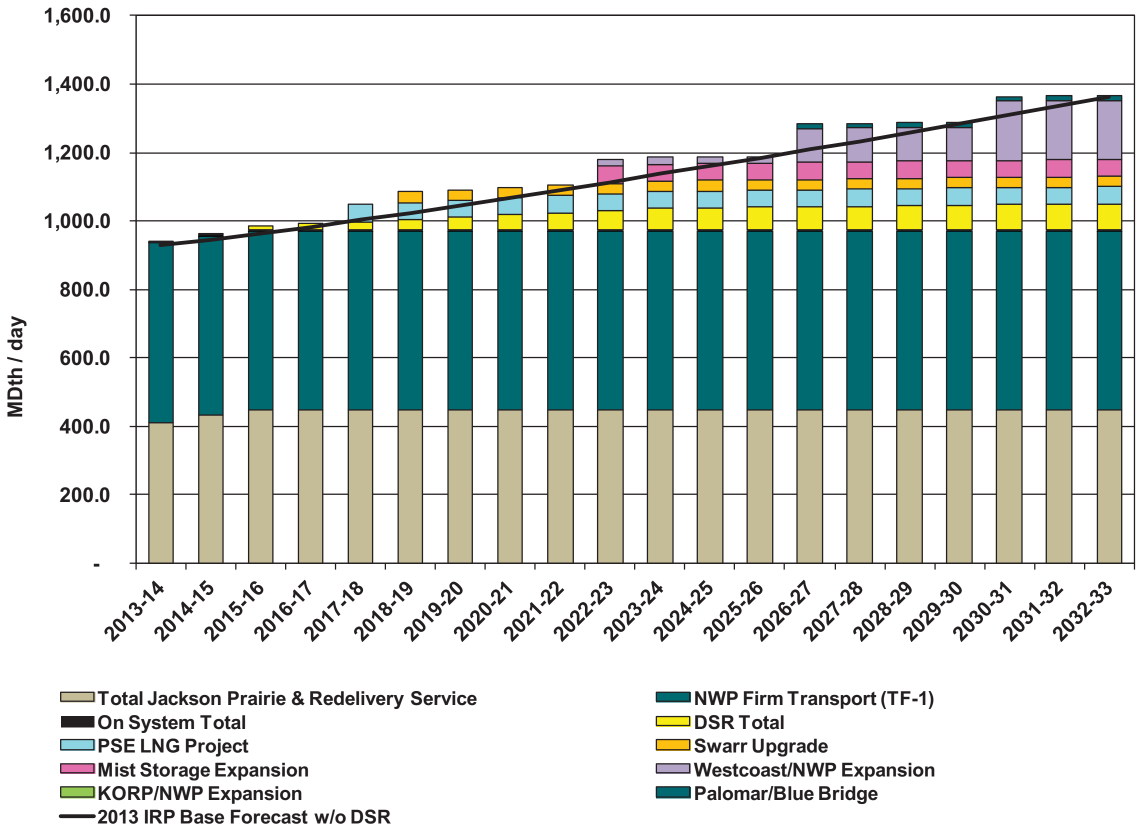
Base + Low CO_2 Optimal Portfolio – Gas Sales



APPENDIX L – GAS ANALYSIS

Figure L-10

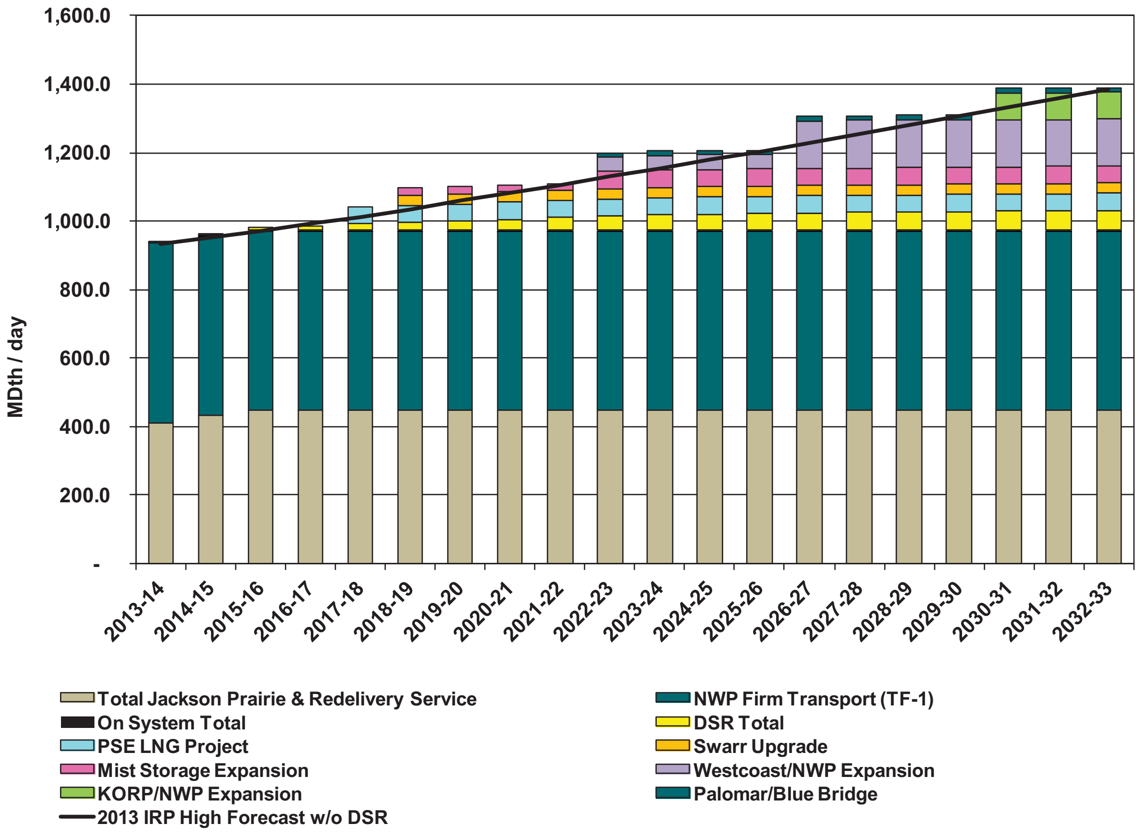
Base + Very High CO_2 Scenario Optimal Portfolio – Gas Sales



APPENDIX L – GAS ANALYSIS

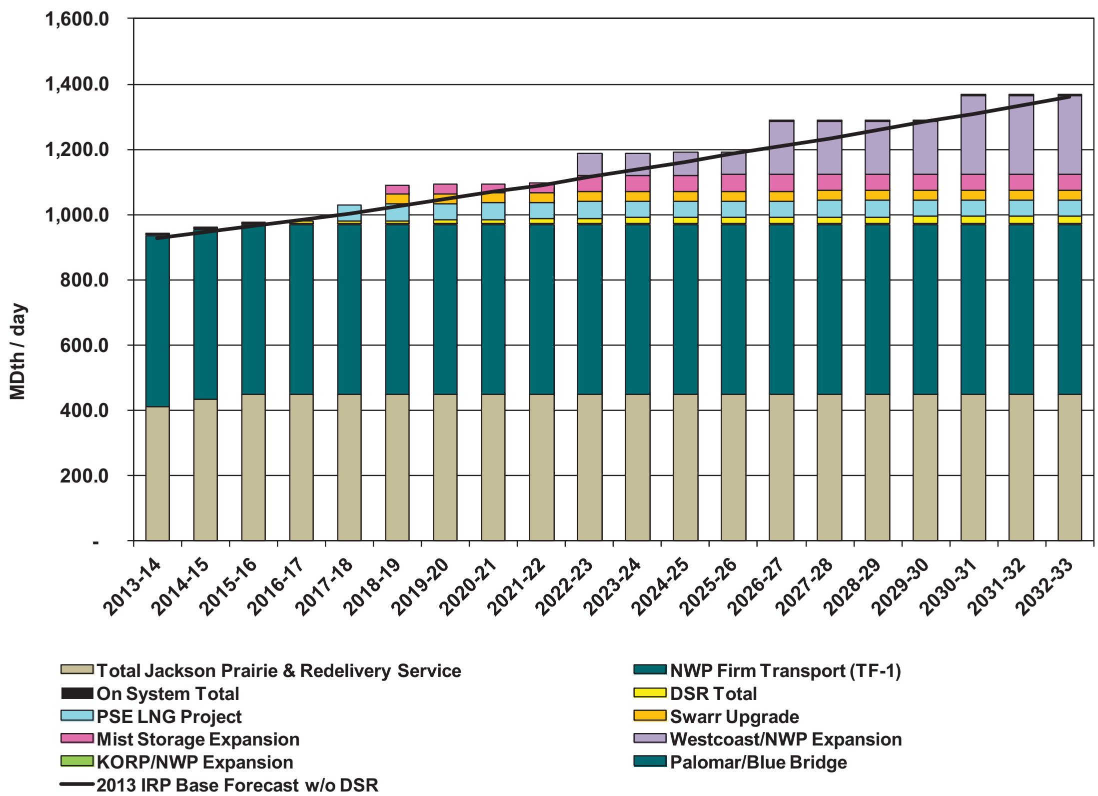
Figure L-11

High + High CO_2 Optimal Portfolio – Gas Sales



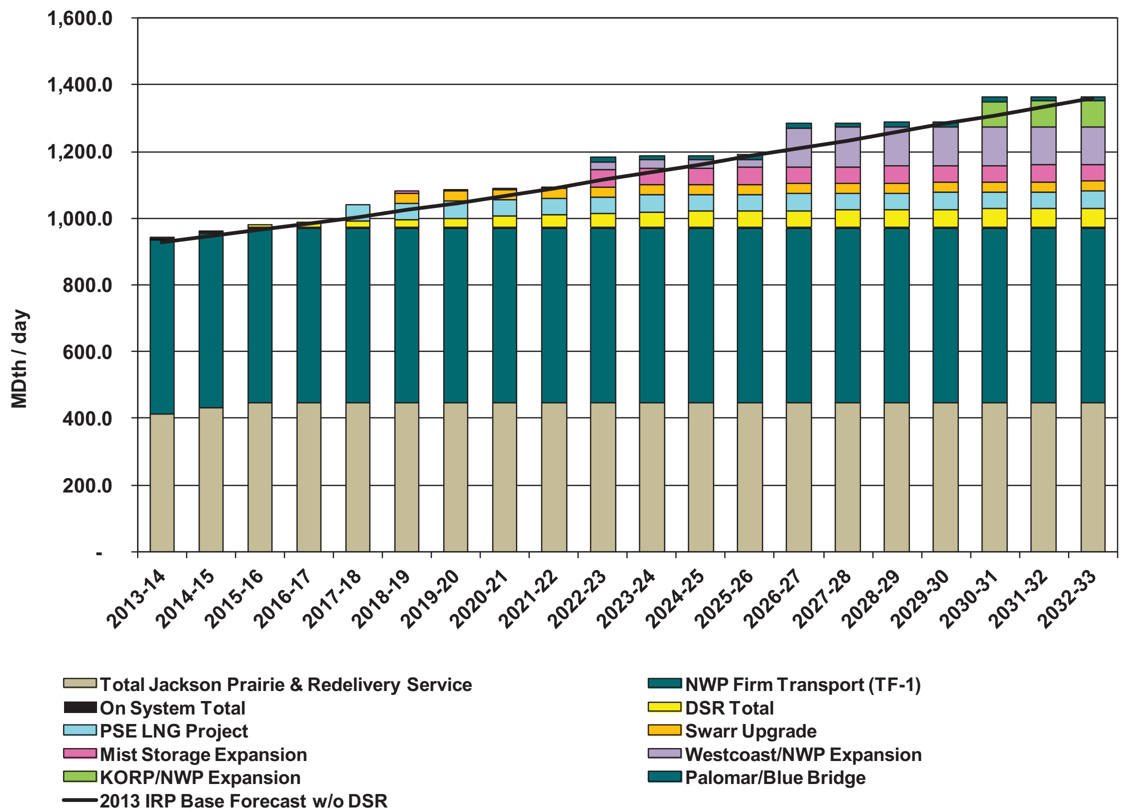
APPENDIX L – GAS ANALYSIS

Figure L-12
Very Low Gas Price Optimal Portfolio – Gas Sales



APPENDIX L – GAS ANALYSIS

Figure L-13
Very High Gas Price Optimal Portfolio – Gas Sales



APPENDIX L – GAS ANALYSIS

Optimal portfolio results of sensitivity tests without PSE LNG Peaking Project & Swarr Upgrade

The resources added in the sensitivity tests for the Base Scenario without the PSE LNG Peaking Project and the Swarr Upgrade project for the winter periods 2018-19, 2022-23, and 2032-33 are shown in Figures L-14, L-15, and L-16 respectively. Graphs of the resource additions are shown in Figures L-17 and L-18.

Figure L-14
PSE LNG Peaking Project & Swarr Upgrade Sensitivity Test,
Resource Additions for 2018-19

	Base	Base w/o PSE LNG	Base w/o PSE LNG & Swarr
DSR	15	15	15
Westcoast/NWP Expansion	0	17	44
KORP/NWP Expansion	0	0	0
Palomar/Blue Bridge	0	0	3
Mist Storage Expansion	17	50	50
PSE LNG Project	50	0	0
Swarr Upgrade	30	30	0

Figure L-15
PSE LNG Peaking Project & Swarr Upgrade Sensitivity Test,
Resource Additions for 2022-23

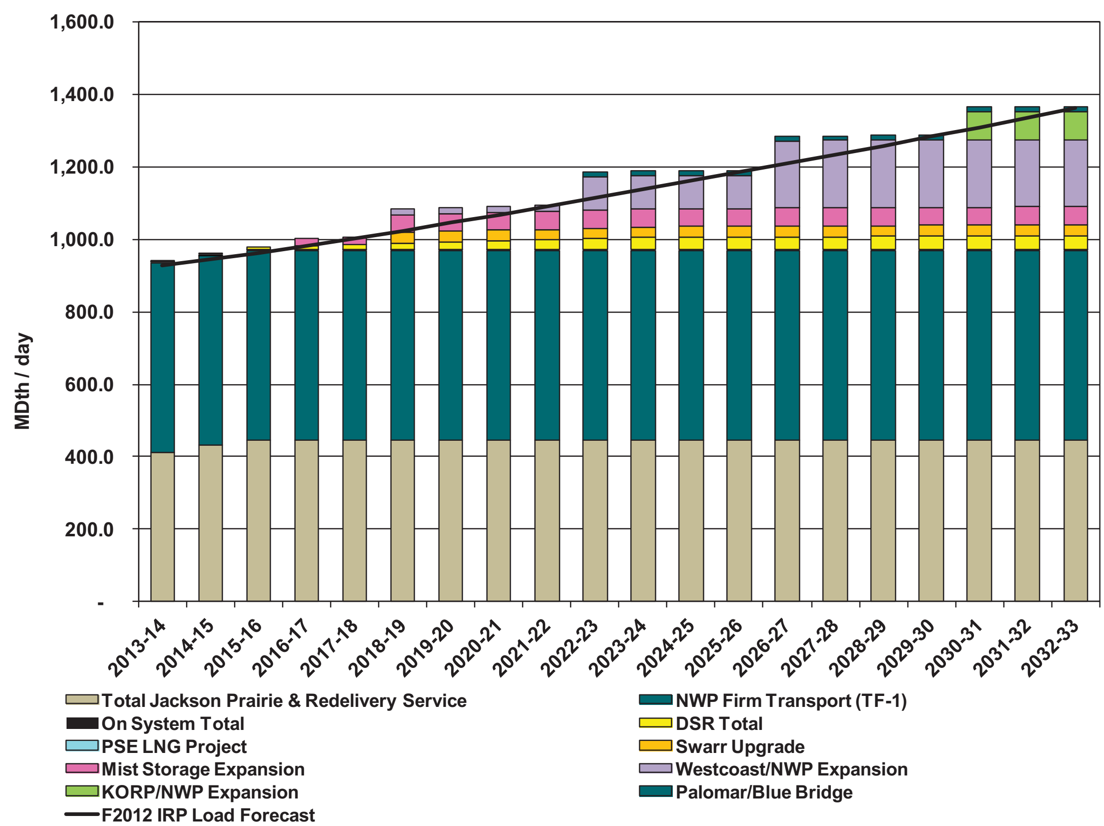
	Base	Base w/o PSE LNG	Base w/o PSE LNG & Swarr
DSR	28	28	28
Westcoast/NWP Expansion	41	91	121
KORP/NWP Expansion	0	0	0
Palomar/Blue Bridge	13	13	13
Mist Storage Expansion	50	50	50
PSE LNG Project	50	0	0
Swarr Upgrade	30	30	0

APPENDIX L – GAS ANALYSIS

Figure L-16
PSE LNG Peaking Project & Swarr Upgrade Sensitivity Test,
Resource Additions for 2032-33

	Base	Base w/o PSE LNG	Base w/o PSE LNG & Swarr
DSR	37	37	37
Westcoast/NWP Expansion	135	185	214
KORP/NWP Expansion	78	78	78
Palomar/Blue Bridge	13	13	13
Mist Storage Expansion	50	50	50
PSE LNG Project	50	0	0
Swarr Upgrade	30	30	0

Figure L-17
Base Scenario without PSE LNG Peaking Project Optimal Portfolio – Gas Sales

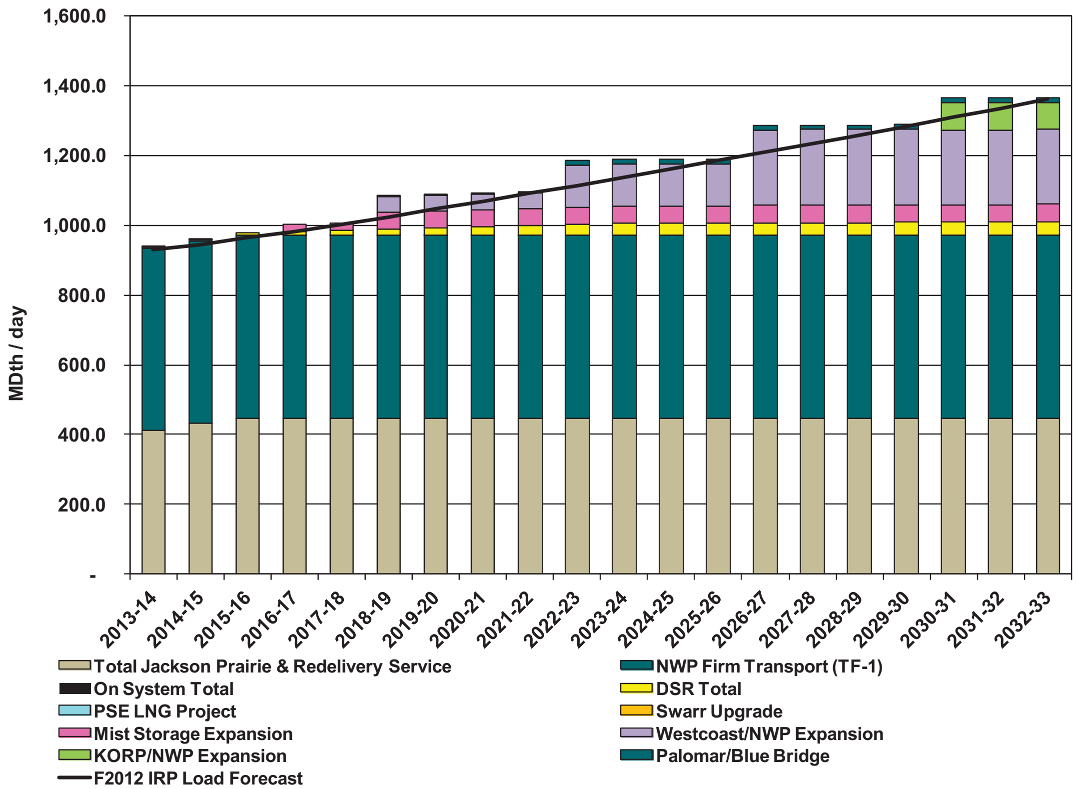


APPENDIX L – GAS ANALYSIS

Figure L-18

Base Scenario without PSE LNG Peaking Project & Swarr Upgrade

Optimal Portfolio – Gas Sales



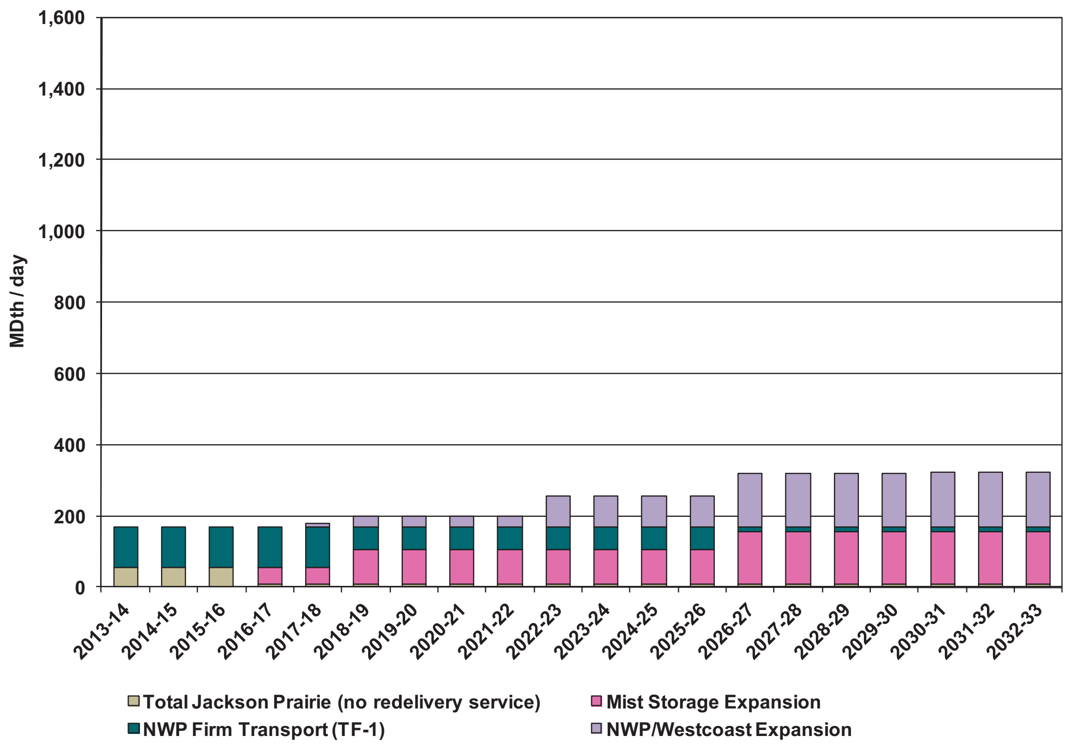
APPENDIX L – GAS ANALYSIS

Optimal portfolio results of Gas-for-power Base Scenario

The average resource additions across the 100 Monte Carlo draws done for the gas-for-power portfolio are shown in Figure L-19.

Figure L-19

Resource Additions for Gas-for-Power Base Scenario



3. Portfolio Delivered Gas Costs

The average delivered portfolio cost for the gas sales scenarios are shown graphically in Chapter 6. They are presented below in tabular form in Figure L-20. Note however, these costs represent the cost of gas delivered to PSE's system. They do not include the distribution system costs.

Figure L-20
Portfolio Delivered Gas Costs - ($/Dth)

Year	Base	High	Low	Base + High CO2	Base + Very High CO2	Base + Low CO2	Very Low Gas Price	Very High Gas Price
2014	5.18	6.28	4.37	6.28	10.13	5.58	3.52	7.07
2015	5.45	6.51	4.53	6.52	10.56	5.83	3.53	7.71
2016	5.77	6.94	4.75	6.95	11.27	6.11	3.53	8.41
2017	6.45	7.57	5.07	9.05	11.96	6.88	3.72	9.28
2018	7.19	8.53	5.50	10.21	13.20	7.65	4.03	9.99
2019	7.33	8.84	5.61	10.71	13.46	7.80	4.05	10.40
2020	7.77	9.36	5.91	11.30	14.19	8.30	4.16	10.98
2021	8.16	9.96	6.16	12.01	14.76	8.72	4.21	11.81
2022	8.35	10.28	6.27	12.30	15.32	9.01	4.26	12.27
2023	8.72	10.78	6.49	13.11	15.83	9.20	4.45	13.02
2024	8.68	10.74	6.43	13.29	15.91	9.48	4.35	13.02
2025	8.91	11.36	6.59	13.96	16.49	9.67	4.33	13.31
2026	9.34	11.66	6.90	14.65	17.28	9.90	4.38	14.00
2027	9.71	12.28	7.19	15.34	17.99	10.47	4.51	14.36
2028	9.93	12.52	7.27	15.81	18.57	10.78	4.48	14.64
2029	10.20	12.82	7.40	16.36	19.24	11.00	4.48	15.05
2030	10.45	13.08	7.55	17.16	19.90	11.54	4.54	15.48
2031	11.00	13.68	7.96	17.60	20.67	11.81	4.79	16.28
2032	11.21	13.92	8.05	18.37	21.68	12.24	4.80	16.64
2033	11.40	14.14	8.20	18.70	21.51	12.47	4.82	16.89

Staff Report on Gas-Electric Coordination Technical Conferences (Docket No. AD12-12-000)

November 15, 2012

Staff Report on Gas-Electric Coordination Technical Conferences
Docket No. AD12-12-000

This report was prepared by the staff of the Federal Energy Regulatory Commission.
This report does not necessarily reflect the views of the Commission.

Table of Contents

I. Introduction

In recent years, reliance on natural gas as a fuel for electric generation has steadily increased. This trend is expected to continue in the future, leading to greater interdependence between the natural gas and electric industries. In some areas of the country, questions have been raised regarding whether adequate market structures and appropriate regulations are in place to support this increasing reliance on natural gas-fired generation. To explore these issues, the Commission convened five regional conferences throughout the month of August 2012, in advance of the winter heating season, to solicit input from both industries regarding the coordination of natural gas and electricity markets. The conferences were structured around three sets of issues: scheduling and market structures/rules; communications, coordination, and information-sharing; and reliability concerns.

A cross-section of industry representatives participated and/or attended the regional conferences, with total attendance exceeding 1,200 registrants. Perspectives varied by region and across industry sectors as to the issues confronting the industries and actions to be taken. Information gathered at the conferences confirmed that gas-electric interdependence concerns are more acute in some regions than others, with the discussion at each conference focusing on the particular circumstances and needs of each region. Notwithstanding the regional focus of the discussions, recurring themes across the conferences were that more attention needs to be paid to gas-electric interdependence issues and that some matters are appropriate for generic consideration while others are more appropriate for individual regions to address.

This report focuses on several topics that were common to multiple regions. First, conference participants in many regions sought confirmation that sharing information in furtherance of enhancing gas-electric coordination would not run afoul of the Commission's Standards of Conduct or be construed as engaging in undue discrimination or preference.[1] Second, a number of concerns were expressed regarding the misalignment of gas and electric scheduling practices, as well as application of the no-bump rule and pipeline capacity release rules. Third, questions were raised in several regions regarding whether generators have appropriate incentives to deliver firm energy. Finally, industry representatives in multiple regions are considering appropriate steps to take to address reliability considerations in the context of gas-electric coordination. Staff addresses these issues by providing guidance where possible and highlighting relevant activities taking place in individual regions.

As the discussion below indicates, significant industry attention and resources are being dedicated to address these and a host of gas-electric coordination issues. Several regions have implemented or are developing practices to improve coordination and communication between the industries during normal operations as well as in emergency situations. Some regions are considering changes to electric market rules to address increased reliance on gas-fired generation, while pipelines have developed flexible products and scheduling protocols for their customers. These efforts have helped participants in each industry identify improvements that can be made to support effective operations within both industries.

By focusing on the subset of cross-cutting issues identified above, staff seeks to support the progress being made on gas-electric coordination matters. Staff understands that there are a number of other issues unique to each region that must be addressed to

[1] The Standards of Conduct govern communications between interstate natural gas pipelines and their affiliates that engage in marketing functions, and public utilities that own or operate electric transmission facilities and their affiliates that engage in marketing functions. 18 CFR § 358.1(a) and (b) (2012). See discussion in Section IV of this Report, below.

improve coordination across the gas and electric industries. Moreover, staff appreciates that gas-fired generators are only one of many users of the interstate natural gas pipeline system and that any changes to practices or rules within a particular region or the natural gas industry more broadly must be informed by the needs of a broad range of customers. With these considerations in mind, staff will be actively monitoring and engaging industry regarding progress being made in each region to ensure that gas-electric coordination issues are identified and addressed.

II. Background

On February 15, 2012, the Commission issued a notice in Docket No. AD12-12-000 requesting comments on various aspects of gas-electric interdependence and coordination in response to questions posed by Commissioner Philip Moeller and Commissioner Cheryl LaFleur.[2] Recognizing the electric industry's increased reliance on natural gas to generate electricity now and into the future, Commissioners Moeller and LaFleur pointed out the critical importance of the interface between the electric and natural gas industries. In order to better understand that interface and identify areas for improvement, Commissioners Moeller and LaFleur sought comments on a variety of topics including market structure and rules, scheduling, communications, infrastructure and reliability.

The Commission received comments from seventy-nine entities. The commenters raised a wide variety of issues regarding gas-electric interdependence. Many of the commenters asserted that the issues differed on a regional basis and requested that the Commission convene regional technical conferences.

On July 5, 2012, the Commission responded and issued a notice of a series of regional technical conferences to explore coordination between the natural gas and electric industries.[3] During the month of August 2012, Commission staff held five

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[2] *Coordination between Natural Gas and Electricity Markets*, Docket No. AD12-12-000(Feb. 15, 2012) (Notice Assigning Docket No. and Requesting Comments) (*available at* http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=12893828). *See also* Commissioner Philip D. Moeller, *Request for Comments of Commissioner Moeller on Coordination between the Natural Gas and Electricity Markets* (Feb. 3, 2012), *available at* http://www.ferc.gov/about/com-mem/moeller/moellergaselectricletter.pdf; Commissioner Cheryl A. LaFleur, *Statement regarding Standards for Business Practices for Interstate Natural Gas Pipelines* (Feb. 16, 2012), *available at* http://www.ferc.gov/media/statements-speeches/lafleur/2012/02-16-12-lafleur-G-1.asp.

[3] *Coordination between Natural Gas and Electricity Markets*, Docket No. AD12-12-000 (July 5, 2012) (Notice of Technical Conferences) (*available at*

(continued)

regional technical conferences for the Central, Northeast, Southeast, West and Mid-Atlantic regions. Each conference had a staff-led roundtable discussion of the following topics: scheduling and market structures/rules; communications, coordination, and information sharing; and reliability concerns.

III. Summary of Regional Conferences and Ongoing Initiatives to Address Gas-Electric Coordination

Before turning to the discussion of concerns common across multiple regions, staff provides a summary of general observations at each conference (not in chronological order) and information gleaned from publicly available sources. Each regional summary includes identification of initiatives to address gas-electric coordination issues that are either underway or in the planning stages in each region.

A. Northeast Region[4]

Several participants in the Northeast Region conference stated their views that the region is in need of additional pipeline infrastructure. It was noted that New England historically has had strong fuel diversity and dual-fuel capability,[5] and that this region will depend on dispatching generators with alternate fuel sources out of economic order to protect reliability in the face of possible natural gas delivery concerns.

Several pipeline participants reported that their systems within the Northeast are consistently running near their design capacities. According to statements made at the conference, some of the major existing pipelines serving the New England region are

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http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=13023450); 77 Fed. Reg. 41,184 (July 12, 2012) (*available at* http://www.gpo.gov/fdsys/pkg/FR-2012-07-12/pdf/2012-16997.pdf).

[4] The Northeast region technical conference was held August 20, 2012 in Boston, Massachusetts, and included natural gas and electric entities from an area defined by the corporate boundaries of ISO New England Inc. (ISO-NE) and the States of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont.

[5] According to a recent report by ISO-NE, as recently as the 1990s the region's electricity was produced primarily by oil, coal and nuclear generating plants, with little gas-fired generation. In contrast, by 2011, approximately 51% of the electricity consumed in New England was produced by gas-fired generation. ISO New England, *Addressing Gas Dependence*," at 3 (July 2012), *available at* http://www.iso-ne.com/committees/comm_wkgrps/ strategic_planning_discussion/materials/natural-gas-white-paper-draft-july-2012.pdf.

nearly fully subscribed or constrained at specific points on their respective systems. The lack of available capacity may limit regional pipeline flexibility, and frequently results in flow restrictions and strict balance requirements. Both gas and electric industry participants stated that relatively little gas-fired generation in New England is backed by primary firm pipeline transportation contracts. Instead, participants stated that generators typically rely on released secondary firm or, to a much lesser extent, on interruptible transportation (IT) pipeline capacity. Some participants also discussed the roles of marketers in procuring both pipeline transportation service and gas supplies.

Conference participants reported that under the current market structure, generators have few incentives to obtain long-term primary firm pipeline service, invest in alternate fuel capabilities, or take other steps to ensure fuel availability. A representative of ISO-NE reported that several proposed revisions to its forward wholesale electric capacity market are being developed. ISO-NE's representative and other conference participants also discussed a proposal to allow hourly re-offers in the real-time energy market, and revisions to ISO-NE's price mitigation rules to allow bids to be adjusted to reflect actual fuel costs.[6]

Several conference participants indicated that options are limited for addressing the natural gas pipeline infrastructure issue in the near term. A representative of ISO-NE discussed its intentions to review generators' plans for the winter and determine whether individual generating units would be able to continue operating during a cold snap similar to that of January 2004. Pipelines stated their focus for the upcoming winter would be to maximize utilization of existing pipeline capacity to ensure reliability.

In the intermediate term, an ISO-NE representative noted ISO-NE's plans to propose adjustments to the electric market day-ahead scheduling and resource adequacy assessment process. Under its proposal, day-ahead awards may be released as early as 30 hours prior to the start of the electric day, and well in advance of the North American Energy Standards Board (NAESB) timely nomination deadline for gas pipeline capacity. ISO-NE stated its belief that the current timeline leaves it with too little time to mitigate generation supply risks before the start of the operating day. Some conference participants voiced support for such a change, while others stated that it would reduce, but not eliminate, the risk exposure of the generators.

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[6] ISO-NE is proposing to allow hourly offers and intra-day re-offers so that generators would be able to adjust their bids to reflect changes in fuel costs closer to real time. "Accordingly, resources that must buy intra-day gas will be able to reflect their true costs, and generators that might not be able to get gas in real-time and want to switch to oil will have the ability to reflect the cost of switching." ISO New England, *Addressing Gas Dependence*, at 15.

Some electric utility and gas local distribution company (LDC) participants suggested that further, coordinated studies of regional gas and electric infrastructure are needed. A few electric industry participants offered the idea of a regional gas infrastructure planning effort, similar to how the region already performs regional electric infrastructure planning. Gas industry participants did not express support for this idea.

Commentary of participants suggested that they are generally comfortable with the quality of communications between the pipelines, generators, and ISO-NE. Some observed that the communications currently occur on a largely *ad hoc* basis, and suggested that efforts to further formalize the communications procedures could be beneficial.

Northeast Regional Initiatives

Many technical conference participants supported the idea of forming a steering committee to address concerns about gas-electric coordination in the Northeast. The steering group would consider changes to the electric day, maximizing assets in the region through maintenance planning, and changes to ISO-NE's market rules, scenario planning, and funding mechanisms.

Participants at the conference discussed the need for improved coordination of maintenance outages among electric and natural gas industry participants. Representatives of pipelines and LDCs offered that the Northeast Gas Association is willing to lead the efforts to develop communication protocols governing gas and electric maintenance-related outage coordination.

As noted above, and according to the ISO-NE participants at the conference, ISO-NE is considering several potential modifications to its tariff, some to take place sooner than others. In the near-term, ISO-NE is considering a plan to conduct a supplemental procurement for natural gas, liquefied natural gas, or back up oil supplies to ensure adequate supplies over 2013 and 2014. Longer-term, ISO-NE plans to develop certain tariff revisions to move up the timeline for day-ahead unit commitment and the resource adequacy assessment process in an effort to provide additional time to ensure that gas-fired generators may procure gas supplies and delivery services so that adequate generation capacity is available in real time.[7] Further, ISO-NE is considering several

[7] ISO-NE is proposing to move the day-ahead market back so that generators can buy gas and pipeline capacity while the market is still liquid and so that it has more time to call on generators. *See* Janine Dombrowski, *Moving the Day Ahead Market & Reserve Adequacy Assessment Clearing Times*, ISO New England (Aug. 7-8, 2012), *available at* http://www.iso-

(continued)

changes to the market rules to allow energy and capacity prices to better reflect the risk of generator interruptible vs. firm gas procurement, including changes to the capacity product definition, changes to the resource adequacy assessment process, and a review of the consequences of generator non-delivery. ISO-NE is also considering a proposal to modify the real-time energy market and bid mitigation rules to allow generators to update bids to reflect changes in natural gas prices. [8]

B. Mid-Atlantic Region[9]

According to some participants representing generators in the Mid-Atlantic region, power markets provide no incentive to purchase firm contracts for pipeline transportation. Various other participants in the Mid-Atlantic Region conference pointed out that there are multiple ways a gas-fired generator can firm its fuel supplies—through firm contracts for pipeline transportation, dual fuel, storage contracts, and access to more than one pipeline. A North American Electric Reliability Corporation (NERC) representative noted the appeal of a requirement for generator "firmness" that would account for the multiple ways to firm-up fuel supply, and identified a potential firmness requirement as an item more suited for an RTO/ISO proposal rather than a NERC standard.

The prevalence of dual fuel capability in both the NYISO and PJM regions was noted. Participants stated that both the PJM and NYISO markets provide some incentive or requirement for dual fuel. A representative of PJM said that its Reliability Pricing Model (RPM) uses a dual fuel reference unit to determine the Cost of New Entry for the wholesale electric capacity market demand curve, which helps set the price of capacity. In NYISO, according to conference participants, generators in downstate New York (New York City and Long Island) are required to have alternate fuel capability under state reliability requirements. Participants generally indicated that gas markets in PJM are more liquid than those in NYISO given the availability of various pipelines and storage.

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ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2012/aug782012/a07_iso_presentation_08_07_12.ppt.

[8] *See* ISO New England, *Addressing Gas Dependence, supra* n. 5.

[9] The Mid-Atlantic Region technical conference was held August 30, 2012 and included natural gas and electric entities from an area defined by the corporate boundaries of New York Independent System Operator Inc. (NYISO), PJM Interconnection, L.L.C. (PJM) and related areas, including the States of Delaware, Maryland, New Jersey, New York, Ohio, Pennsylvania, Virginia and West Virginia.

While many representatives of generators indicated that they currently are able to secure pipeline capacity, several pipelines noted that liquidity and flexibility experienced thus far in the Mid-Atlantic region are not necessarily indicative of the flexibility that will be available in the future as gas-fired generation grows. Representatives of an LDC and a pipeline also argued that cost causality needs to be matched with cost responsibility. An LDC representative asserted that today certain costs of serving generators' variability and hourly flows are being paid by LDCs.

The issue of the use of secondary firm contracts and recallable capacity release contracts (rather than primary firm contracts) as a means of serving gas-fired generation was discussed. Several contend the practice of relying on types of transportation services other than primary firm transportation to fuel gas-fired generation is not a reliable solution given the higher rate of curtailment of secondary firm customers. Some pipeline participants also noted that while producers have funded some new pipeline capacity, these pipelines only extend far enough to get the natural gas from the producing region to a liquid pooling point, and there is still a need to build infrastructure to get natural gas from the supply area to generators. Some LDC representatives noted that for generators behind their citygates, even if the generator has firm gas contracts on an interstate pipeline, it still needs firm natural gas delivery capacity on the LDC's system.

Several participants also raised concerns about planning—whether the planning horizon is long enough and whether market participants are planning appropriately. Noting the differences between electric and gas planning horizons, a pipeline noted that pipelines do not plan for growth; rather they build to accommodate firm customers. An industrial participant argued that market signals are not a substitute for planning and contended that the region may need a longer-term planning horizon. A generator noted that while a long-term electric planning process exists, what is missing is consideration of fuel security.

There was no consensus among Mid-Atlantic conference participants as to the best way to address the gas-electric scheduling mismatch. A representative of NYISO stated that it currently releases its day-ahead dispatch results earlier (10 a.m. EST) than PJM does (4 p.m. EST). NYISO's representative noted that the earlier release allows gas-fired generators to be better informed for the first timely pipeline nomination cycle which occurs at 11 a.m. (CST). Feedback from participants representing generators on whether they preferred the earlier release or later release was mixed. NYISO's representative also reported that it is considering moving the day-ahead dispatch results release to earlier than 10 a.m. (EST) (when gas markets are more liquid) or later (to facilitate better gas supply and transportation price certainty when bidding), and will continue to explore scheduling through its stakeholder process. Conference participants noted that in PJM, where the natural gas market is relatively liquid and there are many pipelines and storage reservoirs, generators thus far have been able to acquire natural gas supplies and pipeline capacity in later pipeline nomination cycles. Conference participants noted that in

NYISO where the gas market is less liquid it is not always easy to acquire gas after the first timely pipeline nomination cycle.

With regard to the process for allowing generators to modify bids to reflect actual fuel costs, NYISO permits it if a generator had to switch fuels or procure more expensive intra-day gas if the ISO increased its dispatch level. According to the PJM representative, PJM does not currently permit this, but PJM would be open to considering it.

Some participants representing generators encouraged the creation of more nomination cycles. Pipeline representatives noted that some pipelines in the region already offer hourly nomination cycles and stated that more frequent nominations will not help if there is inadequate pipeline capacity.

Regarding communications, a representative of NYISO noted that it does not necessarily understand how pipeline outages impact the electric system and which generators will be affected. Representatives of PJM and a pipeline mentioned a partnership which would include exchanging control room operators. They expect that spending time in each others' control rooms will help to bridge the language gap and learn about each other's industry. Various conference participants also noted their interest in tabletop exercises that simulate reliability scenarios. A representative of NYISO noted that several combined gas-electric utilities, along with certain pipelines within its area, recently ran a useful tabletop exercise.

Conference participants indicated that there is no formal outage coordination process across industries, but some expressed support for a formalized process. Some conference participants noted there is a tension between wanting to openly discuss publicly available information on outages and the impact on operations, and concern about whether unit-specific discussion would violate regulations against undue preference or discrimination. Pipeline representatives noted reluctance to discuss granular impacts at the level of individual shippers beyond the information the pipelines make publicly available on electronic bulletin boards. One participant noted that enhanced outage coordination gives rise to heightened concern over manipulation. Various participants indicated concern about specifying shipper-level information in discussions.

Participants from both the natural gas and electric industries suggested clarification of the Standards of Conduct and Natural Gas Act Section 4b undue preference and anti-manipulation rules would be helpful.[10] One participant suggested

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[10] N. 35, *infra*.

"common sense leeway" to the Standards of Conduct rules in emergencies. A pipeline trade association representative noted that some RTOs/ISOs have adopted the Standards of Conduct in their tariffs and RTOs/ISOs are concerned about sharing information with pipelines. PJM's representative asked whether it can tell pipelines which generator units will be dispatched.

Participants articulated different views on the markets' ability to send appropriate signals. One pipeline representative argued that electric market signals do not factor in reliability and another participant argued that generators in unregulated markets have no incentive to contract for firm pipeline transportation. A PJM representative noted that its wholesale electric capacity market does not pay generators if they do not run and capacity factors[11] decline if generators do not run. A generator representative stated that PJM's capacity market sends the right signals, while a pipeline representative argued that PJM's nonperformance penalties are weak and do not justify paying for fuel security. A NERC representative noted that many capacity market incentives, such as Equivalent Forced Outage Rate—demand (EFORd)[12] penalties, are problematic because they are retrospective and the impact arrives three years later.

In general, participants in this technical conference urged the Commission to "be patient" and check back with the regions to see that they continue to make progress on most issues involving gas-electric coordination, although there was interest in having the communications issues clarified.

Mid-Atlantic Regional Initiatives

A representative of NYISO noted that NYISO, PJM, ISO-NE, the Ontario Independent Electricity System Operator (IESO), and possibly also Midwest Independent System Operator (MISO) are planning a comprehensive study across pipelines serving these regions that would incorporate retirements and infrastructure changes over five to ten years. The study will examine planned generation retirements, new transmission lines, and new pipelines for the next five to 10 years and try to identify any electric reliability problems. The study is expected to be available sometime in 2013.

On communications between the RTOs/ISOs and the pipelines in coordinating outages, representatives of PJM and NYISO discussed educational processes and

[11] Capacity factor refers to the ratio of a plant's output during a period of time to its potential output if it had operated at its full nameplate capacity.

[12] EFORd is a measure of the probability that a generator will not meet its demand periods for generating requirements.

operator training and exchange programs, and the development of protocols for the sharing of maintenance schedules.[13] As mentioned above, several combined utilities went through a tabletop reliability scenario exercise with several pipelines, where they examined different scenarios based upon loss of supply.

C. Central Region[14]

Many participants in the Central Region conference stated that gas-electric coordination in the region is not currently a problem. However, a representative of MISO suggested that this could change in 2013-2015 when it expects approximately 30,000 MW of coal-fired generation to either be retired or taken off line for retrofits to meet emissions standards over the 2012-2015 period. MISO's representative anticipates this will result in a greater reliance upon gas-fired generators, and said that it is particularly concerned about the unavailability of coal units during the December – April period, when natural gas demand is highest.

Participants came down on all sides of the gas-electric scheduling question. Some suggested that both markets would benefit if the market schedules were more aligned: if the electric market cleared earlier in the day and the timely (first) gas nomination cycle occurred later in the day, market participants would be able to make gas supply arrangements at a time when the natural gas market is more liquid, based upon knowing earlier which generation plants were going to run. Others asserted that the earlier day-ahead electric commitments are made, the less accurate the load and price forecasts become. Some firm gas pipeline shippers expressed concern about the impact of increased gas-fired generation upon the quality of their firm pipeline services. Suggestions to improve gas pipeline flexibility include revisiting the "no-bump" rule and making intra-day capacity release more flexible. A few shippers noted what they

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[13] *See, e.g.*, NYISO, NYISO Tariffs, OATT, § 34, Attachment BB, New York State Gas-Electric Coordination Protocol (*available at* http://www.nyiso.com/public/webdocs/documents/ tariffs/oatt/oatt_attachments/att_bb.pdf). The protocol applies where a gas system event would likely lead to a loss of firm electric load on either bulk or local power system; applies in emergency situations only and not to situations where a generator is derated for economic reasons.

[14] The Central Region technical conference was held August 6, 2012 in St. Louis, Missouri, and included natural gas and electric entities from an area defined by the corporate boundaries of MISO, Southwest Power Pool, Inc. (SPP), and Electric Reliability Council of Texas (ERCOT). It included the states of Arkansas, Illinois, Indiana, Iowa, Kansas, Louisiana, Michigan, Minnesota, Mississippi, Missouri, Nebraska, North Dakota, Oklahoma, South Dakota, Texas, and Wisconsin.

described as the high quality and flexibility of their pipeline transportation services. One pipeline representative expressed a willingness to continue to create flexible services for customers, including offering short-term capacity and volumetric rates.

Participants generally reported that there is little direct communication between the pipelines and electric system operators in this region. Many participants asserted that responsibility for information-sharing lies with the generator, and that generators should be responsible for communicating and sharing outage, capacity, and expected gas burn information with both the pipelines and the RTOs/ISOs. Several participants suggested that information sharing could be improved by having RTOs/ISOs provide the gas pipelines with hourly generator commitments, so that pipelines would know in advance which gas-fired generators are likely to run. Many expressed concern, however, about the market sensitivity and the potential for violations of the Commission's regulations prohibiting undue discrimination or preference associated with sharing such information. They suggested that adequate protections would need to be in place to ensure such information was confined only to operating personnel and not shared with marketing departments.

Another example identified at this conference was gas-electric communications during emergencies and peak demand situations. While generators often provide the pipelines with a day-ahead hourly burn profiles as required by NAESB gas-electric business standards,[15] pipelines suggested more real-time information would also be useful, especially during electric contingencies that could affect gas facilities such as electric compression, production or storage. Again, concerns were raised about violating the Commission's regulations against anti-competitive conduct.

Addressing reliability concerns, it was suggested that entities responsible for resource adequacy should evaluate fuel availability in their loss of load probability (LOLP) studies for both winter and summer planning. MISO's representative suggested that this could be accomplished by including unavailability due to lack of fuel in the generators' forced outage rate. However, there was concern expressed that the forced outage rates are historical and do not reflect the expected unavailability due to increases in capacity factors of gas-fired generation.

Central Regional Initiatives

[15] *See* Order No. 698. Order No. 698 mandates that communication protocols be established between interstate pipelines, power plant operators, and transmission owners/operators, and among other things requires power plant operators to provide their projected hourly natural gas flow rates to directly-connected pipelines upon request.

A representative of MISO noted that it is continuing to refine and update an October 2011 study,[16] which looked at whether current generation capacity is sufficient given planned coal plant retirements and planned retrofit outages expected in the 2013-2015 period. MISO's representative committed to working with the pipelines that serve the generators in its control area and obtaining a more definitive planned outage/maintenance schedule from coal-fired generation as they move into the 2013-2015 time period. In addition, he noted that MISO recently formed a task force to work on general gas-electric coordination issues.[17]

A representative of ERCOT suggested it could act as a host for tabletop exercises for RTOs/ISOs and pipelines to review emergency procedures and discuss communication issues and risks on the bulk power and natural gas systems.

D. West Region[18]

Participants at the West technical conference discussed many subregional differences within the region, including resource mix, market structure, and degree of dependence upon natural gas for electric generation. There was general agreement that the West as a whole will have a greater reliance on natural gas for electric generation in the future. Some participants expect the burn profile for natural gas used for electric generation to become more volatile, due both to the normal variation in electric demand and the increased use of gas for balancing, resulting from the increase in renewable generation in the region.

Representatives from both natural gas and electric entities in the West stated that most of the natural gas-fired electric generation in the West region (outside of the

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[16] *See* MISO, *EPA Impact Analysis: Impacts from the EPA Regulations on MISO* (Oct. 2011), *available at* https://www.midwestiso.org/Library/Repository/Study/MISO%20EPA%20Impact%20Analysis.pdf.

[17] MISO's Natural Gas Coordination Task Force was recently formed to address these issues. *See* MISO, Steering Committee Meeting Minutes (Sept. 20, 2012), *available at* https://www.midwestiso.org/Library/Repository/Meeting%20Material/Stakeholder/Steering%20Committee/2012/20121018/20121018%20SC%20Item%2001b%20Minutes%2020120920.pdf.

[18] The West Region technical conference was held August 28, 2012 in Portland, Oregon, and included natural gas and electric entities from an area defined by the Western Interconnection, and included the States of Arizona, California, Colorado, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Washington, and Wyoming.

California Independent System Operator Corp. (CAISO)) is backed by firm gas transportation contracts. Natural gas-fired electric generators served by the LDCs within CAISO mainly use interruptible gas transportation contracts on the LDCs' distribution systems, but this service reportedly performs like firm because gas pipeline infrastructure within CAISO is expanded in anticipation of load, as opposed to responding to long-term firm contracts.

Some conference participants stated that gas-electric coordination issues could be alleviated by having more efficient electric markets in the West region. An energy imbalance market was explicitly mentioned as one way of achieving additional efficiencies. A representative of CAISO indicated that it has no mechanism to look at firmness of fuel, and believes that it should not have a mechanism for this purpose. He noted that CAISO's market has a penalty for non-performance.

Several conference participants requested more opportunities for intra-day nomination adjustments on pipelines, but a few pipelines clarified that these additional nomination opportunities would have value only if they resulted in actual physical changes; actual changes in pipeline flow can only occur if gas can be purchased and injected into the pipeline to accommodate the revised nomination and then delivered. The appropriateness of the "no-bump" rule was challenged on multiple occasions. A few participants from the Southwest opined that both the gas and electric scheduling days should go until midnight local time.

Regarding communications, CAISO's representative discussed recent Commission-approved revisions to its tariff to permit sharing generation and transmission outage information with utilities that operate pipelines and/or deliver gas to gas-fired generators, pursuant to non-disclosure agreements. Additionally, a few participants both inside and outside California currently send estimated burn profiles for electric generation to the pipelines on a day-ahead basis.

Representatives of several pipelines in the region discussed their efforts to improve communications with generators and electric balancing authorities, including updating points of contact and communication methods, conducting regional table top exercises, and reviewing emergency procedures. For example, one pipeline hosted a mock gas supply emergency exercise following the February 2011 cold weather event, and another plans to host a similar mock emergency drill in 2013. Pipeline representatives added that both gas and electric operators could benefit from education about the other's system, in particular how to interpret and determine the important information from the notices and information that is provided, especially given the sheer volume of postings from both sides. The pipeline representatives also described efforts between the RTOs/ISOs and the Interstate Natural Gas Association of America (INGAA), as well as operator training programs that can provide that education. For example, in the wake of the February 2011 Southwest cold weather event, a number of entities participated in the electric and natural gas interdependency conferences at the Western Electricity Institute, which focused upon educating the electric and gas companies about how the other functions.[19]

Several participants stated that FERC's Standards of Conduct are a barrier to communications. For example, the representative of a utility in the Northwest described a tabletop exercise in that region during which it was discovered that some organizations have employees with considerable operational experience within marketing groups. This gave rise to the concern that the Standards of Conduct would prohibit these employees from being involved with efforts to resolve operational problems or emergency situations.

Some participants stated that the Northwest needs to improve gas-electric coordination and communication during normal operating conditions, but noted that there are agreements in place to help during emergency situations. One example mentioned as a model for such coordination is the Northwest Mutual Assistance Agreement (NMAA), which aids coordination between utilities during gas-related emergency situations by maintaining updated emergency contact information, and conducting semi-annual planning meetings and periodic emergency exercises for utilities.[20] Some participants at the technical conference believe that this type of agreement should be extended to the rest of the West region. It was mentioned that the Western Energy Institute maintains the Western Region Mutual Assistance Agreement, but this agreement only covers crew assistance during emergencies.[21]

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[19] FERC Office of Electric Reliability Staff recently conducted technical conferences in Texas and New Mexico (Docket No. AD11-9-000) to discuss actions taken in response to the August 16, 2011 *Report on Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011*. *See* FERC and NERC, *Report on Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011* (Aug. 2011), available at http://www.ferc.gov/legal/staff-reports/08-16-11-report.pdf.

[20] Signatories to the NMAA agreement are defined as entities that utilize, operate or control natural gas transportation and/or storage facilities in the Pacific Northwest. The membership includes pipelines, LDCs, combined utilities, and electric-only utilities. An emergency is defined as "an unplanned event [that] causes, or is likely to cause, a supply shortfall to firm customers or markets beyond the abilities of a Member to manage." *See* Western Energy Institute, *Northwest Mutual Assistance Agreement,* http://www.westgov.org/wieb/meetings/crepcfall2012/briefing/NWmaa.pdf

[21] http://www.westernenergy.org/WRMAA/wrmaa.htm.

The importance of gas storage, especially during emergency situations, was expressed by multiple participants. Representatives of several utilities in Arizona noted that that state has been attempting to get market area storage, without success, for many years. CAISO's representative stated that long-term electric contracts may be needed to finance and construct market area gas storage facilities.

Representatives of several Southwest utilities suggested a regional gas sharing pool or pooling mechanism for pipeline capacity, in which members of the pool could give up pipeline capacity to help a generator that requires more gas. One pipeline representative at this conference commented that this already occurs in the market through capacity releases.

Several participants from the electric industry confirmed that pipeline contingencies are not currently included in planning studies. One participant argued that the probability of an event on the gas side is so low that it is negligible, but others still want it quantified because it may be within the risk parameters that are planned for on the electric side.

West Regional Initiatives

Participants representing entities in the Northwest described regional efforts by the Pacific Northwest Utilities Conference Committee (PNUCC), the Northwest Power and Conservation Council (NPCC), and the Northwest Gas Association (NWGA) to look at long-term resource adequacy needs through analyses of utility integrated resource plans.[22]

Representatives of two utilities in the Northwest discussed regional emergency coordination efforts, including the Northwest Mutual Assistance Agreement described above, that provides procedures to address anticipated cold weather events and critical situations leading to loss of pressure on a pipeline or storage facility. These utility representatives believe that such efforts have led to improved coordination and cooperation among regional entities, but that communications with the Bonneville Power Administration (BPA) could be improved because they are not a customer of any pipeline. A representative of BPA noted that the mutual assistance agreement works well

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[22] *See* PNUCC, *Northwest Regional Forecast of Power Loads and Resources, 2013–2022,* (Mar. 2012), *available at* http://www.pnucc.org/ sites/default/files/file-uploads/2012%20Northwest%20Regional%20Forecast.pdf. This report indicates that while natural gas currently is used primarily for peak demand needs, utilities in the region expect most of the generation added in the next 10 years to be natural gas-fired, followed by wind.

in dealing with emergencies but does not address non-emergency situations. BPA's representative added that the Western Electric Coordinating Council also maintains a "merchant alert protocol" that facilitates communications and coordination between merchant generators and reliability entities prior to an emergency situation occurring.[23]

A representative of CAISO stated that California entities talk frequently and meet at least quarterly to examine outages and coordinate generation and transmission. According to CAISO's representative the result has been that even major pipeline outages have not led to electric outages, and the electric and gas systems within California have been robust enough to weather an extended outage at Southern California Edison Company's San Onofre nuclear plant.

The Northwest transmission planning group, ColumbiaGrid,[24] announced on August 28, 2012, that it has formed a study team to analyze potential impacts of a gas supply limitation in the Interstate 5 corridor area of Oregon and Washington.[25] ColumbiaGrid stated that the study is an exploration of possible consequences if something happened to the natural gas supply system in a way that limited supply to the electric generating stations. Columbia Grid will coordinate the study with PNUCC and NWGA.[26]

In October 2012, members of the Committee on Regional Electric Power Cooperation and State-Provincial Steering Committee formed a task force to identify and study issues at the interface of the gas and electric industries. The Task Force is currently

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[23] *See, Merchant Alert Protocol (MAP) Guideline*, WECC (April 20, 2011), *available at* http://www.wecc.biz/committees/StandingCommittees/MIC/Shared%20Documents/Guideline%20-%20Merchant%20Alert%20Protocol.pdf.

[24] ColumbiaGrid is a non-profit membership corporation formed in 2006 to improve the operational efficiency, reliability, and planned expansion of the Pacific Northwest transmission grid. The corporation itself does not own transmission, but its members and the parties to its agreements own and operate an extensive network of transmission facilities. ColumbiaGrid has substantive responsibilities for transmission planning, reliability, Open-Access Same-Time Information System (OASIS), and other development services.

[25] The area is home to about 4,400 MW of natural gas-fired generation that serves the Portland and Seattle areas.

[26] *See* ColumbiaGrid, http://www.columbiagrid.org/GasElectric-overview.cfm.

engaged in outreach to determine the scope of its work and potential for collaboration with others, with the goal of providing direction to states and provinces as they consider the interface issues most important to the West.

E. Southeast Region[27]

While some participants in the Southeast Region had specific concerns about certain current gas scheduling rules, they generally did not believe that the reliability of natural gas service for electric generation was an issue in their region. Conference participants explained that in this region, most of the entities use integrated resource planning, examining both transmission and generation jointly with expected load growth to determine areas where either transmission or generation capacity is required. These studies also include fuel supply interactions for generation. Generators in this region typically have firm pipeline transportation service, and utilize a combination of released firm or IT service to meet peak needs. For example, a utility representative noted that it requires all new gas-fired generation capacity additions to have firm gas transportation and storage. A Florida utility representative noted that Florida entities use similar processes, although it was noted that a third natural gas pipeline into Florida would enhance reliability.

Many of the Southeast technical conference participants agreed that weather driven electric load variations will increasingly be supplied by gas generation. They also agreed that the need to rely upon gas-fired generation to meet daily and hourly variations is not consistent with interstate pipelines' standard firm transportation service, including the timely nomination cycle and the no-bump rule. Some representatives of generation owners with firm pipeline capacity stated that they would like the ability to use the firm service as flexibly as possible. For example, one electric utility representative stated that it often is not able to use its firm capacity to make nomination changes because of the no-bump rule and other service priority rules. Other participants stated that they have not experienced the same limitations, in part due to completing their electric day analysis before gas prior day timely nominations must be submitted.

In contrast, representatives of some gas shippers, such as industrial users, argued in favor of retaining the no-bump rule. They stated loss of the no-bump rule could cause

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[27] The Southeast region technical conference was held August 23, 2012 and included natural gas and electric entities from an area defined by the corporate boundaries of Southern Company, Tennessee Valley Authority, and other areas south of PJM and east of SPP and ERCOT. It included the States of Alabama, Arkansas, Florida, Georgia, Kentucky, Louisiana, Mississippi, North Carolina, South Carolina, and Tennessee.

fewer shippers to use IT, resulting in lower overall utilization of pipeline capacity and a greater share of fixed costs allocated to firm shippers.

A utility representative also asserted that the present analysis used to determine nominations in gas system operations (forward haul and back haul pipeline capacity, storage, and LDCs' local capabilities) "leaves too much on the table" by not allowing utilization of dynamic gas system capabilities. The representative further stated that gas-fired electric generators need to supply the net electric demand over a short time frame without impacting operational flexibility on the gas system.

Several generator representatives stated that they rely upon marketers and asset managers, who hold a mix of firm and interruptible transportation and storage services to manage their load swings throughout the day. They believe that additional flexibility could be achieved through FERC changes to the capacity release rules, which in turn could result in more efficient pipeline capacity utilization.

Participants stated that communications between the major electric entities and pipelines in the region are robust. For example, during a cold weather event in January 2010, an electric utility shifted away from gas generation to allow pipeline packing for use on the coldest day. This allowed the utility to stay within its long term contractual withdrawal limits while allowing sufficient withdrawals to occur on the critical electrical demand day. Participants stated that gas and electric entities share locations of electric driven natural gas compressor stations, which account for usually less than 20% of the flow capacity on the pipelines. However, one participant identified that there are critical locations that are supplied by electric-only compressor stations.

Participants stated that maintenance outages on the electric and gas systems are informally coordinated between major entities, resulting in selected changes in the timing of maintenance on both systems. They state that this is accomplished through a number of informal meetings per year. Participants also agreed that the communications that take place between the pipelines and their customers, including power generators, have been adequate to address reliability concerns both day-to-day and during emergencies. No concerns were expressed regarding the Standards of Conduct.

One utility representative stated that his utility plans its system to include gas system limitations and selected contingencies. This includes the complete outage of a single pipeline (and all generation attached). This utility has sufficient generation supplied by other fuels and the transmission to deliver that generation to be able to supply firm load for at least one to two days.

Southeast Regional Initiatives

According to participants, the Florida Reliability Coordinating Council (FRCC) created a flow model of the pipelines in Florida. FRCC also created a Fuel Reliability Working Group (FRWG) that reports to the FRCC Operating Reliability Subcommittee on matters relating to fuel and impacts to Bulk Electric System reliability. Specifically, the FRWG provides the administrative oversight of a regional fuel reliability forum that studies the interdependencies of fuel availability and electric reliability and supports coordinated regional responses to fuel issues and emergencies.[28]

At least one pipeline in the region offers an enhanced nomination service, and others are contemplating a similar service.

IV. Topics Common to Multiple Regions

The conferences summarized above were planned as a series of regional discussions given that the particular circumstances and needs of each region are distinct. Notwithstanding the regional focus of the discussions, a recurring theme across all of the conferences was that more attention needs to be paid to gas-electric interdependence issues. Participants in multiple conferences also stressed that some matters may be more appropriate for generic consideration while others are more appropriate for individual regions to address. In addition, several topics were of particular interest to participants across the conferences. The discussion below focuses on these topics:

- communications, coordination, and information sharing, including the Standards of Conduct and prohibitions on undue preference and discrimination;
- scheduling-related issues, including the no-bump rule and pipeline capacity release policies;
- electric resource adequacy, including RTO and ISO wholesale electric capacity markets; and
- reliability issues.

Industry representatives participating in the technical conferences described ongoing efforts to address each of these topics, noting that some issues implicate rules of general applicability while others are tied more closely to market structures or the resource mix of a particular region. For example, conference participants generally stated that communications and coordination improvements could be made on a regional basis, but that generic guidance regarding Commission rules and policies would facilitate progress. Similarly, while electric scheduling practices within a particular region can be

[28] *See* FRCC, Scope of FRCC Fuel Reliability Working Group (Feb. 1, 2008), https://www.frcc.com/FRWG/ Shared%20Documents/ FRCC%20FRWG%20Scope%2002-01-08.pdf.

refined to better align with gas scheduling opportunities, changes to gas scheduling rules would require national coordination given the way pipeline systems are operated. In comparison, resource adequacy and reliability issues are often tied to the structure and performance of the electric system in a particular region.

Staff discusses on-going efforts in each of these cross-cutting areas below. Where relevant, staff provides guidance regarding applicable Commission rules and policies and highlights regional activities that will be monitored for progress.

A. Communications, Coordination, and Information-Sharing

Gas and electric industry representatives participating in the technical conferences described a variety of actions that are being taken to improve communications and information sharing between their industries. However, participants at multiple conferences expressed concern that Commission rules and policies could be impeding further efforts to improve communication between the industries. Industry representatives asked that the Commission provide guidance regarding application of the Standards of Conduct and prohibitions on undue discrimination and preference in the context of gas-electric coordination. After reviewing actions already being taken across the regions, relevant Commission regulations and precedent are discussed and opportunities for further progress are highlighted below.

Groups have been formed in multiple regions to enhance communication and coordination across the gas and electric industries. For example, in the Northeast, ISO-NE, representatives of its stakeholders, the Northeast Gas Association, and pipelines serving the region have formed a working group/steering committee to foster improved communications within the region.[29] NYISO formed an Electric Gas Coordination Working Group earlier this year,[30] and in August the MISO announced a taskforce to

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[29] In the wake of the 2004 cold snap in New England, ISO-NE and the Northeast Gas Association formed the Electric/Gas Operations Committee (EGOC), consisting of representatives from the regional pipelines and gas LDCs as well as ISO-NE, NYISO and PJM. The EGOC is responsible for cross-training of electric and gas system operators, establishing emergency communications protocols and procedures, assessing coordination of electric and gas system maintenance requirements, and other common issues. *See* ISO New England, Electric/Gas Operations Committee, http://www.iso-ne.com/committees/comm_wkgrps/othr/egoc/index.html.

[30] *See* NYISO, Electric Gas Coordination Working Group, http://www.nyiso.com/public/committees/documents.jsp?com=bic_egcwg&directory=2012-03-05.

work on general gas-electric coordination issues.[31] In the West, the Northwest Mutual Assistance Agreement aids coordination between utilities during gas-related emergency situations by maintaining updated emergency contact information and conducting semiannual planning meetings.[32]

Several regions have conducted emergency exercises to test inter-industry coordination and communication. In New York, pipelines, LDCs and generators conducted a "tabletop" reliability exercise under different loss of supply scenarios. Signatories to the Northwest Mutual Assistance Agreement periodically undertake emergency exercises that prepare participants to take timely and effective action when an emergency does occur. One pipeline in the Southwest hosted a mock gas supply emergency exercise in the fall of 2011, and another plans to host a similar mock emergency drill in 2013.

Responding to issues arising from outage coordination, CAISO amended its tariff to enhance communications on gas-related maintenance activities within California.[33] The CAISO tariff now specifically authorizes the CAISO to share outage information with natural gas pipelines, with or without notice to the affected market participant. This includes, but is not limited to, the identity of individual natural gas-fired generation resources that are needed to support reliability of the CAISO balancing authority area in the event of a natural gas shortage, natural gas pipeline testing and maintenance, or other curtailment of natural gas supplies. ISO-NE has announced that it is considering revising its policies to allow sharing of real-time operational information with gas pipeline operators.[34]

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[31] MISO's Natural Gas Coordination Task Force was recently formed to address these issues. *See* MISO, Steering Committee Meeting Minutes (Sept. 20, 2012), *available at* https://www.midwestiso.org/Library/Repository/Meeting%20Material/Stakeholder/Steering%20Committee/2012/20121018/20121018%20SC%20Item%2001b%20Minutes%2020120920.pdf.

[32] *See* Western Energy Institute, *Northwest Mutual Assistance Agreement*, *available at* http://www.westgov.org/wieb/meetings/crepcfall2012/briefing/NWmaa.pdf.

[33] *See Cal. Indep. Sys. Operator Corp.*, Docket No. ER12-278-000 (Dec. 8, 2011) (delegated letter order).

[34] *See* John Norden, *Information Policy Changes to Facilitate Electric and Gas Coordination*, ISO New England (Oct. 11, 2012), *available at* http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2012/oct10112012/a13_iso_presentation_10_11_12.ppt.

At multiple conferences, however, gas and electric industry representatives questioned whether the FERC Standards of Conduct are impeding further efforts to improve communication between the industries. For example, one entity at the West technical conference raised the concern that information-sharing in an emergency situation could be a problem for companies where employees with operational knowledge are also wholesale merchant function employees. Many entities requested that the Commission provide clarity about what types of information can be shared and when.

Some pipelines and RTOs/ISOs also noted at the technical conferences that, although they make significant amounts of operational information publicly available, there is reluctance to share information on a more granular level because of concerns about violating statutory prohibitions against undue preference for any customer or customer class.[35] So, for example, in response to one RTO/ISO's comment that it was not able to interpret a pipeline's posted outage information in terms of which specific generators would be affected, several pipelines expressed discomfort with going beyond what was publicly posted.[36] Pipelines also noted that, in situations where information regarding pipeline capacity limitations has been posted, they typically will be queried on how much interruptible or secondary transportation is available, but they are not required to provide more specific information beyond their public postings.[37]

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[35] Both the Federal Power Act (FPA) and the Natural Gas Act (NGA) prohibit undue discrimination or preference. See 16 U.S.C. § 824d(b); 15 U.S.C. § 717c (b). Section 205(b) of the FPA provides that no public utility

> shall, with respect to any transmission or sale subject to the jurisdiction of the Commission, (1) make or grant any undue preference or advantage to any person or subject any person to any undue prejudice or disadvantage, or (2) maintain any unreasonable difference in rates, charges, service, facilities, or in any other respect, either as between localities or as between classes of service.

Nearly identical language is contained in section 4(b) of the NGA, 15 U.S.C. § 717c(b).

[36] *See* 18. C.F.R. § 284.13 (2012) (Reporting requirements for interstate pipelines).

[37] Pipelines are required to post estimates of their operationally available capacity based on prior schedules. They are not required to separately report how much interruptible or secondary firm transportation is available. *See* 18 C.F.R. § 284.13 and NAESB Version 2.0 WGQ Standard No. O.4.2.

At several conferences, pipelines indicated a desire to receive timely information from RTOs/ISOs about the dispatch of the gas-fired generation fleet and the expected impacts after generation forced outages. Some RTOs/ISOs expressed interest in knowing whether the gas-fired units scheduled in the day-ahead market have the necessary gas supply and transportation arrangements in place. While several generators and RTOs/ISOs expressed concern about the market sensitivity of sharing such information, at least one generation operator stated that generation plant operating profiles are regularly communicated to the pipelines to which they are attached, which facilitates those pipelines' ability to accommodate the generators' needs for flexible services. Several entities noted that the Commission's issuance of Order No. 698,[38] which requires generators to provide pipelines with hourly gas burn estimates upon request, has improved gas-electric communications for normal operations.

Subsequent to the August conferences, staff conducted additional outreach to solicit more specific feedback from pipelines, RTOs/ISOs and generators about concerns with information sharing. Pipelines and RTOs/ISOs would like to exchange information that allows each to operate their systems more efficiently and reliably. Generally, this would include information about pipeline capacity scheduled (for generation) and available, individual generator's expected burn rates, quick notice of significant changes in capacity or operations, and coordination of maintenance planning and scheduling.

One RTO suggested some form of a "one call" system so that it could quickly and efficiently inform all relevant gas industry participants supplying a particular generator (or a specific group of generators) of an unexpected change in electric system operations.[39] Some natural gas-fired electric generators would like assistance in perfecting nominations for gas flow, especially later in the day after earlier nominations were rejected due to insufficient available pipeline capacity. Some generators are

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[38] *Standards for Business Practices for Interstate Natural Gas Pipelines; Standards for Business Practices for Public Utilities*, Order No. 698, FERC Stats. & Regs. ¶ 31,251 (2007), *order on clarification and reh'g,* Order No. 698-A, 121 FERC ¶ 61,264 (2007) (collectively, Order No. 698). Order No. 698 mandates that communication protocols be established between interstate pipelines, power plant operators, and transmission owners/operators, and among other things requires power plant operators to provide their projected hourly natural gas flow rates to directly-connected pipelines upon request.

[39] Regional cooperation and appropriate contractual measures would appear to be required to accomplish any form of "one call" system such as this. Staff does not address this suggestion further in this report.

concerned that information exchanged between a pipeline and an RTO/ISO may lead to unilateral action by either the pipeline or the RTO/ISO which could cause competitive harm to the generator, or may act as a conduit for third parties to gain access to information about a specific generator causing competitive harm to the generator in the marketplace.

In response to concerns expressed by industry representatives at the technical conferences and in subsequent outreach, staff takes this opportunity to provide its views regarding application of the Commission's Standards of Conduct and statutory restrictions on undue preference or discrimination.[40] The discussion of these issues at the conference was general in nature and, therefore, so is staff's response. To the extent a natural gas pipeline or electric transmission operator has questions regarding the application of Commission rules or regulations in specific circumstances, it should seek appropriate guidance from the Commission or staff.[41]

Standards of Conduct

The Standards of Conduct govern communications between interstate natural gas pipelines and their affiliates that engage in marketing functions, and public utilities that own or operate electric transmission facilities and their affiliates that engage in marketing functions.[42] In other words, the Standards of Conduct apply to communications only within the same organization (*i.e.*, between the affiliated entities of a single corporate family). The Standards of Conduct do not apply to communications between two different natural gas and electric transmission organizations. By their terms, then, the Standards of Conduct do not limit communications between natural gas pipelines and electric transmission operators. Moreover, under section 358.1(c) of the Commission's regulations, the Standards of Conduct do not apply to Commission-approved RTOs or ISOs.[43]

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[40] Under section 358.7(a) of the Commission's regulations, a transmission provider must provide equal access to non-public transmission information disclosed to its affiliated merchant function, to all its transmission customers. 18 C.F.R. § 358.7 (2012). *See also*, n.35 *supra*.

[41] *Obtaining Guidance on Regulatory Requirements*, 123 FERC ¶ 61,157 (2008).

[42] 18 C.F.R. § 358.1(a) and (b) (2012).

[43] 18 C.F.R. § 358.1(c) (2012).

In those situations where the Standards of Conduct govern the disclosure of non-public transmission information between the transmission function and marketing function of an organization, the Commission's regulations already permit communications during "emergency circumstances," such as hurricanes or earthquakes, when information is needed to comply with reliability standards or to maintain/restore system operations.[44] Two sections of the Standards of Conduct specifically authorize communications that may be necessary to address emergency conditions: (1) section 358.7(g)(2) authorizes transmission providers to suspend posting requirements in an emergency; and (2) section 358.7(h)(2) permits communication among employees needed to comply with reliability standards, restore system operations and provide for generation dispatch.[45] These sections provide relief from the Standards of Conduct rules, including the Independent Functioning Rule, the No-Conduit Rule, and the Transparency Rule.[46]

Given that the Standards of Conduct do not govern communications or coordination between a natural gas pipeline and an electric transmission operator, and that exceptions to the Standards of Conduct already are provided to allow communications between the merchant function and transmission function of the same organization during emergencies, staff believes that further discussion with industry is necessary to address the continuing perception that the Standards of Conduct can act as a barrier to effective coordination of the gas and electric industries. In addition, Staff encourages industry representatives to contact staff with specific questions regarding application of the Standards of Conduct in the context of gas-electric coordination.

Undue Discrimination or Preference

Separate questions have been raised by industry representatives regarding whether sharing of certain types of information between natural gas pipelines or electric utilities could be viewed as unduly discriminatory or preferential, triggering questions regarding compliance with NGA section 4 and FPA section 205.[47] Staff notes that a number of

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[44] 18 C.F.R. § 358.7(g)(2), (h)(2) (2012).

[45] 18 C.F.R. § 358.7(g)(2), 358.7(h)(2) (2012). *See Standards of Conduct for Transmission Providers*, Order No. 717, FERC Stats. & Regs. ¶ 31,280 (2008), *order on reh'g*, Order No. 717-A, FERC Stats. & Regs. ¶ 31,297, *order on reh'g*, Order No. 717-B, 129 FERC ¶ 61,123 (2009), *order on reh'g*, Order No. 717-C, 131 FERC ¶ 61,045 (2010), *order on reh'g*, Order No. 717-D, 135 FERC ¶ 61,017 (2011) (collectively, Order No. 717).

[46] 18 C.F.R. §§ 358.5, 358.6, 358.7 (2012).

[47] *See* n.35 *supra*.

communication protocols already have been adopted to facilitate the exchange of information between the industries and additional enhancements are being considered by many regions. For example, typical day-to-day practices within each industry provide for the sharing of transmission information among natural gas pipelines, and among electric transmission operators. Pipelines routinely exchange information with other pipelines and other upstream and downstream entities needed to confirm transportation nomination requests, and to coordinate flows between each other. Transmitting electric utilities routinely share eTag information, scheduled interchanges, and related operational data to ensure the safe and reliable transmission of electric power across a region.

As between industries, natural gas pipelines and electric generators have established protocols for sharing a significant amount of information pursuant to Order No. 698. Under the North American Energy Standards Board (NAESB) Wholesale Gas Quadrant (WGQ) Version 2.0 Business Practice Standard 0.3.12, a generator and its directly connected natural gas pipeline(s) "should establish procedures to communicate material changes in circumstances that may impact hourly flow rates." These communications can help natural gas pipelines anticipate problems, devise solutions and take timely action to avoid operational problems.[48] NAESB WGQ Version 2.0 Business Practice Standard 0.3.14 further provides that a pipeline "should provide Balancing Authorities and Reliability Coordinators" and generators with notification of operational flow orders and other critical notices. NAESB Wholesale Electric Quadrant (WEQ) Version 002.1 Business Practice Standard 11.1.4 states that RTOs and ISOs "should sign up to receive" these pipeline notices. These communications can help electric transmission operators better manage their systems by reallocating resources in response to changing conditions on natural gas pipelines.

As noted above, CAISO has begun sharing with natural gas pipelines information regarding outages of generation or transmission facilities within its footprint. Specifically, CAISO is authorized to provide outage information to natural gas pipelines for their use in managing, coordinating, planning, forecasting, and/or scheduling outages, maintenance, repairs, and/or curtailment of their gas transmission pipeline or storage systems.[49] This allows CAISO and natural gas pipelines to coordinate outages and

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[48] Anecdotal evidence from the technical conferences and staff outreach suggests that this practice may not be in widespread use among pipelines nationwide, notwithstanding the opportunity provided by the NAESB standards.

[49] Cal. Indep. Sys. Operator Corp., *Business Practice Manual for Outage Management*, at section 4.2.1.2 (Apr. 30, 2012) (setting forth the terms of a non-disclosure and use of information agreement), *available at* https://bpm.caiso.com/bpm/bpm/doc/000000000001211.

maintenance of generation and transmission resources necessary to ensure the safe and reliable operation of the natural gas system.[50] In recognition that the information exchanged can be sensitive, CAISO requires natural gas pipelines to execute non-disclosure agreements that define the purposes for which information may be used and affirms the pipeline's commitments to follow the Commission's Standards of Conduct with regard to further communication of the information.

Industry participants at multiple technical conferences expressed a desire for inter-industry communication of the sort currently engaged in by CAISO and natural gas pipelines. The CAISO tariff provisions and non-disclosure agreement serve as an example to other electric transmission operators seeking to implement communication protocols with natural gas pipelines. Other types of information may be useful for natural gas pipelines to share with electric transmission operators. For example, information regarding generators' scheduled natural gas flow, alternatives where available pipeline capacity would allow deliveries to flow to natural gas-fired generators not yet scheduled, and future available capacity alternatives may assist electric transmission operators respond to changing system conditions more efficiently and maintain reliability of the electric transmission grid. A natural gas pipeline wishing to exchange non-public capacity-related information with electric transmission system operators without subjecting itself to possible future complaints of undue discrimination or preference might also look to the CAISO outage management model, with its non-disclosure agreement and reliance on the Commission's Standards of Conduct to ensure that any information shared is appropriately used and protected.

As with concerns related to the Commission's Standards of Conduct, staff appreciates that representatives from both the natural gas and electric industries seek additional comfort that enhanced communication and coordination practices will not violate statutory prohibitions on undue discrimination or preference. Staff believes that further discussion with industry is necessary to identify and address concerns in this area. Conference participants described a number of initiatives to improve inter-industry communication and coordination, including:

- Development of communication protocols governing gas and electric maintenance-related outage coordination, suggested by MISO and pipeline and LDC members of the Northeast Gas Association;
- ISO-NE's consideration of revised policies to allow sharing of real-time operational information with gas pipeline operators;

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[50] *See* Cal. Indep. Sys. Operator Corp., Docket No. ER12-278-000, Oct. 31, 2011 Filing at 2.

- The possibility of brief exchanges of pipeline and electric transmission provider control room operators, for cross-training purposes, as noted by PJM and a Mid-Atlantic pipeline;
- The development of a "one call" system to allow an RTO/ISO to inform relevant gas industry participants of unexpected changes in electric system operations;
- Enhancement of inter-industry communication and coordination during normal operating conditions under the Northwest Mutual Assistance Agreement; and,
- The use of tabletop exercises in multiple regions to examine different scenarios based on loss of supply.

Staff will monitor progress being made on these and other initiatives, and provide guidance where possible to ensure that concerns regarding Commission rules and policies do not hinder industry progress.

B. Scheduling-Related Issues

Several conference participants raised issues related to gas and electric scheduling and pipeline capacity release.[51] Generators participating in the RTO/ISO markets stated that managing fuel procurement risk can be a challenge because the operating days between the natural gas and electric industries are not aligned, and the timeframe for nominating natural gas transportation service, including pursuant to a capacity release, is not synchronized with the timeframe during which generators receive confirmation of their bids in the day-ahead electric markets. While electric scheduling practices and market rules within some regions are being refined to better align with gas scheduling opportunities, changes to gas scheduling practices can have national implications given the way pipeline systems are operated. As a result, whether gas scheduling practices need to be changed and, if so, what changes are warranted has been a matter of debate among the industries for a number of years.

Scheduling Practices

Standard pipeline services are generally designed as daily services, and the gas day covers a 24-hour period beginning at 9:00 a.m. Central clock time (CCT). For most rate schedules, tariffs provide that the pipeline may insist that gas be taken on a uniform hourly rate of flow although the pipeline tariffs generally provide that the pipeline permits fluctuations in flow on a best efforts basis. The NAESB gas standards, which the

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[51] The Commission rules governing capacity release on interstate pipelines are at 18 C.F.R. § 284.8 (2012).

Commission regulations incorporate by reference, currently provide shippers one day-ahead nomination opportunity, the Timely Nomination Cycle (11:30 a.m. CCT the day prior to gas flow), and three opportunities to revise that nomination, one in the day-ahead (the Evening Nomination Cycle (6 p.m. CCT the day before gas flow) and two within the gas day (the Intra-Day 1 (10 a.m. CCT the day of gas flow) and Intra-Day 2 (5 p.m. CCT the day of gas flow)). In the event a pipeline cannot fulfill all service requests, the pipeline allocates capacity according to its nomination priorities. As a general matter, (1) nominations of firm transportation service from "primary" points of receipt to "primary" points of delivery, which is termed "primary firm" service, have the highest priority; (2) nominations from alternative or additional "secondary" receipt or delivery points, which is termed "secondary firm service," is next in priority and (3) interruptible service is the lowest priority.

Schedules made during the Timely Nomination Cycle establish the allocation of pipeline capacity for the next gas day. In this cycle, the priorities listed above apply so primary firm nominations have priority over all other nominations. During the next three cycles, primary and secondary point nominations are treated equally, so a request to change quantities at a primary point will not bump already scheduled secondary firm service. A revised firm nomination during the Evening and Intra-Day cycles, however, can bump already scheduled interruptible service from prior cycles. During the final Intra-Day- 2 cycle, primary and secondary firm nominations cannot bump already scheduled interruptible service. Pipelines are permitted to offer additional nomination opportunities.

In contrast, electric generators are dispatched during the operating day hour-by-hour. A gas-fired generator may operate for many hours throughout the day or may operate only during peak hours. Increasingly, gas-fired generators are being dispatched as flexible resources, ramping up and down within the hour and across the day to help balance the electric system.

There is no defined electric day, but for most entities the standard 24-hour calendar day begins at 12:00 a.m. local time. Similar to the gas industry, electric generators in wholesale electric markets bid into the market prior to the given electric day, commonly known as the day-ahead market. For these generators, the time to obtain the best natural gas prices is typically before the Timely Nomination Cycle, because the gas markets would be most liquid at this time.[52] However, an electric generator's day-

[52] Natural gas is traded in bilateral markets. Daily transactions are mostly consummated in the morning hours before the first timely day-ahead pipeline nomination deadline. The ability to find willing buyers and sellers to act as counterparties of a commodity transaction is greatest during these normal trading periods; the gas market is "liquid" during this time of the day.

ahead electric bids generally are not confirmed by the RTO/ISO until after the Timely Nomination Cycle for pipeline service.[53]

Various generators participating in the RTO/ISO markets noted that these differing timelines result in significant price and/or supply risk for gas-fired generators because, to obtain the best gas price, the generators would need to nominate pipeline transportation service before they know if their electric bid has been confirmed. Generators also noted that, given the operating day mismatch, a pipeline nomination will cover parts of two electric days and therefore involve multiple iterations of the unit commitment process as day-ahead commitments turn into real time dispatch and the day-ahead commitments for the next electric day.[54] Concern also was expressed about whether the standard gas nomination schedule provides sufficient ability for generators to revise their nominations as needed by dispatch requirements, whether located within or outside RTO and ISO markets.

Representatives from the gas and electric industries participating in the conferences offered different perspectives on whether changes need to be made in either industry's scheduling framework. As several pipeline representatives pointed out, some pipelines offer to shippers more than the NAESB standard four daily nomination cycles. For example, in March of this year, the Commission approved a proposal by Texas Gas Transmission LLC (Texas Gas) to allow firm shippers contracting for Enhanced Nominations Service an additional eleven nomination cycles each gas day.[55] Some pipelines offer a firm no-notice service under which firm shippers can receive delivery of gas on demand up to their firm entitlements on a daily basis, without incurring daily scheduling and balancing penalties. The purpose of no-notice service is to enable firm shippers to meet unexpected requirements such as sudden changes in temperature. Some pipelines also offer firm shippers enhanced services that allow for greater flexibility in the rate at which their gas can flow. This service, as well as the no-notice service described above, is provided at a higher rate.

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[53] Electric scheduling timelines are set forth in the respective RTO/ISO tariffs and are not uniform across entities.

[54] Conversely, an electric generator may seek to procure gas during two successive daily cycles to accommodate the needs of a single electric day.

[55] *See Texas Gas Transmission LLC*, 137 FERC ¶ 61,093 (2011), *order on compliance filing*, 138 FERC ¶ 61,176 (2012) (collectively, *Texas Gas*) (offering enhanced nomination service with bumping of interruptible service permitted until 5 p.m.).

Also, representatives of the NYISO and ISO-NE present at the conferences stated that they have considered ways to change the schedule of the day-ahead unit commitment process to better coincide with the gas timely nomination cycle. For example, ISO-NE is considering moving up the timeline for day-ahead unit commitment and the resource adequacy assessment process in an effort to provide additional time to gas-fired generators to procure gas supplies and transportation services so that adequate generation capacity is available in real time.[56] However, it was pointed out by several participants at the conference that one disadvantage of moving the day-ahead unit commitment timeframes closer in time to the gas Timely Nomination Cycle and therefore, further from the real time, is that electric load forecasts become less accurate. Some conference participants also indicated that one reason it has been difficult to change the day-ahead unit commitment process is the absence of a standardized electric schedule across markets, similar to the standardized gas day.

A related scheduling issue raised by conference participants involved the service priorities for transportation services offered by interstate pipelines and the "no-bump" rule.[57] As noted above, primary and secondary nominations cannot bump already scheduled interruptible service during the final Intra-day 2 cycle, which is at 5 p.m. CCT.[58] Discussion at some of the technical conferences indicated that the general consensus supporting the no-bump rule may no longer exist. Some generators with firm pipeline service stated that they would like to see additional nomination opportunities and in some cases, elimination of the no-bump rule. They contended that the current gas nomination cycles do not provide sufficient flexibility to generators facing weather-driven electric load variations, and the no-bump rule impedes their ability to use their firm service flexibly. However, other firm gas shippers, such as industrial users in the Southeast, argued in favor of retaining the no-bump rule. They stated that elimination of

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[56] ISO-NE is proposing to move the day-ahead market back so that generators can buy gas and pipeline capacity while the market is still liquid and so that ISO-NE has more time to call on generators. *See Moving the Day Ahead Market & Reserve Adequacy Assessment Clearing Times*, ISO New England (Aug. 7-8, 2012), *available at* http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2012/aug782012/a07_iso_presentation_08_07_12.ppt.

[57] As noted above, at the Intra-Day 2 cycle, a firm nomination will not bump already scheduled interruptible service. This is referred to as the "no-bump" rule.

[58] *Standards for Business Practices of Interstate Natural Gas Pipelines*, Order No. 587-G, FERC Stats. & Regs. ¶ 31,062, at 30,670-72 (1998). This rule also applies to those pipelines that offer enhanced nomination services.

the no-bump rule could cause fewer shippers to use interruptible transportation, resulting in lower overall utilization of pipeline capacity and a greater share of fixed costs allocated to firm shippers.

As noted by many conference participants, prior efforts of NAESB participants did not reach consensus on the creation of a unified gas and electric timeline,[59] revisions to the gas nomination schedule to permit additional intra-day changes, or elimination of the no-bump rule. Several participants maintained that these changes were not a high priority and accordingly, should not be a priority for the Commission. To the extent changes are made, most conference participants agreed that these issues are interrelated and cannot be considered in isolation, and that any changes would need to be implemented in a way that makes sense for both industries from both regional and national perspectives.

Staff believes that further discussion is necessary to explore whether coordinated refinements to gas and electric scheduling rules are appropriate. Existing Commission policies and regulations provide a certain degree of flexibility in the near term for utilities to address coordinated scheduling issues on a regional basis and for pipelines to provide enhanced scheduling. As noted above, several RTOs/ISOs are considering or have refined their market practices and some pipelines have modified services and nomination cycles to meet the needs their customers. These efforts improve operations across both the gas and electric industries and should continue to be pursued. However, they do not address whether industry-wide changes would be appropriate to improve the longer-term harmonization of gas and electric operations. Taking a broader view of gas-electric scheduling issues could lead to greater operational efficiencies in both industries.

To that end, staff will continue to engage industry on gas and electric scheduling issues, including the effect of the Commission's no-bump rule. During this outreach, staff will monitor the progress being made on the following activities highlighted by conference participants:

- ISO-NE's consideration of moving the timeline for its day-ahead unit commitment and resource adequacy assessment process and allowance of bid adjustments and hourly re-offers;
- NYISO's consideration of moving releasing day-ahead dispatch results to early than 10 AM (EST), when gas markets are more liquid; and,
- The ability of natural gas pipelines to offer additional nomination opportunities after 5 PM or provide for electronic scheduling that could be completed faster than the current four hour processing time.

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[59] S*tandards for Business Practices for Interstate Natural Gas Pipelines*, Order No. 587-U, FERC Stats. & Regs. ¶ 31,307 at P 27 (2010).

Progress on these nearer-term activities may facilitate greater coordination between the gas and electric markets while longer-term initiatives are being evaluated.

Capacity Release

In many regions, natural gas LDCs contract for firm long-term pipeline service based on their winter peak demand. Consequently, those LDCs generally have excess natural gas transportation capacity in the summer when gas demand is lower. In contrast, gas-fired electric generation in most, but not all, regions experience demand peaks in the summer time when LDC use of pipeline capacity is relatively low.[60] As a result, gas-fired generators have generally been able to utilize released pipeline capacity from the LDCs to meet their gas delivery needs.[61]

As the relative amount of gas-fired generation increases, some contend that in the future these dynamics will no longer hold true. Gas-fired generation has increased to an extent that some pipelines are operating at increasing load factors, with diminishing availability of capacity to serve new gas-fired generation needs. For example, in New England, which experiences relatively high winter electric demand, gas-fired generators are increasingly competing with LDCs for pipeline capacity.

In response to these concerns, participants at every technical conference expressed a desire for more flexible capacity release on pipelines. Issues raised included a desire for more opportunities for intra-day releases and short-term or even hourly releases, enhanced ability to facilitate pre-arranged bilateral release deals, and more streamlined processing of capacity release transactions. In some cases, technical conference participants discussed “gas demand response,” but did not specify what that meant or how it could be implemented on the gas pipelines. In at least one case, a large generator with firm gas contracts suggested that more transparency regarding how pipelines analyze their systems to determine available pipeline capacity would be desirable.

The Commission’s current pipeline capacity release program is designed to permit expeditious and flexible releases.[62] A firm shipper (releasing shipper) sells its capacity

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[60] Gas-fired generators in other regions of the country, particularly the Southeast, do not rely on interruptible transportation or capacity release to ensure reliability, but contract directly for firm primary point transportation service with the pipelines.

[61] The Commission rules governing capacity release on interstate pipelines are at 18 C.F.R. § 284.8 (2012).

[62] 18 C.F.R. § 284.8 (2012).

by returning its capacity to the pipeline for reassignment to the buyer (replacement shipper).[63] Released capacity is offered for bid on the pipeline's website and awarded to the highest bidder. Firm shippers may also enter into a pre-arranged release directly with a replacement shipper. If the prearranged release is for a term of one month or less it need not be posted for bidding. The replacement shipper may pay less than the pipeline's maximum tariff rate, but not more for releases that are long term in nature. Short term releases, those for one year or less, are not subject to price limitations tied to a pipeline's maximum tariff rate.[64] Many pipelines also permit replacement shippers to prequalify for releases, which expedites the assignment of capacity.

With respect to the flexibility of releases, the regulations provide that releasing shippers can release capacity at any time and that "pipelines must permit shippers acquiring released capacity to submit a nomination at the earliest available nomination opportunity after the acquisition of capacity."[65] Under the regulations, the pipelines must process these releases in one hour. As a consequence of the Commission's posting and bidding rules, an LDC and a generator, for example, could negotiate a short term release at a market-determined rate at any nomination cycle permitted by the pipeline, including releases during the intra-day process.[66] In addition to capacity release, shippers can make bundled gas sales to third-parties.[67]

The Commission's capacity release regulations, including the NAESB WGQ standards, therefore provide shippers with considerable flexibility to acquire released capacity or obtain gas on a timely basis. However, the implementation of a capacity release remains subject to the scheduling opportunities available. As a result, it may be

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[63] The pipeline contracts with, and receives payment from, the replacement shipper and then issues a credit to the releasing shipper.

[64] The results of all releases are posted by the pipeline on its Internet web site and made available through standardized, downloadable files. 18 C.F.R. § 284.13(b)(1) (2012).

[65] 18 C.F.R. § 284.12 (b)(1)(ii)(A) (2012).

[66] In the intra-day process, shippers are permitted to release the unused portion of their contract demand.

[67] For example, an LDC could sell its gas to an electric generator. Under the Commission regulations, a holder of pipeline capacity can redirect that capacity without a requirement for rescheduling that supply, so long as the original contract provides for service beyond any constraint point. NAESB WEQ Standard 1.3.80.

that the concerns expressed by conference participants are driven more by the desire for greater pipeline scheduling flexibilities, or by an unwillingness of firm transportation contract holders to release capacity, than the Commission's capacity release rules. Staff notes that no specific reforms in the area of capacity release were suggested by conference participants, nor was the relationship between capacity release and underlying pipeline scheduling opportunities generally discussed. Nonetheless, given the significant number of conference participants that raised capacity release rules as an issue to be address, staff believes is it necessary to continue to engage industry with respect to this issue.

C. Electric Resource Adequacy

The question of whether generators in a particular region have appropriate incentives to deliver firm energy was raised at several of the technical conferences. At every conference, natural gas pipeline representatives emphasized that they are in the business of delivering gas to meet customer needs, but that the customers themselves must arrange for gas supplies. There were differences of opinion, however, with regard to the perceived need for firm delivery arrangements from natural gas pipelines as between electric industry representatives at the conferences.

In the Southeast, characterized by electric service being provided by vertically-integrated electric utilities, firm natural gas pipeline arrangements appear to be the norm. As a result, in this region, there appears to be little concern about ensuring adequate pipeline infrastructure.[68] In regions with restructured electric markets and an RTO or ISO, natural gas-fired generators appear to rely more heavily on pipeline capacity release and interruptible services for delivery of gas supplies. Some contend that this practice appropriately reflects the variability with which gas-fired generators are dispatched in RTO/ISO regions, while others suggested the practice indicates a need to provide greater incentives to generators to arrange for fuel supplies in a way that ensures reliability. Conference participants suggesting enhancements to RTO/ISO market rules generally focused on the terms of organized wholesale electric capacity markets and performance incentives for resources clearing in those markets. Several participants at the Northeast conference stated there is a need for additional pipeline infrastructure but there was also recognition that options are limited for addressing the gas infrastructure issue in the near term and that, under current market structures, generators have few incentives to obtain long-term primary firm pipeline service or invest in alternative fuel capabilities.

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[68] The exception to this is Florida, which is highly dependent upon gas for electric generation. Some Southeast regional conference participants identified a need for a third natural gas pipeline into Florida for reliability purposes.

Most organized wholesale electric capacity markets provide no more than a one-year or seasonal price. Various technical conference participants noted the tension between a short-term one-year price from capacity markets and the long-term decision to contract for firm fuel supply. Representatives from the RTOs and ISOs with organized capacity markets indicated that they are aware of this tension and are exploring potential market design changes. PJM stakeholders are considering multi-year pricing mechanisms, including a voluntary long-term auction.[69] A recent letter from PJM indicated that stakeholders are still discussing long-term options and noted that stakeholders agreed to attempt to develop business rules for a multi-year pricing mechanism in time for a May 31, 2013 filing, which could be applied to the May 2014 auction.[70]

Participants in some regions questioned whether the incentives, penalties, and/or participation requirements in the organized wholesale electric capacity markets are adequate to incent performance and ensure a firm fuel supply. Participants in virtually all regions with capacity markets indicated that their capacity markets do not consider the firmness of a generator's fuel supply when clearing resources. At the Northeast conference, a representative of ISO-NE indicated that a generator's Forward Capacity Market (FCM) penalties for not showing up are too low, though one generator argued that forward capacity market nonperformance penalties are substantial. ISO-NE's representative indicated that its Strategic Planning Initiative includes plans to strengthen capacity market performance incentives. On October 22, ISO-NE shared with stakeholders a white paper on FCM performance incentives that included a proposal to make FCM resources' revenue contingent on performance during scarcity conditions.[71] Stakeholders are currently considering these proposed modifications.

In the Mid-Atlantic region, one gas company in PJM argued that PJM's Reliability Pricing Model (RPM)[72] nonperformance incentives are too weak to encourage a

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[69] PJM Multi-year Pricing Mechanism, http://www.pjm.com/committees-and-groups/issue-tracking/issue-tracking-details.aspx?Issue={B709F188-450F-4A06-A5EB-BD61B601C9EF}.

[70] PJM Interconnection, L.L.C., Docket No. ER12-513-000, July 31, 2012 Supplemental Information Filing, available at http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=13038241.

[71] ISO-NE, *FCM Performance Incentives* (Oct. 2012) *available at* http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/materials/fcm_performance_white_paper.pdf.

[72] RPM refers to PJM's capacity market.

generator to pay for firm contracts or dual fuel; the gas company argued that PJM should consider increasing penalty provisions or treating a capacity resource as a limited capacity resource. A representative of PJM, however, noted that a generator with an RPM commitment that fails to perform will be penalized with an Unforced Capacity (UCAP)[73] reduction and thus earn less in future years. A NYISO representative indicated that they could consider improving their UCAP nonperformance penalty. A representative of NERC noted that because many capacity market incentives such as Equivalent Forced Outage Rate (EFORd)[74] penalties are retrospective, the penalty's impact does not arrive until three years later. The NERC representative noted that this may be a concern given not only the longer-term dependence on gas, but the near-term dependence on gas because in the next three years a substantial number of coal units will be going offline for retrofit.

Discussion at the conferences affirmed that each region meets resource adequacy requirements in its own way. Focusing on the RTO/ISO markets that rely on capacity market constructs regulated by the Commission, a number of issues have been raised regarding whether and how to structure gas-fired generator's performance incentives. PJM, ISO-NE and NYISO each have somewhat different market designs and each has commenced work to evaluate performance incentives in their respective regions. MISO continues to study the issue, with plans to refine and update studies evaluating whether generation capacity is sufficient. In CAISO, conference participants stated that gas infrastructure is expanded in anticipation of load (as opposed to responding to firm contracts) and CAISO's non-performance penalties are adequate.

Staff believes that resource adequacy issues in these markets should continue to be addressed in the first instance by market participants, states, and other stakeholders in each region. Unlike the communication and scheduling issues discusses earlier in this report, generic guidance may not be helpful at this time for regions considering how to structure market rules to ensure that generators have appropriate incentives to deliver firm energy. Significant attention and resources are being devoted to these matters, concrete issues have been identified, and responses to those issues are being formulated.

[73] UCAP refers to installed capacity adjusted by forced outage rates. UCAP represents the amount of MWs a resource can sell into a capacity market. For instance, a 100MW resource with a 20% forced outage rate would have its installed capacity (100 MW) reduced by its 20% forced outage rate so that the resource could only sell 80 MW of unforced capacity into a capacity market.

[74] Equivalent Forced Outage Rate (EFORd) refers to the probability that a generator will not be available due to forced outages or forced deratings when there is demand for the unit to generate.

Staff will monitor progress on these initiatives and encourages industry representatives to contact staff if guidance is required.

D. NERC Activity

A representative of NERC discussed its efforts to study gas electric interdependency reliability issues at several of the conferences, including a potential need to revise reliability assessments such that the assessments would take fuel supply into account. NERC's representative also indicated that it will complete phase 2 of its Gas-Electric Interdependency Study by the end of 2012[75] and suggested that recommendations in the phase 2 of the report would include the creation of a taskforce to further identify potential revisions to NERC standards. NERC's representative also stated that factors associated with the loss of gas lines (such as a gradual loss of gas pressure) may exempt this scenario from the planning standards requirements regarding surviving the loss of the single largest contingency (N-1).[76]

Participants in several conferences suggested that gas-electric coordination and fuel availability problems could be addressed, in part, with the development of new NERC Reliability Standards or modifications to existing standards. Other participants, such as ISO-NE and PJM, stated that they are addressing electric system performance within their respective regions, whether performance is adversely impacted by fuel supply issues, and what might be needed to address those impacts. Some participants suggested approaches that would establish requirements to study fuel availability and other gas-electric interdependency issues, without mandating specific changes to resource procurement. In the Southeast region, for example, at least one utility indicated that its contingency planning already considers the loss of a single natural gas facility. Other participants expressed concern that fuel supply or resource adequacy requirements could intrude on traditional areas of state jurisdiction.

Staff looks forward to the results of NERC's interdependency study and the consideration by industry of what additional steps are appropriate to take to address reliability considerations in the context of gas-electric coordination. Staff will monitor the progress of this initiative and encourages active industry participation.

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[75] *See* North American Electric Reliability Corporation, *2011 Special Reliability Assessment: A Primer of the Natural Gas and Electric Power Interdependency in the United States* (Dec. 2011), *available at* http://www.nerc.com/files/Gas_Electric_Interdependencies_Phase_I.pdf.

[76] TPL-002.

V. **Closing**

As indicated in the discussion above, significant industry attention and resources are being dedicated to a host of issues related to the coordination of the gas and electric industries. While the focus of this report is on the coordination, scheduling, resource adequacy and reliability issues that were common to multiple technical conferences, Staff appreciates that there are a number of other issues unique to each region that must be addressed to improve coordination across the gas and electric industries. Staff will be actively monitoring and engaging industry regarding progress made in each region to ensure that gas-electric coordination issues are identified and addressed.

The Western Gas-Electric Regional Assessment Task Force

The State-Provincial Steering Committee (SPSC) is launching an initiative to perform a natural gas and electric sector critical needs assessment across the West. This initiative will build on current and past efforts by other groups such as the Northwest Power and Natural Gas Planning Task Force, California PUC Risk Assessment Unit and California Energy Commission. As a first step, SPSC is forming a task force to scope out the critical issues to address and work to be performed in a regional assessment.

The growing interdependency between the natural gas and electric sectors raises new questions and challenges focused on maintaining a reliable gas network and electric grid. The significance of this issue across North America and the West were addressed at the October 4 joint meeting of SPSC and the State-Provincial Committee on Regional Electric Power Cooperation (CREPC). At the meeting, a panel of industry experts discussed the need for a regional infrastructure assessment to understand the risks and assess the reliability of the integrated natural gas and electric systems in the West. (See agenda at 9:50 on October 4. Recording of session is at http://westgov.adobeconnect.com/p3qqlxbem22/; starts at 2:27:00.)

The SPSC approved a motion to form a task force of experts in the gas and electric industry and SPSC/CREPC members. The task force will have two primary deliverables: (1) develop the scope of work for an assessment of the issues at the interface of the western natural gas and electric systems; and (2) explore collaborations with other organizations to join with SPSC/CREPC in this effort.

It will be essential for the task force to have a core set of technical experts from the gas and electric industries to address the following questions in shaping a regional assessment:

- What are the biggest risks when it comes to gas-electric interdependence?
- How could an assessment aid both electric and gas sectors in such areas as resource and supply planning, operations, transmission and pipeline planning, and reliability compliance?
- What types of findings are relevant to your organization and/or your region?
- What are the available sources of data to build an assessment?
- What are the key interface issues between regions in the Western Interconnection?
- What is the appropriate study methodology?
- What other entities or organizations could play a role in an assessment?

For further information, please contact (dlarson@westgov.org; 303.573.8910 x1) or Alaine Ginocchio (aginocchio@westgov.org; 303.573.8910 x209).

N.M.A.A

Northwest Mutual Assistance Agreement

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NORTHWEST MUTUAL ASSISTANCE AGREEMENT

PURPOSE

Each signatory to this Agreement is an entity that utilizes, operates or controls natural gas transportation and/or storage facilities in the Pacific Northwest (British Columbia, Alberta, Washington, Oregon, Nevada, and Idaho). Each entity participating in this agreement has a responsibility or mandate to exercise due diligence in its operations and planning to be able to provide and maintain firm service during emergency condition(s) and to restore normal service to its customers as quickly as possible after such events occur; and all participants have a vested interest in maintaining a secure, reliable regional natural gas system.

There is no membership (i.e., signatory) limitation to this Agreement and membership is voluntary. The emergency responses which members are asked to provide to other members needing assistance are emergency supply and/or emergency service.

In the event of a major emergency in the Pacific Northwest, it is expected that many or all parties who are signatories to this Agreement could be directly involved in providing assistance. With the combined assistance of these parties, it is expected that the impact and duration of an emergency condition to affected regional markets could be minimized.

This Agreement is intended to define the terms and conditions for cooperation and/or assistance between the parties in an emergency if such aid is volunteered. Another objective is to maintain and improve communication linkages between the Members as they pertain to emergency planning and incident response. However, it does not impose any obligation whatsoever on the parties to provide or continue cooperation, aid or assistance.

1. DEFINITIONS

a) Affected Member: A Member experiencing an Emergency Condition.

b) Assisting Member: A Member providing Emergency Service to the Affected Member.

c) Emergency Condition: That situation which exists when an unplanned event causes, or is likely to cause, a supply shortfall to firm customers or markets beyond the abilities of a Member to manage.

d) Emergency Service: The service provided, by mutual agreement, from an Assisting Member to an Affected Member during an Emergency Condition.

e) Members: The companies listed in Appendix A of this Agreement.

f) Northwest Mutual Assistance Agreement ("Agreement" or "NMAA"): The pre-arrangements as set out herein to assist in the management of an Emergency Condition.

2. EMERGENCY PLANNING COMMITTEE (EPC)

a) Each Member will have one representative on the EPC. The EPC will operate by majority rule, with each Member having one vote. The EPC representatives (which may be changed from time to time by notifying the Chair and The Western Energy Institute ("WEI") in writing) are listed in Appendix A.

b) The EPC will plan to hold two meetings annually. A spring meeting is intended to be held in the 2nd quarter to review the previous winter operations, make recommendations to revise the agreement, as necessary, and make plans to implement the changes prior to the following winter season. A fall meeting is intended to be held to review the changes and discuss the upcoming winter season.

c) To facilitate communications among the Members, the EPC will maintain a listing of key contact information for all Members' gas acquisition, scheduling, gas control, and public relations representatives, and others as the EPC may deem appropriate, as Appendix B to this Agreement.

d) A Chair and Vice-Chair of the EPC will be chosen from the representatives of the Member companies (and will serve without remuneration). These positions will generally serve for two years, with a year being defined as November 1 to October 31.

e) The Chair, with assistance from WEI, will administer the EPC, which will include organizing meetings, ensuring that the EPC list is reviewed and updated, and overseeing changes to the Agreement, as agreed upon, prior to the start of each winter operating season.

f) The Vice-Chair, with assistance from WEI, shall keep and distribute minutes and maintain and review the emergency contacts list (Appendix B) and distribute updates to the EPC whenever appropriate. Neither the Chair, the Vice-Chair nor WEI will be held liable for any matters whatsoever arising from their involvement in these positions, the actions or arrangements between or among the Members, or implementation of any plan.

g) The EPC may modify this agreement from time to time by simple majority rule. Changes may be recommended to the Chair and WEI in writing; the Chair and WEI will consolidate any such changes and work to achieve acceptance from members by majority rule.

3. UNDERLYING EMERGENCY SERVICE EXPECTATIONS

a) Notwithstanding any other terms or conditions in this Agreement or its Appendices, any activity performed by an Affected or Assisting Member shall:
   i. Be agreed upon by the Affected and Assisting Members;
   ii. Be subject to the Member's contractual and operational limitations; and
   iii. Be subject to all applicable tariffs, regulations and policies.

b) Each Affected Member shall be responsible for initiating requests for assistance, and detailing requirements, expected duration and such other information reasonably needed to determine the severity of the emergency.

c) Each Assisting Member will notify the Affected Member of the level of Emergency Service that can be made available.

d) Terms and conditions for Emergency Services shall be as mutually agreed between the Affected Member and Assisting Member.

e) The transporting pipeline(s) will use reasonable efforts, within their existing tariffs, agreements and applicable regulations, to facilitate the necessary services.

4. EMERGENCY COMMUNICATIONS

a) In an Emergency Condition that affects multiple Members, the Member pipeline company whose system is primarily affected by the Emergency Condition shall promptly notify all shippers and connecting pipelines of the Emergency Condition, and convene an emergency meeting of the EPC, via teleconference, to discuss the Emergency Condition, including estimated duration and possible mitigation alternatives.

b) In the event of an extended, extreme weather forecast, the EPC Chair or Vice Chair may convene an emergency meeting, via teleconference, to discuss regional system status and preparedness.

c) Arrangements for Emergency Services, however, shall be made via bilateral discussions between members.

5. CONTRACTUAL ARRANGEMENTS

a) Each Member should have a form of enabling agreement in place with each other member (or at least several members) governing the purchase and sale of natural gas related services and supply (e.g., NAESB contract). Each Member shall be responsible for making such arrangements with each other Member before Emergency Service transactions take place.

6. INVOICING

a) The Assisting Member will issue an invoice to the Affected Member pursuant to the terms of the underlying enabling agreement governing the transactions.

7. APPLICABLE LAW / DISPUTE RESOLUTION

a) Nothing in this Agreement is intended to modify or change the terms of the underlying enabling agreement between the Members, or between an Assisting Member and an Affected Member including, but not limited to the applicable law and dispute resolution provisions of such underlying enabling agreement.
b) Each Member agrees that its activities pursuant to this Agreement will and are intended to comply with all applicable laws, including all applicable antitrust laws.

8. LIMITATION of LIABILITY

a) Under no circumstances whatsoever shall a Member be liable to any other member for any losses or damages resulting from or arising out of any alleged or actual default by the Member with respect to this Agreement or any failure to performance related hereto, howsoever caused, including without limitation, any lost or prospective profits or any other special, indirect, incidental or consequential losses or damages.

9. MEMBERSHIP

a) Requests for membership in the NWMAA shall be made in writing to the Chair of the EPC by completing and signing the Request for Membership form (attached hereto as Appendix C). By signing the Request for Membership form, applicant acknowledges its acceptance of the terms of this Agreement. Upon acceptance of the application by the EPC, such acceptance not to be unreasonably conditioned, the Chair of the EPC will notify the applicant of the effective date of the applicant’s NWMAA membership.

b) Any Member may terminate its participation in the NWMAA upon written notice to the Chair of the EPC.

10. APPENDICES

Each member is responsible to ensure that the information contained in the Appendices is current. Changes should be communicated in writing to the Chair, Vice-Chair and WEI.

Appendix A - Member Companies & EPC Representatives

COMPANY	EPC REPRESENTATIVE	PHONE	CELLULAR	E-MAIL	FAX
Avista Corp.	Steve Harper, Director Gas Supply	509-495-2076	509-981-5809	Steve.Harper@avistacorp.com	509-495-8490
FortisBC Energy Inc.	Bryan Lane, Midstream Operations Manager	604-592-7892	604-831-1359	Bryan.Lane@fortisbc.com	604-592-7895
Cascade Natural Gas	Chris Robbins, Manager Gas Supply	509-734-4588	425-879 0123	chris.robbins@cngc.com	509- 734-9834
Clark County PUD	Terry Toland, Energy Manager	360-992-3060	360-953-9137	ttoland@clarkpud.com	360-992-3091
BPA	Fran Halpin	503-230-7545	503-705-2880	fjhalpin@bpa.gov	503-230-5377
Idaho Power	Mike Polito	208-388-2538	208-859-8408	mpolito@idahopower.com	
Intermountain Gas	Marty Benson, Gas Supply	208-377-6121		Marty.Benson@intgas.com	
Northwest Natural Gas	Randolph S. Friedman Director, Gas Supply	503-721-2475	503-650-1234	randy.friedman@nwnatural.com	503-220-2421
PacifiCorp	Bruce Evans, Manager, Gas	503-813-7036	503-516-2124	Bruce.evans@pacificorp.com	
Pacific Northern Gas Ltd.	Craig Donohue, Director Regulatory Affairs and Gas Supply	604-691-5673	604-868-7955	cdonohue@png.ca	607-697-6210
TransCanada	Jay Story, Director Gas Control and Transportation	503-883-4309	503-709-3506	Jay_Story@transcanada.com	503-833-4395
Portland General Electric	Val Yildirok, Manager, Fuels Trading	503-464-7565	503-702-1167	Val.Yildirok@pgn.com	503-464-7157
Puget Sound Energy	Clay Riding, Director, Natural Gas Resources	425-462-3179	425-985-7077	Clay.Riding@pse.com	425-456-2481
Ruby Pipeline	Dean Makings, Manager, Gas Control	719-520-4766	719-659-3523	Dean.makings@elpaso.com	719-667-7946
Seattle City Light	Jerry Koenig, Emergency Management Strategic Advisor	206-684-3095	206-794-1593	Jerry.koenig@seattle.gov	206-615-1191
Spectra Energy	Michael Parker, Manager Daily Commercial Operations	403- 699-1503	403-510-4002	MJParker@spectraenergy.com	403-699-1619
Tacoma Power	Bill Dickens, Sr. Utilities Economist	253-502-8553	850.459.6890	bdickens@ci.tacoma.wa.us	253-502-8628
Northwest Pipeline GP	Jan Caldwell Terry Hardman	801-584-7155 801-584-6522	801-580-8563 801-580-7923	Jan.m.caldwell@williams.com Terry.w.hardman@williams.com	801-584-7076 801-584-6816

EPC Chair Clay Riding, Puget Sound Energy

EPC Vice-Chair Jan Caldwell, Northwest Pipeline GP

Appendix B - Emergency Contacts

COMPANY		Gas Control	Gas Scheduling	Emergency Call Center	Public Relations
Avista Corp.	Telephone: Fax: Email: Cellular: Satellite:	(509) 495-5631*	(509) 495-8001* (509) 495-8490 #gasscheduling@avistacorp.com	(509) 495-4859*	(509) 495-4174*
FortisBC Energy Inc.	Telephone: Fax: Email: Cellular: Satellite:	(604) 592-7500 (604) 592-7610 gas.control@fortisbc.com* (866) 447-9335*	(604) 592-7799* (604) 592-7895* tradelog@fortisbc.com (604) 632-6634*	(604) 576-7163* (604) 576-7027 service.centre@fortisbc.com (866) 447-9420	(604) 592-7801
Cascade Natural Gas	Telephone: Fax: Email: Cellular: Satellite:	WBI Gas Control (701) 530-1648 WBIGOGasControl@WBIP.com	MDU Gas Supply (701) 222-7930 (701) 220-3695	(888) 522-1130	MDUR (701) 530-1093 Mark.Hanson@MDUResources.com
Clark County PUD	Telephone: Fax: Email: Cellular: Satellite:		509-688-6110 (Shell)	360-992-3073 (RRGP Control Room)	360-992-3238 (Erica Erland)
BPA	Telephone: Fax: Email: Cellular: Satellite			Senior Dispatcher Dittmer (Primary POC) 360-418-2282 Munro (Backup POC) 509-465-0315	800-622-4519
Idaho Power Company	Telephone: Fax: Email: Cellular: Satellite	(208) 388-5275 (208) 388-5234	(208) 388-5275 (208) 388-5234 Danderson3@idahopower.com	(208) 388-2672	(208) 388-2200
Intermountain Gas Company	Telephone: Fax: Email: Cellular: Satellite	WBI Gas Control (701) 530-1648 WBIGOGasControl@WBIP.com	(208) 377-6121 Marty.Benson@intgas.com	(888) 522-1130	MDUR (701) 530-1093 Mark.Hanson@MDUResources.com
Northwest Natural Gas	Telephone: Fax: Email: Cellular: Satellite:	(503) 224-3532* (503) 721-2507* (503) 367-7039* 8816-2241-7451	(503) 226-4211, x. 4616 (503) 220-2421 rfm@nwnatural.com (503) 819-9784	(800) 422-4012*	(503) 818-9845*
PacifiCorp	Telephone: Fax: Email: Cellular: Satellite		503-813-7036 503-516-2124	503-813-5394	
Pacific Northern Gas Ltd.	Telephone: Fax: Email: Cellular: Toll Free: Satellite:	(604) 691-5566 (604) 691-5668 (800) 420-4977 (600) 700-3787	(604) 592-7799* (604) 592-7895* tradelog@fortisbc.com (604) 632-6634*	See Gas Control	See Gas Control

Northwest Mutual Assistance Agreement

COMPANY		Gas Control	Gas Scheduling	Emergency Call Center	Public Relations
Portland General Electric	Telephone: Fax: Email: Cellular: Satellite	(503) 464-8950 (503) 464-7157	(503) 464-2882 (Kyle) (503) 464-7536 (Jason) Kyle.Broderick@pgn.com Jason.Horner@pgn.com	See Gas Scheduling	(503) 464-8949
Puget Sound Energy	Telephone: Fax: Email: Cellular: Satellite:	(425) 882-4622 (425) 882-4480 (425) 766-0300	(425) 462-3040 (425) 462-3836 gastrans@pse.com	(425) 462-3500	(888) 831-7250
TransCanada (ANG)	Telephone: Fax: Email: Cellular: Satellite:	(403) 920-2401 (600) 700-0661	(403) 920-2401	(403) 920-7473	(403) 920-7859
Ruby Pipeline	Telephone: Fax: Email: Cellular: Satellite1: Satellite2:	(719) 520-4221* (719) 329-5802* ciggascontrol@elpaso.com (719) 440-7604* (877) 225-8351* (800) 286-7327	(800) 238-3764, option 2 (719) 520-4529 cigsched@elpaso.com	(877) 712-2288*	(713) 420-6828 (713) 420-6406 (832) 643-8929
Seattle City Light	Telephone: Fax: Email: Cellular: Satellite:			206-794-1593	206-386-4233*
Spectra Energy	Telephone: Fax: Email: Cellular: Toll Free: Satellite:	(604) 691-5566 (604) 691-5668 (800) 420-4977 (600) 700-3787	(403) 699-1600	(800) 663-9931	(403) 699-1506
Tacoma Power	Telephone: Fax: Email: Cellular: Toll Free: Satellite:			253.502.8000	
Northwest Pipeline GP	Telephone: Fax: Email: Cellular: Satellite:	(801) 584-6949 (801) 584-6816 (800) 235-8966	(801) 584-7229 (801) 584-7794 nwpsched@williams.com (801) 584-7301 (hotline)	(800) 972-7733 (801) 584-6816 (877) 214-4620	(801) 584-7048 (801) 584-6336 Michele.swaner@williams.com (801) 580-5950

Note: * indicates 24 Hour availability

APPENDIX C

Request for Membership

Request for Membership

To: ____
Chair, Emergency Planning Committee (EPC)

Please accept this application for membership in the Northwest Mutual Assistance Agreement on behalf of:

Company Name: ____
Address: ____
____
____

The following is the membership information required for the agreement:

Appendix A
Company Representative for Emergency Planning Committee (EPC):

Name: ___________________________ Cell: ______________________
Email: ___________________________ Title: ______________________
Fax: ___________________________ Phone: ____________________

Appendix B

24 Hour Emergency Numbers:

	Gas Control	Gas Scheduling	Emergency Call Center	Public Relations
Telephone:				
Fax:				
Email:				
Cellular:				
Satellite Tel.:				

This Agreement serves to outline the principles under which assistance can be requested or provided. Nevertheless, it is our understanding that participation in emergency assistance is strictly voluntary.

Signature: ____________________________

Title: ____________________________

Date: ____________________________

March 5, 2013

Valeria Annibali
Federal Energy Regulatory Commission
888 1st Street NE
Washington DC 20426

Dear Valeria,

The Pacific Northwest Utilities Conference Committee (PNUCC) and the Northwest Gas Association appreciate the Federal Energy Regulatory Commission's (FERC) attention to the suite of issues relating to natural gas and electric system coordination. We are especially gratified by FERC's particular interest in our region's gas-power coordination work.

As you are aware, we committed to providing FERC with periodic updates on our efforts here in the Pacific Northwest. To that end, we convey the attached report summarizing our efforts over the last few years, preceding FERC Docket AD12-12.

To summarize, our activities have improved communications between our respective industries. These efforts are also yielding a better understanding of the issues and challenges confronting each of our industries in the context of increasing interdependencies.

Of particular note is the Power and Natural Gas Planning Task Force (Task Force). Facilitated by the PNUCC, the Task Force consists of the mid and long-range planning experts from the power and gas sectors including the major distribution and transmission operators in the region, both public and private. In addition to providing for more informed planning, this effort is a great forum for developing relationships that improve ongoing communications.

Another highlight is the revitalization and recasting of the Northwest Mutual Assistance Agreement (NMAA). NMAA is designed to be a tool for communicating about and addressing system reliability issues during disruptions or other periods of significant stress. NMAA includes the balancing authorities and transmission operators, most of the major electric and gas distributors and the gas pipeline companies that serve the Pacific Northwest. NMAA has purchased equipment that allows for immediate communications between NMAA participants during a system event, and will conduct periodic exercises to test the system and operating assumptions.

To conclude, in the Northwest we are making real strides in the three areas that FERC is most interested in: ongoing communications between the two energy sectors, urgent communications to address immediate system reliability issues, and more fully informed mid- and long-term planning. Please don't hesitate to contact either of us with any questions you may have.

Sincerely,

Dan Kirschner	Dick Adams
NWGA, Executive Director	PNUCC, Executive Director

cc: Caroline Daly and Jacob Lucas, FERC Staff
Northwest Power and Natural Gas Planning Task Force

Quarterly Report to FERC

Power and Natural Gas Planning Task Force

March 2013

NWGA
NORTHWEST GAS ASSOCIATION

PNUCC
Bringing the *Power* of good ideas *Together*.

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Background

Electric power and natural gas are two distinct but interdependent industries in the United States. One-time competitors for energy load, electric power and natural gas have become increasingly interconnected in recent years for a number of reasons, including regulation, economics, and the environment.

A stark reminder of this interdependence occurred in February 2011 within the boundaries of the Electric Reliability Council of Texas. An unusual combination of record cold temperatures and power plant failures led to rolling blackouts across Texas. The blackouts shut down key compressor stations that keep gas moving through the pipelines. Without adequate pipeline pressure, gas-fired power plants were left without an adequate fuel supply, which caused more power outages. As a result of this colossal system failure, FERC joined others in launching an investigation to examine the interdependence between electric power and natural gas.

While the Northwest has avoided such a crisis, the power and natural gas connection here is gaining strength. Most of the incremental demand for natural gas over the next 20 years is expected to come from new gas-fired power plants, which are on the drawing boards to replace base-load coal-fired generation and take up the slack in firming up Variable Energy Resources – mainly wind generation.

Leaders in the Northwest's electric power and natural gas industries joined forces in early 2011 to assess their growing interdependence and to become better acquainted with practices and issues that could affect the region's energy supply. They have looked to their trade associations, Pacific Northwest Utilities Conference Committee (PNUCC) and the Northwest Gas Association (NWGA), to coordinate these efforts. The industries' desire to work jointly to understand their intersection and interdependence was the impetus for the activities described in this report.

Joint Efforts Take Root in 2011

Natural Gas & Electricity Workshop

PNUCC and the NWGA held a joint workshop in May 2011 that brought together the region's power and natural gas planners along with system operators to talk about how each foresees its role over the next five to 20 years. The purpose was to increase mutual understanding about the industries. The agenda and presentations from the workshop are available at www.pnucc.org/system-planning/natural-gas-for-electric-power/natural-gas-and-electric-power-industries-workshop-ma.

One thing was immediately clear: like the rest of the nation, Northwest utilities expect their demand for natural gas will grow to fuel base-load plants that provide 24/7 power, peaking units, and to firm up wind power. To meet the demands of intermittent renewable resources, power producers are counting on the ability to draw on large amounts of natural gas on a 24-hour basis.

But that did not necessarily match the reality electric utilities heard from gas pipeline operators. Because of the relatively slow speed of gas transportation (between 10 and 20 mph) relative to electricity's near lightning speed, it is very difficult for the gas industry to accommodate large-scale changes in gas flows within the day. It would take significant gas storage infrastructure and firm reservations on existing or new pipelines to provide that kind of service to the power industry.

Gas Scheduling Discussion

PNUCC saw the need for a follow-up discussion on how the natural gas industry schedules its deliveries to customers. At PNUCC's July 2011 System Planning Committee meeting, members pointed out how much recent national attention was being given to the use of natural gas for electricity generation. The issues were clearly capturing the region's attention.

A follow-up discussion hosted by PNUCC focused on the details of the electric power and natural gas scheduling days. Gas traders and schedulers described the steps in a typical trading day. The audience gained a better understanding of operational issues associated with intraday natural gas trading in the Northwest. It was clear that the travel rate of gas through a pipeline and the gas scheduling protocols present a challenge for delivering an adequate fuel supply to serve large-scale power generation needs in the region.

As a result of the discussion and presentations, group members agreed an analysis was needed to quantify the potential future draw on the gas system. This would help clarify whether structural changes are necessary to provide the needed gas supply and operating flexibility. Knowing the potential demand, gas producers and pipeline operators would be able to assess how much intraday flexibility they could provide.

2012 Plugging In to Natural Gas Conference

A joint industry conference, sponsored by Bonneville Power Administration (BPA), NWGA, and PNUCC, took place in January 2012. The conference provided an opportunity for national and regional leaders to meet and discuss issues and learn more about the convergence of these two industries. Specifically, the focus of the day-long event was to:

- Raise the visibility of the gas/power reliability relationship.
- Identify cross-industry impacts and opportunities for maintaining a reliable, affordable energy infrastructure and services.
- Build on recent research efforts.

The agenda, presentation, and other conference materials are available at www.pnucc.org/system-planning/natural-gas-for-electric-power/plugging-natural-gas-2012-energy-summit-january-25-20.

The region's Power & Natural Gas Planning Task Force was an outgrowth of this conference.

Power & Natural Gas Planning Task Force

The Northwest currently has over 8,000 MW of gas-fired turbine capacity, and a significant amount of gas-fired generation is planned over the next decade. In addition, almost 8,000 MW of wind generation has been built in the region. The intermittent and unpredictable nature of wind generation poses a new set of challenges in daily system operations. Additional peaking capacity is likely to be needed in the Northwest to provide hourly balancing services – beyond what the hydro system can supply – for wind generation. Much of that capacity is expected to be met with natural gas-fired generation. Some electric utilities are already seeing peak demand grow and are building natural gas-fired capacity to meet peak, as well as base-load energy needs.

Purpose

PNUCC and the NWGA established the Power & Natural Gas Planning Task Force in March 2012 to investigate the growing interdependence of natural gas and electricity generation and to promote information sharing on the issues in the Northwest. The task force, made up of experts from the gas and electricity industries, meets bimonthly to explore and address policy, planning, and reliability challenges.

The task force meetings have created an opportunity to increase understanding about the functions and practices of both industries. The meeting agendas and presentations are available at www.pnucc.org/meetings/power-and-natural-gas-taskforce-meetings. The task force has supported the development of the *Natural Gas-Electricity Primer* and the *Role of Natural Gas White Paper*, and offered guidance on an I-5 Corridor analysis described below.

Participants

The list of task force participants varies from meeting to meeting. The criterion for participation is an interest in working with industry colleagues on issues of joint concern and a desire to know more about these issues. The task force directs its own activities, which are reported on to the PNUCC and NWGA boards of directors and others, depending on the issue. The following is a list of regular participants:

Avista (electric & natural gas)
BPA - Power
BPA - Transmission
Clark Public Utilities
ColumbiaGrid
PacfiCorp
NW Gas Association staff
NW Industrial Gas Users
NW Natural
NW Power & Conservation Council staff
Pend Oreille PUD
PNUCC staff
Portland General Electric
Puget Sound Energy (electric & natural gas)
Seattle City Light
Tacoma Power
TransCanada Gas Transmission NW
Williams NW Pipeline

Information Sharing Forum

Task force meetings are made up of pre-planned presentations and updates on various aspects of the electric power and natural gas industries. They are designed to promote understanding and an appreciation for the issues each industry confronts in planning and operations. The following are examples of the topics at past meetings:

- Review of local natural gas distribution company planning
- Review of natural gas system modeling tools
- Review of Bonneville Power Adminstration transmission planning
- Review of electricity and natural gas long-range planning
    - Specific utility (gas and electricity use)
    - Electric power regional perspective, PNUCC 's *Northwest Regional Forecast*
    - Natural gas regional perspective, NWGA's *Natural Gas Outlook*
- Overview of Northwest Power and Conservation Council's natural gas price forecast
- Discussion of FERC Order 587-V natural gas-electricity coordination and communication
- Update on Western Interstate Energy Board natural gas efforts
- Update on ColumbiaGrid Transmission Study

Natural Gas-Electricity Primer

In August 2012, the Power and Natural Gas Planning Task Force released its first joint paper, the *Natural Gas-Electricity Primer*. The primer was written as a background piece to facilitate communication. It outlines key issues surrounding the growing interdependence of natural gas and electricity in the region and provides fundamental information about the two industries.

Role of Natural Gas – White Paper

BPA drafted a white paper, *The Role of Natural Gas in the Northwest's Electric Power Supply*, that was finalized in August 2012. The paper discusses the region's shift toward gas-fueled electricity generation and provides an overview of several presentations from the Northwest electricity and natural gas summit held in early 2012.

I-5 Corridor Analyses 2011-2013

Quantifying Natural Gas Demand

In July and August 2011, a small group spearheaded by PNUCC's System Planning Committee investigated three detailed scenarios to determine the natural gas supply needed to meet base-load and peak electricity generation, plus the generation to integrate intermittent wind generation. The three scenarios were:

> **July 6th, 2011 –** a day when electricity supply is tight in the afternoon and some gas turbines would not operate when called upon.
> **July 27, 2011** – a day when BPA was having problems on its transmission system and cut schedules into the Puget Sound area.
> **December 9, 2009** – a day when gas supply was an issue and curtailing gas-fired electric generation was considered.

These discussions about the three specific dates helped define the broader analysis in the Interstate-5 corridor. No formal report was produced.

Assessing Infrastructure Adequacy

In September 2012, the Power & Natural Gas Planning Task Force undertook an effort to answer the following question: Is the I-5 corridor natural gas delivery infrastructure adequate to meet the needs of local distribution companies and power generators?

Using a regional production cost model, analysts simulated one year of hourly power generation to meet forecasts for the year 2015 and came up with a range of daily and hourly natural gas volumes needed for power generation. The rates of change were examined for both TransCanada GTN and Williams Northwest pipelines.

The results led the group to recommend further analysis. A Phase 1 report is currently being drafted to document the analysis, describe what was learned, and identify next steps. The Phase 1 report will be completed in the next few months.

Transmission System Reliability in the Corridor

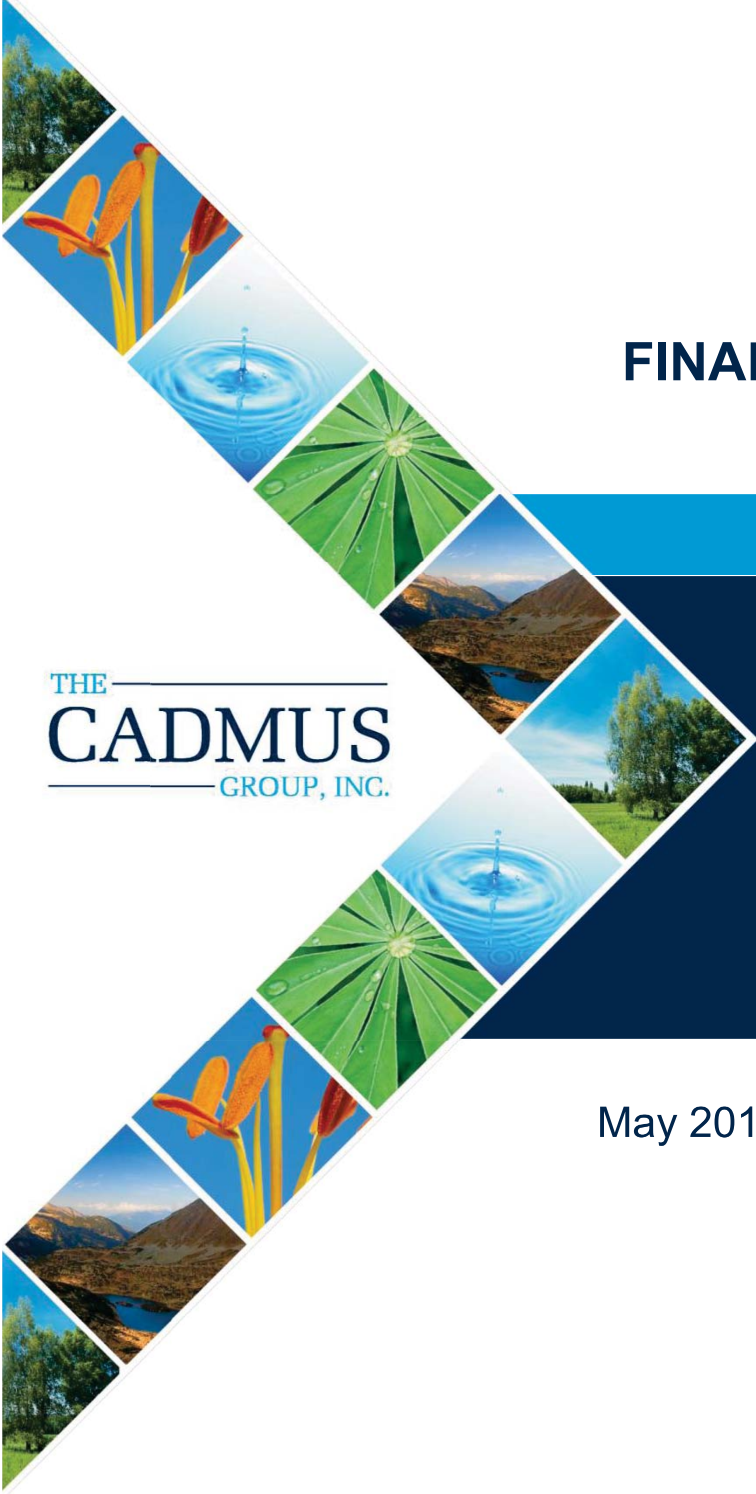
In September 2012, ColumbiaGrid began a study of transmission system reliability issues that could arise if the natural gas supply to generators in the I-5 corridor were limited. The first phase of the study investigated whether electric system reliability would be adequate during a total curtailment of natural gas to all power plants in the I-5 corridor. Only those natural gas plants capable of switching to an alternative fuel supply would remain in service. The study tests the ability of the transmission system to serve loads in the I-5 corridor with local generation curtailed and a greater dependence on resources outside of the area (e.g., the Columbia River hydro system).

The Gas-Electric Interdependencies Study Team released its third draft of the transmission system reliability study in December 2012. The Power and Natural Gas Planning Task Force reviewed the draft and provided comments and recommendations. Additional information on the ColumbiaGrid study can be found at www.columbiagrid.org/GasElectric-overview.cfm.

Northwest Mutual Assistance Agreement

The Northwest Mutual Assistance Agreement has been revitalized in recent years under the auspices of the Western Energy Institute. Puget Sound Energy has led an effort to develop an additional agreement among electric and gas utilities that defines the terms and conditions for voluntary cooperation and/or assistance in an emergency. Another function of the Northwest Mutual Assistance Agreement is to maintain and improve communication linkages between parties for emergency planning and incident response. The agreement does not, however, impose an obligation on the parties with regard to providing aid or assistance.

A copy of the September 2012 version of the Northwest Mutual Assistance Agreement is available here.



THE CADMUS GROUP, INC.

FINAL REPORT

Comprehensive Assessment of Demand-Side Resource Potentials (2014–2033)

May 2013

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EXECUTIVE SUMMARY

Overview

This report summarizes the results of an independent study of the technical and achievable potential for electric and natural gas demand-side resources (DSR) in Puget Sound Energy's (PSE) service territory from 2014 to 2033. PSE commissioned the study as part of its biennial integrated resource planning (IRP) process.

The study, building upon PSE's 2012–2031 assessment of DSR resources, incorporates PSE's programmatic accomplishments in the intervening years. Further, it updates baseline and DSR data informed by primary and secondary data collection, and is informed by the work of other entities in the region, such as the Northwest Power and Conservation Council (the Council) and the Northwest Regional Technical Forum (RTF). The methods used to evaluate the technical and achievable technical potential draw upon best utility industry practices, and remain consistent with the methodology used by the Council in its assessment of regional conservation potentials in the Northwest 6th Regional Power Plan (6th Plan).

Summary of Results

Table 1 summarizes the potentials identified in this study. As shown, electric DSRs account for 619 aMW and 1,017 winter peak MW of achievable technical potential by 2033. These potentials represent 19% of retail energy sales and 22% of winter peak demand.[1] Similarly, achievable technical natural gas potential accounts for 21% of forecasted 2033 retail sales. High-level potentials by resource follow below, with more detailed results presented in the body of this report. All values are reported at generator and assume line loss of 6.9% for electric resources and 0.8% for gas resources. In addition, the numbers discussed in this report do not account for intra-year ramping. DSR bundles used as input into PSE's IRP analysis do reflect intra-year ramping, as discussed in "Chapter 1: General Approach and Methodology" under "About Hourly DSR Estimates."

[1] Demand response potentials do not account for program interactions; thus, this potential would likely be reduced if multiple programs were competing for participants.

Table 1. Summary of Energy and Capacity Saving Potentials, Cumulative in 2033

	Energy (aMW / million therms)		Winter Coincident Peak Capacity (MW)	
Resource	Technical Potential	Achievable Technical Potential	Technical Potential	Achievable Technical Potential
Electric Resources				
Energy Efficiency	714	521	878	661
Fuel Conversion	240	61	575	110
Demand Response	N/A	N/A	N/A	213
Distributed Generation	N/A	36	N/A	33
Electric Resources Total	954	619		1,017
Natural Gas Resources				
Energy Efficiency	347	229	N/A	N/A

Energy Efficiency

Table 2 shows 2033 forecasted baseline electric sales and potential by sector. Study results indicate 714 aMW of technically feasible electric energy-efficiency potential will be available by 2033, the end of the 20-year planning horizon. Upon taking market constraints into account, this translates to an achievable technical potential of 521 aMW. Provided all this potential proves cost-effective and realizable, it will result in a 16% reduction in 2033 forecast retail sales.

Consistent with the Council's method, this study assumes that 85% of electric resources will be achievable over time. However, due to the timing of lost opportunity resource acquisition, achievable technical potential amounts to less than 85% of technical potential (described in greater detail in Section 1: General Approach and Methodology).

Table 2. Electric Energy-Efficiency Potential by Sector, Cumulative in 2033

		Technical Potential		Achievable Technical Potential	
Sector	Baseline Sales	aMW	Percent of Baseline Sales	aMW	Percent of Baseline Sales
Residential	1,619	356	22%	240	15%
Commercial	1,546	331	21%	258	17%
Industrial	132	28	21%	23	18%
Total	3,297	714	22%	521	16%

Table 3 shows 2033 forecasted baseline natural gas sales and potential by sector. Study results indicate roughly 350 million therms of technically feasible natural gas energy-efficiency potential by 2033, translating to an achievable technical potential of 231 million therms. If all this potential proves cost-effective and realizable, it will result in a 21% reduction in 2033 forecasted retail sales.

Table 3. Natural Gas Energy-Efficiency Potential by Sector, Cumulative in 2033

		Technical Potential		Achievable Technical Potential	
Sector	Baseline Sales	Million Therms	Percent of Baseline Sales	Million Therms	Percent of Baseline Sales
Residential	668	226	34%	147	22%
Commercial	404	120	30%	81	20%
Industrial	26	4	16%	3	12%
Total	1,099	350	32%	231	21%

Comparison to 2011 IRP

This energy-efficiency potential assessment largely updates the analysis conducted for PSE's 2011 IRP. However, a number of differences between the two studies have led to differences in technical and, thus, achievable technical potential. These differences primarily include:

- Updating residential baseline data from PSE's 2010 Residential Characteristic Survey (RCS);
- Utilization of PSE's most recent energy and sales forecasts;
- Incorporation of assumptions, data, and new measures from the RTF;
- Adjustments to remaining potential, based on PSE's actual 2010–2011 and projected 2012–2013 energy-efficiency program accomplishments;
- Updating data on measure costs, savings, lifetime, and applicability; and
- Incorporation of new codes and standards.
- Use of Simple Energy and Enthalpy Model (SEEM) building simulations.

By sector, Table 4compares electric and natural gas technical potentials from the two studies. At an aggregate level, the study indicates electric technical potential approximately 31% (318 aMW) lower than that of the 2011 IRP (714 aMW in the 2013 IRP vs. 1,032 aMW in the 2011 IRP).

Table 4. Comparison of Energy-Efficiency Technical Potential, 2011 IRP to 2013 IRP

	Electric (aMW)		Natural Gas (million therms)	
Sector	2011 IRP	2013 IRP	2011 IRP	2013 IRP
Residential	608	356	305	226
Commercial	401	331	118	120
Industrial	24	28	7	4
Total	1,032	714	430	350

Four factors largely drive this decrease, listed in order of their magnitude:

- Higher saturations of efficient plug loads in the residential and commercial sectors, informed by recent ENERGY STAR shipment data.[2] Table compares ENERGY STAR equipment penetrations from the 2011 and 2013 IRPs.

Table 5. Comparison of ENERGY STAR Plug Load Equipment Penetrations

	ENERGY STAR Penetration	
End Use	2011 IRP	2013 IRP
Computer	10%	60%
Dehumidifier	75%	77%
DVD	44%	63%
Home Audio System	39%	34%
Monitor	12%	70%
Set Top Box	5%	51%
TV	12%	74%

  Higher ENERGY STAR equipment penetrations contribute to a 102 aMW decrease in 20-year technical potential in the residential sector and 17 aMW decrease in the commercial sector. Overall, this accounts for roughly 37% of the total difference.[3]

- PSE Energy Efficiency program activity, most notably with efficient lighting; Residential lighting 20-year savings is 88 aMW lower in the 2013 IRP, compared to the 2011 IRP.

  This accounts for 28% of the total difference in 20-year technical potential between the two studies.

- Additional codes and standards, and a more robust analysis of codes and standards considered in the 2011 IRP; This had the largest impact in the commercial sector, where standards were not treated as rigorously in the 2011 IRP. This change accounts for 21% of the decrease.

- Measure updates from various sources, including the RTF. This accounts for the remaining 14% of the 318 aMW decrease.

As with the electric energy-efficiency resource, the study indicates lower natural gas technical potential (350 MM therms vs. 430 MM therms). As illustrated in Table 4, most the difference is in the residential sector. This is primarily due to lower savings for a handful of residential measures where Cadmus updated savings using building simulations.

For the residential sector, the Council and RTF use the Simple Energy and Enthalpy Model (SEEM), a building simulation model.[4] Cadmus used SEEM v0.94 to develop estimates of both gas and electric HVAC baseline and measure consumptions (e.g., central air conditioning, heat

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[2] United States Environmental Protection Agency. "ENERGY STAR Unit Shipment and Sales Data Archives." http://www.energystar.gov/index.cfm?c=partners.unit_shipment_data_archives

[3] Updated ENERGY STAR saturations contributed to 16 aMW decrease in commercial plug load.

[4] http://www.nwcouncil.org/energy/rtf/measures/support/SEEM/Default.asp

pumps, furnaces and insulation) in single-family, multifamily, and manufactured homes.[5] Model inputs were adjusted for PSE's territory, thereby customizing parameters such as building square feet and climate zones to match customer-specific data. Thus, the methodology to estimate savings was the same as used by the Council and RTF, but the actual savings differ due to unique characteristics of houses within PSE's service territory compared to Northwest regional averages.[6]

Table 5 lists five top residential gas saving measures from the 2011 assessment and provides a comparison of savings between the two assessments. These five measures account for roughly 84% of the decrease in gas technical potential.

Table 5. Measures with Reduced Savings in 2013 Assessment.

Measure Name	2011 IRP (million therms)	2013 IRP (million therms)	Change in 2013 Assessment
Thermal Shell - Infiltration @0.2 ACH w/HRV	25	3	Building simulations indicate lower savings
Ceiling Insulation	22	7	Building simulations indicate lower savings
Thermostat - Multi-Zone	19	5	Reduced applicability of measure. Measure removed from multifamily in 2013 study.
Wall Insulation 2x4	17	10	Building simulations indicate lower savings
Duct Sealing - Aerosol-Based	15	5	Building simulations indicate lower savings
Total	97	30	

In general, the 2011 IRP estimated higher gas consumption for new construction than for 2013 study. This difference can explain most of the variation in the discrepancies. The 2011 gas consumption values were originally developed for the 2008 potential study, which were based on ENERGY-10 building simulations. The 2013 study used SEEM building simulations to estimate electric consumption then convert to gas consumption (accounting for efficiency differences). The SEEM models were developed for the 2013 study to provide a better consistency with the RTF analytic approach, which also used SEEM modeling. The lower gas baseline consumptions for 2013 result in lower savings potential. Other differences can be explained by the measure assumptions used in the analysis.

- Thermal Shell - Infiltration @0.2 ACH w/HRV: The 2011 study estimated savings are based on 6th Power Plan engineering calculations deemed values resulting in 19% savings. The 2013 study savings are derived directly from SEEM modeling inputs and resulted in 9%.
- Ceiling Insulation: The 2011 study estimated savings are based on 6th Power Plan engineering calculations deemed values. The 2013 study savings are derived directly from SEEM modeling inputs. For example, in 2011 R-0 to R-49 resulted in 56% savings while in 2013 the same measure resulted in 15% to 21% depending on end use.

[5] Cadmus recognizes that the Council and RTF only model electric energy-efficiency. For consistency across fuels, Cadmus used SEEM models for both electric and gas measures.

[6] The Northwest region includes Idaho, Oregon, Washington, and Western Montana.

- Wall Insulation 2x4: The applicability (technical limitations and available penetration) for this measure was updated for the 2013 study. The 2011 study determined 16% applicability. This was updated to 9% for 2013 to account for additional limitations such knob and tube wiring and access space as well as PSE's accomplishments for the past 2 years.
- Duct Sealing: The 2011 study savings are based on percent savings of 10% from ENERGY STAR assumptions. The 2013 study savings are derived directly from SEEM modeling inputs resulting in 5% savings. Additional applicability adjustments were made for the 2013 resulting in a reduction in potential.

Fuel Conversion

The fuel conversion analysis estimates available potential from converting electric equipment to natural gas for two main customer types: customers in PSE's natural gas service territory who do not currently have natural gas service; and those who do have natural gas service, but retain electric equipment (e.g., water heaters or appliances) that could be converted to natural gas. Table 6 shows the available technical and achievable technical potential in 2033 for each customer type.

Table 6. Summary of Fuel Conversion Potentials, Cumulative in 2033

	Technical Potential		Achievable Technical Potential	
Customer Type	Electric Savings (aMW)	Additional Gas Usage (million therms)	Electric Savings (aMW)	Additional Gas Usage (million therms)
Electric-Only	165	7	42	3
Existing Gas Customer	75	4	15	1
Total	240	11	57	4

Comparison to 2011 IRP

As with energy efficiency, this analysis largely updates the 2011 IRP. The analysis builds upon the same updated data cited above, including: baseline data, PSE's sales and customer forecasts, and measure assumptions. Table 7 compares estimated technical and achievable technical potential, as compared to the 2011 IRP. This study incorporates customers not included in the 2011 IRP, such as those in smaller homes (1,800 sq. ft.) and those a moderate distance from a gas main. In addition, this assessment addresses additional conversion measures, including conversion to an integrated space and water heater. Thus, this study indicates a notable increase in technical and achievable technical potential.

Table 7. Comparison of Fuel Conversion Potential, 2011 IRP to 2013 IRP

	Technical Potential (aMW)		Achievable Technical Potential (aMW)	
Customer Type	2011 IRP	2013 IRP	2011 IRP	2013 IRP
Electric-Only	25	165	11	45
Existing Gas Customer	34	75	12	16
Total	59	240	24	62

Demand Response

Table 8 presents estimated winter and summer resource potentials for all demand response resources for the residential, commercial, and industrial sectors. The total market potential available in the winter is 213 MW, equating to 4.7% of winter peak; the total market potential available in the summer is 166 MW, which accounts for 4.1% of summer peak.

Table 8. Demand Response Market Technical Potential, MW in 2033

Sector	Winter Market Potential (MW)	Summer Market Potential (MW)	Percent of System Peak – Winter*	Percent of System Peak – Summer*
Residential	130	77	2.9%	1.9%
Commercial	78	85	1.7%	2.1%
Industrial	4	5	0.1%	0.1%
Total	213	166	4.7%	4.1%

*System peak is based on PSE's average load in the top 20 hours and is calculated for each season.

Comparison to 2011 IRP

This study focuses on the same program strategies as the 2011 IRP, but relies on a new methodology for the direct load control (DLC) analysis.

In addition to updating the methodology, Cadmus updated the program assumptions, with the new assumptions based on PSE's experience with pilot programs over the last two years as well as on new industry information. By sector, Table 9 compares estimated market potential during peak periods.

Table 9. Comparison of Demand Response Achievable Technical Potential, 2011 IRP to 2013 IRP

	Winter MW		Summer MW	
Sector	2011 IRP	2013 IRP	2011 IRP	2013 IRP
Residential	110	130	32	77
Commercial	79	78	82	85
Industrial	4	4	5	5
Total	193	213	119	166

The two studies' results exhibit the largest differences in the residential sector, where potentials have increased considerably. This primarily results from an increase in overall potential achieved through the residential DLC programs (which have been based on the pilot program PSE implemented from 2009 through 2011). Data from this program was not available for the 2011 study.

Distributed Generation

Though this study does not estimate distributed generation potentials, it updates costs for individual distributed generation technologies and incorporates these in the 2013 IRP. For detailed potentials from the 2013 IRP analysis, see Cadmus' 2008 report.[7]

Comparison to the 6th Plan

This study employed methodologies consistent with the 6th Plan to estimate available energy-efficiency potential (see Appendix A for a detailed comparison of methodologies). Additionally, Cadmus conducted a thorough review of baseline and measure assumptions used by the Council, including costs, savings, applicability, and current saturations. Although this study relied on data specific to PSE's service territory whenever possible, where appropriate, it incorporated Council assumptions.

By applying PSE's share of regional sales, by sector, to the Council's regional potential, one can estimate the 6th Plan's share of potential in PSE's service territory. However, a number of factors must be considered in comparing that allocated potential to this study's results:

- The Council, by necessity, relied on average regional data; whereas this study utilized primary data from PSE's service territory. Therefore, allocating regional potential based on sales may not account for PSE's unique service territory characteristics (such as customer mix, use per customer, end-use saturations, fuel shares, and current measure saturations). Similarly, some industries included in the 6th Plan may not exist in PSE's service territory.
- PSE and the Council relied on unique baseline energy forecasts, each of which served as a major driver in the respective potential estimates.
- Both studies assessed potential over a 20-year period; however, the 6th Plan began in 2010, while this study's estimation of potential began in 2014.
- Due to the timing of the 6th Plan's release, not all upcoming codes and standards were removed from the potential (most notably, new standards relating to commercial lighting and residential water heating, as described in Section 1: General Approach and Methodology).
- The 6th Plan, completed in 2010, used data sources current at that time. In addition to using the PSE-specific data noted above, this study used more current data, particularly with regard to measure costs.

With these caveats in mind, Table 10 compares the 10-year achievable technical potentials this study estimates for 2014 to 2023, as compared to the 6th Plan. The 6th Plan's numbers derived

[7] http://www.pse.com/SiteCollectionDocuments/2009IRP/AppL1_IRP09.pdf

from applying PSE's share of regional sales, by sector, to the 6th Plan estimates[8] of regional potential.[9]

Table 10. Comparison of 2013 IRP and 6th Plan Achievable Technical Potential (aMW)

	10-Year Achievable Technical Potential (2014–2023)	
Sector	2013 IRP	6th Plan
Residential	185	302
Commercial	182	138
Industrial	22	18
Total	389	458

Details on sector-level differences follow below.

Residential Sector

As shown, the residential sector accounts for the largest differences in long-term achievable technical potential estimates. Though differences in end-use definitions make it difficult to compare the two studies at a detailed, end-use level, Table 11 shows distributions of 20-year potential by major end-use group for each study. Differences in assumptions by end use include the following:

Table 11. Comparison of 20-Year Residential Achievable Technical Potential by End Use

	10-Year Achievable Technical Potential	
End Use Group	2013 IRP	PSE Share of Regional Forecast
Appliances and Water Heating	75	124
Consumer Electronics and Other Plug Loads	8	73
HVAC	102	130
Lighting	25	11
Total	210	337

- ***Appliances and water heating*** are combined for this comparison as a large portion of appliance potential derives from water heating savings produced by clothes washers and dishwashers. A key difference in the modeling approaches arises from the incorporation of new residential water heating standards in the 2013 IRP, as described in this report's Section 1: General Approach and Methodology. This study assumes new equipment installed after 2014 would need to meet the new minimum efficiency requirements,

[8] Bus bar savings from the 6th Plan have been adjusted to savings at the customer meter using the Council's line loss factors.

[9] Report 6th Plan potentials by sector and end use have been based on summarization of measure-specific Council workbooks, available at: http://www.nwcouncil.org/energy/powerplan/6/supplycurves/default.htm

reducing the potential for high-efficiency water heating equipment. Additionally, substantial differences occur in the assumed percentage of water heaters using electricity (42% in PSE's service territory versus 64% for the region).

- ***Consumer electronics and other plug loads*** contain a variety of end uses, including televisions, computers, and other household electronics. Additionally, the 6th Plan includes commercial computers and monitors as part of the residential potential, while Cadmus' study only includes units in residences. Cadmus includes commercial computer and monitor savings in commercial sector potential.***HVAC*** encompasses heating, cooling, and ventilation savings, which have been combined due to differences in model structures. These differences largely arose from: assumed saturations of central cooling (11% in PSE's service territory versus 53% for the region); and the share of electric heating (17% for PSE's service territory versus 35% for the region).
- ***Lighting*** savings in the 2013 IRP assume the availability of a technology meeting the minimum requirements of the Energy Independence and Security Act of 2007 (EISA), and that savings from CFL installations will remain available. After accounting for PSE's program activity, Cadmus estimated that 33% of sockets have CFLs, compared to the regional average of 10% assumed in the 6th Plan.

Commercial Sector

Although this study estimates higher two-, 10-, and 20-year achievable technical potential in the commercial sector than the 6th Plan, this difference largely arises as a function of differing ramp rates. Higher potential in this study's early years result from the 10-year acceleration of all discretionary potential.

Industrial Sector

As the two assessments rely on the same measure assumptions, differences in potential are driven by the mix of industries in PSE's service territory. For example, in the Northwest region on the whole, pulp and paper industries account for the largest portion of baseline sales and achievable technical potential (roughly 30% and 40%, respectively). However, in PSE's service territory, these facilities account for less than 1% of baseline consumption. Additionally, PSE forecasts industrial sales lower than its allocated share of the regional forecast.

Incorporation of DSR into PSE's IRP

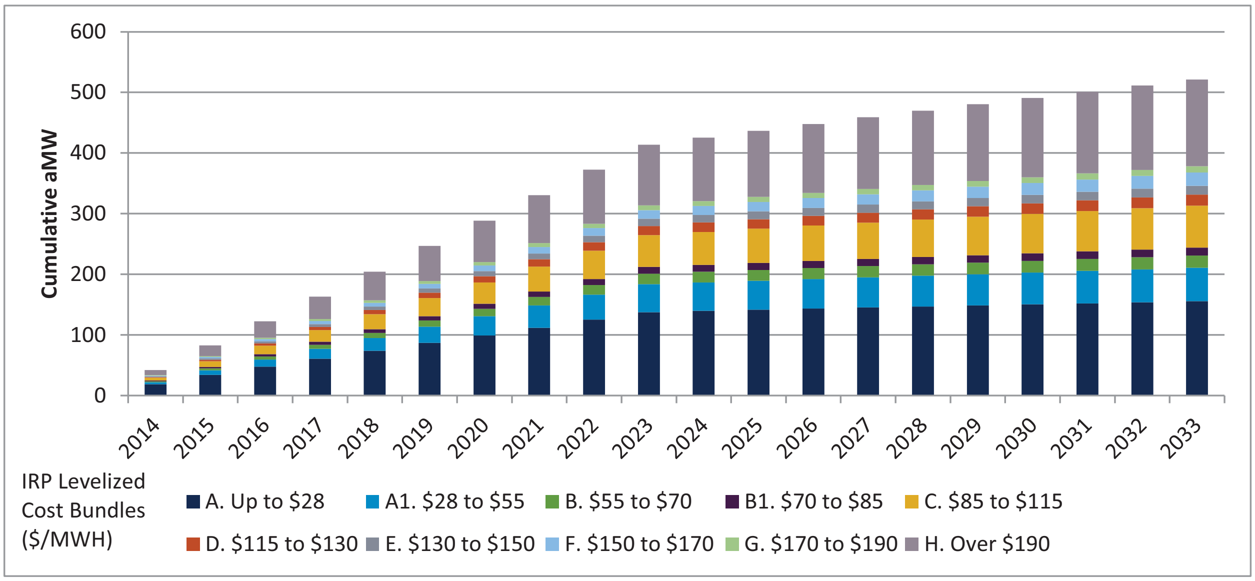
The achievable technical potentials shown above have been grouped by the levelized cost of conserved energy for inclusion in PSE's IRP model. These levelized costs have been calculated over a 20-year program life; Section 1: General Approach and Methodology, provides additional detail on the levelized cost methodology. Bundling resources into a number of distinct cost groups allows the model to select the optimal amount of annual DSR, based on expected load growth, energy prices, and other factors.

Cadmus spread the annual savings estimates over 8,760 hour load shapes to produce hourly DSR bundles. In addition, Cadmus assumed savings are gradually acquired over the year, as opposed to instantly on January 1st. PSE provided to Cadmus intra-year DSR acquisition schedules, which

Cadmus used to "ramp" hourly savings across months. See "About Hourly DSR Estimates" in "Chapter 1:General Approach and Methodology" for additional detail.

Figure 1 shows the annual cumulative combined potential for energy efficiency, fuel conversion, and distributed generation by each cost bundle considered in PSE's 2013 IRP. Figure 2 shows electric achievable potential by resource type.
Figure 3 shows annual DSR bundles for natural gas energy efficiency.

Figure 1. Annual Electric DSR Bundles by Cost Group[a]



[a]Includes energy efficiency, fuel conversion, and distributed generation

Figure 2. Electric Achievable Potential by Resource Type

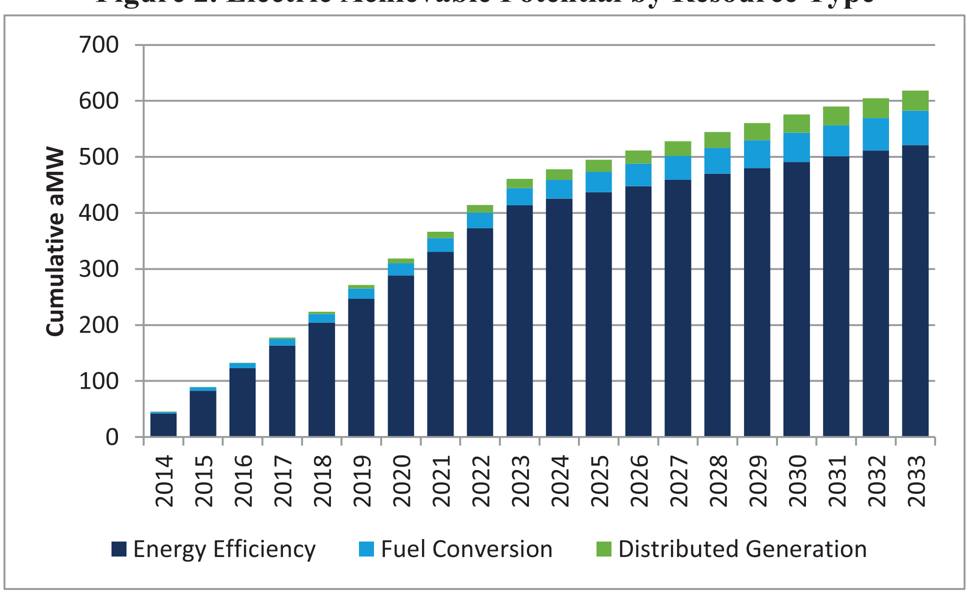
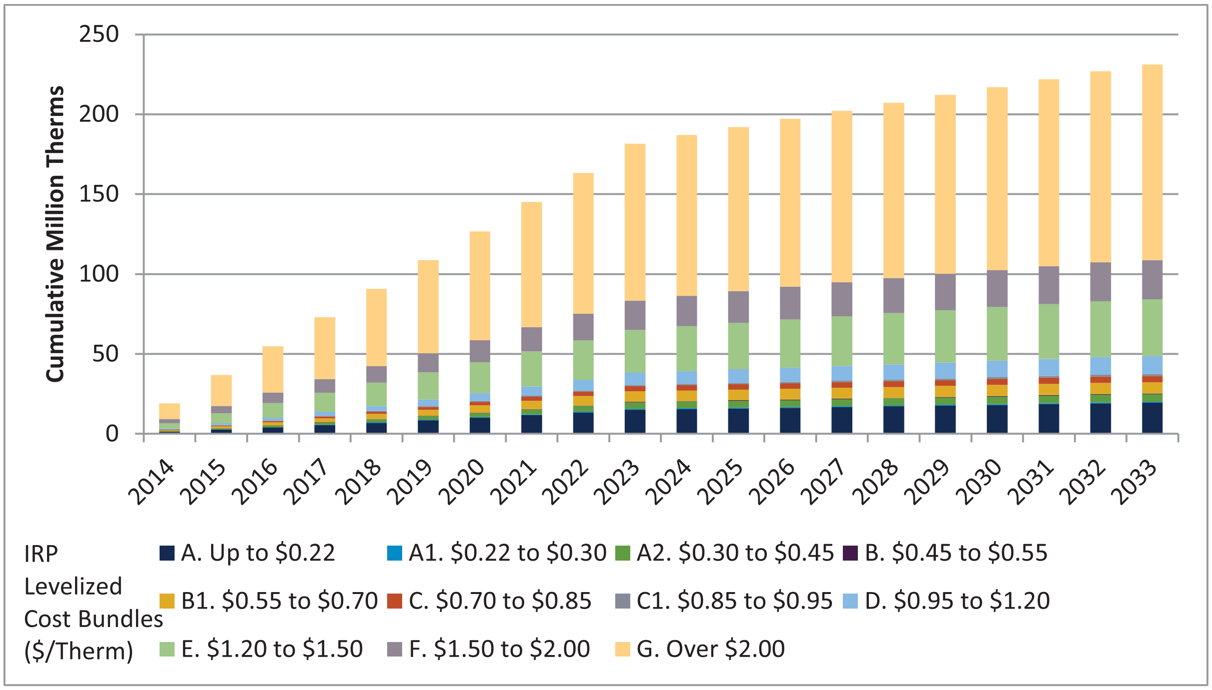


Figure 3. Annual Natural Gas DSR Bundles by Cost Group



In addition to the energy efficiency, fuel conversion, and distributed generation bundles shown above, PSE includes three other resource bundles in its IRP:

1. The expected effects of codes and standards (including EISA and DOE standards). PSE includes "standards" bundles in both gas and electric IRP models.
2. Capacity-only impacts of demand response.
3. Savings associated with distribution efficiency improvements (which fall outside the scope of this study).

Organization of the Report

The body of this report has been organized in four sections. The first outlines the general methodology for assessing potential used for each resource type, while the remaining three sections present the key assumptions and results for each resource. The document's appendices present: additional technical information; and descriptions of data used and their sources.

1. GENERAL APPROACH AND METHODOLOGY

This report describes the technologies, data inputs, data sources, data collection processes, and assumptions used in calculating technical and achievable technical long-term potentials.

General Approach

The demand-side resources (DSR) analyzed in this study differ with respect to technology, availability, types of load impact, and target consumer markets. Analysis of their potentials, therefore, requires using customized methods to address the unique characteristics of each resource. These methods, however, spring from the same conceptual framework, and seek to achieve estimates of two distinct types of potential: technical and achievable technical:

- ***Technical potential*** assumes that all technically feasible resource opportunities may be captured, regardless of their costs or other market barriers. Notably, the concept of technical potentials proves less relevant to some resources, such as demand response, since, from a strictly technical point of view, nearly all end-use loads may be subject to interruption or displacement by on-site generation.
- ***Achievable technical potential*** is defined as: the portion of technical potential that might be assumed achievable in the course of the planning horizon, regardless of the acquisition mechanism. (For example, savings may be acquired through utility programs, improved codes and standards, or market transformation.)

In addition to the quantity of available potential, the timing of resource availability presents a key consideration. For this analysis, resources split into two distinct categories:

- ***Discretionary resources*** are retrofit opportunities in existing facilities that, theoretically, remain available at any point over the course of the study period.
- ***Lost opportunity resources*** are those with pre-determined availability, such as replacements after equipment failure and opportunities in new construction.

About Levelized Costs

Identified potential is grouped by levelized cost over the 20-year study horizon, allowing Puget Sound Energy's (PSE) integrated resource planning (IRP) model to pick the optimal DSR amount, given various assumptions regarding future resource requirements and costs. The 20-year levelized cost calculation incorporates numerous factors, which are consistent with the Council's methodology and shown in Table 12.

Table 12. Levelized Cost Components

Type	Component
Costs	Incremental Measure Cost
	Incremental O&M Cost[a]
	Administrative Adder
Benefits	PV of Non-energy Benefits
	Present Value of T&D deferrals
	Conservation Credit
	Secondary Energy Benefits

[a]Some measures may have a reduction in O&M costs, which is effectively treated as a benefit in the levelized cost calculation

In addition to the upfront capital cost and annual energy savings, the levelized cost calculation incorporates several other factors, consistent with the Council's methodology:

- ***Incremental Measure Cost.*** This study considers the costs required to sustain savings over a 20-year horizon, including reinstallation costs for measures with useful lives less than 20 years. If a measure's useful life extends beyond the end of the 20-year study, Cadmus incorporates an end effect that treats the levelized cost of that measure over its useful life (EUL)[10] as an annual reinstallation cost for the remainder of the 20-year period.[11]

  For example, Figure 4 shows the timing of initial and reinstallation costs for a measure with an eight-year lifetime in context with the 20-year study. The measure's final lifetime in this study ends after the study horizon, so the final four years (Year 17 through Year 20) are treated differently by levelizing measure costs over its eight-year useful life and treating these as annual reinstallation costs.

Figure 4. Illustration of Capital and Reinstallation Cost Treatment

	Year																			
Component	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Initial Capital Cost																				
Re-Installation Cost																	End Effect			

- ***Incremental operations and maintenance (O&M) costs or benefits.*** As with incremental measure costs, O&M costs are considered annually over the 20-year horizon. The present value is used to adjust the levelized cost upward for measures with costs above baseline technologies and downward for measures that decrease O&M costs.
- ***Administrative Adder.*** Cadmus assumed a program administrative cost equal to 20% of incremental measure costs for electric measures across all sectors. For gas measures, Cadmus assumed program administrative costs of 15% in the residential sector and 25% for the commercial and industrial sectors.

[10] This refers to levelizing over the measure's useful life, equivalent to spreading incremental measure costs over its EUL in equal payments assuming a discount rate of PSE's weighted average cost of capital.

[11] This method is applied both to measures with a useful life of greater than 20 years and those with a useful life that extends beyond the 20^{th} year at the time of reinstallation.

- ***Non-energy benefits*** are treated as a reduction in levelized costs for measures that save resources, such as water or detergent. For example, the value of reduced water consumption due to the installation of a low-flow showerhead reduces the levelized cost of that measure.
- ***The regional ten percent conservation credit, capacity benefits during PSE's system peak, and transmission and distribution (T&D) deferrals*** are similarly treated as reductions in levelized cost for electric measures. The addition of this credit per the Northwest Power Act[12] is consistent with Council methodology, and is effectively an adder to account for unquantified external benefits of conservation when compared to other resources.
- ***Secondary energy benefits*** are treated as a reduction in levelized costs for measures that save energy on secondary fuels. This treatment is necessitated by Cadmus' end-use approach to estimating technical potential. For example, consider the cost for of R-60 ceiling insulation for a home with a gas furnace and an electric cooling system. For the gas furnace end use, Cadmus considers energy savings that R-60 insulation produces for electric cooling systems, conditioned on presence of a gas furnace, as a secondary benefit that reduces the levelized cost of the measure. This adjustment impacts only the measure's levelized costs; the magnitude of energy savings for the R-60 measure on the gas supply curve is not impacted by considering secondary energy benefits.

Data Sources

The full assessment of resource potential required the compilation of a large set of measure-specific technical, economic, and market data, obtained from secondary sources and through primary research. The study's main data sources included:

- ***PSE Internal Data.*** These encompass historical and projected sales and customers, hourly load profiles, and historic and projected DSR accomplishments.

- ***Primary Data.*** This study relies on several data sources specific to PSE's service territory and customers, including: the 2010 Residential Characteristic Survey; 2008 Fuel Conversion Survey; 2007 Puget Sound-Area Regional CFL Saturation Study; and NEEA's 2009 Commercial Building Stock Assessment (CBSA).

- ***Secondary Pacific Northwest Sources.*** Several Northwest entities provided data critical to this study, including: the Council, the Regional Technical Forum (RTF), and the Northwest Energy Efficiency Alliance (NEEA). Information derived from these sources included: technical information on measure savings, costs, and lives; hourly end-use load shapes (to supplement building simulations described above); and commercial building and energy characteristics.

- ***Building Simulations:*** This study required building simulations (using the Simple Energy Enthalpy Model [SEEM]) for the residential sector, with separate models created for each customer segment, and construction vintage.

- ***Additional Secondary Sources.*** The study relied on a number of secondary sources to characterize measures, assess baseline conditions, and benchmark results against other

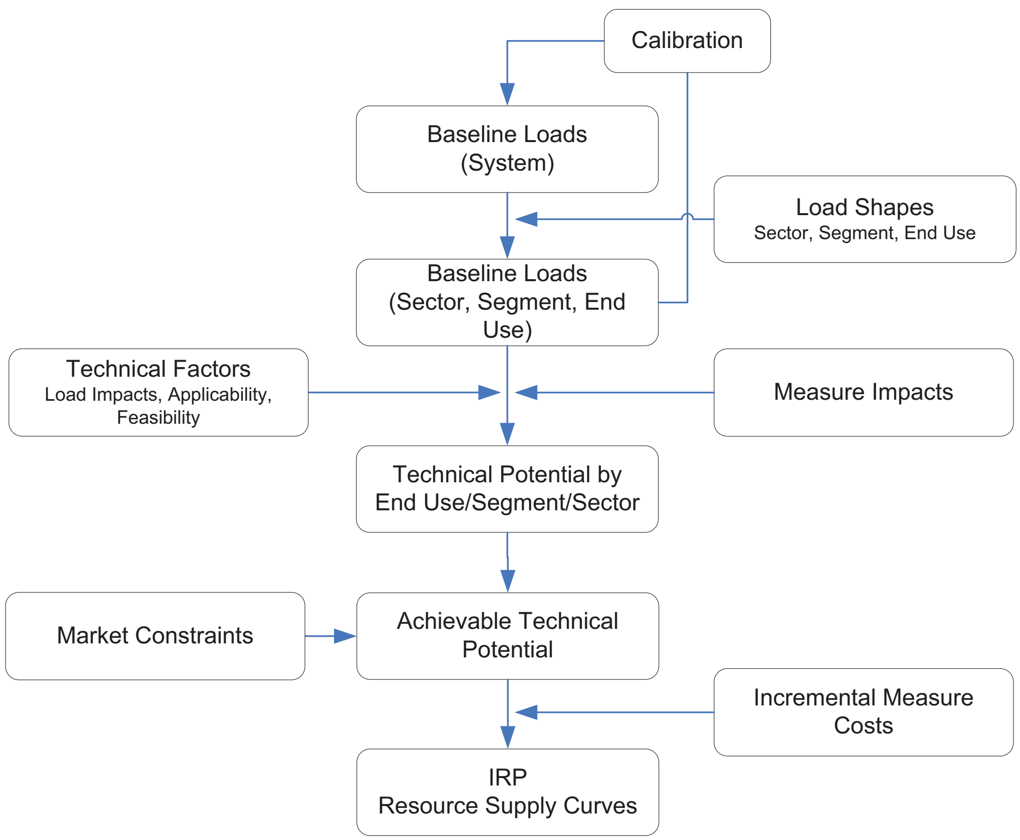
[12] See http://www.nwcouncil.org/library/poweract/default.htm

utilities' experiences. These sources included: the California Energy Commission's Database of Energy Efficiency Resources (DEER); ENERGY STAR; the Energy Information Administration; and various utilities' annual and evaluation reports on energy-efficiency and demand-response programs.

Energy Efficiency

The methodology used for estimating the technical and achievable technical energy-efficiency potential draws upon standard industry practices, and proves consistent with the Council's assessments of conservation potentials for the 6^{th} Northwest Regional Power Plan (6^{th} Plan). The general approach, shown in Figure 5, illustrates how baseline and efficiency data have been combined to develop estimates of potential for use in PSE's IRP process.

Figure 5. General Methodology for Assessment of Energy-Efficiency Potentials



The study considers three types of potential: naturally occurring, technical, and achievable technical.

Naturally occurring conservation refers to reductions in energy use that occur due to normal market forces, such as technological change, energy prices, market transformation efforts, and improved energy codes and standards. This analysis accounted for naturally occurring conservation in three ways:

- First, the assessment accounted for gradual efficiency increases due to the retirement of older equipment in existing buildings and the subsequent replacement with units that meet minimum standards at that time. For some end uses, the technical potential associated with certain energy-efficiency measures assumed a natural adoption rate. For example, savings associated with ENERGY STAR appliances accounted for current trends in customer adoption.

- Second, energy consumption characteristics of new construction reflected current state-specific building codes.
- Third, the assessment accounted for improvements to equipment efficiency standards that are pending and will take effect during the planning horizon. The assessment did not, however, forecast changes to standards that have not passed; rather, it treated these at a "frozen" efficiency level.

- These impacts resulted in a change in baseline sales, from which the technical and achievable technical potential could be estimated.

Technical potential includes all technically feasible energy-efficiency measures, regardless of costs or market barriers. Technical potential divides into two classes: discretionary (retrofit) and lost-opportunity (new construction and replacement of equipment on burnout).

This study's technical potential estimations for energy-efficiency resources drew upon best-practice research methods and standard analytic techniques in the utility industry. Such techniques remained consistent with conceptual approaches and methodologies used by other planning entities, such as those of the Council in developing regional energy-efficiency potential, and remained consistent with methods used in PSE's 2009 and 2011 Assessments.

Achievable technical potential represents the portion of technical potential that might reasonably be achievable in the course of the 20-year planning period, given the possibility that market barriers could impede customer adoption. At this point, it does not consider cost-effectiveness, as identified levels of achievable technical potential principally serve as planning guidelines and to inform the IRP process.

Developing sound utility IRPs requires knowledge of alternative resource options and reliable information on the long-run resource potential of achievable technologies. DSM resource potential studies principally seek to develop reasonably reliable estimates of the magnitude, costs, and timing of resources likely available over the planning horizon's course; they do not, however, provide guidance as to *how* or by *what means* identified resources might be acquired. For example, identified potential for electrical equipment or building shell measures might be attained through utility incentives, legislative action instituting more stringent efficiency codes and standards, or other means.

Overview

Estimating energy-efficiency potential draws on a sequential analysis of various energy-efficiency measures in terms of technical feasibility (technical potential) and expected market acceptance, considering normal barriers possibly impeding measure implementation (achievable technical potential). The assessment utilized three primary steps:

- ***Baseline forecasting:*** Determining 20-year future energy consumption by state, sector, market segment, and end use. The study calibrated the base year, 2013, to PSE's sector load forecasts. As described above, the baseline forecasts shown in this report include the Cadmus team's estimated impacts of naturally occurring potential.[13]

- ***Estimation of alternative forecasts of technical potential:*** Estimating technical potential, based on alternative forecasts, that reflect technical impacts of specific energy-efficiency measures.
- ***Estimation of achievable technical potential:*** Achievable technical potential calculated by applying ramp rates and an achievability percentage to the technical potential, as this section later describes in detail.

This approach offered two advantages:

- First, savings estimates would be driven by a baseline calibrated to PSE's base year (2013) sales. Although subsequent baseline years may differ from PSE's load forecast, comparisons to PSE's sales forecast helped control for possible errors. Other approaches may simply generate the total potential by summing estimated impacts of individual measures, which can result in total savings estimates representing unrealistically high or low baseline sales percentages.
- Second, the approach maintained consistency among all assumptions underlying the baseline and alternative (technical and achievable technical) forecasts. The alternative forecasts changed relevant inputs at the end-use level to reflect impacts of energy-efficiency measures. As estimated savings represented the difference between the baseline and alternative forecasts, they could be directly attributed to specific changes made to analysis inputs.

Developing Baseline Forecasts

As shown, the first step entails creating a baseline (no-DSR) forecast. In the residential and commercial sectors, the analysis relies on a bottom-up forecasting approach, beginning with annual consumption estimates by segment, end use, and equipment efficiency level. Average base-year use per customer can then be calculated from saturations of equipment, fuel, and efficient equipment. Comparisons to PSE's historical use per customer validates these estimates, and a forecast of future energy sales can then be created based on expected new construction and equipment turnover rates.

In the industrial sector, as standard practice, PSE's industrial forecast has been disaggregated to end uses, based on data available from the Energy Information Administrations' (EIA) Manufacturing Energy Consumption Survey.

To bundle potential by cost, Cadmus collected data on measure costs, savings, and market size at the most granular level possible. Within each fuel and sector, the study distinguished between customer segments or facility types and their respective applicable end uses. Cadmus then conducted the analyses for the following customer segments:

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[13] The Cadmus team's baseline forecast accounted for codes and standards not embedded in PSE's load forecast. Due to these adjustments, 2033 baseline sales presented in this report may not match PSE's official load forecast.

- Six residential segments (existing and new construction for single-family, multifamily, and manufactured homes);
- Twenty commercial segments (10 building types within the existing and new construction vintages);
- Seventeen industrial segments (17 facility types, treated only as an existing construction vintage).

Estimating Technical Potential

An important aspect of technical potential is that it assumes installation of the highest-efficiency equipment, wherever possible.

For example, this study examines solar water heaters, heat pump water heaters, and efficient storage water heaters in residential applications, with technical potential, assuming that, as equipment fails or new homes are built, customers will install solar water heaters wherever technically feasible, regardless of cost. Where applicable, heat pump water heaters are assumed installed in homes ineligible for solar water heaters. Efficient storage water heaters are assumed installed in home ineligible for neither solar water heaters nor heat pump water heaters. The study treats competing non-equipment measures in the same way, assuming installation of the highest-saving measures, where technically feasible.

In estimating technical potential, one cannot merely sum up savings from individual measure installations, as significant interactive effects can result from installation of complementary measures. For example, upgrading a heat pump in a home where insulation measures have already been installed can produce fewer savings than in an uninsulated home.

Analysis of technical potential accounts for two types of interactions:

- **Interactions between equipment and non-equipment measures:** As equipment burns out, technical potential assumes it will be replaced with higher-efficiency equipment, reducing average consumption across all customers. Reduced consumption causes non-equipment measures to save less than they would have, had equipment remained at a constant average efficiency. Similarly, savings realized by replacing equipment decrease upon installation of non-equipment measures.
- **Interactions between non-equipment measures:** Two non-equipment measures applying to the same end use may not affect each other's savings. For example, installing a low-flow showerhead does not affect savings realized from installing a faucet aerator. Insulating hot water pipes, however, would cause water heaters to operate more efficiently, thus reducing savings from either measure. This assessment accounts for this interaction by "stacking" interactive measures—iteratively reducing baseline consumption as measures are installed, thus lowering savings from subsequent measures.

While theoretically, all retrofit opportunities in existing construction (often called "discretionary" resources) could be acquired in the study's first year, this would skew the potential for equipment measures, and provide an inaccurate picture of measure-level potential.

Therefore, the study assumes realizations for these opportunities in equal annual amounts, over the 20-year planning horizon. By applying this assumption, natural equipment turnover rates, and other adjustments, described above, the study estimates annual incremental and cumulative potential by: state, sector, segment, construction vintage, end use, and measure.

To estimate technical potential, Cadmus developed a comprehensive list of measures for all sectors, segments, and end uses. For the residential and commercial sectors, the study began by reviewing of a broad range of energy-efficiency measures. These measures were then screened to only include measures fitting the following criteria:

1. Commonly available.
2. Based on a well-understood technology.
3. Applicable to PSE's buildings and end uses.

Industrial sector measures drew upon the Council's 6th Plan and other general process improvement categories.[14]

As shown in Table 13, the study encompasses: 290 *unique* electric energy-efficiency measures; and 116 unique gas energy-efficiency measures. When expanded across segments, end uses, and construction vintages, this results in over 6,000 measures. (Appendix B.2 provides a comprehensive list of measures included in the analysis, with inputs and outputs provided in Appendix B.3.)

Table 13. Energy-Efficiency Measure Counts by Fuel

Sector	Electric Measure Counts	Gas Measure Counts
Residential	96 unique 740 permutations across segments	53 unique 345 permutations across segments
Commercial	148 unique 2,838 permutations across segments	63 unique 1,173 permutations across segments
Industrial	46 unique 852 permutations across segments	7 unique process improvements, 111 permutations across segments

For every measure permutation contained in the study, the following key inputs—varying by segment and end use—were compiled:

- ***Measure savings***: Energy savings associated with a measure as a percentage of the total end-use consumption. Sources include: engineering calculations, energy simulation modeling, the RTF, the Council's 6th Plan, and secondary sources, such as ENERGY STAR and DEER.
- ***Measure costs***: Per-unit cost (full or incremental, depending on the application) associated with measure installations. Sources include: the Council's 6th Plan, the RTF, DEER, RS Means, and merchant Websites.

[14] Industrial improvements derive from a variety of practices and specific measures, defined in the U.S. Department of Energy's Industrial Assessment Centers Database: http://www.iac.rutgers.edu/database/.

- ***Measure life***: The measure's expected useful life (EUL). Sources include the Council's 6th Plan, the RTF, DEER, and demand-side management (DSM) program evaluations.
- ***Measure applicability.*** A general term encompassing a number of factors, such as the technical feasibility of installation, the measure's current saturation, measure interactions, competition, and projected market share. Where possible, applicability factors draw upon PSE survey data and account for PSE's energy-efficiency program accomplishments.

The study created an alternate sales forecasts, incorporating the effects of all technically feasible measures, with the difference between this forecast and the baseline forecast representing the technical potential. This method allowed for long-term estimates of technical potential by measure, while accounting for changes in baseline conditions inherent in the baseline forecast.

Incorporation of Upcoming Codes and Standards

Electric

While Cadmus' analysis does not attempt to predict how energy codes and standards may change, it captures enacted legislation, even if it does not take effect for several years. The most notable, recent efficiency regulation has been the Energy Independence and Security Act of 2007 (EISA), which set new standards for general service lighting, motors, and other end-use equipment. Capturing the effects of this legislation proved especially important, as residential lighting has played a large role in PSE's energy-efficiency programs over the past several years.

EISA requires general service lighting to become roughly 30% more efficient than current incandescent technology, with standards phased in by wattage from 2012 to 2014. In addition to the 2012 phase-in, EISA contains a backstop provision that requires still higher-efficacy technologies, beginning in 2020.

While the new residential lighting standards have the largest effect on potential, this study explicitly accounts for several other codes and standards. For the residential sector, these include: dryer, freezer, heat pumps, and water heating standards. For the commercial sector, these include: linear fluorescent, screw base incandescent bulbs, and water heating standards. **Error! Reference source not found.** provides a comprehensive list of standards Cadmus considered in this study:

Table 14. Enacted or Pending Standards Accounted For – Electric End Uses

Equipment Type	Baseline	Standard	Sector	Year Effective*
Appliances				
Clothes Washer	MEF = 1.66 Market Baseline	RTF Market Standard 2016 Clothes Washer - MEF 2.29 and WF 4.5**	Residential	2016
Clothes Washer	MEF = 1.66 Market Baseline	RTF Market Standard 2018 Clothes Washer - MEF 2.36 and WF 4.1**	Residential	2018

Equipment Type	Baseline	Standard	Sector	Year Effective*
Commercial Refrigeration Equipment - (Semivertical and Vertical Cases)	Commercial Refrigeration Equipment 2010 (Varies by equipment class)	Commercial Refrigeration Equipment 2012 (Varies by equipment class)	Commercial	2012
Cooking Oven	National Appliance Energy Conservation Act 1990	Range and Oven Standards 2012	Residential	2012
Dehumidifier	Federal Standard 2007 Dehumidifier	Federal Standard 2012 Dehumidifier	Residential	2013*
Dishwasher	RTF Market Baseline 2010 Dishwasher - 313 kWh/yr and 4.76 gal/cycle**	RTF Market Standard 2013 Dishwasher - 289 kWh/yr and 5.0 gal/cycle**	Commercial/Residential	2014*
Dryer	Federal Standard 1994 Dryer - EF 3.01	Federal Standard 2015 Dryer - CEF 3.73	Residential	2015
Freezer	Federal Standard 2001 Freezer	Federal Standard 2014 Freezer	Commercial/Residential	2015*
Refrigerator	Refrigerator - Federal Standard 2001	Refrigerator - Federal Standard 2014	Commercial/Residential	2015
Vending Machines	Existing Conditions (No federal standard prior to 2012)	Vending Machines - Federal Standard 2012	Commercial	2012
Motors				
Small Electric Motors	NEMA Standards Publication MG1-1987	Small Electric Motor Standard 2015	Commercial/Industrial	2015
Water Heaters				
Water Heater > 55 gallons	Federal Standard 2004 Storage Water Heater - EF 0.871	Federal Standard 2015 Heat Pump Water Heater - EF 1.973	Commercial/Residential	2015
Water Heater ≤ 55 gallons	Federal Standard 2004 Storage Water Heater - EF 0.917	Federal Standard 2015 Storage Water Heater - EF 0.948	Commercial/Residential	2015
HVAC				
Heat Pump - Air Source	Federal Standard 2006 Heat Pump - SEER 13 and HSPF 7.7 (Split System)	Federal Standard 2015 Heat Pump - SEER 14 and HSPF 8.2 (Split System)	Residential	2015
Lighting				
Lighting General Service	Fluorescent	Linear Tube	Commercial/Industrial	2012

Equipment Type	Baseline	Standard	Sector	Year Effective*
Fluorescent Lamp – EISA	Linear Tube Standards 1995	Fluorescent Lamp Standards 2012		
Lighting General Service Lamp - EISA	Existing Conditions (No federal standard prior to EISA 2007)	EISA of 2007 (Phased in over 3 years)	Commercial/Industrial/Residential	2012, 2013, 2014
Lighting General Service Lamp - EISA Backstop Provision	Existing Conditions (No federal standard prior to EISA 2007)	EISA Backstop Provision 2020	Commercial/Industrial/Residential	2020
Lighting Specialty Lamp - EISA Incandescent Reflector Lamps	IRL Standards 1995	EISA of 2007 Impacts 2.5 Inch Diameter Reflectors and Above 2012	Residential	2013

To ensure an accurate assessment of remaining potential, Cadmus created a new forecast, netting out the effect of future standards (shown in **Error! Reference source not found.** and **Error! Reference source not found.**). This forecast drew upon a strict interpretation of the legislation, assuming that affected end uses would be replaced with technologies meeting minimum federal standards.

Figure 6. Residential Forecasts Before and After Adjusting for Standards

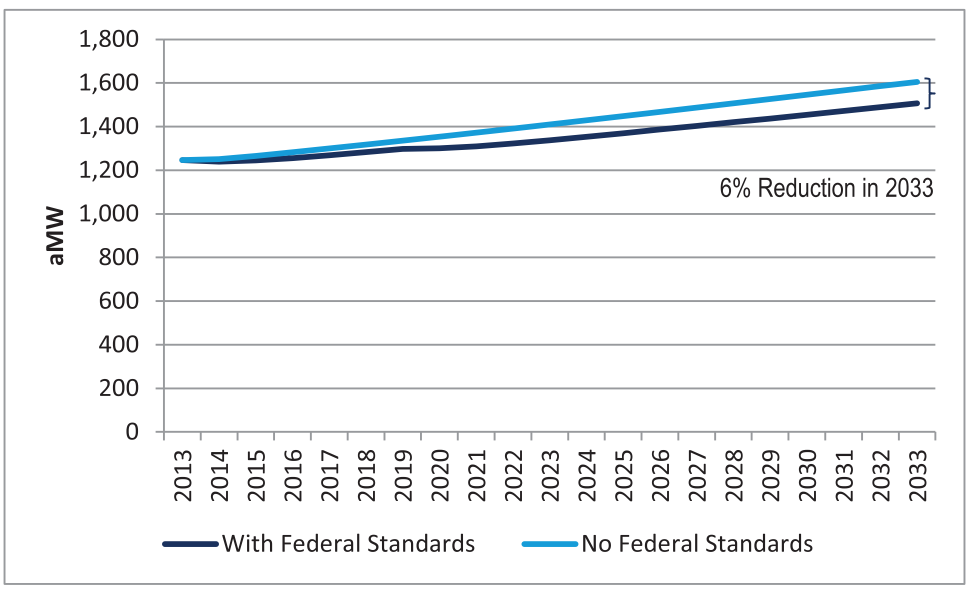
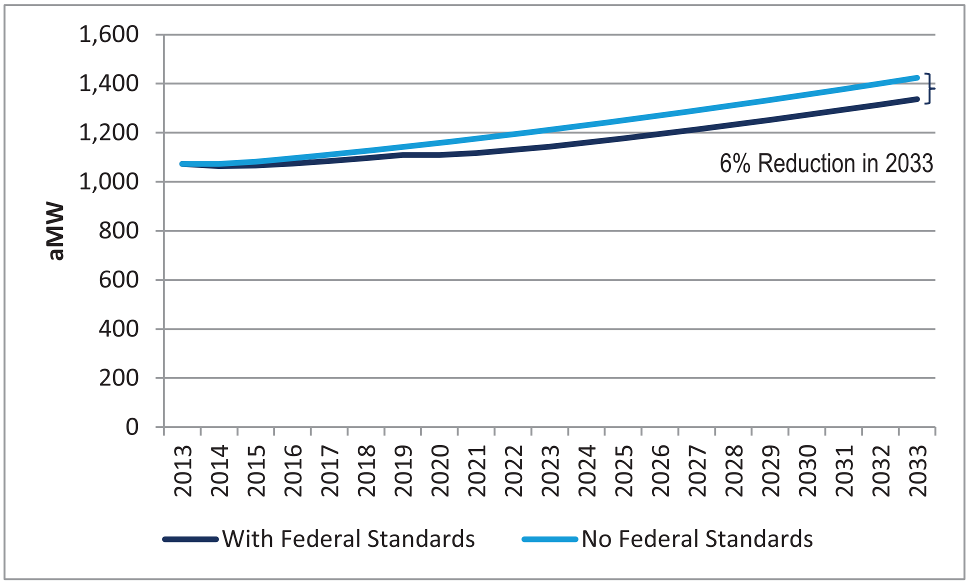


Figure 7. Commercial Forecasts Before and After Adjusting for Standards



After accounting for enacted and pending federal standards, both commercial and residential base case forecasts fell by 6% in 2033. Lighting standards primarily drove this lower consumption. The preceding figures indicate a fall in 2020 consumption due to the pending EISA backstop provision, which requires standard screw base bulbs to have a minimum efficacy of 45 lumens per watt. If savings due to standards were included in technical potential, it would account for 22% of savings in the residential sector and 21% of savings in the commercial sector. **Error! Reference source not found.** and **Error! Reference source not found.** break out the impacts of federal standards on forecasted sales in each year of the study, by end use.

Figure 8. Impacts of Standards by End Use—Residential Sector

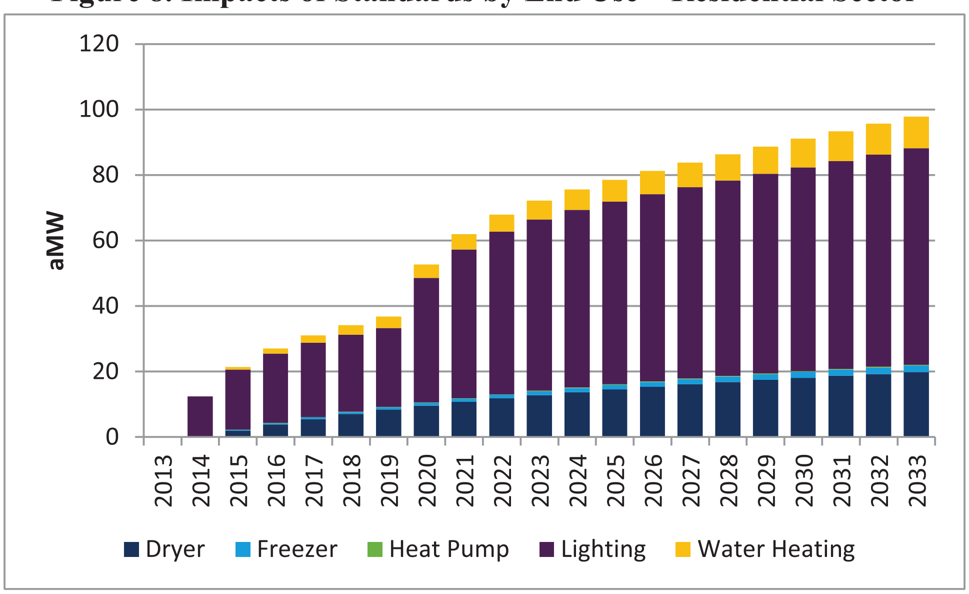
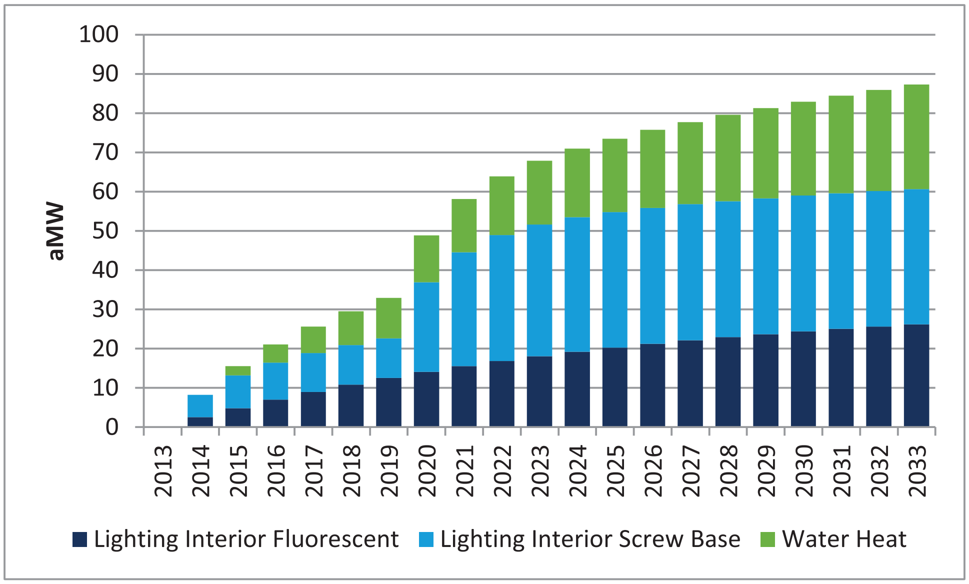


Figure 9. Impacts of Standards by End Use—Commercial Sector



Gas

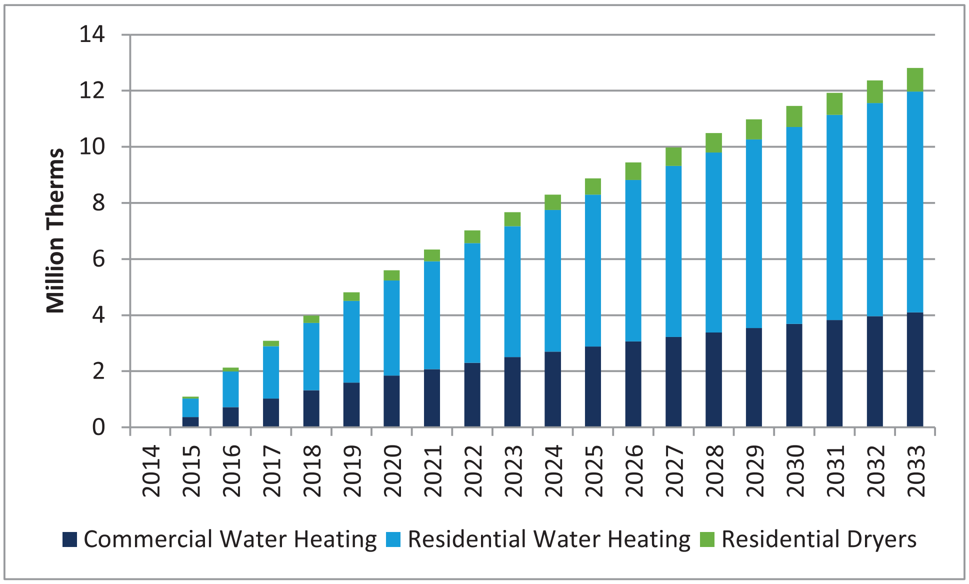
Cadmus also captured the impact of U.S. Department of Energy rulings on minimum efficiencies for water heaters and dryers. Overall, gas standards have a small impact on consumption. Standards reduce 2033 residential consumption by 8 million therms (1.2%) in the residential sector and 4 million therms (1.0%) in the commercial sector. If savings from standards were included in technical potential, it would account for 4% of residential savings and 3% of commercial savings in 2033.

Table 15. Enacted or Pending Standards Accounted For – Gas End Uses

Equipment Type	Baseline	Standard	Sector	Year Effective*
Water Heater > 55 gallons	Federal Standard 2001 Storage Water Heater - EF 0.528	Federal Standard 2015 Condensing Water Heater - EF 0.743	Commercial/Residential	2015
Water Heater ≤ 55 gallons	Federal Standard 2004 Storage Water Heater - EF 0.594	Federal Standard 2015 Storage Water Heater - EF 0.615	Commercial/Residential	2015
Dryer	Federal Standard 2011 Dryer – EF 2.67	Federal Standard 2015 Dryer – EF 3.30	Residential	2015

Error! Reference source not found. shows the impacts of federal gas equipment standards. By 2033, 93% of savings due to standards comes out of water heating (and 7% comes out of dryers).

Figure 10. Impacts of Federal Gas Equipment Standards



Similar to electric. Cadmus created a gas "standards" bundle for inclusion in PSE's IRP. This bundle is treated as a zero-cost "must take" bundle. Inclusion of these standards reduced technical potential, compared to the 2011 IRP—savings that were previously captured by measures in the 2011 IRP are captured by standards in the 2013 IRP.

Naturally Occurring Conservation

Cadmus' baseline forecast is inclusive of naturally occurring conservation, which refers to reductions in energy use occurring due to normal market forces, such as technological change, energy prices, market transformation efforts, and improved energy codes and standards. These impacts resulted in a change in baseline sales from which the technical and achievable technical potential were then estimated.

This analysis accounted for naturally occurring conservation in four ways:

- The potential associated with certain energy-efficiency measures assumes a natural adoption rate and is net of current saturation. For example, the total potential savings associated with ENERGY STAR appliances accounts for current trends in customer adoption. As such, the total technical potential from ENERGY STAR appliances is reduced from the 2011 IRP and these savings are reflected in the baseline energy forecast.
- The assessment has accounted for gradual efficiency increases due to retirement of older equipment in existing buildings, followed by replacement with units meeting or exceeding minimum standards at the time of replacement.
- The assessment has accounted for pending improvements to equipment efficiency standards that will take effect during the planning horizon as discussed above. The assessment does not, however, forecast changes to standards that have not been passed.

- New construction consumption characteristics reflect the Washington State Energy Code (WSEC) that went into effect in 2011. All energy efficiency measures in this study meet or exceed WSEC and where applicable, energy savings are calculated using a WSEC baseline. For example, current building code requires R-49 ceiling insulation, so energy savings for all ceiling insulation measures are calculated with R-49 as a baseline. Consequently, this study does not attribute savings to ceiling insulation levels below R-49 in new construction. It should be noted that building codes have the smallest impact of the four classes of naturally occurring conservation given their applicability to new construction only.

Achievable Technical Potential

Achievable technical potential can be defined as the portion of technical potential expected to be reasonably achievable over the course of a planning horizon. This estimate accounts for likely acquisition rates and market barriers to customer adoption, but does not address cost-effectiveness or acquisition mechanisms (e.g., utility programs, codes and standards, market transformation). Thus, the savings a utility can expect to acquire cost-effectively may be substantially lower than the achievable technical potential estimate.

This study, consistent with the Council's 6th Plan, assumes an 85% achievability factor for electric energy efficiency. For lost opportunity measures, this number (applied directly to the total technical potential for discretionary measures) ramps in at a rate determined by the technology and its useful life. Given this ramp-up, less than 85% of the lost opportunity potential will be acquired over the planning horizon, consistent with the Council's methodology.[15]

Due to higher upfront equipment costs for gas resources, Cadmus assumes 75% of the technical potential can be achieved over the planning horizon.

As previously discussed, lost opportunity measures experience inherent technical ramping, based on new construction and equipment turnover rates. In contrast, discretionary opportunities can be acquired at any point.

This study assumes all achievable electric and gas discretionary measures can be acquired within 10 years. (PSE considered this 10-year accelerated ramp-in for discretionary measures as a reasonable representation of the overall energy savings acquisition rate for resource planning analyses.) Actual market ramp rates will vary for specific measures.

Fuel Conversion

In the study's context, "fuel conversion" refers to electric savings opportunities involving substitution of natural gas for electricity through replacements of space heating systems, water heating equipment, and appliances. The study considers fuel conversion only for existing single-

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15 This remains consistent with the Council's assumption that 65% of lost opportunity resources can be acquired, as discussed in: *A Retrospective Look at the Northwest Power and Conservation Council's Conservation Planning Assumptions,* April 2007: http://www.nwcouncil.org/library/2007/2007-13.htm

family homes, new multifamily buildings, and existing and new commercial facilities: the segments considered most likely and able to convert.

Cadmus' analysis extends the energy-efficiency analysis described above, identifying applicable equipment and customers based on the following criteria:

- Customers must be within PSE's combined service territory (that is, areas where PSE provides both electricity and natural gas).
- Customers must be existing gas customers or on a gas main.
- For existing construction, customers must have a ducted system for space heating conversion.
- New natural gas equipment must meet energy-efficiency program criteria (e.g., 90% AFUE furnace, ENERGY STAR water heater).

Once eligible populations for each equipment type could be identified, measure costs and savings were compiled, consistent with the energy-efficiency analysis. Cadmus accounted for additional upfront costs required due to natural gas conversion (e.g., line extensions, piping). The cost of natural gas consumed over the life of a measure, based on forecasted avoided costs, was treated as an O&M cost, and was included in the calculation of the cost of conserved electricity.

As with energy efficiency, the technical potential assumes all eligible pieces of equipment can be converted to natural gas. Achievability draws upon results from PSE's 2008 fuel conversion survey, which asked customers about their likelihood of participating at various incentive levels. Based on this survey, this analysis assumes that 63% of technical potential can be achieved: the value associated with self-reported customer participation, if PSE covered the entire incremental cost of conversion. Available potential is assumed to be acquired in equal amounts annually over the 20-year planning horizon.

Demand Response

Scope of Analysis

Demand response programmatic options seek to achieve the following:

- Help reduce peak demand during system emergencies or periods of extreme market prices;
- Promote improved system reliability; and
- In some cases, balance variable-load resources (particularly wind energy).

Benefits from demand response resources accrue by providing incentives for customers to curtail loads during utility-specified events (e.g., direct load control [DLC]), or by offering pricing structures to induce participants to shift load away from peak periods (e.g., critical peak pricing programs).

Cadmus' analysis focused on program options that include residential DLC for space heat, room heat and water heat, critical peak pricing for residential and commercial customers, and nonresidential load curtailment. These strategies include price- and incentive-based options for all major customer segments and end uses within PSE's service territory, with the list informed by the 2011 IRP, PSE's demand response pilot program experience, and programs offered by other utilities.

General Approach

This study utilizes a hybrid, top-down, and bottom-up approach for estimating demand response potentials.

The approach began by using utility system loads, disaggregated into sector, segment, and applicable end-uses. For each program, Cadmus first assessed potential impacts at the end-use level. End-use load impacts then could be aggregated to obtain estimates of technical potentials. This allowed market factors, such as likely program and event participation levels, to be applied to technical potentials to obtain estimates of market potentials. General analytic steps involved in estimating market potential (with the exception of the residential DLC programs) follow below.

1. **Define customer sectors, market segments, and applicable end-uses**. In estimating the load basis, the study first defined customer sectors, customer segments, and applicable end uses, similar to those used in estimating energy-efficiency potentials. System loads were disaggregated into three sectors: residential, commercial and industrial. The study further broke each sector down by market segment (as shown in Table 16), and end use (such as cooking, cooling, heating, heat pumps, HVAC, lighting, plug load, refrigeration, space heat, and hot water heating).

Table 16. Customer Sectors and Segments

Residential	Commercial	Industrial
Single-Family	Dry Goods Retail	Chemical manufacturing
Manufactured	Grocery	Electronic equipment manufacturing
Multifamily	Hospital	Fabricated metal products
	Hotel/Motel	Food manufacturing
	Office	Industrial machinery
	Other	Miscellaneous manufacturing
	Restaurant	Nonmetallic mineral products
	School	Paper manufacturing
	University	Petroleum refining
	Warehouse	Plastics rubber products
		Primary metal manufacturing
		Printing related support
		Transportation equipment manufacturing
		Wastewater
		Water
		Wood product manufacturing

2. **Compile utility-specific sector/end-use loads.** Establishing reliable estimates of demand response potentials depended on correct characterizations of sector, segment, and end-use

loads. The study developed load profiles for each end-use, and determined contributions to system peak of each end use, based on end-use load shapes.

3. **Screen customer segments for eligibility.** This step involved screening customer segments for applicability of specific program strategies. For example, only customers with maximum monthly demand of at least 100 kW could be considered eligible for the nonresidential load curtailment program.

4. **Estimate technical potential**. Technical potential for each program was assumed to be a function of customer eligibility in each class, affected end uses in that class, and the expected strategy impact on targeted end uses. Analytically, technical potential (*TP*) for each demand-response program option *(p)* was calculated as the sum of impacts at the end-use level (*e*), generated in customer sector (*s*) by:

$$TP_p = \sum_{es} TP_{pes}$$

and

$$TP_{pes} = LE_{ps} \times LI_{pes}$$

where,

LE_{ps} (load eligibility) represented the portion of customer sector (*s*) loads (MW) applicable for program option (*p*), referenced as "Eligible Load" in the program assumptions.

LI_{pes} (load impact) was the percentage reduction in end-use load (*e*) for each sector (*s*) resulting from the program (*p*), referenced as "Technical Potential as % of Load Basis" in the program assumptions.

5. **Estimate market potential**. Market potential accounted for customers' ability and willingness to participate in capacity-focused programs, subject to their unique business or household priorities, operating requirements, and economic (price) considerations. Market potential estimates derived from adjusting the technical potential by two factors: expected program participation rates (the percentage of customers likely to enroll in the program); and expected event participation rates (the percentage of customers that will participate in a demand response event—applicable to programs such as the residential DLC program). Market potential for the program option (MP_p) was calculated as the product of technical potential for the customer sector (*s*), program participation (sign-up) rates (PP_{ps}), and expected event participation (EP_{ps}) rates:

$$MP_p = TP_{ps} \times PP_{ps} \times EP_{ps}$$

For each program, projected sign-up rates for all customer segments were informed by secondary research, described in the program assumptions, as well as on PSE's past program experience.

6. **Estimate costs and develop supply curves.** The levelized cost ($/kW-year) of each program option was calculated using estimates of program development, technology, incentive, ongoing maintenance, administration, and communications costs.

Administrative costs for all programs were based on the assumption that a fully loaded FTE costs $50/hour.

About Residential DLC

Residential DLC proves unique in that, unlike other demand response options, it affects specific end uses and equipment (e.g., room heaters and water heaters). Therefore, market potential may be quantified more directly as the product of four variables:

- The number of eligible customers.
- Expected per unit (kW) impacts.
- Equipment saturation rate.
- Expected program participation.

Derivation of Per-Unit Impacts

PSE implemented a DLC pilot program from October 2009 through September 2011. This pilot program targeted residential customers with electric space or room heat and/or electric water heat. DLC switches were installed on the customers' heating systems and/or water heaters; so these end uses could be cycled on and off during peak events. Cadmus relied on the kW impact per-switch, as reported in PSE's 2011 EM&V Report, to calculate the market potential for a full-scale program. As the EM&V report calculated impacts for morning, afternoon, and evening events, Cadmus weighted these results based on the composition of the top 20 system hours during which events would be called in a full-scale program. The general program assumptions in Chapter 4 provide per-switch impacts.

Equipment Saturation Rates

Equipment saturation represents the percentage of customers eligible for participating in the program (i.e., to participate in the DLC program, a customer must have an electric furnace or electric room heat). Equipment saturation levels for each residential customer segment were derived from PSE data and were consistent with saturations used to estimate energy-efficiency potential.

Expected Participation

Due to the rarity of electric heating DLC programs, and the minimal data existing on participation rates for such programs, Cadmus relied on the average participation rate for national DLC cooling programs and on PSE's experience.

Distributed Generation

Although this study did not estimate distributed generation potentials, Cadmus updated the costs of the distributed generation resources, with results presented in a Section 5 summary table. For detailed information regarding distributed generation potentials, see Cadmus' 2008 report.[16]

[16] http://www.pse.com/SiteCollectionDocuments/2009IRP/AppL1_IRP09.pdf

Incorporation of Demand Side Resources into PSE's IRP

In addition to the energy efficiency, fuel conversion, and distributed generation bundles, PSE included three other resource bundles in its IRP:

1. The expected effects codes and standards (including EISA)
2. Capacity-only impacts of demand response, and
3. Savings associated with distribution efficiency improvements (outside the scope of this study).

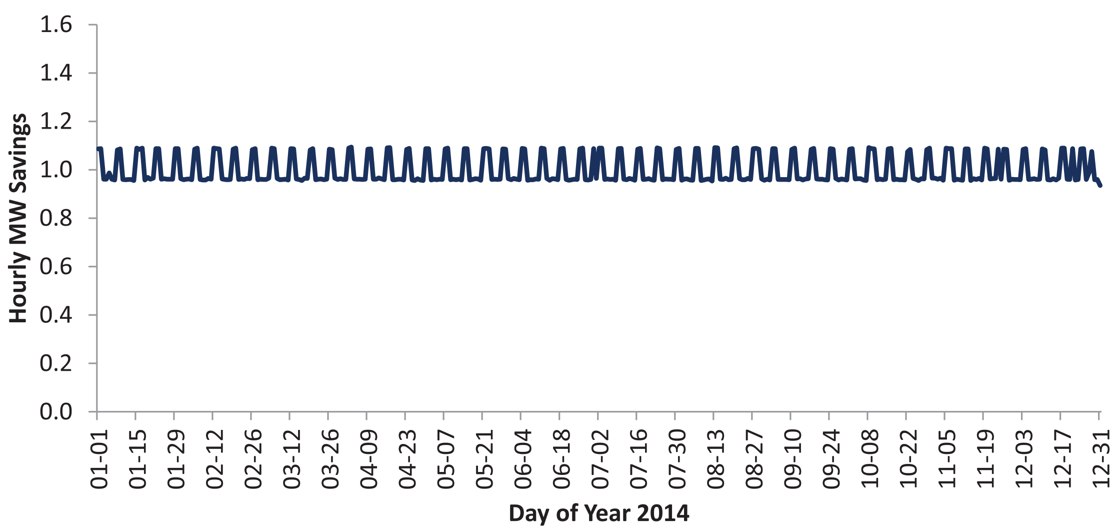
This section discusses how Cadmus developed hourly inputs for PSE's IRP model from the annual estimates developed for each of the energy efficiency, fuel conversion, and distributed generation resources bundles.

About Hourly DSR Estimates

Annual energy savings are the appropriate viewpoint from the perspective of energy-efficiency programs and Washington Initiative 937 (I-937) compliance. However, from a resource planning perspective, the focus must shift from an annual to an hourly view of energy savings. Simply spreading the annual demand side resources over an hourly load shape is not sufficient for developing this hourly view; this section discusses Cadmus' methodology for allocating annual savings to an hourly level for the 2013 IRP.

Cadmus developed hourly DSR estimates for each resource bundle in a two-step process. First, the annual achievable technical potential for each measure was spread over an hourly loadshape. As an example, Figure 11 shows hourly savings for a residential lighting measure with 1 aMW of achievable potential in the year 2014. This represents hourly savings from the I-937 compliance perspective.

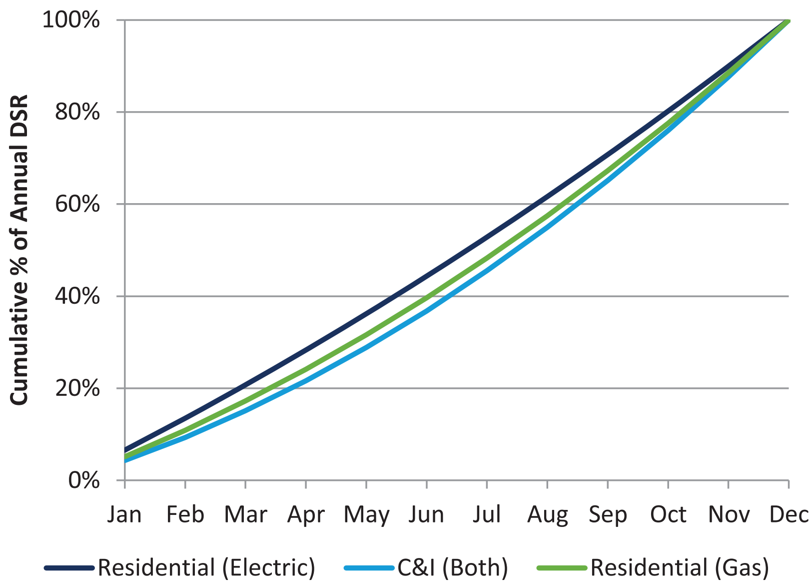
Figure 11. Example - Compliance Perspective Year 2014 Hourly Savings Spread



However, this perspective implicitly assumes that all of the 1 aMW of annual savings are obtained in 2014 on the first hour of January 1, 2014. Realistically, this implicit assumption is not attainable and overstates the actual amount of DSR available in a given hour. This overstatement is especially large early in the year.

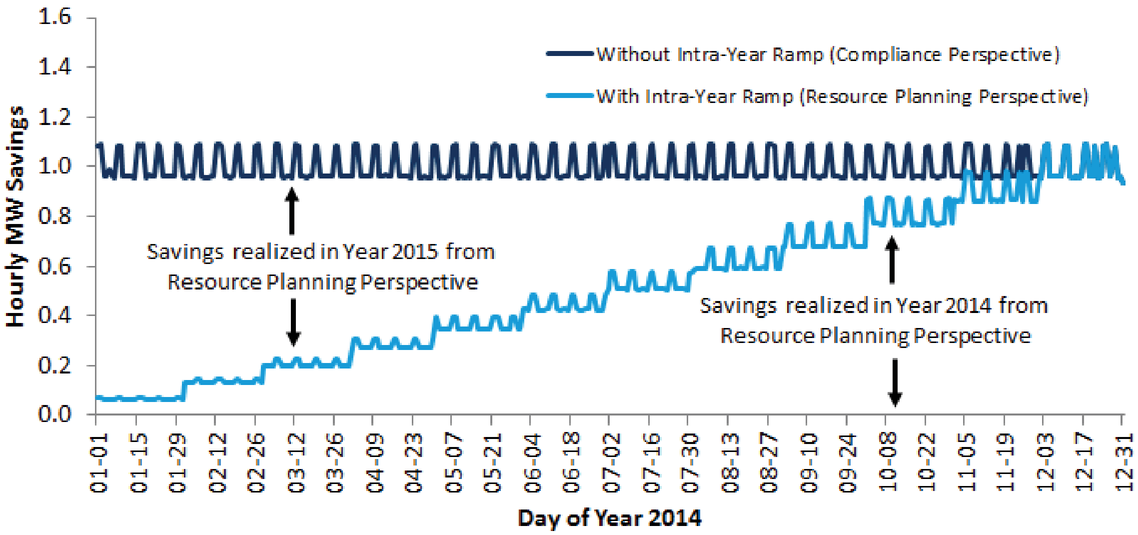
Consequently, PSE provided to Cadmus an intra-year schedule based on historic trends in DSR acquisition that was used to "ramp" the achievable technical potential throughout the year. The fraction of annual DSR available in a given month grows throughout the year until it reaches 100% in December, as shown in Figure 12.

Figure 12. Intra-Year Ramping by Sector and Fuel



In the second step of the process, Cadmus overlays the intra-year ramping on top of the hourly savings from the first step. A result of this overlay, the IRP model explicitly assumes that only a small fraction of the annual savings is available in the month of January. Using the same 1 aMW example above, the result of this overlay is shown in Figure 13.

Figure 13. Example – Resource Planning Perspective Year 2014 Hourly Savings Spread

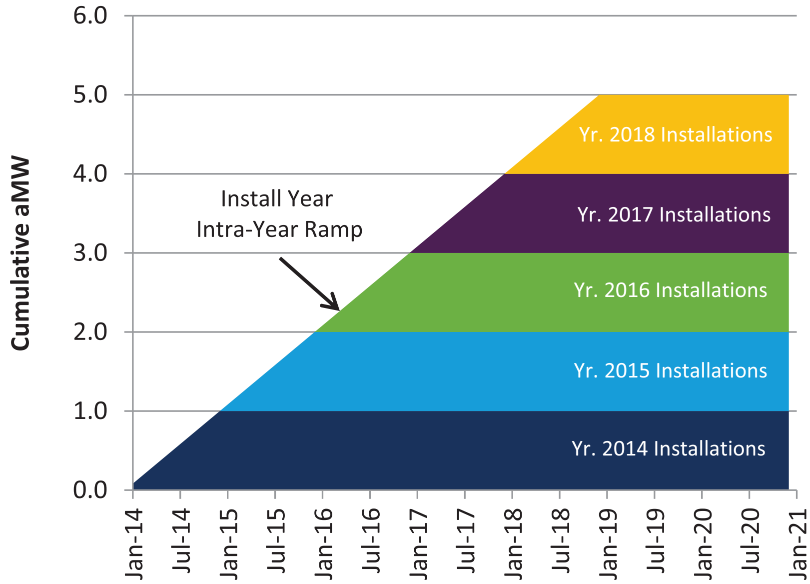


It should be noted that in the above example that the year 2014 energy savings after intra-year ramping has been applied is approximately one half of the savings without intra-year ramping because of the way in which those savings were acquired throughout the year. From a resource planning perspective, the "missing" half the savings from measures installed in calendar year 2014 are realized in year 2015. Not shown in Figure 13 are the savings from measures installed during calendar year 2013 that are realized in 2014; those savings are reflected in the load forecast.

The ramped savings shape shown in Figure 13 above is applicable only for the first year that a measure is installed. The IRP model assumes full savings beyond the first year of installation.

Figure 14 shows a stylized example of this concept, assuming that the same measure used in the examples above has 1 aMW of annual, incremental achievable technical potential in each of the years 2014 through 2018.

Figure 14. Example: Intra-Year Ramping Beyond Year of Installation



2. ENERGY-EFFICIENCY POTENTIALS

Scope of Analysis

This assessment primarily seeks to develop accurate estimates of available energy-efficiency potential, essential for PSE's IRP and program planning efforts. To support these efforts, Cadmus performed an in-depth assessment of technical potential and achievable technical potential for electric and gas resources in the residential, commercial, and industrial sectors. This potential then could be bundled in terms of costs of conserved energy, allowing the IRP model to determine the optimal amount of energy-efficiency potential for selection.

The remainder of this section divides into two parts: (1) a summary of resource potentials by fuel; and (2) detailed results by fuel and sector.

Summary of Resource Potentials—Electric

Table 17 shows 2033 forecasted baseline electric sales and potential by sector.[17] As shown, study results indicate 714 aMW of technically feasible electric energy-efficiency potential will be available by 2033, the end of the 20-year planning horizon. This translates to an achievable technical potential of 521 aMW. Should all this potential prove cost-effective and realizable, it will result in a 16% reduction in 2033 forecasted retail sales.

Table 17. Electric Energy-Efficiency Potential by Sector, Cumulative in 2033

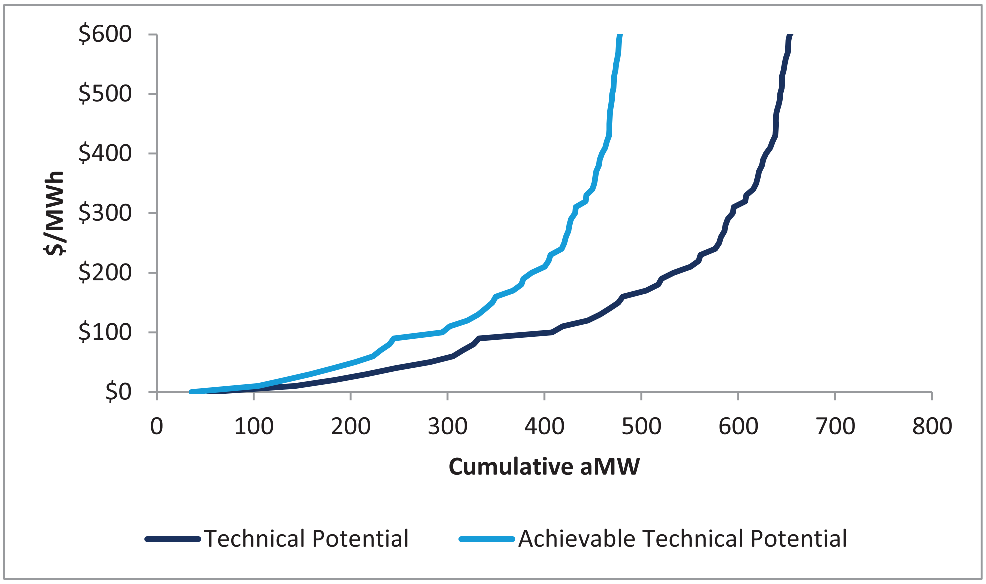
		Technical Potential		Achievable Technical Potential	
Sector	Baseline Sales	aMW	Percent of Baseline Sales	aMW	Percent of Baseline Sales
Residential	1,619	356	22%	240	15%
Commercial	1,546	331	21%	258	17%
Industrial	132	28	21%	23	18%
Total	3,297	714	22%	521	16%

Figure 15 illustrates the relationship between identified technical potential and achievable technical potential, and the corresponding cost of conserved electricity.[18] For example, approximately 320 aMW of achievable potential exists, at a cost of less than $120 per MWh.

17 These savings derive from forecasts of future consumption, absent any utility program activities. While consumption forecasts account for the past savings PSE has acquired, the estimated potential is inclusive of—not in addition to—current or forecasted program savings.

18 In calculating levelized costs of conserved energy, non-energy benefits are treated as a negative cost. This leads to some measures having a negative cost of conserved energy, although incremental upfront costs would occur.

Figure 15. Electric DSR Supply Curves—Cumulative in 2033[a]



[a]Note: The maximum cumulative technical potential shown in this figure is less than technical potential reported in Table 17 because resources above $600/MWh are not shown.

Figure 16 shows the cumulative potential annually available in each sector. The study assumes all discretionary resources will be acquired on a 10-year schedule between 2014 and 2023. The 10-year acceleration of discretionary resources will lead to the change in slope after 2023, at which point lost opportunity resources offer the only remaining potential.

Figure 16. Electric Energy-Efficiency Acquisition Schedule by Sector

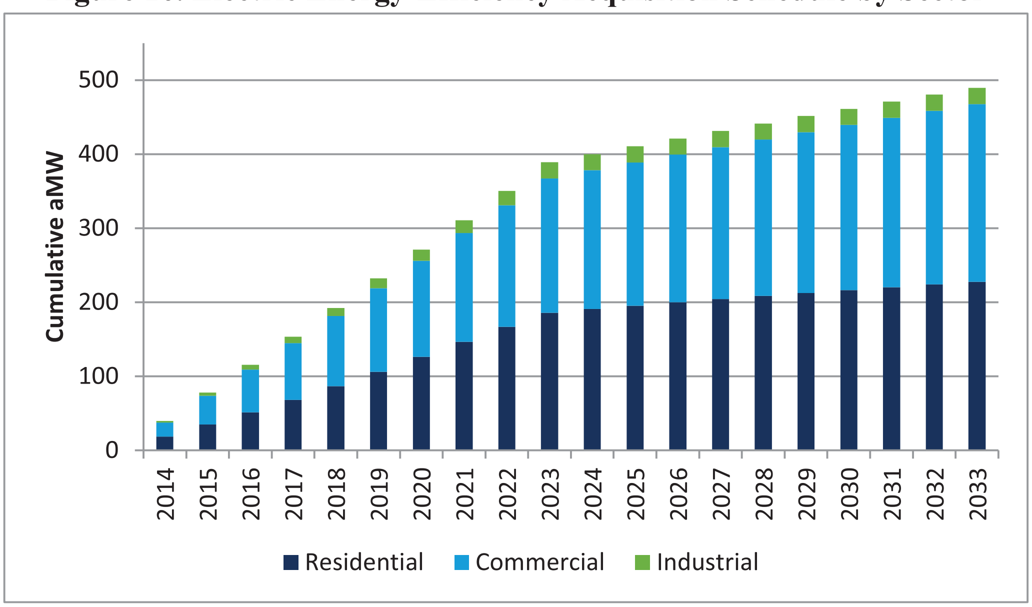
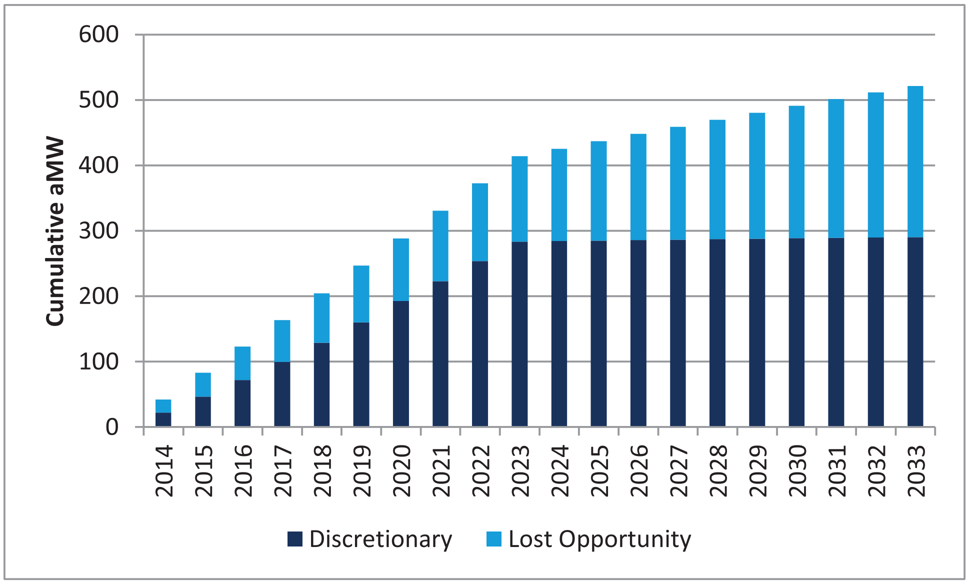


Figure 17 shows cumulative annual achievable electric savings by resource type (discretionary vs. lost opportunity). Overall discretionary measures account for 56% of cumulative savings in 2033, and lost opportunity measures account for the remaining 44%.

Figure 17. Electric Cumulative Annual Achievable Technical Potential by Resource Type



Summary of Resource Potentials—Natural Gas

Table 18 illustrates the 2033 forecasted baseline natural gas sales and potential by sector. As shown, study results indicate roughly 350 million therms of technically feasible energy-efficiency potential by 2033, the end of the 20-year planning horizon. This translates to an achievable technical potential of 231 million therms. Should all of this potential prove cost-effective and realizable, it will amount to a 21% reduction in 2033 forecasted retail sales.

Table 18. Natural Gas Energy-Efficiency Potential by Sector, Cumulative in 2033

		Technical Potential		Achievable Technical Potential	
Sector	Baseline Sales	Million Therms	Percent of Baseline Sales	Million Therms	Percent of Baseline Sales
Residential	674	226	34%	147	22%
Commercial	408	120	29%	81	20%
Industrial	26	4	16%	3	12%
Total	1,108	350	32%	231	21%

Figure 18 illustrates the relationships between identified technical potential and achievable technical potential, and the corresponding costs of conserved energy. For example, roughly 39 million therms of achievable potential will be available, at a cost of less than $1 per therm.

Figure 18. Natural Gas DSR Potential Supply Curves, Cumulative in 2033

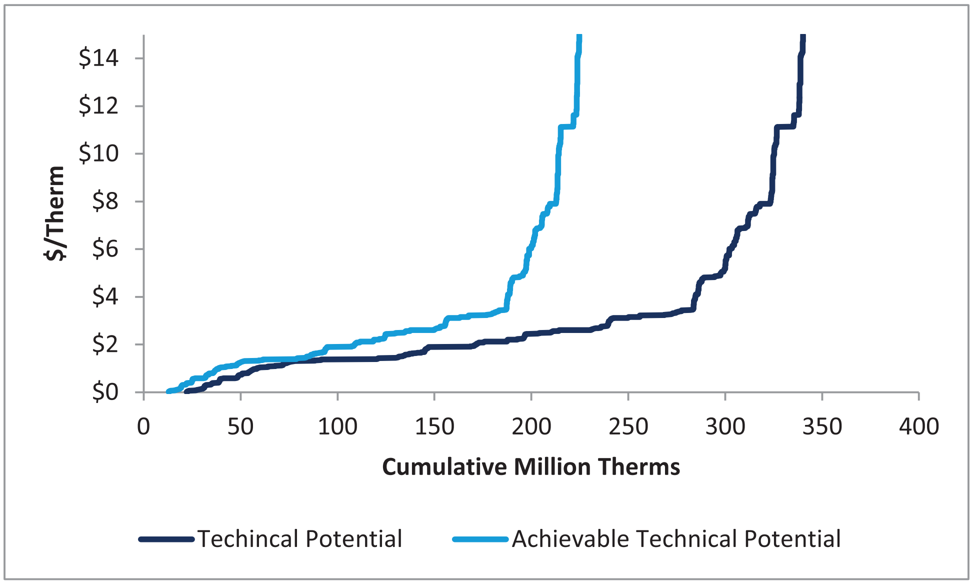


Figure 19 shows the cumulative potential annually available in each sector. As with electric potential, the study assumes all achievable discretionary opportunities will be acquired over 10 years.

Figure 19. Natural Gas Energy-Efficiency Acquisition Schedule by Sector

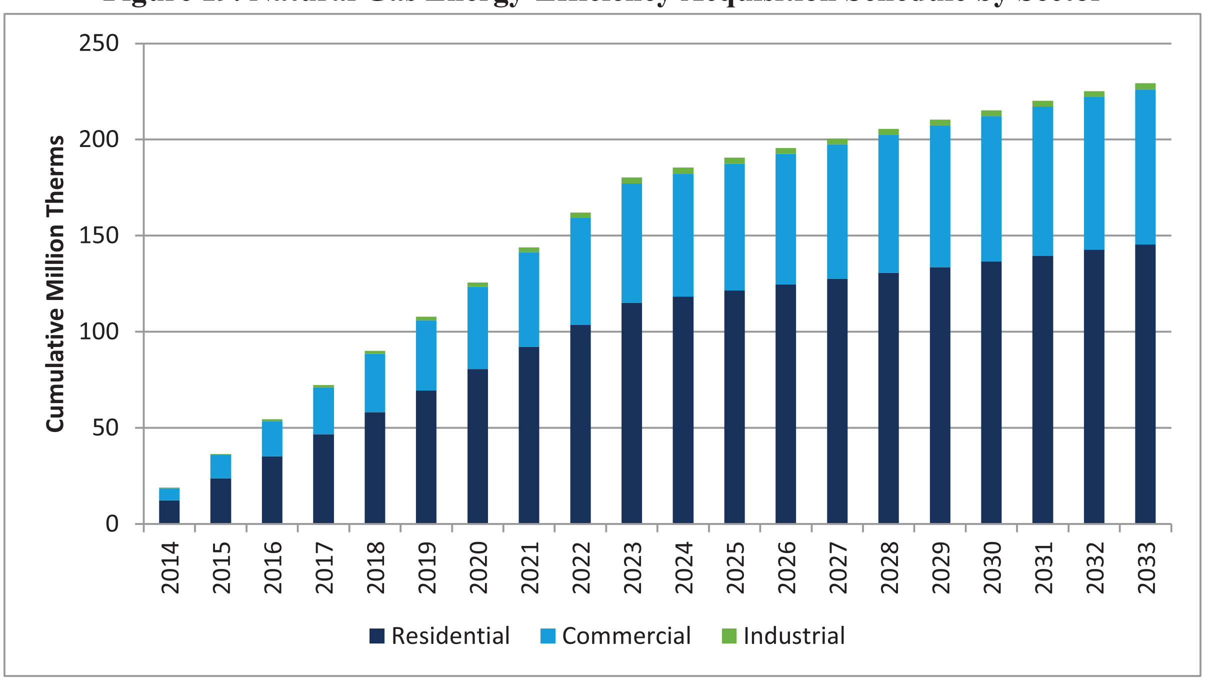
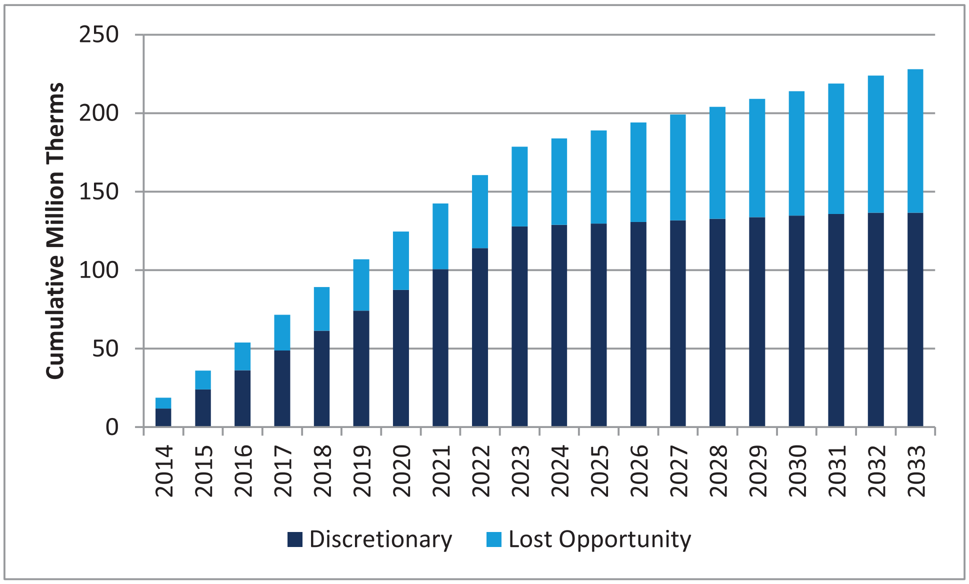


Figure 20 shows cumulative annual gas achievable technical potential by resource type (discretionary vs. lost opportunity). In 2033, discretionary measures account for

Figure 20. Gas Cumulative Annual Achievable Technical Potential by Resource Type



Detailed Resource Potentials

Residential Sector—Electric

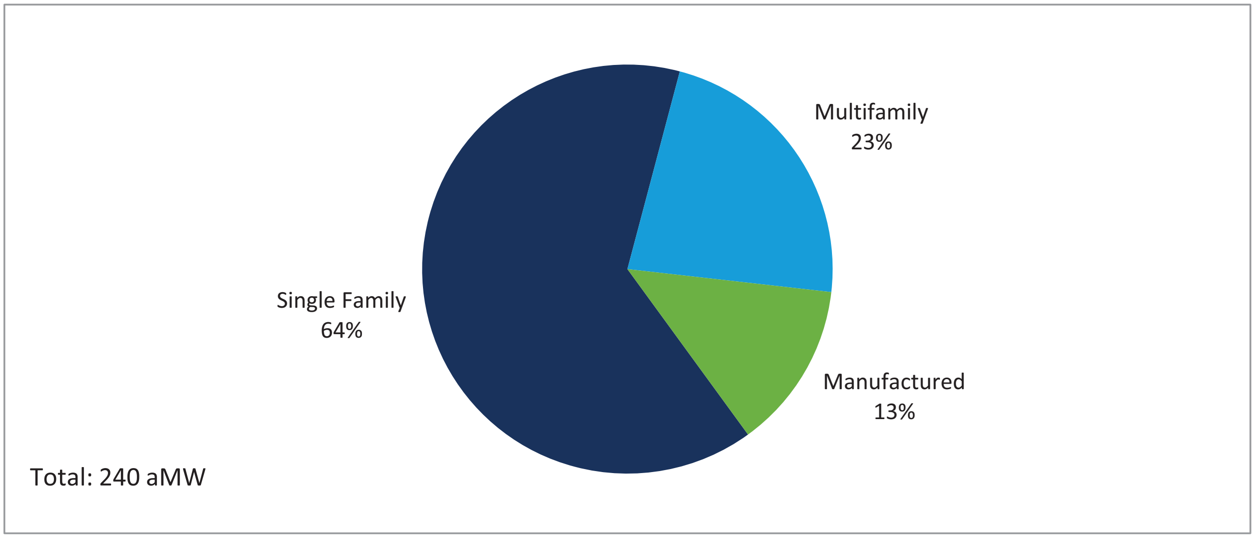
By 2033, residential customers in PSE's service territory will likely account for almost one-half of baseline electric retail sales.

The single-family, manufactured, and multifamily dwellings comprising this sector present a variety of potential savings sources, including: equipment efficiency upgrades (e.g., air conditioning, refrigerators); improvements to building shells (e.g., insulation, windows, air sealing); and increases in lighting efficiency (e.g., CFLs and LEDs). As described in Section 1: General Approach and Methodology, the expected impacts of new lighting standards established through EISA have been removed from the potential presented in this section.

As shown in Figure 21, single-family homes represent 64% of the total achievable technical residential electric potential, followed by multifamily (23%) and manufactured homes (13%). Each home type's proportion of baseline sales primarily drive these results, but other factors play an important role in determining potential, such as heating fuel sources.

For example, a higher percentage of manufactured homes use electric heat than do other home types, which increases their relative share of the potential. However, manufactured homes also tend to be smaller than detached single-family homes, *and* experience lower per-customer energy; so the same measure may save less in a manufactured home than in a single-family home. Volume II, Appendix B.3 provides a comprehensive list of the factors impacting segment-level energy-efficiency potential.

Figure 21. Residential Electric Achievable Technical Potential by Segment, Cumulative in 2033



Heating end uses represent the largest portion (36%) of achievable technical potential. Water heating, lighting, and appliances also represent over 10% of the total identified potential. A considerable amount of energy-efficiency potential remains in the lighting end use, even after EISA effects have been removed from the baseline forecast. Figure 22 shows the total achievable technical potential by end-use group. Table 19 presents detailed potentials by end use.

Figure 22. Residential Electric Achievable Technical Potential by End Use, Cumulative in 2033

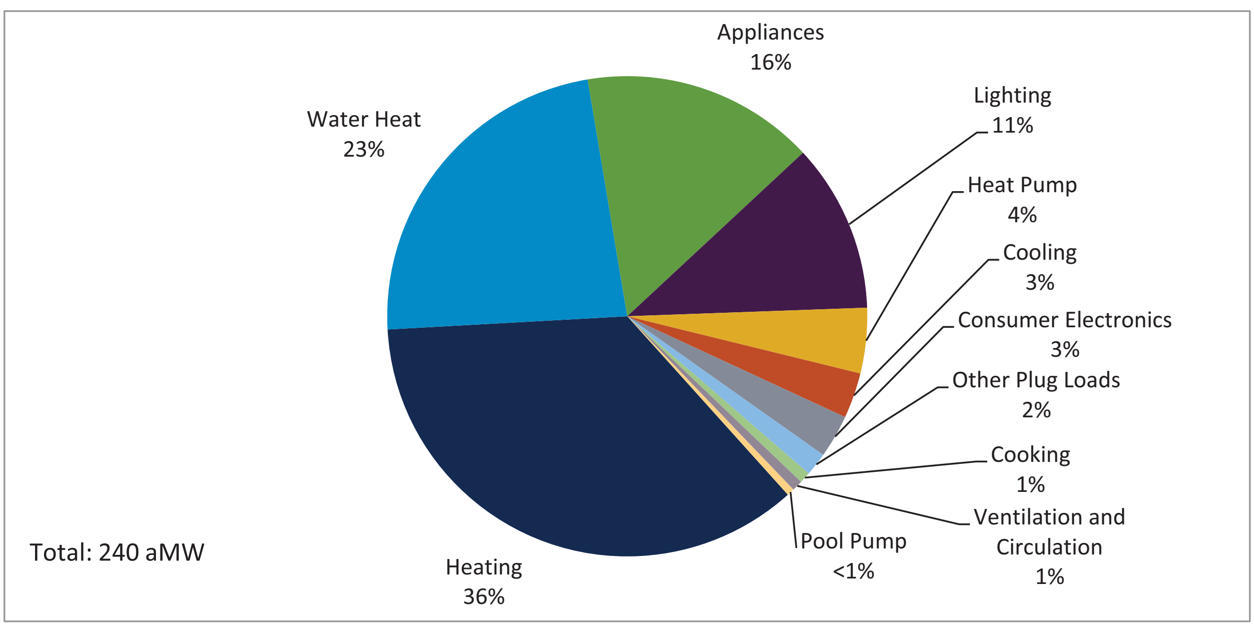


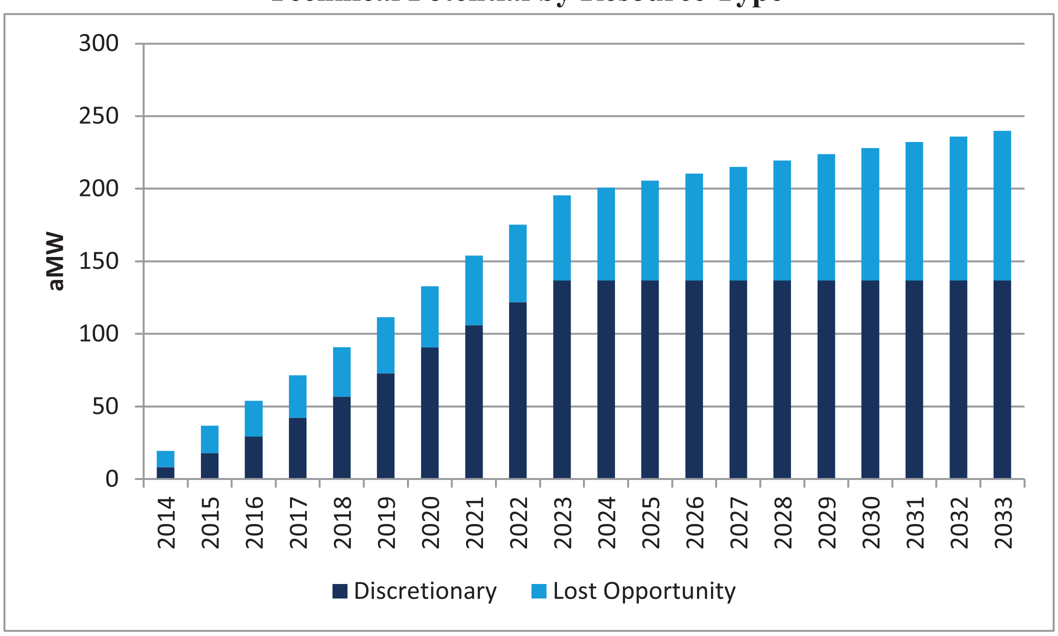
Table 19. Residential Electric Potential by End Use, Cumulative in 2033

		Technical Potential		Achievable Technical Potential	
End Use	Baseline Sales (aMW)	aMW	Percent of Baseline Sales	aMW	Percent of Baseline Sales
Appliances	213	56	26%	38	18%
Consumer Electronics	169	15	9%	7	4%
Cooking	31	4	14%	2	6%
Cooling	27	10	38%	7	28%
Heat Pump	39	15	37%	11	27%
Heating	285	105	37%	86	30%
Lighting	85	43	50%	27	32%
Other Plug Loads	478	5	1%	4	1%
Pool Pump	5	3	58%	1	27%
Ventilation and Circulation	84	5	6%	2	2%
Water Heat	203	95	47%	56	27%
Total	1,619	356	22%	240	15%

Volume II, Appendix B.3 provides additional details regarding the savings associated with specific measures assessed within each end use.

Figure 23 shows annual cumulative achievable technical potential by resource type for the sector. Discretionary measures, acquired in equal increments over a 10-year period, account for 57% of the 20-year cumulative achievable technical potential.

Figure 23. Residential Electric Annual Cumulative Achievable Technical Potential by Resource Type

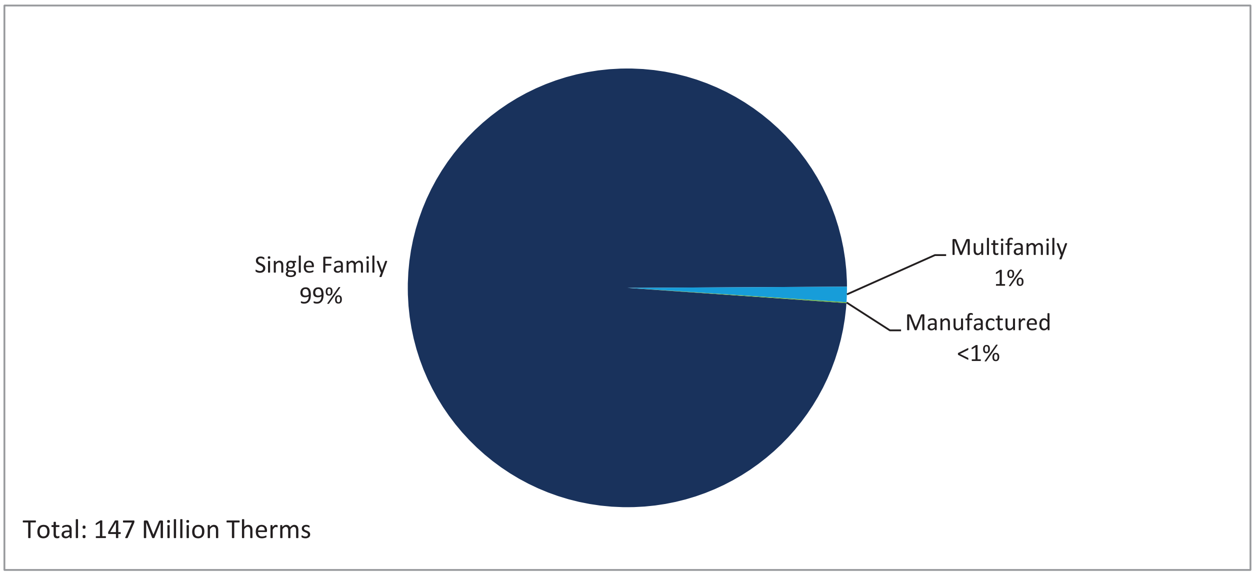


Residential Sector—Natural Gas

By 2033, residential customers will likely account for over 61% of PSE's natural gas sales. Unlike residential electricity consumption, relatively few natural gas-fired end uses exist (primarily space heating, water heating, and appliances); however, significant energy savings opportunities remain available. Based on the energy-efficiency measures used in this assessment, achievable technical potential in the residential sector will likely provide about 145 million therms over 20 years, corresponding to a 22% reduction of forecasted 2033 sales.

Single-family homes account for 99% of the identified achievable technical potential, as shown in Figure 24. Less than 2% of total achievable technical potential occurs in multifamily and manufactured residences due to a lack of gas connections.

Figure 24. Residential Natural Gas Achievable Technical Potential by Segment, Cumulative in 2033



As shown in Figure 25, space heating and water heating end uses account for over 99% of the identified achievable technical potential, which combines high-efficiency equipment (such as condensing furnaces and water heaters) and retrofits (such as shell measures, duct and pipe insulation, and low-flow showerheads). Table 20 presents detailed potentials by end use.

Figure 25. Residential Natural Gas Achievable Technical Potential by End Use, Cumulative in 2033

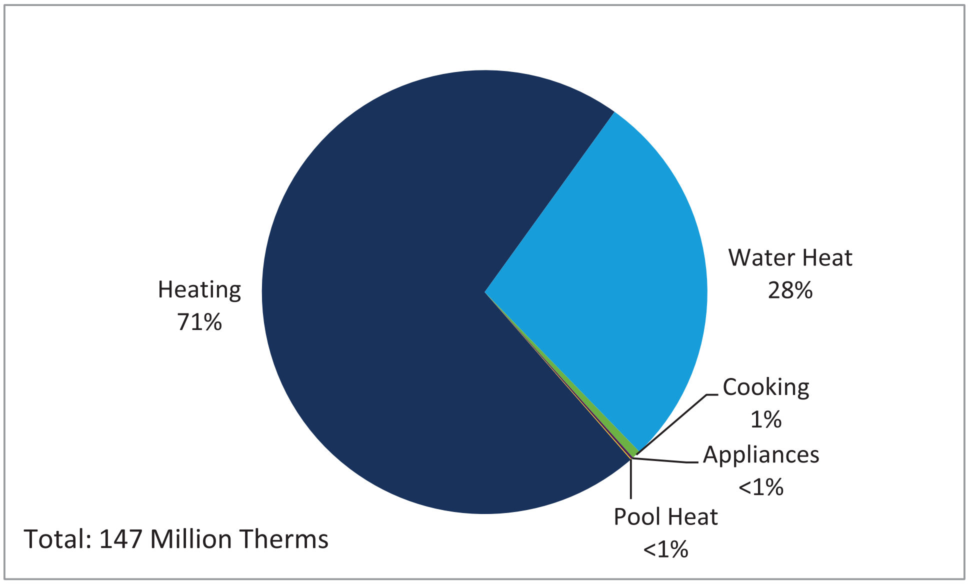
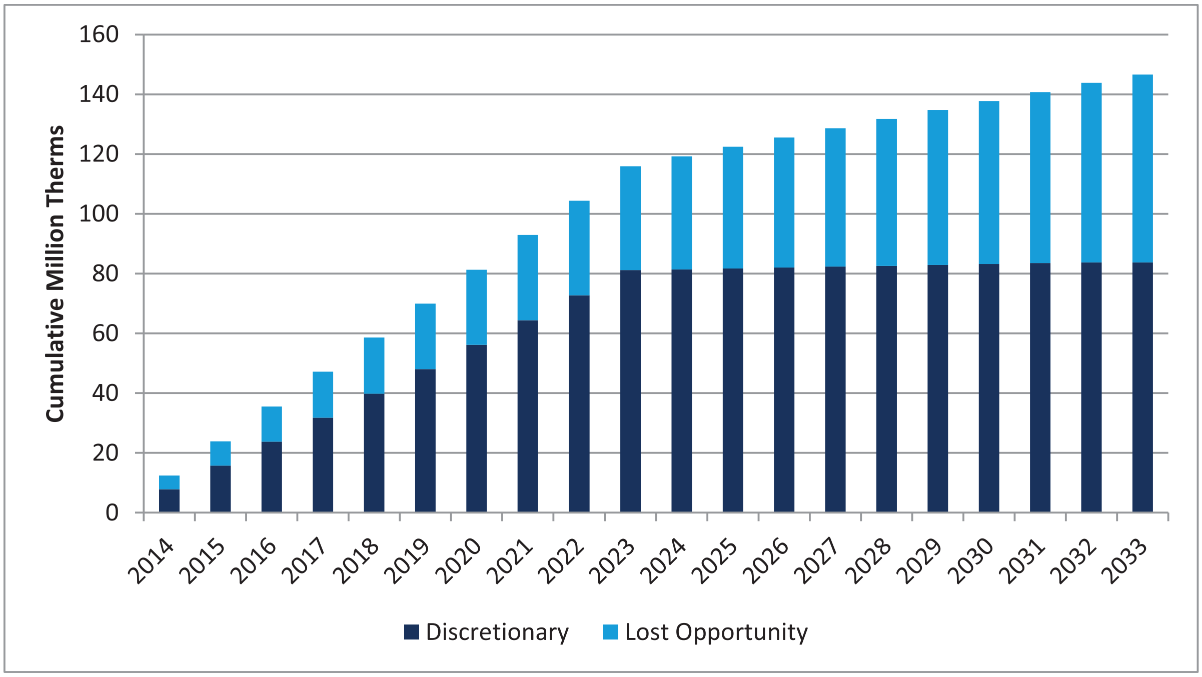


Table 20. Residential Natural Gas Potential by End Use, Cumulative in 2033

		Technical Potential		Achievable Technical Potential	
End Use	Baseline Sales (Million Therms)	Million Therms	Percent of Baseline Sales	Million Therms	Percent of Baseline Sales
Cooking	13	2	12%	1	7%
Dryer	4	0	9%	0	5%
Heating	429	151	35%	105	24%
Miscellaneous End Uses	35	0	0%	0	0%
Pool Heat	3	0	5%	0	3%
Water Heat	191	73	38%	41	21%
Total	674	226	34%	147	22%

Figure 26 shows residential natural gas annual cumulative achievable technical potential by resource type. Discretionary measures, acquired in equal increments over a 10-year period, account for 57% of the 20-year cumulative, achievable technical potential.

Figure 26. Residential Natural Gas Annual Cumulative Achievable Technical Potential by Resource Type

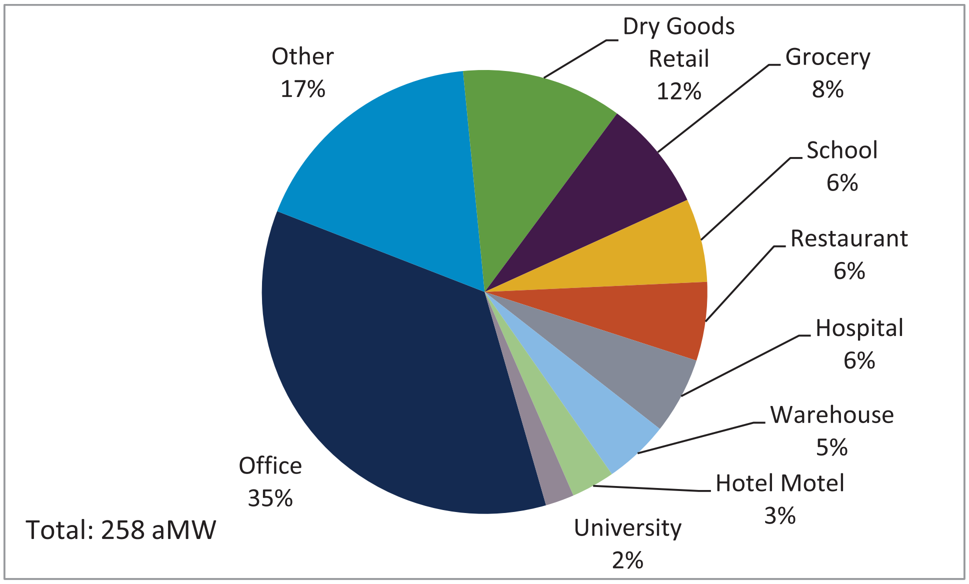


Commercial Sector—Electric

Based on resources included in this assessment, electric achievable technical potential in the commercial sector will likely be 258 aMW over 20 years, a 17% reduction in forecasted 2033 commercial sales.

As shown in Figure 27, offices represent slightly over one-third of the available potential (35%). Miscellaneous facilities also represent a large portion of available potential (17%). The miscellaneous segment includes: customers not fitting into the other categories; and customers with insufficient information for classification.

Figure 27. Commercial Electric Achievable Technical Potential by Segment, Cumulative in 2033



As shown in Figure 28, lighting efficiency improvements by far represent the largest portion of achievable technical potential in the commercial sector (40%), followed by ventilation and circulation (13%), cooling (10%), and space heating (9%). The large lighting potential includes bringing existing buildings to code, and exceeding code in new and existing structures. Table 21 shows distributions of baseline sales and savings across end uses.

Figure 28. Commercial Electric Achievable Technical Potential by End Use, Cumulative in 2033

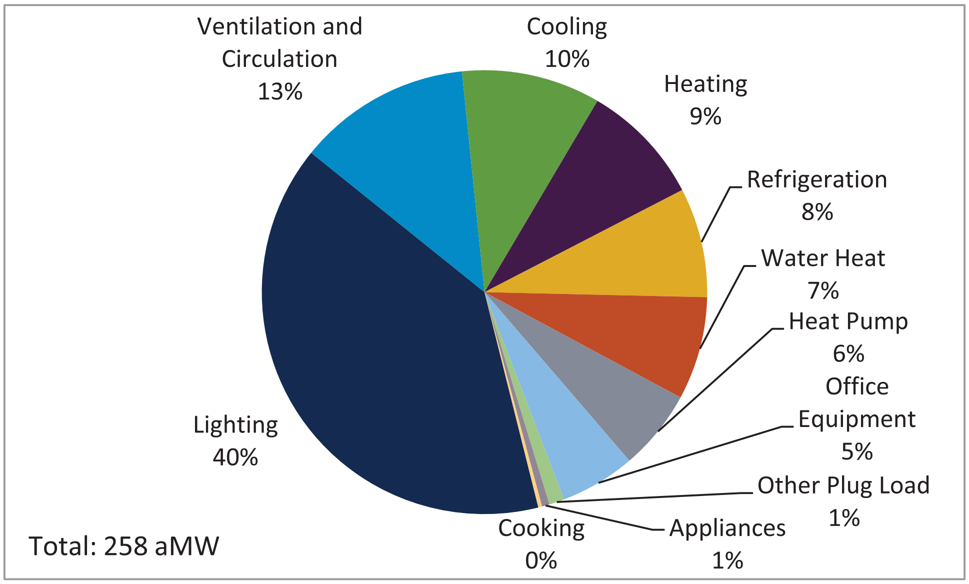
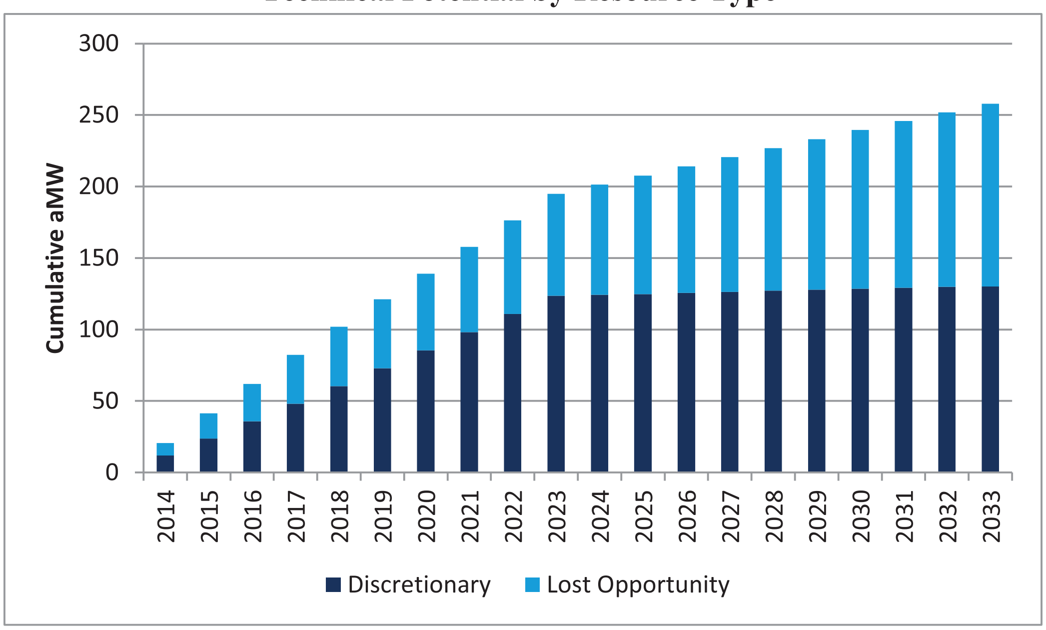


Table 21. Commercial Electric Potential by End Use, Cumulative in 2033

		Technical Potential		Achievable Technical Potential	
End Use	Baseline Sales (aMW)	aMW	Percent of Baseline Sales	aMW	Percent of Baseline Sales
Appliances	7	2	24%	1	21%
Cooking	17	1	5%	1	4%
Cooling	140	31	22%	26	19%
Heat Pump	58	19	33%	15	26%
Heating	79	28	35%	23	29%
Lighting	681	131	19%	102	15%
Office Equipment	104	17	17%	14	14%
Other Plug Load	81	3	4%	3	4%
Refrigeration	77	24	31%	21	27%
Ventilation and Circulation	219	38	17%	32	15%
Water Heat	81	37	46%	19	24%
Total	1,546	331	21%	258	17%

Figure 29 shows commercial electric annual cumulative achievable technical potential by resource type. Discretionary measures, acquired in equal increments over a 10-year period, account for 50% of the 20-year cumulative achievable technical potential.

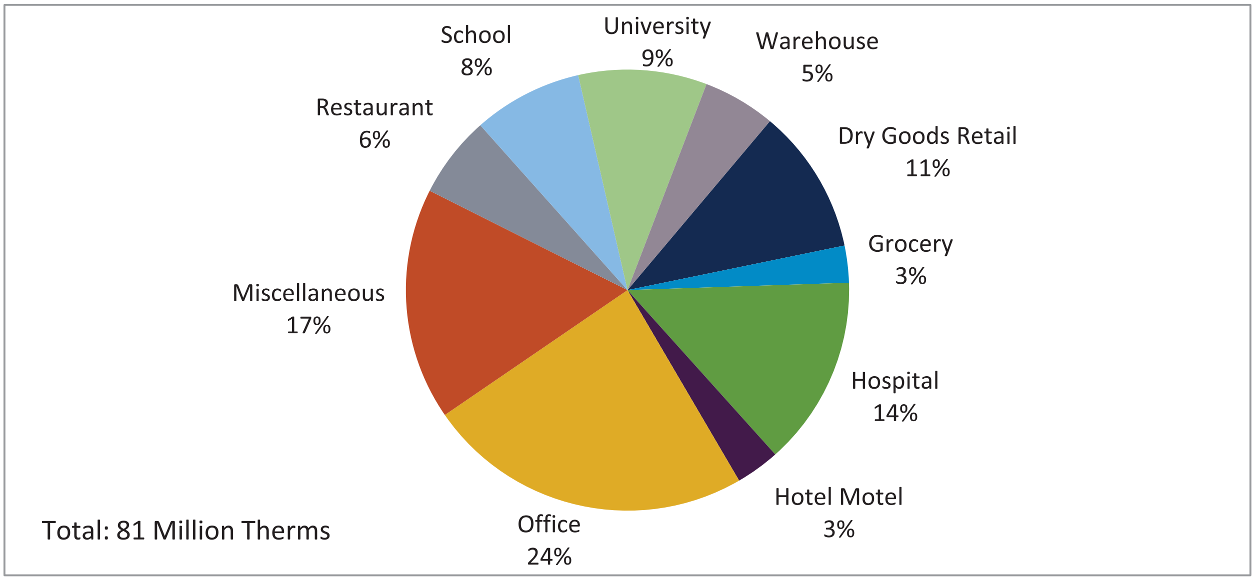
Figure 29. Commercial Electric Annual Cumulative Achievable Technical Potential by Resource Type



Commercial Sector—Natural Gas

Based on resources included in this assessment, natural gas achievable technical potential in the commercial sector will likely be 81 million therms over 20 years, a 20% reduction in forecasted 2033 commercial sales. Achievable technical natural gas potential in the commercial sector represents about one-third of the total identified potential across all sectors. As shown in Figure 30, for electric customers, office buildings represent the largest portion of potential (24%). Significant amounts of achievable technical potential exist in miscellaneous facilities (17%) and education buildings (17%).

Figure 30. Commercial Natural Gas Achievable Technical Potential by Segment, Cumulative in 2033



As in the residential sector, far fewer gas-fired end uses exist than electric end uses. Space heating accounts for 67% of the identified potential, with the remaining potential mostly in water heating (28%), with small amounts in cooking and pool heating (as shown in Figure 31 and detailed in Table 22).

Figure 31. Commercial Natural Gas Achievable Technical Potential by End Use, Cumulative in 2033

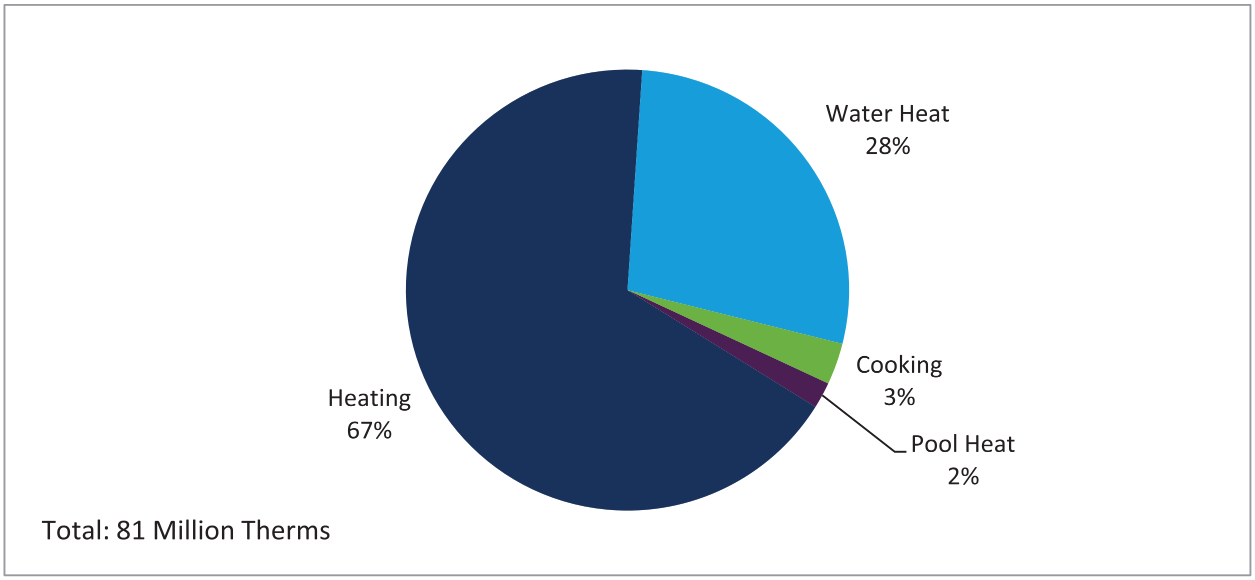
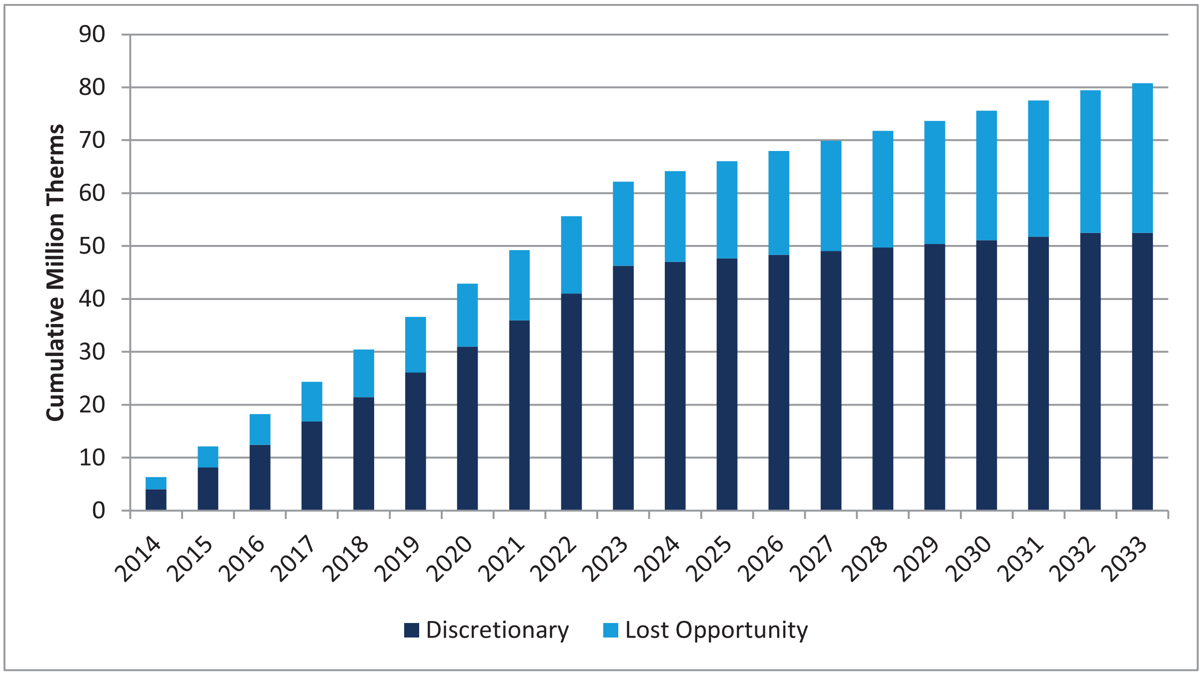


Table 22. Commercial Natural Gas Potential by End Use, Cumulative in 2033

End Use	Baseline Sales (Million Therms)	Technical Potential		Achievable Technical Potential	
		Million Therms	Percent of Baseline Sales	Million Therms	Percent of Baseline Sales
Cooking	57	4	7%	2	4%
Heating	251	75	30%	54	22%
Pool Heat	15	2	15%	2	10%
Water Heat	81	37	46%	22	28%
Total	404	119	29%	81	20%

Figure 32 shows commercial natural gas annual cumulative achievable technical potential by resource type. Discretionary measures, acquired in equal increments across a 10-year period, account for 65% of 20-year cumulative achievable technical potential.

Figure 32. Commercial Natural Gas Annual Cumulative Achievable Technical Potential by Resource Type

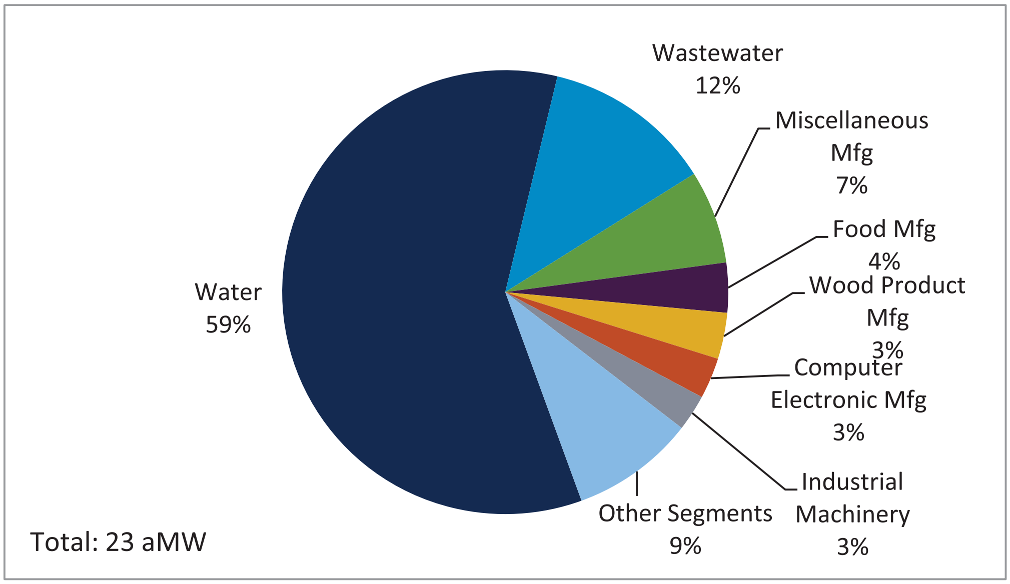


Industrial Sector—Electric

The study estimates technical and achievable technical energy-efficiency potential for major end uses within 17 major industrial sectors. (Volume II, Appendix B.1. provides a list of these industries, along with baseline information.) Across all industries, achievable technical potential totals approximately 23 aMW over the 20-year planning horizon, corresponding to an 18% reduction of forecasted 2033 industrial consumption.

Figure 33 shows 20-year industrial achievable technical potential by segment.

Figure 33. Industrial Sector Electric Achievable Technical Potential by Segment



Note: "Other Segments" include: Printing Related Support, Transportation Equipment Mfg, Fabricated Metal Products, Paper Mfg, Nonmetallic Mineral Products, Electrical Equipment Mfg, Plastics and Rubber Products, Chemical Mfg, Petroleum Coal Products, and Primary Metal Mfg.

As shown in Figure 34, the majority of electric achievable technical potentials in the industrial sector (51%) result from pumps. Process improvement measures (15%) and fans (13%) also comprise significant portions of available technical potential. A small amount of additional potential exists for lighting and other facility improvements. Table 23 presents detailed potentials by end use. All industrial measures should be considered discretionary, with savings acquired over a 10-year time frame.

Figure 34. Industrial Electric Achievable Technical Potential by End Use, Cumulative in 2033

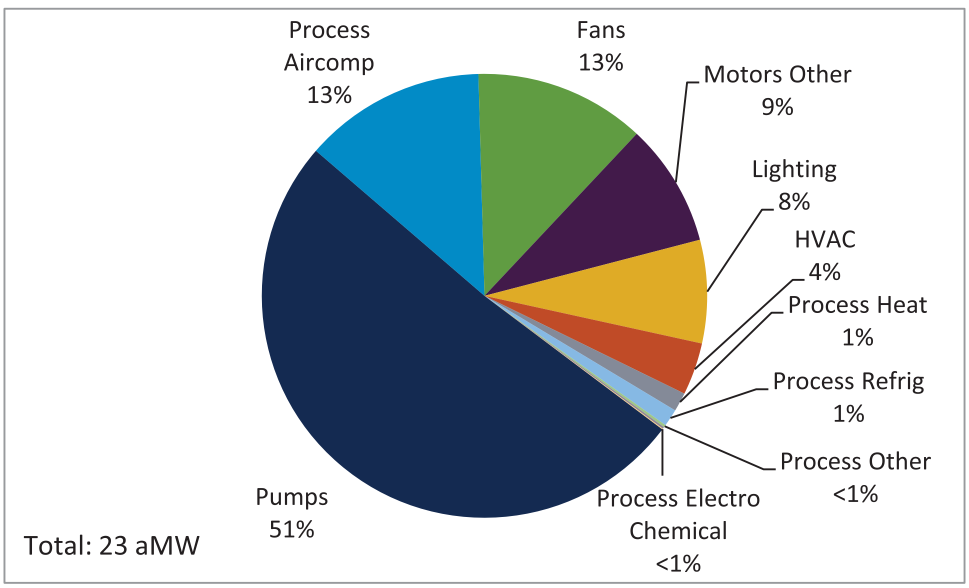


Table 23. Industrial Electric Potential by End Use, Cumulative in 2033

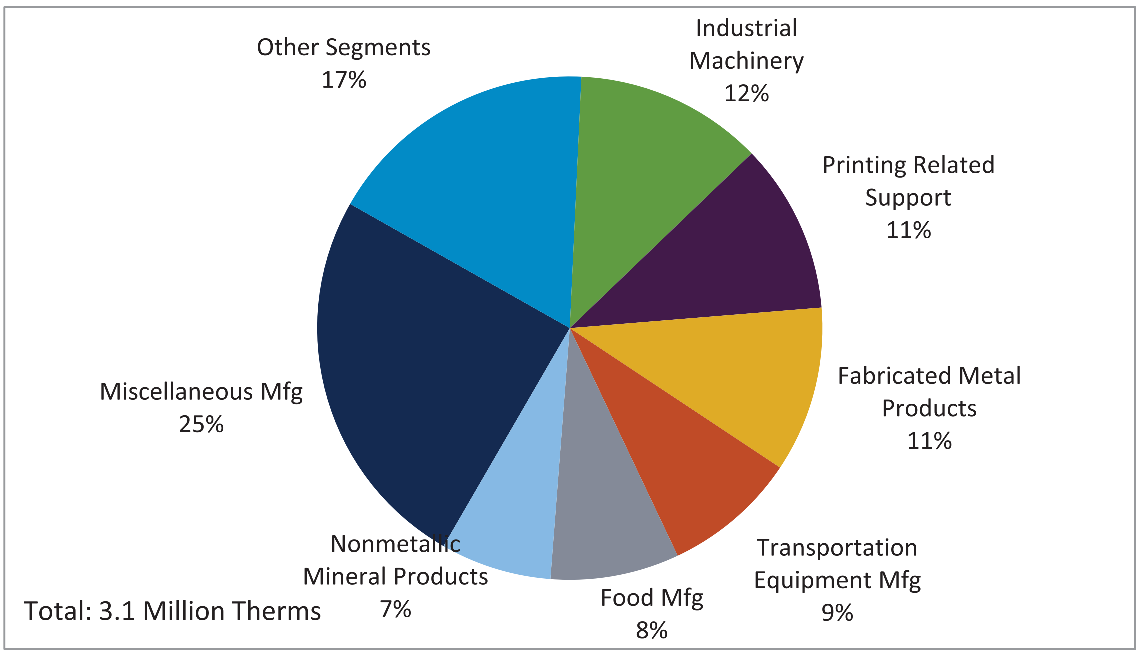
		Technical Potential		Achievable Technical Potential	
End Use	Baseline Sales (aMW)	aMW	Percent of Baseline Sales	aMW	Percent of Baseline Sales
Fans	9	3	36%	3	31%
HVAC	12	1	9%	1	8%
Indirect Boiler	1	0	0%	0	0%
Lighting	9	2	22%	2	19%
Motors	18	2	14%	2	12%
Other	12	0	0%	0	0%
Process	28	4	16%	4	14%
Pumps	42	14	33%	12	28%
Total	132	28	21%	23	18%

Industrial Sector—Natural Gas

As electricity powers most industrial processes and end uses, the industrial sector represents a small portion of natural gas baseline sales and potential.

Across all industries, achievable technical potential totals approximately 3 million therms over 20 years. Although this represents 12% of forecasted 2033 industrial sales, it accounts for only 2% of the achievable technical potential across the three sectors. As shown in Figure 35, substantial achievable technical potential occurs in: miscellaneous manufacturing (25%), machinery (12%), metals (11%), and paper (11%).

Figure 35. Industrial Natural Gas Achievable Technical Potential by Segment, Cumulative in 2033



Note: "Other Segments" include: Computer Electronic Mfg, Wood Product Mfg, Electrical Equipment Mfg, Plastics Rubber Products, Chemical Mfg, Primary Metal Mfg, Paper Mfg, Petroleum Coal Products, and Water/Wastewater.

Two-thirds of achievable technical potential derive from process improvements. As shown in Figure 36 and detailed in Table 24, the remaining potentials occur in HVAC and boiler improvements**.** All industrial measures should be considered discretionary, with savings acquired over a 10-year time frame.

Figure 36. Industrial Natural Gas Achievable Technical Potential by End Use

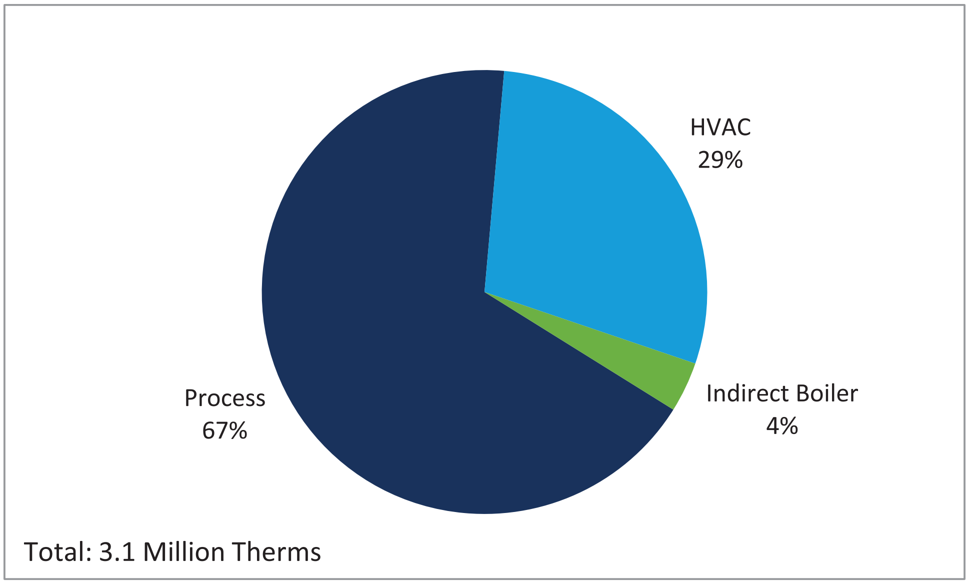


Table 24. Industrial Natural Gas Potential by End Use, Cumulative in 2033

End Use	Baseline Sales (Million Therms)	Technical Potential: Million Therms	Technical Potential: Percent of Baseline Sales	Achievable Technical Potential: Million Therms	Achievable Technical Potential: Percent of Baseline Sales
HVAC	7.3	1.2	16%	0.9	12%
Indirect Boiler	7.2	0.1	2%	0.1	2%
Other	0.4	0.0	0%	0.0	0%
Process	11.0	2.8	25%	2.1	19%
Total	25.9	4.1	16%	3.1	12%

3. FUEL CONVERSION POTENTIALS

Scope of Analysis

In this study's context, fuel conversion refers to electricity-saving opportunities involving substitution of natural gas for electricity through replacement of space heating systems, water heating equipment, and appliances.

Where PSE provides both gas and electric service, the study examines fuel conversion potentials for: existing residential single-family homes; existing and new commercial buildings; and new multifamily structures. Analysis includes three end uses for single-family and multifamily homes: space heating, water heating, and appliances (clothes dryers and cooking ranges). For new multifamily homes, Cadmus' analysis includes the potential from converting electric baseboard heating to natural gas furnaces. For commercial buildings, analysis only examines space and water heating end uses.

Summary of Resource Potentials

The study calculates fuel conversion technical potentials by assuming conversion of all applicable customers and end uses.

As part of the 2009 IRP, Cadmus conducted a survey of residential customers to aid in determining customers' willingness to switch from an electric heating system to a gas heating system. Based on this survey, approximately 63% of respondents indicated they would be likely or highly likely to convert from electric to gas space heating if the utility paid 100% of the cost. As such, the achievable technical potential would be assumed to represent 63% of the technical potential. In the absence of comparable primary data, analysis used the same percentage for the commercial sector.

Based on survey results and on previous PSE experiences, of the new residential-sector gas customers converting a space heater, 70% would also convert a water heater, and 5% would convert a range and/or dryer. For existing gas customers, all would convert a water heater, and 5% would convert a range and/or dryer. The analysis assumes similar percentages for water heating conversions in the commercial sector.

Estimates indicate 240 aMW cumulative electric technical potential from fuel conversion by 2033. Acquisition of the indicated electricity savings will, however, result in increased gas consumption of about 11 million therms by 2033. After adjusting for the achievability described above, the total achievable technical electric savings potential of fuel conversion in 2033 is estimated at just over 61 aMW. This achievable technical potential corresponds to increased gas consumption of about 4 million therms.

Table 25 and Table 26 show, respectively, technical and achievable technical potential by customer type and market segment.

Table 25. Fuel Conversion Potentials by Customer Type, Cumulative in 2033

	Technical Potential		Achievable Technical Potential	
Customer Type	Electric Savings (aMW)	Additional Gas Usage (million therms)	Electric Savings (aMW)	Additional Gas Usage (million therms)
Electric-Only	165	7	45	3
Existing Gas Customer	75	4	16	1
Total	240	11	61	4

Table 26. Fuel Conversion Potentials by Market Segment, Cumulative in 2033

	Technical Potential		Achievable Technical Potential	
Market Segment	Electric Savings (aMW)	Additional Gas Usage (million therms)	Electric Savings (aMW)	Additional Gas Usage (million therms)
Single-family	198	8	39	2
Multifamily	2	<1	<1	<1
Commercial	40	3	22	2
Total	240	11	61	4

Detailed Resource Potentials

Residential Sector

The fuel conversion potential for single-family homes targets existing customers, while the multifamily conversion targets new construction, with the new construction market size cumulative over 20 years, as estimated from PSE's customer forecast, and assuming a consistent percentage of multifamily homes. The potential market size accounts for current measure saturations. For example, some existing single-family homes already have a gas water heater; so water heater conversion would not be considered for those customers. In addition, the potential market size for new construction excludes the percentage of customers that have historically included gas systems.

Measures Considered

Cadmus' analysis of fuel conversion considers opportunities for three major end uses in residential dwellings: central heating: water heating (including conversion to integrated space and water heating units); and appliances (clothes dryer and oven). For space heating conversions, the study's treatment of multifamily homes differs slightly from that used with single-family homes for baseboard heating systems:

- For new multifamily buildings, the study examines conversion of room (or zonal) heating systems to natural gas furnaces.
- For existing single-family buildings, the study does not consider the cost of converting an existing baseboard system to a central system, given the high cost of installing the necessary ductwork.

Clothes dryers and cooking ranges were the only appliances considered in the study. Table 27 shows applicable measures and their assumed technical specifications. These measures serve as the equivalent to those used for the energy-efficiency analysis, and detailed descriptions can be found in Volume II, Appendix B.

Table 27. End Uses and Measures Assessed

End Use	Gas Measure	Electric Baseline
Space heating	95% AFUE condensing furnace	Electric furnace Electric baseboard (new MF only)
	Wall Heater 84% (space and zonal)	Electric baseboard (existing SF only)
	Gas Fireplace	Electric baseboard (existing SF only)
Integrated space & water heating	95% AFUE integrated space & water heater	Electric furnace, electric water heater, 55 gal.
	90% AFUE Boiler	Electric baseboard, electric water heater, 55 gal. (new MF only)
Water heating	EF = 0.67 storage water heater	Electric water heater
	EF = 0.82 tankless water heater	
Appliances	High-efficiency dryer	2015 Standard Electric dryer
	High-efficiency cooking oven	2012 Standard oven

Gas Availability

In terms of service extension costs, gas availability and its implications present important considerations in determining the potential for fuel conversion. A major factor in determining the cost of new gas service is whether an electric-only customer is on a gas main.

For existing single-family customers, the study used data from multiple sources (including PSE's 2010 RCS) to determine availability. Analysis also considered the size range of single-family homes, given that larger homes would likely use more energy for space heating. Cadmus divided the single-family homes into three size categories: 1,800 sq. ft., 2,100 sq. ft., and 2,400 sq. ft., with the percentage of homes in each category determined from the RCS.

PSE currently provides gas to approximately 49% of single-family homes in its electric service area. Customers currently receiving gas service from PSE can be considered candidates only for *additional* gas-using equipment, without imposing additional line extension costs. Cadmus used the RCS to estimate the total number of gas-heated, single-family homes with electric water heaters and other appliances. This estimate resulted in over 46,500 existing gas homes eligible for conversion.

Of electric customers without PSE gas service, approximately one-third reside in PSE's gas service territory. Based on the latest data available from PSE, approximately 24% of these customers are located on a gas main, 9% are a short distance (50 feet) from a gas main, and 18% are a moderate distance (200 feet) from a gas main. The remaining customers are too far from a gas main to be considered eligible for conversion.

For new electric multifamily customers, approximately 14% reside in PSE combination territory, with one-quarter on a main, and another one-quarter near a main. Of those within the combination territory, approximately 15% of customers will install baseboard heating systems without programmatic intervention (and thus can be considered part of the conversion potential).

Conversion Costs and Savings

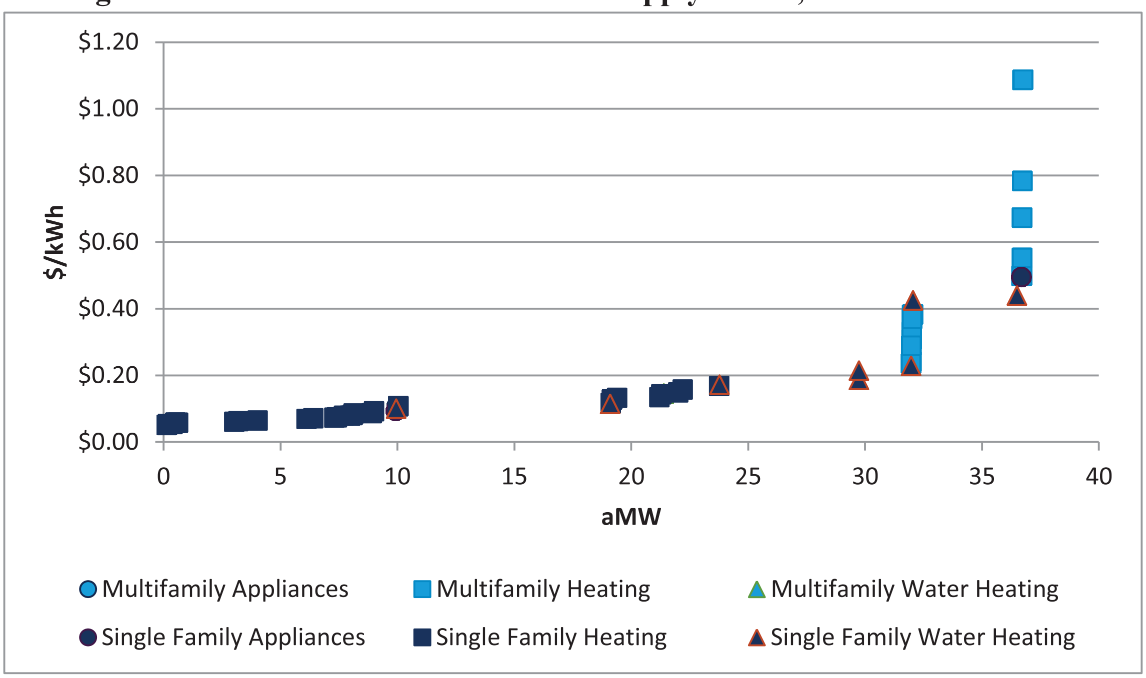
The study uses the total resource cost (TRC) perspective to assess conversion costs. This assumes the installed cost of the gas measure, less the cost of an equivalent electric measure, and includes gas line extension costs.

For electric-only customers, connecting a house to a gas main will likely require a service line extension of $3,406. Customers a short distance (50 feet) from a gas main experience an additional $2,000 cost, and those a moderate distance (300 feet) from a main experience an additional $12,000 cost.

This analysis includes the cost of line extensions for the gas furnaces. However, as water heaters may be converted without the furnace, the study includes a proportional amount for water heating measures. An appliance end use only has an additional cost for interior piping (estimated at $200 per piece of equipment, as determined through interviews with local HVAC contractors on PSE's Contract Referral Service List, conducted in 2008).

Figure 37 shows cumulative electric savings, categorized by home type and end use, and distributed by levelized cost. Conversion savings estimates are based on the same assumed levels of unit energy consumption (UEC) as that used in the energy-efficiency analysis, described in Section 2: Energy Efficiency Potentials. Calculation of levelized cost includes increased gas usage, counted as an ongoing annual O&M cost. For baseline values, the study uses electric UECs (kWh/yr) and gas UECs (therms/year) from the baseline forecast for existing single-family and new multifamily homes.

Figure 37. Residential Fuel Conversion Supply Curve, Cumulative in 2033



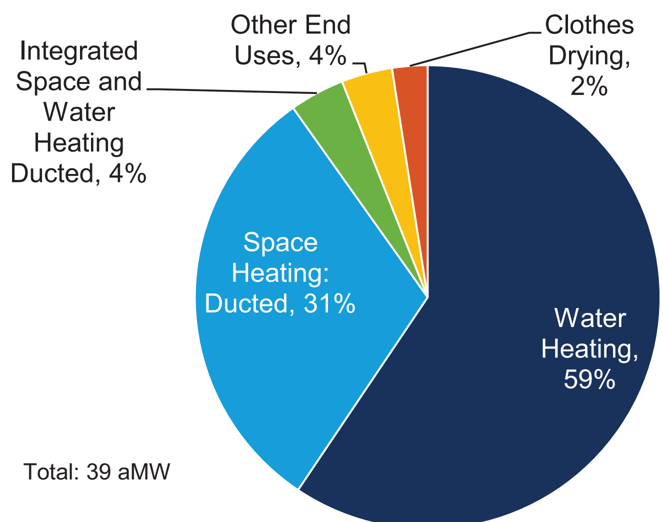
Potential

Table 28 and Figure 38 provide the technical and achievable technical conversion potential in 2033 for the residential sector (single family and multifamily dwellings), by end use.

Table 28. Residential Fuel Conversion Potential by End Use, Cumulative aMW in 2033

End Use	Technical Potential	Achievable Technical Potential
Clothes Drying	32	1
Cooking	7	0
Space Heating: Baseboard	16	1
Integrated Space and Water Heating Boiler	1	0
Space Heating: Ducted	39	12
Integrated Space and Water Heating Ducted	47	2
Zonal Heating	16	1
Water Heating	42	23
Total	200	39

Figure 38. Residential Fuel Conversion Achievable Technical Potential by End Use, Cumulative 2033



Note: 'Other End Uses' includes: Space Heating: Baseboard: 1.6%, Zonal Heating: 1.4%, Cooking: <1%, Integrated Space and Water Heating Bolier: 0%

Commercial Sector

The fuel conversion potential for the commercial sector includes conversion of equipment in existing buildings and new facilities.

Measures Considered

For existing facilities in the commercial sector, the measures considered include: 94% AFUE furnaces, and high-efficiency water heaters (≥0.67 EF storage and EF=0.82 tankless). The new construction segment includes the same measures, plus the additional measures provided in Table 29.

Table 29. New Construction Additional End Uses and Measures Assessed

End Use	Gas Measure	Electric Baseline
Space heating	Gas warm up heat	Electric furnace
	80% AFUE gas packaged systems	Packaged rooftop unit
Integrated space & water heating	90% Thermal Efficiency Boiler	Packaged rooftop unit, electric water heater, 50 gal. Packaged rooftop variable air volume w/ electrical resistance reheat & electric water heater, 50 gal.

Gas Availability

Data from the 2008 CBSA, coupled with PSE's nonresidential customer database, provided market shares by territory and end use.

Of existing electric-only customers, approximately 60% are in PSE gas territory, with around 25% of those on a main line. For new customers, approximately 32% will be expected to be within the combination service territory, 25% will be on a gas main, 9% will be a short distance (50 feet) from a gas main, and 18% will be at a moderate distance (200 feet) from a gas main. The remaining customers will be too far from a gas main to be considered for conversion.

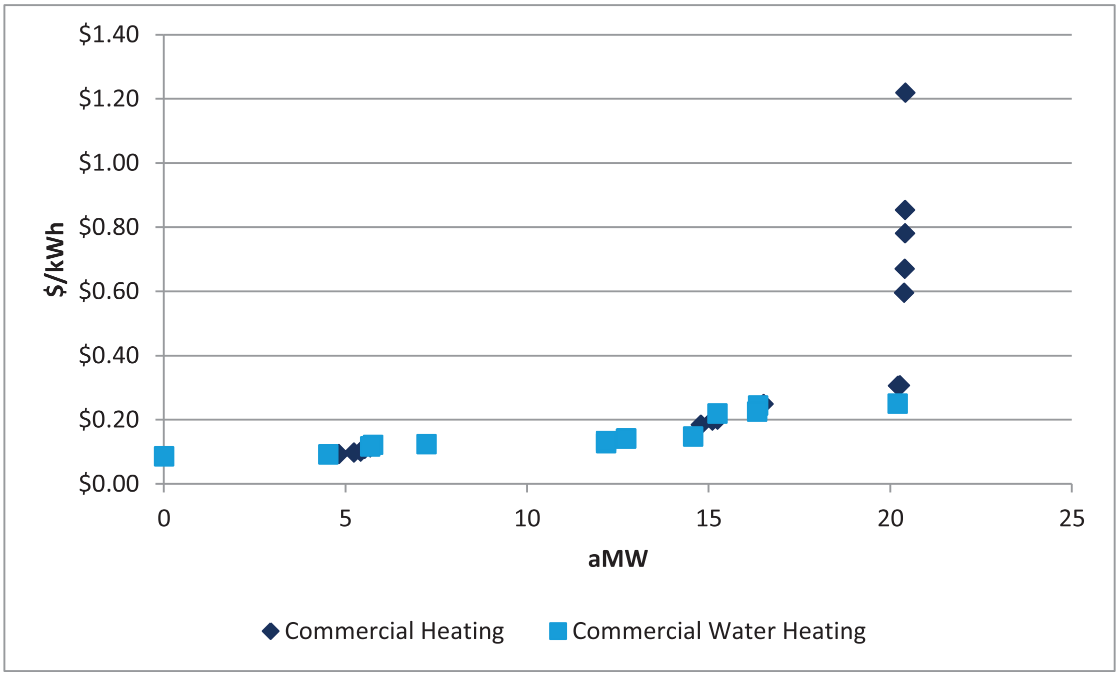
By applying this percentage to PSE's commercial new customer forecast and accounting for saturation of furnaces, Cadmus estimates about 774 customers will be eligible over the 20-year study to install a furnace. This number excludes customers expected to install a gas line anyway. Additional potential exists for current gas customers without gas water heaters (approximately 7,300 customers).

Conversion Costs and Benefits

Analysis estimates conversion savings based on assumed UEC levels, consistent with those used in the energy-efficiency analysis, described in Section 2: Energy Efficiency Potentials. Increased gas usage, counted as an ongoing annual O&M cost, is included in the calculation of levelized cost. For baseline values, the study uses electric UECs (kWh/yr) and gas UECs (therms/year) from the baseline forecast.

Figure 39 shows cumulative electric savings, by end use, distributed by levelized cost. Similar to the residential sector, the service-line connection cost applies only to existing customers for the furnace cost. For simplicity, commercial buildings assume energy consumption as the weighted average of all segments, based on the likelihood of equipment being used in the given facility.

Figure 39. Commercial Fuel Conversion Supply Curve, Cumulative in 2033



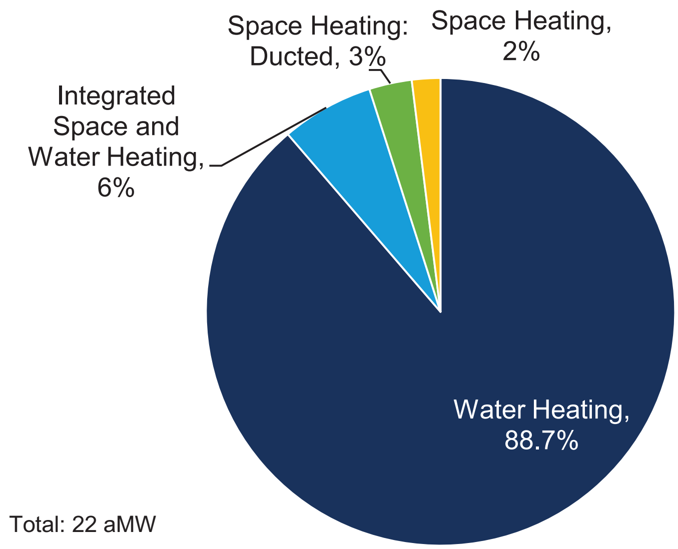
Potential

Table 30 and Figure 40 show the technical and achievable technical conversion potential in 2033 by end use. The end-use “Space Heating: Ducted” represents conversion for electric furnaces in existing buildings, while the “Space Heating” end use represents both furnace and gas warm-up heat conversions in new construction.

Table 30. Commercial Fuel Conversion Potential by End Use, Cumulative aMW in 2033

End Use	Technical Potential	Achievable Technical Potential
Space Heating	1	0
Space Heating: Ducted	1	1
Integrated Space and Water Heating	2	1
Water Heating	35	19
Total	40	22

Figure 40. Commercial Fuel Conversion Achievable Technical Potential by End Use, Cumulative in 2033



4. DEMAND RESPONSE POTENTIALS

Scope of Analysis

Focusing on reducing a utility's capacity needs, demand-response programs rely on flexible loads, which may be curtailed or interrupted during system emergencies or when wholesale market prices exceed the utility's supply cost. These programs seek to help reduce peak demand and promote improved system reliability. In some instances, the programs may defer investments in delivery and generation infrastructure.

Demand-response objectives may be met through a broad range of strategies, both price-based (such as time-varying rates or interruptible tariffs) and incentive-based (such as DLC) strategies. This assessment utilizes three demand response strategies:

- ***DLC*** programs allow a utility to interrupt or cycle electrical equipment and appliances remotely at a customer's facility. This study assesses DLC program potential for two programs in the residential sector:
    - A combination program of central electric heating (including heat pumps) and electric water heating; and
    - A combination program of room heating and electric water heating.
- ***Load Curtailment*** programs refer to contractual arrangements between a utility and a third-party aggregator that works with utility customers. The third-party aggregator typically guarantees a specific curtailment level during an event period, achieving load reduction by working with utility customers that agree to curtail or interrupt their loads in whole or part when requested. In most cases, customers must participate once enrolled in the program and incentives are paid per curtailed kW. Cadmus' analysis of these programs assumes they target nonresidential customers with average monthly loads greater than 100 kW. Customers may use backup generation to meet displaced loads.
- ***Critical Peak Pricing*** (CPP) or extreme-day pricing refers to programs aiming to reduce system demand by encouraging customers to reduce their loads for a limited number of hours during the year. When such events occur, customers may curtail their usage or pay substantially higher-than-standard retail rates. CPP programs integrate a pricing structure similar to a time-of-use (TOU) program, though CPPs use more extreme pricing signals during critical events. This assessment examines CPP options for both the residential and commercial sectors.

As this study updates the 2011 IRP, the program options listed above largely have been based on that assessment, with revisions based on PSE's input. After Cadmus reviewed new demand response literature including recent program evaluations on programs across the country as well as on PSE's pilot programs, updates were made to each program. This section details the design specifications and assumptions underlying the analysis for each program strategy.

Summary of Resource Potentials

Table 31 presents estimated resource potentials for all demand-response strategies for the residential, commercial, and industrial sectors during summer and winter. The greatest market potential occurs in the residential sector, due to the DLC programs. Notably, this analysis does not account for program interactions and overlap; thus, the total market potential estimates may not be fully attainable upon implementation of all program strategies.

Table 31. Demand Response Market Potential, MW in 2033

Sector	Winter Market Potential (MW)	Summer Market Potential (MW)	Percent of System Peak – Winter*	Percent of System Peak – Summer*
Residential	130	77	2.9%	1.9%
Commercial	78	85	1.7%	2.1%
Industrial	4	5	0.1%	0.1%
Total	213	166	4.7%	4.1%

*System peak is based on PSE's average load in the top 20 hours and is calculated for each season.

Resource Costs and Supply Curves

Resource acquisition costs fall into multiple categories, including: infrastructure, administration, maintenance, data acquisition, hardware costs, marketing expenses, and incentives

Cadmus developed estimates for each expense category within each program using PSE’s program data and experience, and using secondary sources, such as reports on similar programs offered by other utilities. In developing estimates of levelized costs, the study allocates program expenses annually over the program’s expected life cycle, and discounts by PSE’s cost of capital (7.8%). The ratio of this value and the discounted kW reduction produces the levelized per-kW cost for each program.

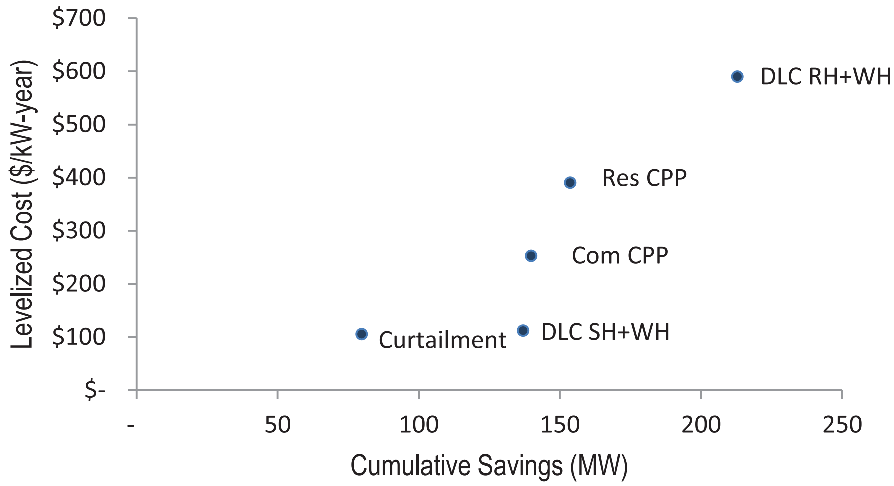
Table 32 displays per-unit ($/kW per year) costs by program for the estimated market potential during the winter season. Estimates find the Load Curtailment program for large, nonresidential customers to be the least-expensive option, with a levelized cost of $105/kW per year, while, due to high technology installation costs, the residential DLC—room and water heat program proves the most costly, with a levelized cost of $590/kW per year.

Table 32. Demand Response Market Potential and Levelized Costs, Winter MW in 2033

Program Strategy	Achievable Potential (MW)	Levelized Cost ($/kW-year)
Residential Direct Load Control - Space and Water Heat	57	$112
Residential Direct Load Control - Room and Water Heat	59	$590
Residential Critical Peak Pricing	14	$390
Commercial & Industrial Critical Peak Pricing	3	$252
Commercial & Industrial Curtailment	80	$105
Total	213	

Cadmus constructed supply curves from quantities of estimated market potential and per-unit costs for each program option. Figure 41 shows the quantity of market demand-response potential available during winter peak hours in 2033 as a function of levelized cost.

Figure 41. Demand Response Supply Curve, Winter MW in 2033



Resource Acquisition Schedule

Cadmus assumes each program will require an ample start-up period before achieving full participation. Therefore, each program option has an associated ramp rate, as described below:[19]

- The curtailment program is assumed to be the first to begin, reaching maximum participation in 2017.
- Residential DLC programs and the Residential CPP program will start in 2016 as two-year pilot programs. In 2018, the programs will begin to grow to full participation by 2020. This schedule has been partially dictated by PSE's schedule for installing advanced metering infrastructure (AMI) in the residential sector.
- The CPP programs are assumed to start as a three-year pilot 2017 to account for the time required to create a new tariff and to place necessary infrastructure. In 2020, the programs will begin to ramp up, growing to full deployment by 2022.

Figure 42 and Figure 43 show the acquisition schedule for achievable potential for winter and summer impacts, respectively.

[19] Once programs reach full participation, impacts continue to grow due to forecasted load growth.

Figure 42. Demand Response Annual Achievable Technical Potential by Strategy—Winter

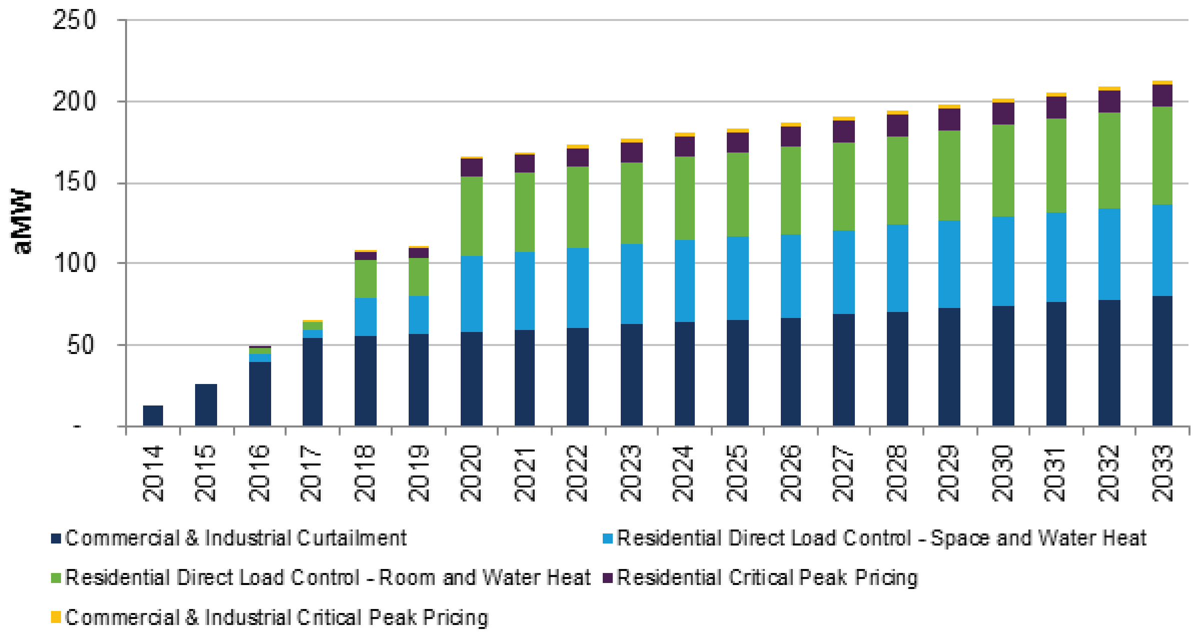
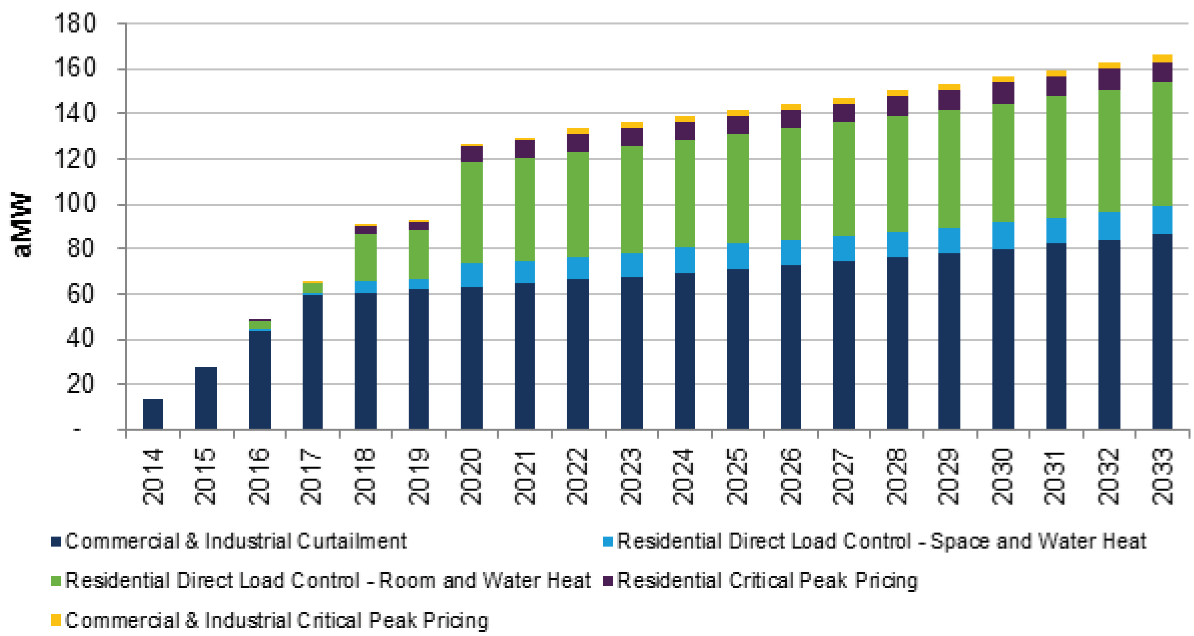


Figure 43. Demand Response Annual Achievable Technical Potential by Strategy—Summer



Detailed Resource Potentials by Program Strategy

Residential DLC

DLC programs seek to interrupt specific end-use loads at customer facilities through utility-directed control. When deemed necessary, the utility, through a third-party contractor, is authorized to cycle or shut off participating appliances or equipment for a limited number of hours on a limited number of occasions. Customers do not have to pay for the control equipment or installation of control systems, and they typically receive incentives, paid through monthly credits on their utility bills.

For such programs, receiver systems installed on customer equipment enable utility communications and execution of controls. Historically, DLC programs have become mandatory once a customer elects to participate; however, voluntary participation has become an option for some programs with more intelligent control systems and override capabilities at the customer facility.[20]

Because PSE's system peak occurs in the winter, this assessment focuses on two DLC programs controlling heating loads. Although residential DLC for air conditioning has been one of the most well-established programs in the nation (utilized by PacifiCorp, MidAmerican Energy, Alliant Energy, Florida Power and Light, Xcel Energy, and other utilities), the central and room heating DLC programs remain a relatively new idea, with minimal data available through secondary research.

PSE implemented a space-and-water-heating DLC pilot from 2009 through 2011. Due to the minimal secondary data available for such programs, some summer DLC program assumptions have been adapted to supplement PSE's pilot data for this assessment.

Central Heating and Water Heating

Table 33 shows the market potential results by end use, per season. Although this program primarily focuses on reducing the winter peak, water heaters will be available for control in the summer.

Table 33. Residential DLC Central Heat and Water Heat: Technical and Achievable Technical Potential, MW in 2033

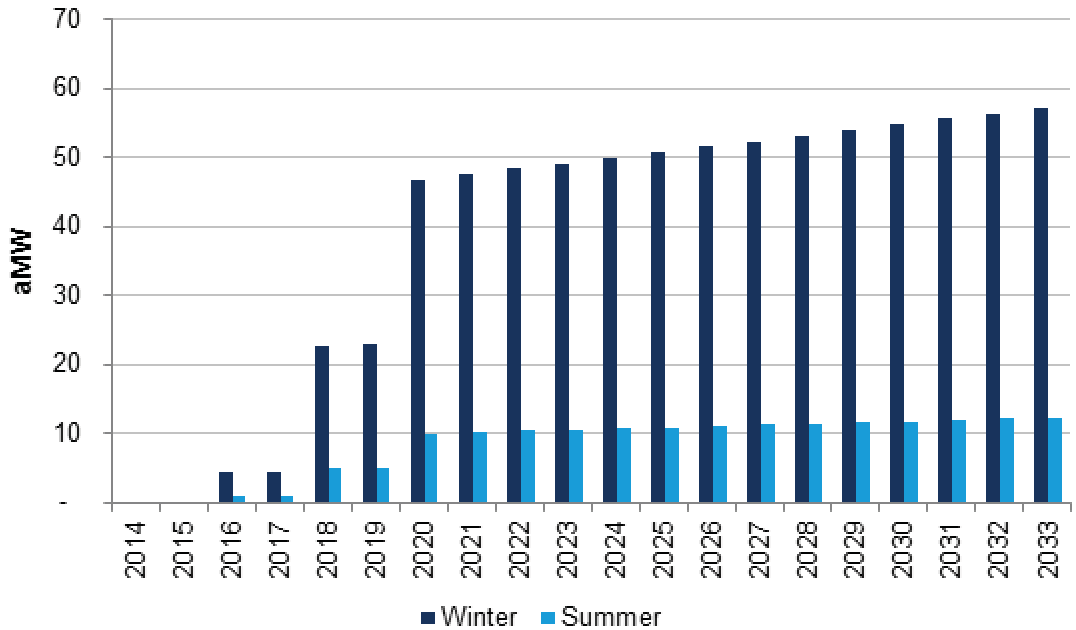
End Use	Winter Market Potential	Summer Market Potential	Percent of System Peak – Winter*	Percent of System Peak – Summer*
Central Heat	45	-	1.0%	0.0%
Water Heat	12	12	0.3%	0.3%
Total	57	12	1.3%	0.3%

*System peak is based on PSE's average load in the top 20 hours and is calculated for each season.

[20] Typically, penalties are associated with non-compliance or opt-outs.

Figure 44 shows the achievable potential for the central heat DLC program, based on an acquisition schedule for a two-year pilot program, starting in 2016 and ramping up to full participation in 2020.

Figure 44. Residential DLC Central Heat and Water Heat Acquisition Schedule



Utility incentives for residential DLC programs can vary greatly, from a free programmable thermostat, to a set incentive amount per month, to a 15% discount on customers' summer electricity bills (which may range from $50 to $60 annually for many participants). This analysis assumes incentives set at $32/year for central heat cycling, with an additional $8 for water heating control. Additional costs assessed for this program include the following:

- $25 of marketing; per new customer.
- $7 for communications per existing customer.
- A third-party vendor administrative cost.

Table 34 and Table 35 provide detailed assumptions.

Table 34. Residential DLC Central Heat and Water Heat: Program Basics

Program Concept	Assumptions
Customer Sectors Eligible	Residential customers in single-family and manufactured homes
End Uses Eligible for Program	Electric central heating (including air-source heat pumps) and electric water heaters
Customer Size Requirements, if any	N/A
Winter Load Basis	Top 20 hours
Summer Load Basis	Top 20 hours

Table 35. Residential DLC Central Heat and Water Heat: Inputs and Sources

Inputs	Value	Sources or Assumptions
Annual Attrition (%)	5%	Studies found 7% (composed of 5% change-of-service and 2% removals) from utilities, including: PacifiCorp, Xcel Energy, Eon US, Sacramento Municipal Utility District, Florida Power and Light (removals range from 1% to 3%). Removals are accounted for in event participation.
Per Customer Impacts (kW)	1.74 central heat 0.58 water heat	Based on PSE's central and water heating pilot. Per switch impacts are weighted by the morning and afternoon impacts.
Annual Administrative Costs (percent of annual costs)	5%	An additional utility administrative cost is added to the vendor program cost.
Annual Vendor Administrative Costs (percent of annual costs)	15%	Based on research of vendor bids and informal communications with vendors. Includes maintenance, administrative labor, and dispatch software.
Technology Cost	$280/water heat switch $370/thermostat $275/digital internet gateway	Based on PSE's Residential Demand Response Pilot Program. These costs include labor for installation.
Marketing Cost	$25	Assumes 0.5 hour of staff time, valued at $50/hour (fully loaded). Based on research of vendor bids and informal communications with vendors.
Incentive (annual costs)	Central Heating $32 Water Heating $8	Incentives range from $30 to $35 for most utilities for one piece of equipment and $8 for additional equipment. PSE's pilot program offered $50 for both central and water heating.
Communication Costs (per Customer Per Year)	$7	This value accounts for annual per-customer communication of a one-way transmission system.
Eligible Load (%)	100%	Assumes all electric central heating customers and associated loads qualify for the program.
Technical Potential (as a percent of gross)	Central Heating 50% Water Heating 100%	Assumes all central heating units and heat pumps can be retrofit, and the program employs a 50% cycling strategy. Due to the tank, water heaters can be shut off for the entire event (100% reduction).
Program Participation (%)	Single-family and Manufactured 20% Multifamily 0%	Assumes 20% of single-family and manufactured homes with electric central heating will participate. Minimal data for DLC heating programs exist; therefore, this assumption has been based on the average participation rate for national DLC cooling programs (between 15% and 20% of all residential customers, which translates to 20% to 30% of eligible customers). This is consistent with the 2009 FERC study estimate of 25% program participation for DLC cooling programs. As customers with electric central heating will include water heating, the water heating participation rates reflect the portion of electric water heaters in homes with electric central heating. Due to difficulties in reaching the multifamily segment, these customers have been removed from the potential.
Event Participation (%)	94%	Based on utility experience with DLC cooling programs, accounting for homeowners removing units and operational breakdowns (from 2.5% to 5.8%).

Room Heating and Water Heating

Similar to a central heating DLC program, a room heating DLC program is a relatively new idea, with little or no data available through secondary research. Table 36 provides market potential results by end use, for winter and summer. As with the central heating, greater potential exists in the winter, since all the heating load occurs at that time. The program's summer portion only targets the water heating load.

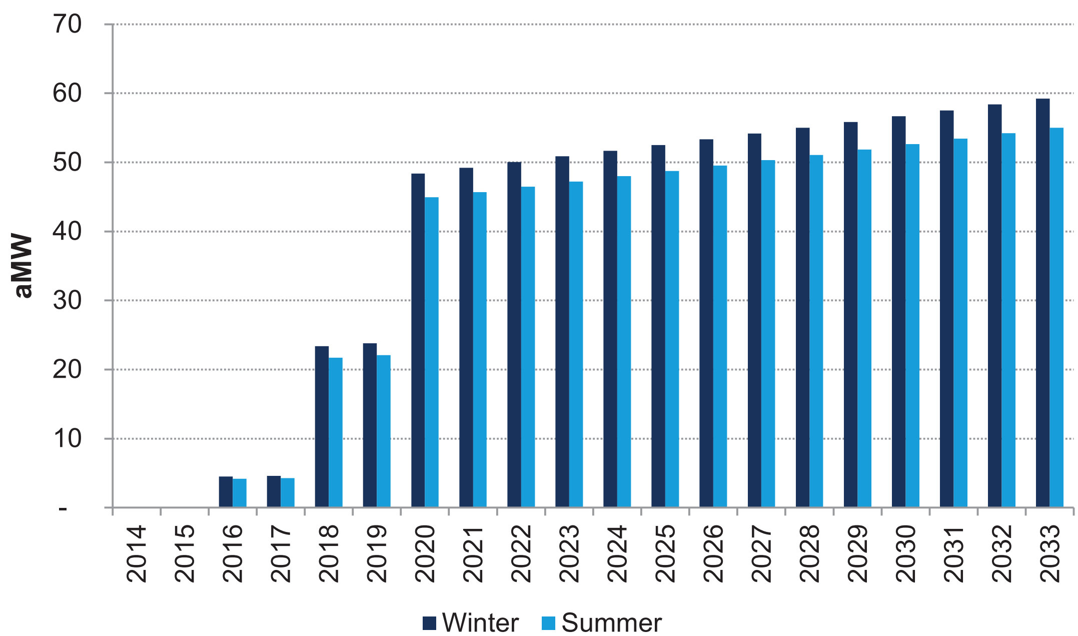
Table 36. Residential DLC Room Heat and Water Heat: Achievable Technical Potential, MW in 2033

End Use	Winter Market Potential	Summer Market Potential	Percent of System Peak - Winter	Percent of System Peak - Summer
Room Heat	4	-	0.1%	0.0%
Water Heat	55	55	1.2%	1.3%
Total	59	55	1.3%	1.3%

*System peak is based on PSE's average load in the top 20 hours and is calculated for each season.

Figure 45 shows the achievable potential for the central heat DLC program, based on an acquisition schedule starting in 2016, with a two-year pilot program, ramping up to full participation in 2020.

Figure 45. Residential DLC Room Heat and Water Heat Acquisition Schedule



All cost assumptions (except for technology costs) remain consistent with the central heating program. Table 37 and
Table 38 provide detailed assumptions.

Table 37. Residential DLC Room Heat and Water Heat: Program Basics

Program Concept	Assumptions
Customer Sectors Eligible	Residential customers in single-family and manufactured homes
End Uses Eligible for Program	Electric room heating (baseboard) and electric water heaters
Customer Size Requirements, if any	N/A
Winter Load Basis	Top 20 hours
Summer Load Basis	Top 20 hours

Table 38. Residential DLC Room Heat and Water Heat: Inputs and Sources

Inputs	Value	Sources or Assumptions
Annual Attrition (%)	5%	Studies have found 7% (composed of 5 % change-of-service and 2% removals) from utilities, including: PacifiCorp, Xcel Energy, Eon US, Sacramento Municipal Utility District,, Florida Power and Light (removals range from 1% to 3%). Removals are accounted for in event participation.
Per Customer Impacts (kW)	0.05 room heat 0.58 water heat	Based on PSE's central and water heating pilot. Per switch impacts are weighted by the morning and afternoon impacts.
Annual Administrative Costs (percent of annual costs)	5%	An additional utility administrative cost is added to the vendor program cost.
Annual Vendor Administrative Costs (percent of annual costs)	15%	Based on research of vendor bids and informal communications with vendors. Includes maintenance, administrative labor, and dispatch software.
Technology Cost	$280/water heat switch $280/baseboard switch $275/digital internet gateway	Based on PSE's experience during its Residential Demand Response Pilot Program. These costs include labor for installation. Assumes two baseboard switches per home.
Marketing Cost	$25	Marketing costs are based on 0.5 hour of staff time, valued at $50/hour (fully loaded).
Incentive (annual costs)	Room Heating $32 Water Heating $8	Incentives range from $30 to $35 for most utilities for one piece of equipment, and $8 for additional equipment. PSE's pilot program offered $50 for both space and water heating.
Technical Potential (as percent of Gross)	Room Heating 50% Water Heating 100%	Assumes all room units can be retrofit and the program employs a 50% cycling strategy. Due to the tank, water heating can be shut off for the entire event (100% reduction).
Program Participation (%)	Single-family and Manufactured 20% Multifamily 0% Room Heating, 20% Water Heat	Assumes 20% of customers with electric room heating will participate. Minimal data for DLC heating programs exists; therefore, the assumption is based on the average participation rate for national programs for DLC AC programs (between 15% and 20% of all residential customers, which translates to 20% to 30% of eligible customers). Due to the difficulty of reaching the multifamily segment, it is assumed that multifamily customers will only participate in this program's water heating portion. All customers with electric room heating will include water heating in the program; so participation rates have been adjusted to account for the percentage of electric heating customers with electric water heat.

Inputs	Value	Sources or Assumptions
Event Participation (%)	94%	Based on utility experience with DLC cooling programs, accounting for homeowners removing units and operational breakdowns (from 2.5% to 5.8%).

Nonresidential Load Curtailment

Load curtailment programs utilize contractual arrangements between the utility, a third-party aggregator that implements the program, and utility nonresidential customers that agree to curtail or interrupt their operations (in whole or part) for a predetermined period when requested by the utility. In most cases, mandatory participation or liquidated damage agreements are required once the customer enrolls in the program; however, the terms of each contract limit the number of curtailment requests—both in total and on a daily basis.

Generally, customers are not paid for individual events, but receive compensation through a fixed monthly amount per kW of pledged curtailable load, or through a rate discount. Typically, contracts require customers to curtail their connected load by a set percentage (typically, from 15% to 20%) or a predetermined level (e.g., 100 kW). Such programs often involve long-term contracts, with penalties for non-compliance, which range from simply dropping the customer from the program to more punitive actions, such as requiring the customer to repay the utility for the committed (but not curtailed) energy at market rates.

For this study, Cadmus assumes nonresidential customers with a monthly demand of at least 100 kW qualify for such a program. Backup generation plays a key role in potential savings associated with the curtailment program. As these participants can turn on a backup generator during critical peak times, customers with backup generators experience minimal burdens. In many utility programs (excluding those in California), customers may use backup generators to meet curtailment requirements; this assessment includes such customers.

Table 39 shows the estimated market potential by sector for winter and summer. The commercial sector makes up the majority of the estimated potential during both seasons.

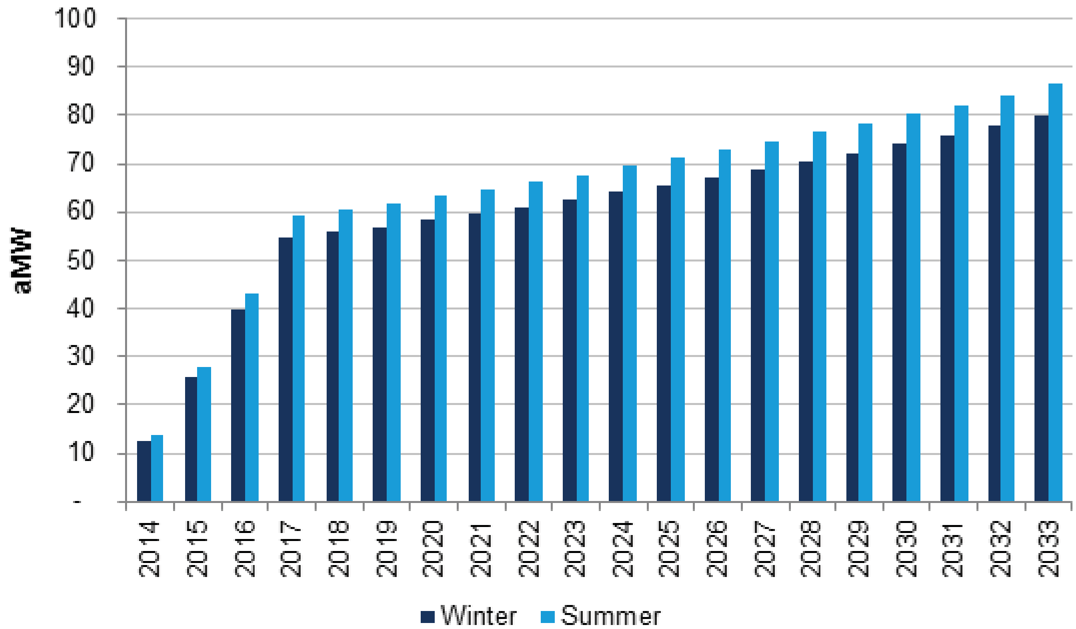
Table 39. Load Curtailment Achievable Technical Potential, MW in 2033

Sector	Winter Market Potential	Summer Market Potential	Percent of System Peak – Winter*	Percent of System Peak – Summer*
Commercial	76	82	1.7%	2.0%
Industrial	4	5	0.1%	0.1%
Total	80	87	1.8%	2.1%

*System peak is based on PSE's average load in the top 20 hours and is calculated for each season.

Figure 46 shows the curtailment program's achievable potential, based on an acquisition schedule beginning in 2014, and achieving approximately 25% of participation annually, until reaching full participation in 2017.

Figure 46. Load Curtailment Acquisition Schedule



Typically, curtailment programs run through third-party aggregators, which charge a set $/kW fee. This assessment considers utility administrative costs in addition to third-party aggregator costs. Table 40 and Table 41 provide detailed assumptions, including values and sources from which potential and levelized costs have been derived.

Table 40. Load Curtailment Program Basics

Program Concept	Assumptions
Customer Sectors Eligible	All industrial and commercial market segments
End Uses Eligible for Program	Total load of all end uses
Customer Size Requirements, if any	Customers >100kW
Winter Load Basis	Top 20 hours
Summer Load Basis	Top 20 hours

Table 41. Load Curtailment Inputs Consistent Across Market Segments

Inputs	Value	Sources or Assumptions
Vendor Costs	$80/kW	Based on third-party aggregator bid.
Annual Administrative Costs (%)	5%	Administrative costs are rolled into the $/kW cost.
Technology Cost (per new participant)	N/A	Included in third-party aggregator bid.
Marketing Cost (per new participant)	N/A	Included in third-party aggregator bid.
Incentives (annual costs per participating kW)	N/A	Included in third-party aggregator bid.
Overhead: First Costs	N/A	Included in third-party aggregator bid.
Technical Potential	30%	Customers shed between 26.9% and 34% of load for day-of and day-ahead events, respectively (2010 and 2011 Statewide Aggregator Demand Response Programs: Final Report, Christensen Associates).
Program Participation (%)	20%	Programs across the country experience participation rates from 4% (the Mid American Curtailment Program has 4.5%) to 30% (Georgia Power and Indiana Michigan Power Company).
Event Participation (%)	95%	Range of PJM and MidAm programs (90%–95%).

CPP

Under a CPP program, customers receive a discount on their retail rates during non-critical peak periods in exchange for paying premium prices during critical peak events. The peak price, however, is determined in advance, providing customers with some degree of certainty about participation costs.

The program follows the basic rate structure of a TOU tariff, where the rate has fixed prices for usage during different blocks of time (typically on-, off-, and mid-peak prices by season). During CPP events, the normal peak price under a TOU rate structure is replaced with a much higher price, generally set to reflect the utility's avoided cost of supply during peak periods.

CPP rates only take effect for a limited number of times during the year. In times of emergency or high market prices, the utility can invoke a critical peak event, notifying customers that rates have become much higher than normal and encouraging customers to shed or shift load. Most CPP programs provide advanced notice in addition to event criteria (such as a threshold for forecasted weather temperatures) to help customers plan their operations. One attractive feature of the CPP program is the absence of a mandatory curtailment requirement.

A CPP rate offers a benefit over a standard TOU rate in that an extreme price signal can be sent to customers for a limited number of events. For several reasons, utilities have found typically greater demand reductions during these events than during TOU peak periods:

- Customers under CPP rates often utilize automated controls, triggered by a signal from the utility.
- The higher CPP rate serves as an incentive for customers to shift load away during the CPP event period.
- The relative rarity of CPP events may encourage short-term behavioral changes, resulting in reduced consumption during the events.

As the CPP rate only applies on select days, this raises a number of questions about when a utility can call an event, for how long, and how often. The rules governing utility dispatch of CPP events vary widely by utility and by program, with some utilities reserving the right to call an event at any time, while others must provide notice one day before the event. This analysis assumes approximately 10 four-hour events will be called during the summer and winter, for a total of 40 event hours.

Table 42 shows the estimated market potential by sector for winter and summer.

Table 42. CPP Technical and Achievable Technical Potential, MW in 2033

Sector	Winter Market Potential	Summer Market Potential	Percent of System Peak – Winter*	Percent of System Peak – Summer*
Residential	14	9	0.3%	0.2%
Commercial	3	3	0.1%	0.1%
Industrial	0.1	0.2	0.0%	0.0%
Total	17	13	0.4%	0.3%

*System peak is based on PSE's average load in the top 20 hours and is calculated for each season.

Residential CPP

National studies have shown that 13% to 40%[21] of peak demand can be reduced for participating customers. Cadmus' study assumes a 15-percent reduction, based on the California pricing pilot and PSE's experience with the nonresidential curtailable load pilot. Five percent participation is consistent with the 2009 FERC study, with event participation estimated at 100%.

Figure 47 shows the market potential for the residential CPP program, based on an acquisition schedule that begins with a two-year pilot program in 2016, accounting for the time necessary to

[21] Charles River Associates (CRA), Impact Evaluation of the California Statewide Pricing Pilot, March 16, 2005.

California Energy Commission (CEC), Statewide Pricing Pilot load reduction data for Zone 4 (desert and inland climate), provided in MS Excel by Pat McAuliffe, CEC staff, via e-mail November 3, 2006.

Demand Response Research Center (DRRC), Ameren Critical Peak Pricing Pilot, Presentation by Rick Voytas, Manager of Corporate Analysis at Ameren Services, at the Demand Response Town Hall Meeting, Berkeley, CA, June 26, 2006.

International Energy Agency, Demand-Side Management Programme, Task XI: Time of Use Pricing and Energy Use for Demand Management Delivery, Subtask 2: Time of Use Pricing for Demand Management Delivery, April 2005.

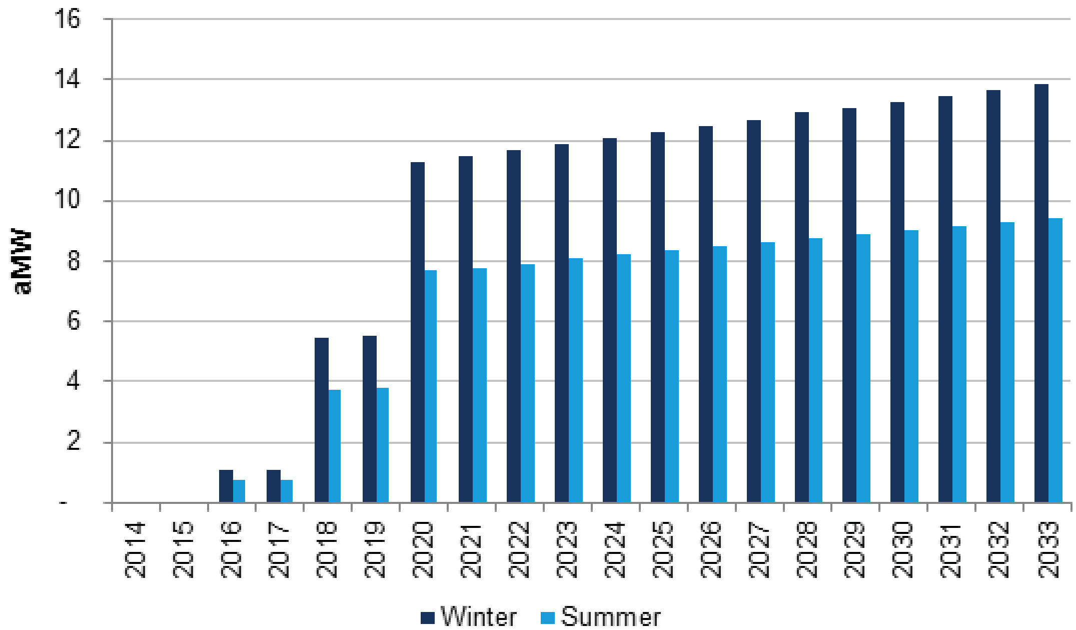
Rocky Mountain Institute, Automated Demand Response System Pilot, Final Report Volume 1: Introduction and Executive Summary, March 2006.

Summit Blue Consulting, Interim Report for the myPower Pricing Segment Evaluation, prepared for PSEG, December 27, 2006.

University of California Energy Institute (UCEI), Dynamic Pricing, Advanced Metering and Demand Response in Electricity Markets, S. Borenstein et al., October 2002.

create a new tariff and to put AMI infrastructure in place. This will likely be followed by two years of increased participation, reaching full participation in 2020.

Figure 47. Residential CPP Acquisition Schedule



The residential CPP program has a start-up cost of $400,000, as a new rate structure will be put in place. Additionally, the program will require installations of a smart thermostat and meter and ongoing communication, priced at $515 and $7 per participant, respectively. Marketing costs remain consistent with other program assumptions, and the program does not offer incentives due to its rate-based structure. Tables 39 and 40 show detailed assumptions of values and sources from which potential and levelized costs have been derived.

Table 43. Residential CPP Program Basics

Program Concept	Assumptions
Customer Sectors Eligible	All residential customers
End Uses Eligible for Program	Total load of all end uses
Customer Size Requirements, if any	N/A
Winter Load Basis	Top 20 hours
Summer Load Basis	Top 20 hours

Table 44. Residential CPP Inputs and Sources

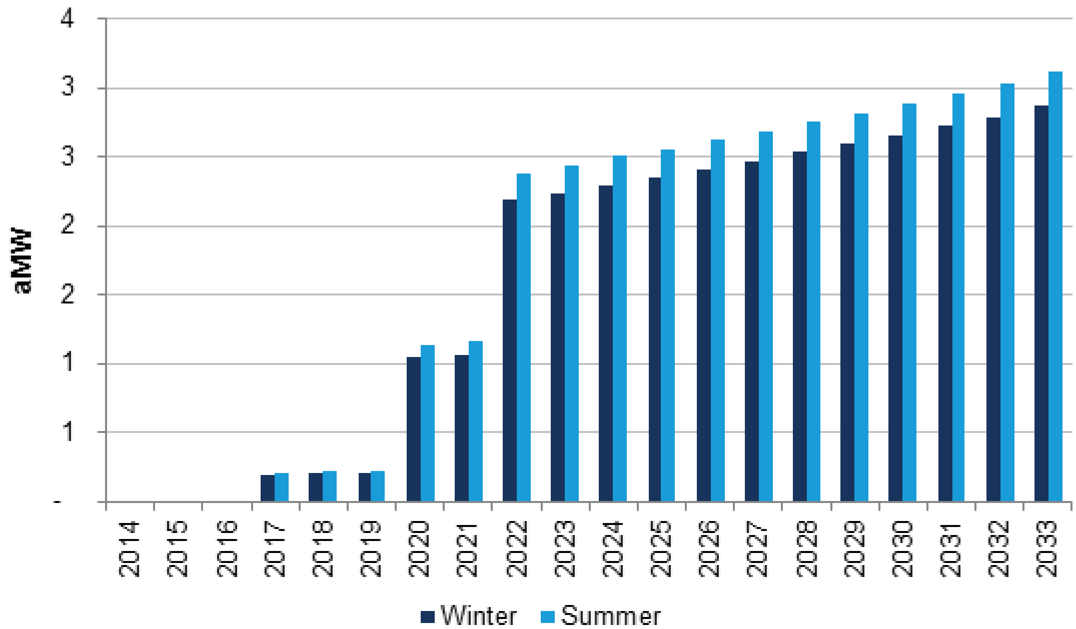
Inputs	Value	Sources or Assumptions
Annual Administrative Costs (%)	15%	Assumes administrative adder of 15%
Technology Cost (per new participant)	$515	Smart Thermostat: $200 installation and $315 for the meter, based on $150 for the installed cost of radio frequency devices (CEC 2004 report) plus an additional $150 to upgrade to AMI and $15/customer communication charge.
Marketing Cost (per new participant)	$25	Marketing costs are based on one-half hour of staff time valued at $50/hour (fully-loaded).
Incentives (annual costs per participant)	N/A	There are no customer incentives, but customers may have a lower bill than they would have on a standard rate.
Communication Costs (per Customer Per Year)	$7	This value accounts for annual per-customer communication of a one-way transmission system.
Overhead: First Costs	$400,000	Standard program development assumption, including necessary internal labor, research, and IT/billing system changes.
Eligible Load (%)	100%	All residential customers are eligible.
Technical Potential	15%	An average statewide reduction of 27% was found for the California residential pilot CPP programs implemented in the summer (Charles River Associates, 2005) with an on-peak rate approximately 6 times the off-peak rate. PSE's experience with a C&I pilot shows that winter events save about 50% less than summer events; therefore, event participation was reduced to 15%.
Program Participation (%)	5%	Gulf Power reported 8,500 participants as of October 2006, out of 350,000 residential customers (2.4%). (Sources: Jim Thompson presentation to PURC Energy Policy Roundtable, October 31, 2006; and FERC Form 861 data, 2005.) Gulf Power expects to reach at least 10% penetration. (Source: Dynamic Pricing, Advanced Metering and Demand Response in Electricity Markets, Severin Borenstein, Michael Jaske, and Arthur Rosenfeld, October 2002.) 2009 FERC study reports a 5% maximum participation rate.
Event Participation (%)	100%	Event participation is captured in the average load impact.

Nonresidential CPP

To develop potential estimates for PSE's CPP program, Cadmus relied on data from several CPP programs currently implemented in California. These data indicate generally low participation rates for commercial customers, ranging from 0.1% to 3.5% in California. Therefore, Cadmus considers a 2% participation rate reasonable for PSE. Table 45 and Table 46 summarize details for other program assumptions.

Figure 48 shows the estimated market potential for the nonresidential CPP program, based on an acquisition schedule that begins with a three-year pilot program in 2017, accounting for the time needed to create a new tariff and to put infrastructure in place. This will likely be followed by two years of increased participation, reaching full participation in 2022.

Figure 48. Nonresidential CPP Acquisition Schedule



The nonresidential CPP program also will have a start-up cost of $400,000, as a new rate structure will be put in place. Additionally, the program will require the installation of metering and communication equipment (priced at $500) and ongoing communication costs of $7 per participant. Marketing costs are assumed to be $500 per new customer; the program does not offer incentives due to its rate-based structure.

Table 45. Nonresidential CPP Program Basics

Program Concept	Assumptions
Customer Sectors Eligible	All nonresidential market segments
End Uses Eligible for Program	Total load of all end uses
Customer Size Requirements, if any	Nonresidential customers with monthly load greater than 100 kW
Winter Load Basis	Top 20 hours
Summer Load Basis	Top 20 hours

Table 46. Nonresidential CPP Inputs and Sources not Varying by Sector or Segment

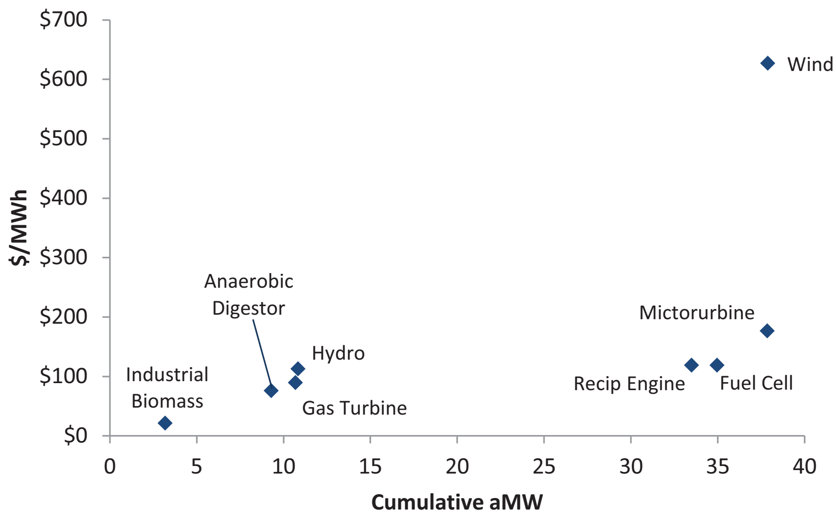
Inputs	Value	Sources or Assumptions
Annual Administrative Costs (%)	15%	Assumes administrative adder of 15%.
Technology Cost (per new participant)	$500	Based on PSE's estimate.
Marketing Cost (per new participant)	$500	Assumes 10 hours of effort by staff, valued at $50/hour. An additional hour per year is assumed for ongoing marketing and customer support.
Communication Costs (per customer per year)	$7	This value accounts for annual per-customer communication of a one-way transmission system.
Incentives (annual costs per participant)	N/A	There are no customer incentives, but customers may have a lower bill than they would have on a standard rate.
Overhead: First Costs	$400,000	Standard program development assumption, including necessary internal labor, research, and IT/billing system changes.
Technical Potential as percent of Load Basis	5%	In the 2010 CA Statewide Nonresidential CPP Evaluation, program impacts ranged from 2.8% to 5.26% of load for SCE, SDG&E and PG&E. In 2011, load impacts ranged by utility: PG&E averaged 5.9%, SCE averaged 5.7% and SDG&E averaged 5.8%.
Program Participation (%)	2%	Opt-in CPP programs typically exhibit low participation rates. In 2005, California experienced 1.1% participation rate across the state, which accounted for a total of 2.9% of peak load being enrolled. Individual utility participation ranged from 3.5% for PG&E to 0.1% for SCE. PG&E's on-peak energy rates during High-Price Periods and Moderate-Price Periods are five times and three times higher, respectively, than on-peak energy rates during non-event days. High-Price Periods and Moderate-Price Periods are about 9.3 times and 3.3 times higher, respectively, than on-peak rates during non-event.
Event Participation (%)	100%	Event participation is captured in the average load impact.

5. DISTRIBUTED GENERATION

This study does not include estimations for distributed generation potentials. For detailed information regarding distributed generation potentials, see Cadmus' 2008 report.[22]

Cadmus does, however, update the costs of the distributed generation resources for this study, thus impacting the supply curves for PSE's 2013 IRP. Figure 49 illustrates the resulting supply curve.

Figure 49. 20-Year Achievable Supply Curve for Distributed Generation



The levelized cost of energy (LCOE) for many of the DG technologies stayed constant or slightly decreased from the 2011 IRP to the 2013 IRP, as shown in Table 47.

[22] http://www.pse.com/SiteCollectionDocuments/2009IRP/AppL1_IRP09.pdf

Table 47. A Comparison of the Levelized Cost of Energy Results from the 2011 IRP and 2013 IRP

Category	DG Technology	2011 IRP LCOE ($/kWh)	2013 IRP LCOE ($/kWh)
CHP - Renewable	Anaerobic Digesters	$0.08	$0.08
	Industrial Biomass	$0.03	$0.02
CHP - Non-renewable	Reciprocating Engine	$0.13	$0.12
	Microturbine	$0.19	$0.18
	Fuel Cell	$0.21	$0.12
	Gas Turbine	$0.14	$0.09
Small Hydro	Hydro	$0.12	$0.11
Small Wind	Wind	$1.33	$0.63
Solar PV	PV	$0.56	$0.48

There are four technologies where the LCOE decreased substantially: fuel cells, gas turbines, small wind, and solar PV.

For the nonrenewable CHP systems, the change in the LCOE was influenced by changes to fuel cost assumptions, system cost assumptions and system performance assumptions. For the 2011 IRP, the average fuel costs in year one were $13.65. For the 2013 IRP, the average fuel costs in year one were $5.88. An overview of the changes to the other assumptions is shown in Table 48.

Table 48. A Comparison of the Non-Renewable CHP Assumptions for the 2011 IRP and the 2013 IRP

	Installed Cost ($/kW)		O&M Costs ($/kW/yr)		Capacity Factor		Heat Rate (MMBTU/MWh)	
	2011 IRP	2013 IRP*	2011 IRP	2013 IRP	2011 IRP	2013 IRP	2011 IRP	2013 IRP
Recip Engine	$2,300	$1,792	$79	$57	0.9	0.5	5	7.3
Micro Turbine	$2,600	$2,546	$72	$54	0.9	0.5	7.5	12.3
Fuel Cell	$5,900	$4,517	$15	$35	0.95	0.8	5.7	7.3
Gas Turbine	$1,600	$1,746	$49	$57	0.9	0.8	6.6	8.3

*The installed cost for the 2013 IRP is after the federal rebate.

The federal rebate was taken into account in the 2013 IRP, which decreased the installed cost by 10% for reciprocating engines, microturbines, and gas turbines, and by 30% for fuel cells. This was not included in the 2011 IRP. For all CHP systems except fuel cells and gas turbines, the LCOE remained the same or slightly decreased because updated assumptions about performance offset the cost differences. The capacity factors decreased (i.e. the systems were not operating for as many hours) and net heat rates increased (i.e. more fuel was used for the same electricity output) compared to what was used in the 2011 IRP. The net result was that the LCOE remained relatively constant for these systems.

For the fuel cells, however, the capacity factor remained approximately the same, the net heat rate increased, and the installed cost (after the federal rebate) decreased. As the federal rebate for fuel cells is higher than for the other technologies, the net overall impact was that the LCOE for the 2013 IRP decreased substantially relative to the 2011 IRP.

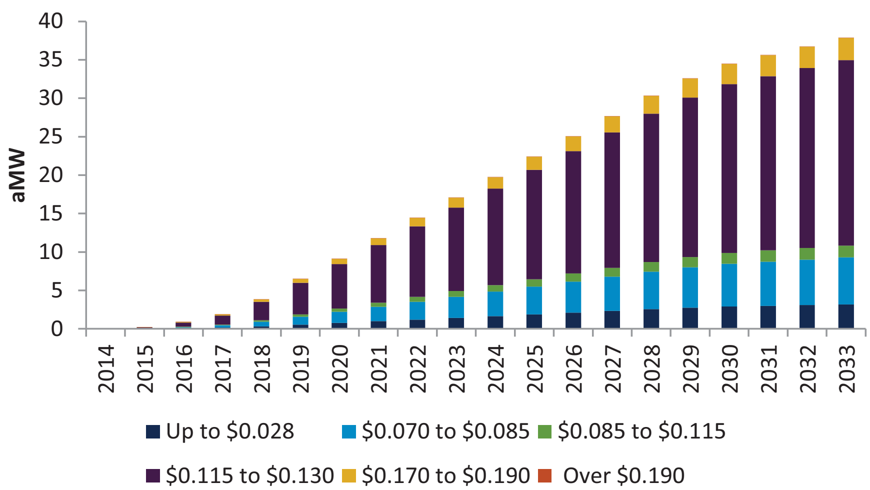
For gas turbines, the main driver in the decreased LCOE value was the decrease in fuel costs. On average, gas turbines are much larger systems than the other CHP systems and are online more hours of the year, therefore using more natural gas. As gas prices have decreased by over 50% from the 2011 IRP to the 2013 IRP, this had a large impact on the LCOE of gas turbines.

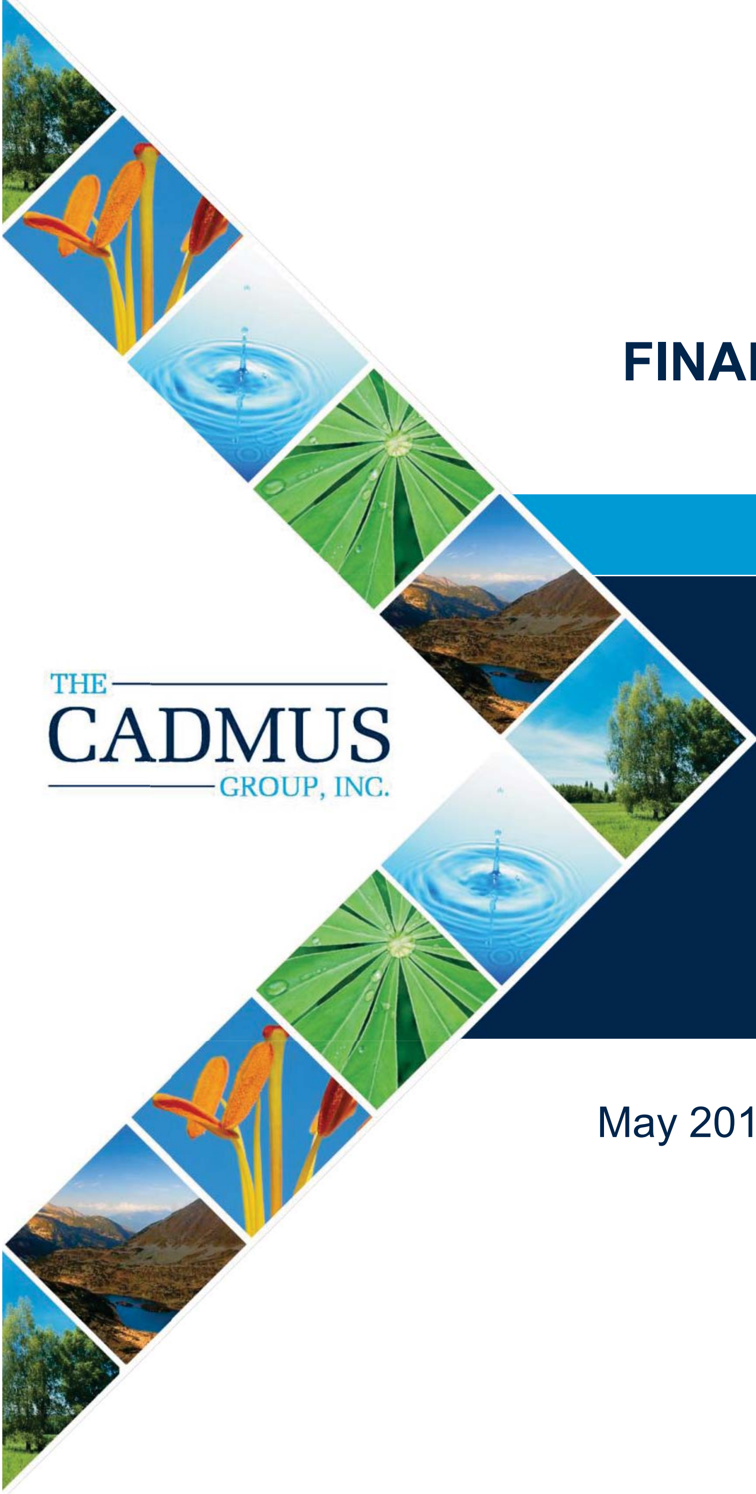
For small wind systems, the installed cost decreased from $9.00 per Watt for a 10 kW system in the 2011 IRP to $5.00 per Watt for a 10 kW system in the 2013 IRP. This drove down the LCOE value.

The cost of PV has decreased over the past few years. For the 2011 IRP we assumed a cost of $9.00 per Watt for both residential and commercial systems. For the 2013 IRP we assumed a cost of $7.45 per Watt for residential systems and $6.67 per Watt for commercial systems. This decrease in installed cost drove the reduction in the LCOE.

Figure 50 shows the cumulative potential available in each year of this study, by levelized cost bundle.

Figure 50. Annual Achievable Distributed Generation Potential by Levelized Cost Bundle





FINAL REPORT

Comprehensive Assessment of Demand-Side Resource Potentials (2014–2033): Appendices

Volume II

May 2013

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Appendix A. Methodological Consistency with the 6th Northwest Power Plan

To facilitate a comparison with the 6th Power Plan, the Council prepared an overview of the methodology used in developing the 6th Power Plan's of conservation potential estimates.[1] This appendix compares the methodology used in PSE's 2013 IRP to the benchmarks established by the Council.

Italics denote descriptions of methodologies used in this study.

Technical Resource Potential Assessment

The assessment reviewed a wide array of energy-efficiency technologies and practices across all sectors and major end uses.

> *The study considered measures from a variety of sources, including the 6th Plan, RTF, ENERGY STAR, and DEER. Appendix B.2 provides descriptions of all measures analyzed.*

Methodology

- Technically feasibility savings = Number of applicable units * incremental savings/applicable unit
- "Applicable" units accounted for:
  - Fuel saturations (e.g., electric vs. gas DHW).

    Whenever possible, fuel saturations were based on data specific to PSE's service territory. PSE's 2010 Residential Energy Study (RES) and NEEA's 2008 Commercial Building Stock Assessment (CBSA) served as the primary sources of this information.
  - Building characteristics (e.g., single-family vs. mobile homes, basement/non-basement).

    Data derived from RES, CBSA, and PSE billing information.
  - System saturations (e.g., heat pump vs. zonal, central AC vs. window AC).

    Whenever possible, system saturations were based on data specific to PSE's service territory. PSE's 2010 RES and NEEA's 2008 CBSA served as the primary sources of this information.
  - Current measure saturations.

    Current saturations were incorporated into the applicability, based on information from the RES and CBSA, the 6th Plan, RTF, and the experience of PSE conservation staff.

[1] http://www.nwcouncil.org/energy/powerplan/6/supplycurves/I937/CouncilMethodology_outline%20_2_.pdf

- New and existing units.

  Existing and new units were calculated based on current and forecasted customers, respectively.

- Measure life (stock turnover cycle).

  Measure decay rates were applied to lost opportunity measures, based on measure life. Discretionary measures were assumed to be reinstalled at the end of their useful life.

- Measure substitutions (e.g., duct sealing of homes with forced-air resistance furnaces vs. conversion of homes to heat pumps with sealed ducts).

  The measure share applicability factor accounted for competition between measures to avoid double-counting.

- "Incremental" savings/applicable unit accounted for:
  - Expected kW and kWh savings, shaped by time-of-day, day of week and month of year.

    Energy and demand savings were either based on deemed values or calculated as a percent reduction in baseline end-use consumption. Hourly impacts were provided to PSE's IRP model.

  - Savings over baseline efficiency.
    - Baseline set by codes/standards or current practices.

      Baselines were set based on current codes, standards, or current practices. Standards passed but not yet implemented became the baseline at the time mandated in the new standard.

    - Not always equivalent to savings over "current use" (e.g., new refrigerator savings measured as "increment above current federal standards," not the refrigerator being replaced).

      Savings from equipment upgrades were calculated based on the minimum standard efficiency level available at the time of burnout.

  - Climate—heating, cooling degree days, and solar availability.

    Savings were based on the typical climate in PSE's service territory.

  - Measure interactions (e.g., lighting and HVAC, duct sealing and heat pump performance, heat pump conversion, and weatherization savings).

    These interactive effects were treated as a reduction in measure savings (e.g., commercial lighting measures might save less due to increased heating requirements).

Economic Potential: Ranking Based on Resource Valuation

- The total resource cost (TRC) served as the criterion for economic screening, and included all cost and benefits of measures, regardless of the parties paying for or receiving them.

- TRC B/C Ratio > = 1.0

  Benefit-to-cost ratios were not calculated. Analysis used the levelized cost of conserved energy, as described below.

- Levelized cost of conserved energy (CCE) < levelized avoided cost for the load shape of the savings could substitute for TRC if "CCE" was adjusted to account for "non-kWh" benefits, including deferred T&D, non-energy benefits, environmental benefits, and the Act's 10% conservation credit.

  Levelized costs, on a TRC basis, were calculated for each measure in comparison with the Integrated Resource Planning's (IRP) supply-side resources. The levelized cost calculation incorporated deferred T&D (for electric resources), non-energy benefits, secondary fuel benefits, and the Act's 10% conservation credit (for electric resources).

Methodology

As valuation of energy and capacity savings was conducted in PSE's IRP model, it was not included as part of this study.

- The energy and capacity value (i.e., benefit) of savings was based on the avoided cost of future wholesale market purchases (forward price curves).
- The energy and capacity value accounted for the shape of savings (i.e., used time and seasonally differentiated avoided costs and measure savings).
- Uncertainties in future market prices were accounted for by performing the valuation under a wide range of future market price scenarios during the IRP process.
- Costs inputs (resource cost elements):

  All costs listed below were included in the per-unit measure costs, where appropriate.

  - Full incremental measure costs (material and labor).
  - Applicable ongoing O&M expenses (plus or minus).
  - Applicable periodic O&M expenses (plus or minus).
  - Utility administrative costs (e.g., program planning, marketing, delivery, ongoing administration, evaluation).
- Benefit inputs (resource value elements):

  All benefits listed below were assessed in calculating the levelized cost of conserved energy, where appropriate.

  - Direct energy savings.
  - Direct capacity savings.
  - Avoided T&D losses.
  - Deferral value of transmission and distribution system expansion (if applicable).
  - Non-energy benefits (e.g., water savings).

    - Environmental externalities.
- Discounted presented value inputs:
    - Rate = After-tax average cost of capital weighted for project participants (real or nominal).

      The analysis used PSE's weighted average capital cost of 7.8%, nominal.
    - Term = Project life; generally equivalent to life of resources added during the planning period.

      Costs were levelized over each measure's expected useful life. Any reinstallation costs over the 20-year planning period were similarly levelized.
    - Money was discounted, not energy savings.

      The IRP analysis used this method.

Achievable Potential

- Annual acquisition targets, established through the IRP process (i.e., portfolio modeling).

  The results of the potentials assessment, bundled by levelized costs of conserved energy, were incorporated in the IRP model. Based on the value of savings, the IRP model selected the appropriate amount of conservation.
- Conservation competed against all other resource options in portfolio analysis:
    - Conservation resource supply curves separated into:
        - Discretionary (non-lost opportunity).

          Defined as retrofit opportunities in existing facilities.
        - Lost-opportunity.

          Including equipment replacements in existing facilities and all new construction measures.
        - Annual achievable potential, constrained by historic "ramp rates" for discretionary and lost-opportunity resources:
            - The maximum ramp-up/ramp-down rate for discretionary was 3x the prior year for discretionary, with an upper limit of 85% over the 20-year planning period.

              Analysis assumed 85% of discretionary resources could be acquired within a 10-year timeframe.
            - The ramp rate for a lost-opportunity was 15% in first year, growing to 85% by the 12th year.

              Lost opportunity ramp rates varied by measure, and were based on the assumptions used in the 6th Plan.

    - Achievable potentials could vary by the type of measure, customer sector, and program design (e.g., measures subject to federal standards could have 100% "achievable" potential).

      While the analysis removed savings from known standards, it did not attempt to predict which savings would be acquired from future codes or standards.

- Revised technical, economic and achievable potential, based on changes in market conditions (e.g., revised codes or standards), program accomplishments, evaluations, and experience.

  Changes taking effect after the finalization of the 2013 IRP will be reflected in the 2015 IRP.

  - All programs should incorporate Measurement and Verification (M&V) plans that, at a minimum, track administrative and measure costs and savings.
  - The International Performance Measurement and Verification Protocols (IPMVP) should be used as a guide.

Appendix B.1: Detailed Results

The following graphs show baseline electric and gas forecasts by sector and segment. The following tables show assumptions of gas and electric equipment, fuel shares, annual per unit energy consumption for residential end uses, and annual per square foot energy consumption for commercial end uses.

Figure B.1.1. Residential Electric Baseline Forecast 2013-2033

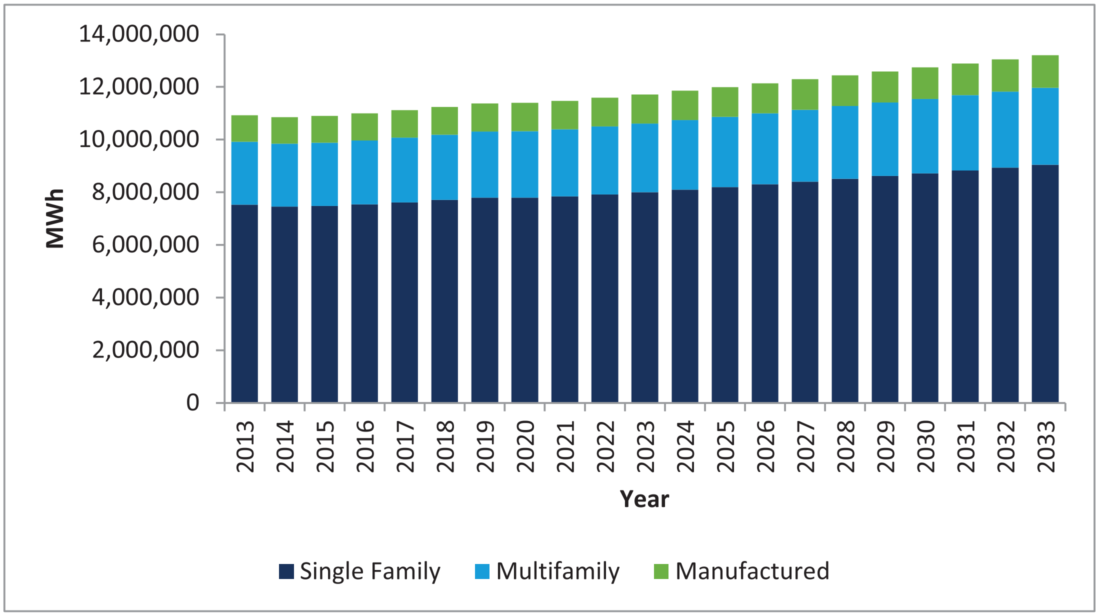

Figure B.1.2. Commercial Electric Baseline Forecast 2013-2033

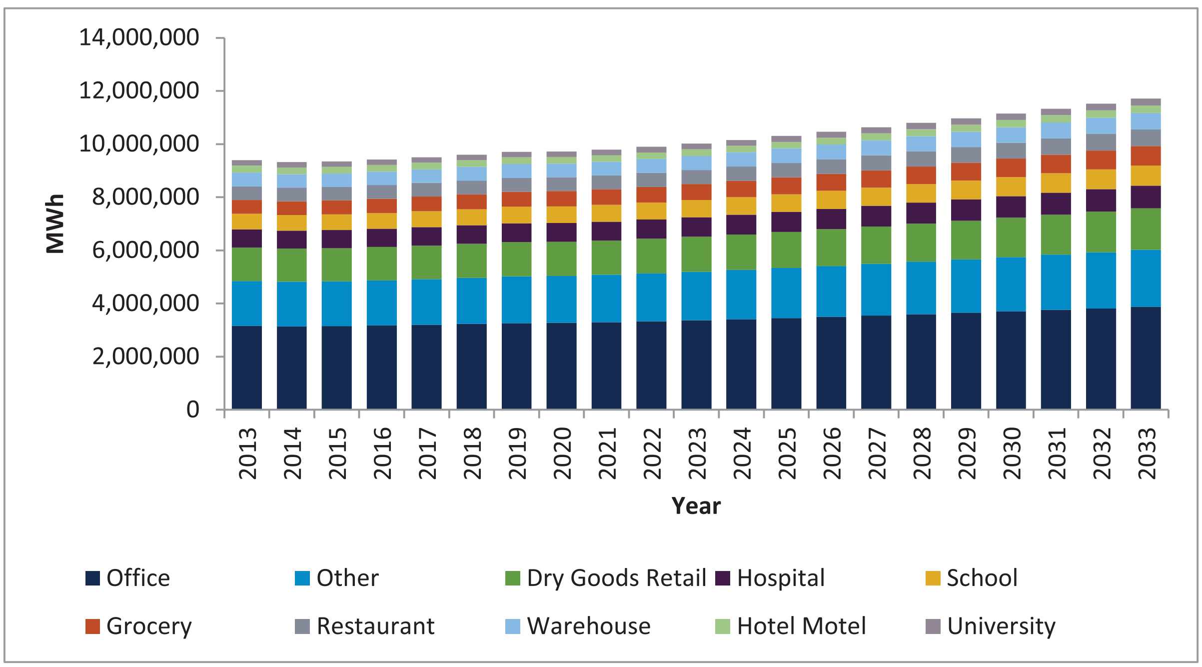

Figure B.1.3. Industrial Electric Baseline Forecast 2013-2033

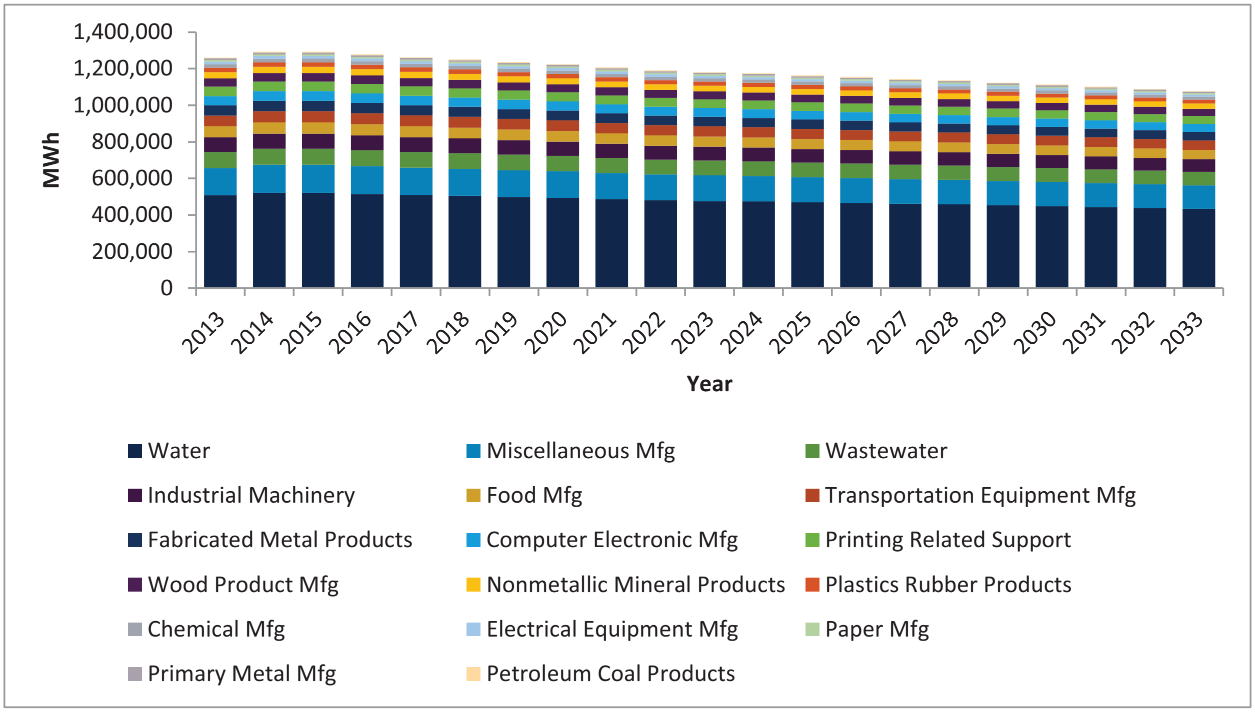

Figure B.1.4. Residential Gas Baseline Forecast

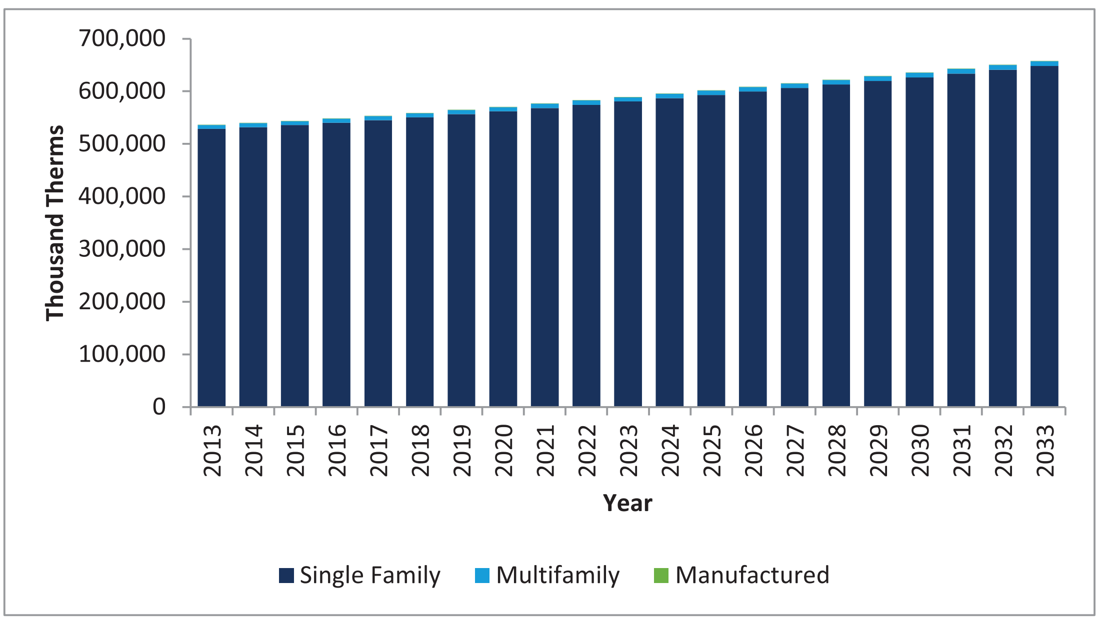

Figure B.1.5. Commercial Gas Baseline Forecast 2013-2033

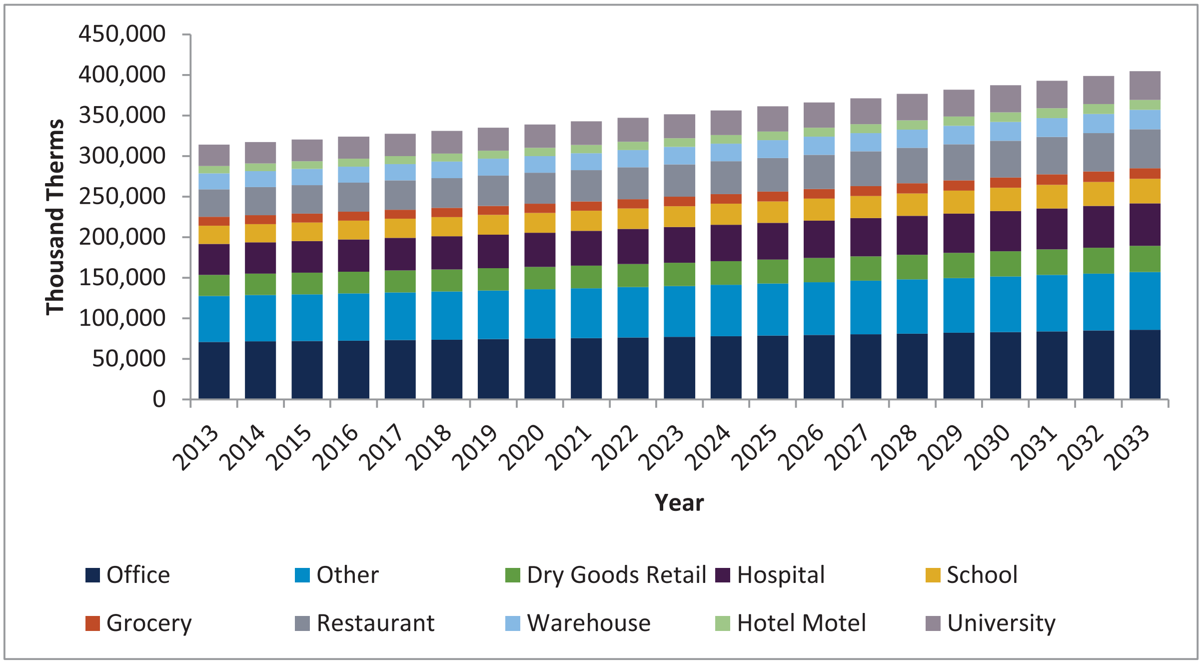

Figure B.1.6. Industrial Gas Baseline Forecast 2013-2033

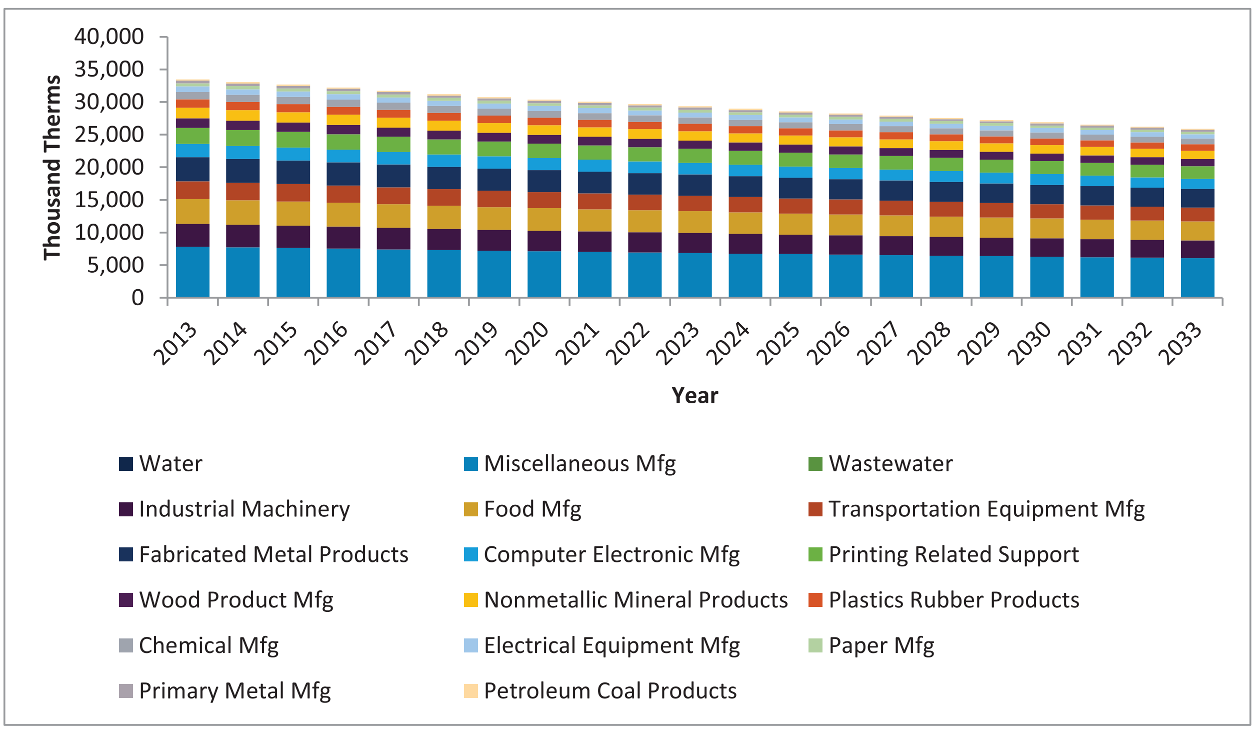

Table B.1.1 Residential Electric Saturations, Fuel Shares, and UECs

Segment	End Use	Saturation	Electric Fuel Share	Weighted Average UEC Existing	Weighted Average UEC New
Manufactured	Computer	0.90	100%	193	184
Manufactured	Cooking Oven	0.71	88%	157	157
Manufactured	Cooking Range	0.67	88%	128	128
Manufactured	Cool Central	0.28	100%	399	332
Manufactured	Cool Room	0.18	100%	146	136
Manufactured	Copier	0.00	100%	84	88
Manufactured	Dehumidifier	0.01	100%	711	685
Manufactured	Dryer	0.93	94%	727	709
Manufactured	DVD	1.46	100%	22	21
Manufactured	Freezer	0.54	100%	345	345
Manufactured	Heat Central	0.66	73%	8,204	3,669
Manufactured	Heat Pump	0.17	100%	4,128	1,955
Manufactured	Heat Room	0.05	100%	6,796	3,229
Manufactured	Home Audio System	0.92	100%	103	96
Manufactured	Lighting Exterior	2.73	100%	81	81
Manufactured	Lighting Interior Specialty	3.43	100%	13	13
Manufactured	Lighting Interior Standard	19.44	100%	22	22
Manufactured	Microwave	0.52	100%	148	148
Manufactured	Monitor	0.72	100%	56	60
Manufactured	Multifunction Device	0.98	100%	16	11
Manufactured	Other	1.00	100%	0	0
Manufactured	Plug Load Other	1.00	100%	0	0
Manufactured	Printer	0.00	100%	71	62
Manufactured	Refrigerator	1.24	100%	391	391
Manufactured	Set Top Box	1.33	100%	187	185
Manufactured	TV	1.69	100%	195	187
Manufactured	TV Bigscreen	0.56	100%	0	0
Manufactured	Ventilation And Circulation	0.66	100%	588	145
Manufactured	Water Heat GT 55 Gal	0.08	88%	3,245	2,875
Manufactured	Water Heat LE 55 Gal	0.92	88%	3,206	2,770
Multifamily	Computer	0.90	100%	193	184
Multifamily	Cooking Oven	0.80	84%	157	157
Multifamily	Cooking Range	0.76	81%	128	128
Multifamily	Cool Central	0.14	100%	267	281
Multifamily	Cool Room	0.10	100%	93	105
Multifamily	Copier	0.05	100%	84	88

Multifamily	Dehumidifier	0.02	100%	711	685
Multifamily	Dryer	0.81	96%	889	867
Multifamily	DVD	1.25	100%	22	21
Multifamily	Freezer	0.15	100%	345	345
Multifamily	Heat Central	0.47	22%	6,607	2,303
Multifamily	Heat Pump	0.01	100%	2,900	1,208
Multifamily	Heat Room	0.63	100%	4,683	1,771
Multifamily	Home Audio System	0.80	100%	103	96
Multifamily	Lighting Exterior	2.25	100%	81	81
Multifamily	Lighting Interior Specialty	2.83	100%	9	9
Multifamily	Lighting Interior Standard	16.02	100%	20	20
Multifamily	Microwave	0.69	100%	148	148
Multifamily	Monitor	1.05	100%	56	60
Multifamily	Multifunction Device	0.89	100%	16	11
Multifamily	Other	1.00	100%	0	0
Multifamily	Plug Load Other	1.00	100%	0	0
Multifamily	Printer	0.00	100%	71	62
Multifamily	Refrigerator	1.09	100%	391	391
Multifamily	Set Top Box	1.01	100%	187	185
Multifamily	TV	1.35	100%	195	187
Multifamily	TV Bigscreen	0.58	100%	0	0
Multifamily	Ventilation And Circulation	0.47	100%	460	117
Multifamily	Water Heat GT 55 Gal	0.08	73%	1,921	1,743
Multifamily	Water Heat LE 55 Gal	0.91	73%	1,897	1,679
Single Family	Computer	1.21	100%	193	184
Single Family	Cooking Oven	0.98	81%	157	157
Single Family	Cooking Range	0.85	63%	128	128
Single Family	Cool Central	0.32	100%	648	569
Single Family	Cool Room	0.08	100%	237	228
Single Family	Copier	0.10	100%	84	88
Single Family	Dehumidifier	0.03	100%	711	685
Single Family	Dryer	0.98	86%	975	951
Single Family	DVD	1.65	100%	22	21
Single Family	Freezer	0.56	100%	345	345
Single Family	Heat Central	0.74	7%	14,344	4,877
Single Family	Heat Pump	0.05	100%	6,744	2,346
Single Family	Heat Room	0.07	100%	9,293	3,160
Single Family	Home Audio System	1.08	100%	103	96
Single Family	Lighting Exterior	4.95	100%	81	81
Single Family	Lighting Interior Specialty	6.21	100%	20	20
Single Family	Lighting Interior Standard	35.22	100%	24	24

Single Family	Microwave	0.83	100%	148	148
Single Family	Monitor	1.30	100%	56	60
Single Family	Multifunction Device	1.21	100%	16	11
Single Family	Other	1.00	100%	0	0
Single Family	Plug Load Other	1.00	100%	0	0
Single Family	Pool Pump	0.03	100%	1,457	1,457
Single Family	Printer	0.00	100%	71	62
Single Family	Refrigerator	1.46	100%	391	391
Single Family	Set Top Box	1.51	100%	187	185
Single Family	TV	1.90	100%	195	187
Single Family	TV Bigscreen	0.87	100%	0	0
Single Family	Ventilation And Circulation	0.74	100%	1,073	403
Single Family	Water Heat GT 55 Gal	0.08	34%	3,356	2,980
Single Family	Water Heat LE 55 Gal	0.97	34%	3,315	2,871

Table B.1.2 Residential Natural Gas Saturations, Fuel Shares and UECs

Vintage	Segment	End Use	Saturation	Natural Gas Fuel Share	Weighted Average UEC - Existing	Weighted Average UEC - New
Existing	Manufactured	Cooking Oven	0.71	16%	23	23
Existing	Manufactured	Cooking Range	0.67	7%	27	27
Existing	Manufactured	Dryer	0.93	6%	28	27
Existing	Manufactured	Heat Central Boiler	0.00	100%	421	185
Existing	Manufactured	Heat Central Furnace	0.88	20%	421	187
Existing	Manufactured	Other	1.00	100%	0	0
Existing	Manufactured	Water Heat GT 55 Gal	0.08	7%	216	173
Existing	Manufactured	Water Heat LE 55 Gal	0.92	7%	199	159
Existing	Multifamily	Cooking Oven	0.80	8%	23	23
Existing	Multifamily	Cooking Range	0.80	19%	27	27
Existing	Multifamily	Dryer	0.81	4%	34	33
Existing	Multifamily	Heat Central Boiler	0.01	100%	663	228
Existing	Multifamily	Heat Central Furnace	0.57	77%	365	126
Existing	Multifamily	Other	1.00	100%	0	0
Existing	Multifamily	Water Heat GT 55 Gal	0.08	27%	185	161
Existing	Multifamily	Water Heat LE 55 Gal	0.91	27%	170	148

Existing	Single Family	Cooking Oven	0.98	17%	23	23
Existing	Single Family	Cooking Range	0.85	33%	27	27
Existing	Single Family	Dryer	0.98	14%	37	36
Existing	Single Family	Heat Central Boiler	0.02	100%	919	261
Existing	Single Family	Heat Central Furnace	0.88	90%	690	197
Existing	Single Family	Other	1.00	100%	0	0
Existing	Single Family	Pool Heat	0.03	32%	258	258
Existing	Single Family	Water Heat GT 55 Gal	0.08	61%	330	264
Existing	Single Family	Water Heat LE 55 Gal	0.97	61%	303	243

Table B.1.3. Commercial Electric Saturations, Fuel Shares, and EUIs

Vintage	Segment	End Use	Saturation	Electric Fuel Share	Weighted Average EUI - Existing	Weighted Average EUI - New
Existing	Dry Goods Retail	Computers	1.00	100%	0.08	0.08
Existing	Dry Goods Retail	Cooling DX	0.48	100%	1.85	0.92
Existing	Dry Goods Retail	Fax	1.00	100%	0.01	0.01
Existing	Dry Goods Retail	Flat Screen Monitors	1.00	100%	0.02	0.02
Existing	Dry Goods Retail	Freezer	1.00	100%	0.00	0.00
Existing	Dry Goods Retail	Heat Pump	0.10	100%	2.85	1.41
Existing	Dry Goods Retail	Lighting Exterior	1.00	100%	1.09	1.09
Existing	Dry Goods Retail	Lighting Interior Fluorescent	1.00	100%	4.75	0.00
Existing	Dry Goods Retail	Lighting Interior HID	1.00	100%	0.84	0.00
Existing	Dry Goods Retail	Lighting Interior Other	1.00	100%	0.23	6.10
Existing	Dry Goods Retail	Lighting Interior Screw Base	1.00	100%	1.62	0.00
Existing	Dry Goods Retail	Other	1.00	100%	0.00	0.00
Existing	Dry Goods Retail	Other Plug Load	1.00	100%	0.64	0.64
Existing	Dry Goods Retail	Photo Copiers	1.00	100%	0.02	0.02
Existing	Dry Goods Retail	Printers	1.00	100%	0.01	0.01

Existing	Dry Goods Retail	Refrigerator	1.00	100%	0.02	0.02
Existing	Dry Goods Retail	Space Heat	0.78	24%	1.98	0.44
Existing	Dry Goods Retail	Vending Machines	1.00	100%	0.07	0.07
Existing	Dry Goods Retail	Ventilation and Circulation	0.88	100%	2.66	2.17
Existing	Dry Goods Retail	Water Heat GT 55 Gal	1.00	68%	0.28	0.28
Existing	Dry Goods Retail	Water Heat LE 55 Gal	1.00	68%	0.27	0.27
Existing	Grocery	Computers	1.00	100%	0.05	0.05
Existing	Grocery	Cooking	1.00	56%	2.66	2.66
Existing	Grocery	Cooling DX	0.59	100%	1.71	1.44
Existing	Grocery	Fax	1.00	100%	0.02	0.02
Existing	Grocery	Flat Screen Monitors	1.00	100%	0.01	0.01
Existing	Grocery	Freezer	1.00	100%	0.00	0.00
Existing	Grocery	Heat Pump	0.13	100%	4.55	1.65
Existing	Grocery	Lighting Exterior	1.00	100%	1.05	1.05
Existing	Grocery	Lighting Interior Fluorescent	1.00	100%	7.04	0.00
Existing	Grocery	Lighting Interior HID	1.00	100%	1.01	0.00
Existing	Grocery	Lighting Interior Other	1.00	100%	0.16	7.43
Existing	Grocery	Lighting Interior Screw Base	1.00	100%	1.12	0.00
Existing	Grocery	Other	1.00	100%	0.00	0.00
Existing	Grocery	Other Plug Load	1.00	100%	0.99	0.99
Existing	Grocery	Photo Copiers	1.00	100%	0.08	0.08
Existing	Grocery	Printers	1.00	100%	0.01	0.01
Existing	Grocery	Refrigeration	1.00	100%	20.12	20.12
Existing	Grocery	Refrigerator	1.00	100%	0.05	0.05
Existing	Grocery	Space Heat	0.73	11%	2.14	0.19
Existing	Grocery	Vending Machines	1.00	100%	0.19	0.19
Existing	Grocery	Ventilation and Circulation	0.87	100%	2.14	2.56
Existing	Grocery	Water Heat GT 55 Gal	1.00	32%	0.30	0.30
Existing	Grocery	Water Heat LE 55 Gal	1.00	32%	0.28	0.30
Existing	Hospital	Computers	1.00	100%	0.35	0.35
Existing	Hospital	Cooking	1.00	32%	0.54	0.54
Existing	Hospital	Cooling Chillers	0.23	100%	1.55	0.42
Existing	Hospital	Cooling DX	0.49	100%	1.89	0.49
Existing	Hospital	Fax	1.00	100%	0.01	0.01
Existing	Hospital	Flat Screen Monitors	1.00	100%	0.08	0.08
Existing	Hospital	Freezer	1.00	100%	0.01	0.01
Existing	Hospital	Heat Pump	0.07	100%	3.62	1.54

Existing	Hospital	Lighting Exterior	1.00	100%	0.58	0.58
Existing	Hospital	Lighting Interior Fluorescent	1.00	100%	4.93	0.00
Existing	Hospital	Lighting Interior HID	1.00	100%	0.11	0.00
Existing	Hospital	Lighting Interior Other	1.00	100%	0.27	4.72
Existing	Hospital	Lighting Interior Screw Base	1.00	100%	1.86	0.00
Existing	Hospital	Other	1.00	100%	0.00	0.00
Existing	Hospital	Other Plug Load	1.00	100%	3.53	3.53
Existing	Hospital	Photo Copiers	1.00	100%	0.02	0.02
Existing	Hospital	Printers	1.00	100%	0.03	0.03
Existing	Hospital	Refrigeration	1.00	100%	0.44	0.44
Existing	Hospital	Refrigerator	1.00	100%	0.11	0.11
Existing	Hospital	Servers	1.00	100%	0.06	0.06
Existing	Hospital	Space Heat	0.87	48%	1.26	0.69
Existing	Hospital	Vending Machines	1.00	100%	0.05	0.05
Existing	Hospital	Ventilation and Circulation	0.93	100%	5.37	4.19
Existing	Hospital	Water Heat GT 55 Gal	1.00	48%	1.41	1.39
Existing	Hospital	Water Heat LE 55 Gal	1.00	48%	1.32	1.37
Existing	Hotel Motel	Computers	1.00	100%	0.08	0.08
Existing	Hotel Motel	Cooking	1.00	8%	0.65	0.65
Existing	Hotel Motel	Cooling Chillers	0.27	100%	1.36	0.46
Existing	Hotel Motel	Cooling DX	0.16	100%	1.68	0.53
Existing	Hotel Motel	Fax	1.00	100%	0.00	0.00
Existing	Hotel Motel	Flat Screen Monitors	1.00	100%	0.02	0.02
Existing	Hotel Motel	Freezer	1.00	100%	0.02	0.02
Existing	Hotel Motel	Heat Pump	0.27	100%	3.80	1.94
Existing	Hotel Motel	Lighting Exterior	1.00	100%	0.66	0.66
Existing	Hotel Motel	Lighting Interior Fluorescent	1.00	100%	1.06	0.00
Existing	Hotel Motel	Lighting Interior HID	1.00	100%	0.04	0.00
Existing	Hotel Motel	Lighting Interior Other	1.00	100%	0.03	2.55
Existing	Hotel Motel	Lighting Interior Screw Base	1.00	100%	3.51	0.00
Existing	Hotel Motel	Other	1.00	100%	0.00	0.00
Existing	Hotel Motel	Other Plug Load	1.00	100%	0.78	0.78
Existing	Hotel Motel	Photo Copiers	1.00	100%	0.01	0.01
Existing	Hotel Motel	Printers	1.00	100%	0.01	0.01
Existing	Hotel Motel	Refrigeration	1.00	#N/A	0.19	0.19
Existing	Hotel Motel	Refrigerator	1.00	100%	0.20	0.20
Existing	Hotel Motel	Space Heat	0.57	53%	4.02	2.56
Existing	Hotel Motel	Vending Machines	1.00	100%	0.09	0.09

Existing	Hotel Motel	Ventilation and Circulation	0.90	100%	3.25	2.02
Existing	Hotel Motel	Water Heat GT 55 Gal	1.00	39%	1.74	1.75
Existing	Hotel Motel	Water Heat LE 55 Gal	1.00	39%	1.64	1.72
Existing	Office	Computers	1.00	100%	0.63	0.63
Existing	Office	Cooling Chillers	0.23	100%	1.62	0.62
Existing	Office	Cooling DX	0.39	100%	1.53	0.54
Existing	Office	Fax	1.00	100%	0.01	0.01
Existing	Office	Flat Screen Monitors	1.00	100%	0.14	0.14
Existing	Office	Freezer	1.00	100%	0.00	0.00
Existing	Office	Heat Pump	0.28	100%	3.00	1.30
Existing	Office	Lighting Exterior	1.00	100%	0.51	0.51
Existing	Office	Lighting Interior Fluorescent	1.00	100%	3.09	0.00
Existing	Office	Lighting Interior HID	1.00	100%	0.12	0.00
Existing	Office	Lighting Interior Other	1.00	100%	0.03	2.74
Existing	Office	Lighting Interior Screw Base	1.00	100%	0.49	0.00
Existing	Office	Other	1.00	100%	0.00	0.00
Existing	Office	Other Plug Load	1.00	100%	0.38	0.38
Existing	Office	Photo Copiers	1.00	100%	0.02	0.02
Existing	Office	Printers	1.00	100%	0.05	0.05
Existing	Office	Refrigerator	1.00	100%	0.04	0.04
Existing	Office	Servers	1.00	100%	0.10	0.10
Existing	Office	Space Heat	0.56	61%	3.21	0.66
Existing	Office	Vending Machines	1.00	100%	0.09	0.09
Existing	Office	Ventilation and Circulation	0.85	100%	1.53	1.29
Existing	Office	Water Heat GT 55 Gal	1.00	82%	0.47	0.47
Existing	Office	Water Heat LE 55 Gal	1.00	82%	0.44	0.46
Existing	Other	Computers	1.00	100%	0.16	0.16
Existing	Other	Cooking	1.00	53%	0.39	0.39
Existing	Other	Cooling Chillers	0.07	100%	1.48	0.70
Existing	Other	Cooling DX	0.29	100%	1.85	0.82
Existing	Other	Fax	1.00	100%	0.02	0.02
Existing	Other	Flat Screen Monitors	1.00	100%	0.04	0.04
Existing	Other	Freezer	1.00	100%	0.00	0.00
Existing	Other	Heat Pump	0.09	100%	3.02	1.38
Existing	Other	Lighting Exterior	1.00	100%	1.23	1.23
Existing	Other	Lighting Interior Fluorescent	1.00	100%	2.53	0.00
Existing	Other	Lighting Interior HID	1.00	100%	0.89	0.00
Existing	Other	Lighting Interior Other	1.00	100%	0.09	3.43

Existing	Other	Lighting Interior Screw Base	1.00	100%	0.76	0.00
Existing	Other	Other	1.00	100%	0.00	0.00
Existing	Other	Other Plug Load	1.00	100%	0.58	0.58
Existing	Other	Photo Copiers	1.00	100%	0.05	0.05
Existing	Other	Printers	1.00	100%	0.02	0.02
Existing	Other	Refrigeration	1.00	100%	0.12	0.12
Existing	Other	Refrigerator	1.00	100%	0.05	0.05
Existing	Other	Servers	1.00	100%	0.53	0.53
Existing	Other	Space Heat	0.73	44%	2.63	0.56
Existing	Other	Vending Machines	1.00	100%	0.08	0.08
Existing	Other	Ventilation and Circulation	0.83	100%	2.13	1.76
Existing	Other	Water Heat GT 55 Gal	1.00	60%	0.38	0.38
Existing	Other	Water Heat LE 55 Gal	1.00	60%	0.36	0.37
Existing	Restaurant	Computers	1.00	100%	0.13	0.13
Existing	Restaurant	Cooking	1.00	18%	8.88	8.88
Existing	Restaurant	Cooling DX	0.51	100%	3.88	1.45
Existing	Restaurant	Fax	1.00	100%	0.02	0.02
Existing	Restaurant	Flat Screen Monitors	1.00	100%	0.03	0.03
Existing	Restaurant	Freezer	1.00	100%	0.00	0.00
Existing	Restaurant	Heat Pump	0.14	100%	4.47	1.76
Existing	Restaurant	Lighting Exterior	1.00	100%	2.22	2.22
Existing	Restaurant	Lighting Interior Fluorescent	1.00	100%	3.24	0.00
Existing	Restaurant	Lighting Interior HID	1.00	100%	0.23	0.00
Existing	Restaurant	Lighting Interior Other	1.00	100%	0.29	5.44
Existing	Restaurant	Lighting Interior Screw Base	1.00	100%	4.38	0.00
Existing	Restaurant	Other	1.00	100%	0.00	0.00
Existing	Restaurant	Other Plug Load	1.00	100%	1.20	1.20
Existing	Restaurant	Photo Copiers	1.00	100%	0.07	0.07
Existing	Restaurant	Printers	1.00	100%	0.01	0.01
Existing	Restaurant	Refrigeration	1.00	100%	5.02	5.02
Existing	Restaurant	Refrigerator	1.00	100%	0.04	0.04
Existing	Restaurant	Space Heat	0.76	12%	1.28	0.29
Existing	Restaurant	Ventilation and Circulation	0.89	100%	3.36	2.68
Existing	Restaurant	Water Heat GT 55 Gal	1.00	38%	8.31	8.16
Existing	Restaurant	Water Heat LE 55 Gal	1.00	38%	7.82	8.02
Existing	School	Computers	1.00	100%	0.51	0.51
Existing	School	Cooking	1.00	55%	0.22	0.22
Existing	School	Cooling Chillers	0.25	100%	0.30	0.16
Existing	School	Cooling DX	0.21	100%	0.34	0.16

Existing	School	Fax	1.00	100%	0.01	0.01
Existing	School	Flat Screen Monitors	1.00	100%	0.12	0.12
Existing	School	Freezer	1.00	100%	0.00	0.00
Existing	School	Heat Pump	0.25	100%	2.69	1.16
Existing	School	Lighting Exterior	1.00	100%	0.76	0.76
Existing	School	Lighting Interior Fluorescent	1.00	100%	2.77	0.00
Existing	School	Lighting Interior HID	1.00	100%	0.29	0.00
Existing	School	Lighting Interior Other	1.00	100%	0.01	2.56
Existing	School	Lighting Interior Screw Base	1.00	100%	0.15	0.00
Existing	School	Other	1.00	100%	0.00	0.00
Existing	School	Other Plug Load	1.00	100%	0.02	0.02
Existing	School	Photo Copiers	1.00	100%	0.05	0.05
Existing	School	Printers	1.00	100%	0.04	0.04
Existing	School	Refrigeration	1.00	100%	0.41	0.41
Existing	School	Refrigerator	1.00	100%	0.04	0.04
Existing	School	Servers	1.00	100%	0.03	0.03
Existing	School	Space Heat	0.74	9%	5.66	1.83
Existing	School	Vending Machines	1.00	100%	0.08	0.08
Existing	School	Ventilation and Circulation	0.99	100%	1.32	0.89
Existing	School	Water Heat GT 55 Gal	1.00	34%	1.50	1.44
Existing	School	Water Heat LE 55 Gal	1.00	34%	1.41	1.41
Existing	University	Computers	1.00	100%	0.50	0.50
Existing	University	Cooking	1.00	55%	0.42	0.42
Existing	University	Cooling Chillers	0.04	100%	0.30	0.16
Existing	University	Cooling DX	0.05	100%	0.34	0.16
Existing	University	Fax	1.00	100%	0.01	0.01
Existing	University	Flat Screen Monitors	1.00	100%	0.12	0.12
Existing	University	Freezer	1.00	100%	0.00	0.00
Existing	University	Heat Pump	0.01	100%	2.68	1.15
Existing	University	Lighting Exterior	1.00	100%	0.76	0.76
Existing	University	Lighting Interior Fluorescent	1.00	100%	5.21	0.00
Existing	University	Lighting Interior HID	1.00	100%	0.46	0.00
Existing	University	Lighting Interior Other	1.00	100%	0.07	6.39
Existing	University	Lighting Interior Screw Base	1.00	100%	1.95	0.00
Existing	University	Other	1.00	100%	0.00	0.00
Existing	University	Other Plug Load	1.00	100%	0.02	0.02
Existing	University	Photo Copiers	1.00	100%	0.05	0.05
Existing	University	Printers	1.00	100%	0.04	0.04
Existing	University	Refrigeration	1.00	100%	0.41	0.41

Existing	University	Refrigerator	1.00	100%	0.04	0.04
Existing	University	Servers	1.00	100%	0.03	0.03
Existing	University	Space Heat	0.95	9%	5.65	1.83
Existing	University	Vending Machines	1.00	100%	0.08	0.08
Existing	University	Ventilation and Circulation	0.96	100%	1.32	0.89
Existing	University	Water Heat GT 55 Gal	1.00	34%	1.50	1.44
Existing	University	Water Heat LE 55 Gal	1.00	34%	1.41	1.41
Existing	Warehouse	Computers	1.00	100%	0.10	0.10
Existing	Warehouse	Cooling Chillers	0.04	100%	0.15	0.20
Existing	Warehouse	Cooling DX	0.14	100%	0.19	0.23
Existing	Warehouse	Fax	1.00	100%	0.01	0.01
Existing	Warehouse	Flat Screen Monitors	1.00	100%	0.02	0.02
Existing	Warehouse	Freezer	1.00	100%	0.00	0.00
Existing	Warehouse	Heat Pump	0.06	100%	0.73	0.53
Existing	Warehouse	Lighting Exterior	1.00	100%	0.28	0.28
Existing	Warehouse	Lighting Interior Fluorescent	1.00	100%	1.10	0.00
Existing	Warehouse	Lighting Interior HID	1.00	100%	0.95	0.00
Existing	Warehouse	Lighting Interior Other	1.00	100%	0.01	1.72
Existing	Warehouse	Lighting Interior Screw Base	1.00	100%	0.52	0.00
Existing	Warehouse	Other	1.00	100%	0.00	0.00
Existing	Warehouse	Other Plug Load	1.00	100%	0.26	0.26
Existing	Warehouse	Photo Copiers	1.00	100%	0.03	0.03
Existing	Warehouse	Printers	1.00	100%	0.01	0.01
Existing	Warehouse	Refrigerator	1.00	100%	0.01	0.01
Existing	Warehouse	Space Heat	0.48	26%	0.00	0.00
Existing	Warehouse	Vending Machines	1.00	100%	0.00	0.00
Existing	Warehouse	Ventilation and Circulation	0.52	100%	0.00	0.00
Existing	Warehouse	Water Heat GT 55 Gal	1.00	82%	0.00	0.00
Existing	Warehouse	Water Heat LE 55 Gal	1.00	82%	0.00	0.00

Table B.1.4. Commercial Natural Gas Saturations, Fuel Shares, and EUIs

Vintage	Segment	End Use	Saturation	Natural Gas Fuel Share	Weighted Average EUI - Existing	Weighted Average EUI - New
Existing	Dry Goods Retail	Other	1.00	100%	0.00	0.00
Existing	Dry Goods Retail	Space Heat Boiler	0.09	100%	0.07	0.04

Existing	Dry Goods Retail	Space Heat Furnace	0.83	81%	0.10	0.06
Existing	Dry Goods Retail	Water Heat GT 55 Gal	0.08	40%	0.03	0.03
Existing	Dry Goods Retail	Water Heat LE 55 Gal	0.92	40%	0.03	0.03
Existing	Grocery	Cooking	1.00	54%	0.19	0.19
Existing	Grocery	Other	1.00	100%	0.00	0.00
Existing	Grocery	Space Heat Boiler	0.01	100%	0.23	0.05
Existing	Grocery	Space Heat Furnace	0.96	88%	0.34	0.07
Existing	Grocery	Water Heat GT 55 Gal	0.08	80%	0.15	0.15
Existing	Grocery	Water Heat LE 55 Gal	0.92	80%	0.13	0.14
Existing	Hospital	Cooking	1.00	67%	0.04	0.04
Existing	Hospital	Other	1.00	100%	0.00	0.00
Existing	Hospital	Space Heat Boiler	0.35	85%	0.32	0.30
Existing	Hospital	Space Heat Furnace	0.56	78%	0.47	0.46
Existing	Hospital	Water Heat GT 55 Gal	0.08	64%	0.48	0.50
Existing	Hospital	Water Heat LE 55 Gal	0.92	64%	0.44	0.45
Existing	Hotel Motel	Cooking	1.00	98%	0.08	0.08
Existing	Hotel Motel	Other	1.00	100%	0.00	0.00
Existing	Hotel Motel	Pool Heat	1.00	44%	0.11	0.11
Existing	Hotel Motel	Space Heat Boiler	0.57	69%	0.16	0.12
Existing	Hotel Motel	Space Heat Furnace	0.31	44%	0.24	0.18
Existing	Hotel Motel	Water Heat GT 55 Gal	0.08	77%	0.37	0.38
Existing	Hotel Motel	Water Heat LE 55 Gal	0.92	77%	0.33	0.34
Existing	Office	Other	1.00	100%	0.00	0.00
Existing	Office	Space Heat Boiler	0.28	66%	0.21	0.10
Existing	Office	Space Heat Furnace	0.57	41%	0.31	0.16
Existing	Office	Water Heat GT 55 Gal	0.08	34%	0.04	0.04
Existing	Office	Water Heat LE 55 Gal	0.92	34%	0.04	0.04
Existing	Other	Cooking	1.00	49%	0.04	0.04
Existing	Other	Other	1.00	100%	0.00	0.00
Existing	Other	Pool Heat	1.00	13%	0.16	0.16
Existing	Other	Space Heat Boiler	0.25	100%	0.14	0.07
Existing	Other	Space Heat Furnace	0.68	73%	0.21	0.11
Existing	Other	Water Heat GT 55 Gal	0.08	58%	0.04	0.04
Existing	Other	Water Heat LE 55 Gal	0.92	58%	0.03	0.03
Existing	Restaurant	Cooking	1.00	82%	1.52	1.52
Existing	Restaurant	Other	1.00	100%	0.00	0.00
Existing	Restaurant	Space Heat Boiler	0.00	100%	0.04	0.03
Existing	Restaurant	Space Heat Furnace	0.92	96%	0.06	0.04
Existing	Restaurant	Water Heat GT 55 Gal	0.08	67%	0.48	0.50
Existing	Restaurant	Water Heat LE 55 Gal	0.92	67%	0.43	0.44
Existing	School	Cooking	1.00	46%	0.02	0.02

Existing	School	Other	1.00	100%	0.00	0.00
Existing	School	Pool Heat	1.00	13%	0.16	0.16
Existing	School	Space Heat Boiler	0.75	98%	0.11	0.09
Existing	School	Space Heat Furnace	0.23	83%	0.17	0.14
Existing	School	Water Heat GT 55 Gal	0.08	79%	0.07	0.07
Existing	School	Water Heat LE 55 Gal	0.92	79%	0.06	0.06
Existing	University	Cooking	1.00	46%	0.05	0.05
Existing	University	Other	1.00	100%	0.00	0.00
Existing	University	Pool Heat	1.00	13%	0.15	0.15
Existing	University	Space Heat Boiler	0.75	98%	0.22	0.19
Existing	University	Space Heat Furnace	0.23	83%	0.33	0.28
Existing	University	Water Heat GT 55 Gal	0.08	79%	0.11	0.12
Existing	University	Water Heat LE 55 Gal	0.92	79%	0.10	0.11
Existing	Warehouse	Other	1.00	100%	0.00	0.00
Existing	Warehouse	Space Heat Boiler	0.01	100%	0.08	0.04
Existing	Warehouse	Space Heat Furnace	0.65	84%	0.12	0.07
Existing	Warehouse	Water Heat GT 55 Gal	0.08	20%	0.02	0.02
Existing	Warehouse	Water Heat LE 55 Gal	0.92	20%	0.02	0.02

Table B.1.5. Industrial Electric End Use Percents by Segment

End Use	Chemical Mfg	Computer Electronic Mfg	Electrical Equipment Mfg	Fabricated Metal Products	Food Mfg	Industrial Machinery	Misc. Mfg	Nonmetallic Mineral Products	Paper Mfg	Petroleum Coal Products	Plastics Rubber Products	Primary Metal Mfg	Printing Related Support	Transport. Equipment Mfg	Waste-water	Water	Wood Product Mfg
Fans	7%	4%	5%	7%	3%	6%	5%	8%	15%	12%	7%	4%	7%	4%	0%	10%	10%
HVAC	7%	28%	15%	10%	8%	23%	25%	6%	5%	3%	11%	3%	19%	19%	0%	0%	5%
Indirect Boiler	2%	1%	0%	0%	2%	0%	2%	0%	4%	1%	1%	0%	1%	1%	0%	0%	1%
Lighting	4%	12%	12%	9%	7%	15%	17%	5%	4%	2%	9%	3%	12%	15%	2%	2%	7%
Motors Other	16%	8%	10%	19%	17%	18%	20%	22%	30%	34%	20%	18%	20%	10%	0%	10%	29%
Other	3%	8%	4%	3%	4%	4%	6%	3%	2%	1%	4%	1%	6%	5%	14%	14%	4%
Process Aircomp	17%	1%	11%	8%	3%	7%	5%	9%	4%	14%	8%	4%	8%	10%	66%	0%	12%
Process Cool	9%	11%	5%	4%	27%	3%	6%	3%	2%	6%	9%	1%	6%	6%	0%	0%	1%
Process Electro Chemical	10%	1%	0%	2%	0%	0%	0%	0%	1%	0%	0%	32%	0%	1%	0%	0%	1%
Process Heat	5%	11%	23%	20%	6%	7%	10%	22%	3%	0%	16%	29%	3%	13%	0%	0%	7%
Process Other	1%	8%	3%	3%	1%	2%	1%	3%	1%	0%	0%	1%	0%	3%	0%	0%	0%
Process Refrig	5%	1%	3%	3%	13%	3%	0%	4%	4%	6%	3%	0%	4%	3%	0%	0%	5%
Pumps	16%	7%	10%	12%	7%	11%	3%	14%	24%	21%	13%	3%	13%	10%	18%	64%	18%

Table B.1.6. Industrial Natural Gas End Use Percents by Segment

End Use	Chemical Mfg	Computer Electronic Mfg	Electrical Equipment Mfg	Fabricated Metal Products	Food Mfg	Industrial Machinery	Misc. Mfg	Nonmetallic Mineral Products	Paper Mfg	Petroleum Coal Products	Plastics Rubber Products	Primary Metal Mfg	Printing Related Support	Transport. Equipment Mfg	Waste-water	Water	Wood Product Mfg
HVAC	2%	40%	21%	15%	5%	40%	55%	4%	3%	1%	20%	6%	17%	41%	0%	0%	8%
Indirect Boiler	60%	47%	18%	16%	58%	27%	18%	5%	62%	34%	47%	9%	12%	20%	0%	0%	30%
Other	1%	3%	2%	2%	0%	1%	0%	2%	3%	0%	3%	11%	8%	0%	100%	100%	0%
Process Heat	28%	7%	57%	67%	34%	32%	23%	87%	28%	61%	26%	71%	62%	36%	0%	0%	58%
Process Other	9%	2%	3%	0%	4%	0%	5%	2%	4%	5%	5%	3%	0%	2%	0%	0%	4%

Appendix B.2: Measure Descriptions

This section contains a brief description of each measure used in the energy-efficiency potential.

Appendix B.2: Measure Descriptions

1. Residential Electric Retrofit Measure Descriptions

Heating and Cooling

Air-to-Air Heat Exchanger. This measure mechanically ventilates homes in cold climates. During the winter, it transfers heat from the air being exhausted to outside air entering the home. Between 50 and 80 percent of the heat normally lost in exhausted air is returned to the house. Air-to-air heat exchangers can be installed as part of a central heating and cooling system or in walls or windows. Wall- and window-mounted units resemble air conditioners and ventilate one room or area.[1]

Canned Lighting Air-Tight Sealing. Proper sealing around recessed lighting fixtures prevents unwanted heat loss through these air spaces due to air pressure differentials in conditioned and unconditioned spaces in homes. The baseline is no sealing around lighting fixtures.

Ceiling Fan. ENERGY STAR®-qualified ceiling fans have improved motor and blade designs that allow the user to increase the thermostat set point by a few degrees, which decreases the AC cooling runtime yet still feels at least 5° cooler. The fans do not create cooler temperatures. This measure does not include light fixtures; all savings are associated with installing an ENERGY STAR® ceiling fan where no prior fan was present.

Ceiling Insulation. This measure represents an increase in R-value. Added ceiling insulation increases the building's thermal performance and brings the resistance value up to and past code, depending on the building vintage. Table B-2.1 summarizes the different resistance values compared in the measure.

Table B-2.1. Ceiling R-Value Comparison

Measure Insulation	Baseline Insulation
R-49	R-0
R-49	R-10
R-60	R-49

Check Me! O&M Tune-up. Performing a system tune-up and regular maintenance ensures that the refrigerant charge and airflow through the evaporator coil (two factors that affect system efficiency) are properly tested and correctly adjusted. Maintenance includes changing filters and cleaning the coils to maintain the overall performance and efficiency of the unit.

Construction, ICF. Building a concrete home with insulating concrete forms (ICFs) saves energy. Greater insulation, tighter construction, and the temperature-moderating mass of the walls conserve heating and cooling energy much better than conventional wood-frame walls.

Construction, SIP. A structural insulated panel (SIP) uses continuous foam insulation throughout the panel, which provides excellent energy efficiency and low levels of air infiltration. The baseline is standard wood framing.

1 http://cipco.apogee.net/res/reevhex.asp

Cool Roofs. ENERGY STAR®-qualified cool roofs have reflective coating and can decrease roof surface temperatures by up to 100º F, thereby decreasing the amount of heat transferred into a building. Cool roofs can reduce the amount of air conditioning needed in buildings and can reduce peak cooling demand by 10 percent to 15 percent.[2] This could be considered a passive measure.

Dehumidifier, Whole House. A high capacity whole house dehumidifier can stand alone in a basement or be ducted into an existing central air conditioning system. These units remove moisture content from the air and prevent mold, mildew, and damp conditions.

Doors. Composite or steel doors with a foam core increase overall insulation, slowing heat loss. This measure includes adding a thermal door with a resistance value of R-5 or R-11 to houses without a thermal or storm door (R-2.5).

Doors, Weatherization. Mounting weather stripping to the bottom of an exterior door minimizes infiltration door sweep. This type of weatherization consists of an extruded aluminum strip holding a flexible vinyl strip that blocks the air space between the door frame and the door. The baseline for this measure is no weather stripping.

Duct Fittings, Leak-Proof. The majority of duct leakage in residential HVAC systems is due to improperly sealed connections between ductwork and fittings. Even when duct connections are initially well-sealed, leakage may increase over time.

Duct Insulation Upgrade. The addition of insulation around ducts in a heating system reduces heat loss to unconditioned spaces. This measure improves existing duct insulation from R-4 to R-8.

Duct Location. Locating ducts in conditioned spaces reduces wasted heat loss.[3] Many homes have ducts that run through unconditioned areas (such as attics, garages, crawlspaces, and basements) for convenience and practical reasons. Ducts in unconditioned areas lose energy because of the temperature difference between conditioned air in the ducts and the surrounding space.

Duct Sealing. Duct sealing cost-effectively saves energy, improves air and thermal distribution (comfort and ventilation), and reduces cross contamination between different zones in the building (such as smoking vs. non-smoking, bio-aerosols, and localized indoor air pollutants).

Duct Sealing, Aerosol-Based. This aerosol technology seals duct holes up to 1/4-inch in diameter by spraying atomized latex aerosol into the inside of a pressurized duct system. A significant amount of energy use in residential buildings is associated with duct losses due to leakage.

Fan, Whole House. A whole house fan is a simple and inexpensive method of cooling a house when outdoor temperatures are lower than indoor temperatures. The fan draws cool outdoor air inside the home through open windows and exhausts hot indoor air through the attic to the outside.

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2 http://www.aceee.org/consumer/cooling
3 http://www.toolbase.org/pdf/techinv/ductsinconditionedspace_techspec.pdf

Floor Insulation. The addition of floor insulation increases the overall resistance value of a home and slows heat transfer from the basement to the upper levels. Table B-2.2 summarizes the different resistance values compared in the measure.

Table B-2.2. Floor R-Value Comparison

Measure Insulation	Baseline Insulation
R-30	R-0
R-38	R-30

Green Roof. The added mass and thermal resistance of green roofs reduces the heating and cooling loads of the building. These roofs reduce the ambient temperature of the roof surface and slow the transfer of heat into the building, which reduces cooling costs. They also add insulation to the roof structure, reducing heating requirements in the winter.[4] Additionally, they reduce the ambient temperature around the roof, which decreases the building's urban heat island effect.

HVAC Unit, Proper Sizing. Correctly-sized HVAC systems operate for longer periods of time (instead of cycling on and off frequently), which results in optimum equipment operating efficiency and better control.[5]

Infiltration Control (Caulk, Weather Strip, etc.) Blower Door Test. Sealing air leaks in windows, doors, the roof, crawlspaces, and outside walls prevents drafts and reduces overall heating and cooling losses.

Radiant Barrier, Ceiling. A radiant barrier generally consists of a thin piece of aluminum installed in a ceiling that reduces the solar heat gain from the sun during the summer and traps heat in during the winter. These barriers reduce heat transfer between the air space of the roof deck and the attic floor.

Smart Siting. This measure, which applies only to new construction, entails optimizing the building orientation to minimize the heating and cooling load on the HVAC system.

Solar Attic Fan. This measure provides forced attic fan ventilation, which reduces residential heat gains from the ceiling. Because this fan is solar-powered, it runs conveniently when the sun is shining. The baseline uses passive ventilation without a fan.

Thermal Shell, Infiltration at 0.2 ACH w/ HRV. Heat recovery ventilation (HRV) provides fresh air and improved climate control, while also saving energy by reducing the heating (or cooling) requirements of a building. Combining this feature with better infiltration control (0.2 air changes per hour) minimizes the energy needed to maintain a healthy level of fresh air and reduces heat loss due to air leakage.

Thermostat, Multi-Zone. A multi-zone programmable thermostat automatically controls the set point temperatures for multiple areas (rooms or zones), ensuring the HVAC system is not running during low-occupancy hours. The baseline for this measure is a programmable thermostat with central control only.

4 http://www.toolbase.org/Technology-Inventory/Roofs/green-roofs
5 http://www.toolbase.org/Technology-Inventory/HVAC/hvac-sizing-practice

Wall Insulation, 2x4 and 2x6. The presence of wall insulation slows the transfer of heat and reduces the heating and cooling loads in a house. Table B-2.3 compares the different insulation levels for 2x4 and 2x6 framing.

Table B-2.3. Wall Insulation Measures

Construction Type	Measure Insulation	Baseline Insulation
2x4	R-13	R-0
2x6	R-21	R-0
	R-21 + R-5 Sheathing	R-21

Windows. This measure provides increased building performance by reducing the U-value in existing and new construction windows, as shown in Table B-2.4.

Table B-2.4. High Efficiency Window Measures

Measure U-Value	Baseline U-Value
0.30	Single Pane
0.30	Double Pane
0.25	0.30
0.22	0.30

Window Overhang. A window overhang shades windows, which reduces solar heat gains and decreases the overall cooling load on the home.

Lighting

Daylighting Controls (Photocell), Indoor/Outdoor. Photocells adjust lighting levels according to the level of daylight the room is receiving. The baseline is no daylighting controls.

Occupancy Sensor. An occupancy sensor turns off the lights after a space is unoccupied for a designated amount of time. The lights turn on again when the sensor detects a person in the space.

Time Clock, Exterior Lighting. This technology allows users to program times for lights outside the residence to be turned on and off automatically. Programmed exterior lighting saves energy by ensuring that lights are not left on during the daytime.

Water Heat

Clothes Washer, ENERGY STAR®. This clothes washer uses less energy and water than regular washers.[6] We compared three levels of efficiency—in units of the corresponding Modified Energy Factor (MEF) —for this measure, as shown in Table B-2.5. The baseline MEF represents the average MEF of non-ENERGY STAR®-qualified models.

[6] http://www.energystar.gov/index.cfm?fuseaction=find_a_product.showProductGroup&pgw_code=CW

Table B-2.5. Clothes Washer Modified Energy Factor Comparisons

Measure Level	Measure MEF	Baseline MEF
ENERGY STAR	2.0-2.19	1.66
CEE Tier 2	2.2-2.45	1.66
CEE Tier 3	2.46 +	1.66

Dishwasher, ENERGY STAR®. This dishwasher uses advanced technology to clean dishes with less water and energy. The efficient model uses less than 307 kWh/year (including standby consumption) and less than 5 gallons of water per cycle. The baseline model consumes 340 kWh/year.

Drain Water Heat Recovery. Also called gravity film heat exchanges, this device recovers heat energy from domestic drain water, which is then used to pre-heat cold water entering the hot water tank. This minimizes the temperature difference between the heating set point and the temperature of the water entering the system.

Hot Water Pipe Insulation. The addition of R-4 insulation around pipes decreases heat loss. The baseline is a hot water pipe without insulation.

Low-Flow Showerheads. Low-flow showerheads mix water and air to reduce the amount of water that flows through the showerhead. The showerhead creates a fine water spray through an inserted screen in the showerhead. This measure reduces a showerhead’s flow rate from 2.5 gallons per minute to 2.0 gallons per minute.

Water Heater Tank Blanket. The installation of R-5 insulation on older models of water heaters helps reduce standby losses.

Water Heater Thermostat Setback. This measure generates savings by reducing the thermostat set point temperature from 135° to 120°F. The set point temperature on hot water systems is often set higher than necessary.

Appliances

Refrigerator/Freezer, Removal of Secondary. This refers to environmentally friendly disposal of unneeded or inefficient appliances such as secondary refrigerators or stand-alone freezers.

Stand-Alone Freezer, Removal. The removal of stand-alone freezers is beneficial because of the inefficient use of energy by these appliances. Proper disposal is required due to their use of hazardous materials such as Freon and CFCs.

Plug Load

1-Watt Standby Power. Standby power is the electricity used by small electrical equipment or appliances when they are switched off or are not performing their main function. Minimizing this loss to one watt or less can reduce this standby energy consumption by more than 50 percent.

Battery Charger, ENERGY STAR®. On average, these battery chargers use 35 percent less energy than conventional battery chargers, which draw as much as five to 20 times more energy than is actually stored in the battery (even when not actively charging a product). Battery charging systems recharge a variety of cordless products, including power tools, small household appliances, and electric shavers. The baseline is a standard battery charger.[7]

Office Copier, ENERGY STAR®. These copy machines are 40 percent more efficient than standard office copy machines.[8]

Office Printer, ENERGY STAR®. These printers are 40 percent more efficient than standard printers.

Smart Strip. Power strips with an occupancy sensor will turn power to all devices plugged into the strip on and off, such as computers, desk lights, and audio equipment, based on occupancy within the work area.

Other (Pool)

Pool Pump Timers. A pool pump with a timer set to run during off-peak times (starting after 8:00 p.m. and cycling off before 10:00 a.m.) reduces energy costs. Cycling the pumps will further reduce monthly costs. The baseline is a continuously running pump.

[7] http://www.energystar.gov/index.cfm?c=battery_chargers.pr_battery_chargers
[8] http://www.energystar.gov/index.cfm?fuseaction=find_a_product.showProductGroup&pgw_code=IEQ

2. Residential Electric Equipment Measure Descriptions

Heating and Cooling

Air or Ground Source Heat Pump (ASHP or GSHP). Electric heat pumps move heat to or from the air or the ground to cool and heat a home. Table B-2.6 displays the different efficiency levels we compared for this measure. The baseline size is the same as the measure size.

Table B-2.6. Heat Pump SEER/HSPF Comparisons

Measure Efficiency	Baseline SEER & HSPF
ASHP 14 SEER, 8.5 HSPF	ASHP 13 SEER, 7.7 HSPF
ASHP 16 SEER, 8.8 HSPF	
GSHP 16.2 EER, 8.8 HSPF	

Central Cooling. This measure consists of several different air conditioner technology/efficiency levels, as summarized in Table B-2.7. The baseline size is the same as the measure size.

Table B-2.7. Central AC SEER Comparison

Measure	Baseline SEER
14 SEER	13 SEER
16 SEER	
18 SEER	

Conversion Baseboard Heating to Ductless Heat Pump (DHP). DHPs move heat to or from the air to cool and heat a home without the need for costly ductwork. This method of heating has a HSPF value of 7.7, consuming less energy than baseboard heating that has a HSPF value of 1.

Conversion Electric Furnace to Air Source Heat Pump (ASHP). ASHPs move heat to or from the air to cool and heat a home. This method of heating has a HSPF value of 7.7, consuming less energy than an electric furnace that has a HSPF value of 1.

Motor, ECM and ECM-VFD. Electronically commutated motors (ECMs) and ECMs with variable frequency drives (VFD) consume less power than the standard motor used in ventilation and circulation systems.

Room Air Conditioner (Room AC), 10,000 BTU/HR. ENERGY STAR®-qualified room ACs use less energy than conventional models through improved energy performance and timers, which allow for better temperature control. ENERGY STAR®-qualified room air conditioners have an efficiency rating of 10.8 EER, compared to standard models, which have an efficiency rating of 9.8 EER.

Room AC Conversion to Ductless Heat Pump (DHP). DHPs use less energy than room AC while also producing less noise and requiring no costly ductwork. DHPs have an efficiency of 13 SEER, replacing a room AC unit with an efficiency rating of 9.8 EER.

Lighting

Compact Fluorescent Lights (CFL), 13, 20, and 25 Watt. Specialty 3-way CFLs use 73 percent to 83 percent less energy and have a longer life than incandescent 3-way, 60, 75, or 150 watt light bulbs.

Compact Fluorescent Lights (CFL), 15 Watt. Standard CFLs use 62 percent less energy than the Energy Independence and Security Act (EISA) 43 watt incandescent bulbs. The baseline for this measure reflects the 2012-2014 changes to accommodate the EISA of 2007, reaching a baseline value of 43 watts.

Compact Fluorescent Lights (CFL), 17 Watt Flood Light. Exterior CFLs use 62 percent less energy than EISA 45 watt incandescent bulbs. The baseline for this measure reflects the 2012-2014 changes to accommodate the EISA of 2007, reaching a baseline value of 45 watts.

Light emitting diodes (LEDs), 7 Watts. LEDs are solid-state devices that convert electricity to light, use 80 percent less energy, and have a long life. The baseline for this measure reflects the 2012-2014 changes to accommodate the EISA of 2007, reaching a baseline value of 43 watts.

Water Heat

Water Heater, Heat Pump. This measure moves heat from a warm reservoir (such as air) into the hot water system.[9] This measure assumes an energy factor (EF) of 2.2, an increase from the standard EF of 0.92.

Water Heater, Storage. A high-efficiency water heater reduces standby loss and is more efficient than a standard electric water heater. This measure assumes an EF of 0.95, an increase from the standard EF of 0.92.

Appliances

Cooking Oven, High Efficiency. A high-efficiency cooking oven uses fans to circulate heat evenly throughout the oven (convection heat), operating at lower temperatures and achieving cook times quicker than a standard oven. The baseline is a standard oven.

Dryer, High Efficiency. A high-efficiency dryer has features (such as moisture sensors) that minimize energy usage while retaining performance. The efficiency levels for this measure are shown in Table B-2.8.

Table B-2.8. Dryer EF Comparison

Measure	Baseline
3.08 EF	
3.19 EF	3.01 EF
3.30 EF	

Freezer, ENERGY STAR. ENERGY STAR® -qualified freezers use 10 percent less energy than standard models due to improvements in insulation and compressors.

9 Description source: U.S. Department of Energy; http://www.energysavers.gov/your_home/water_heating/index.cfm/mytopic=12840

Microwave, High Efficiency. High-efficiency microwaves use more efficient power supplies, fans, magnetron, and reflective surfaces that provide energy savings compared to conventional microwaves.

Refrigerator*, *ENERGY STAR. ENERGY STAR®-qualified refrigerators use 20 percent less energy than standard models, due to improvements in insulation and compressors.

Plug Load

Computer, ENERGY STAR. ENERGY STAR® computers consume less than 2 watts in sleep and off modes, and are more efficient than conventional units in idle mode, resulting in 30 percent to 65 percent energy savings.

Dehumidifier, ENERGY STAR. ENERGY STAR®-qualified models have more efficient refrigeration coils, compressors, and fans than conventional models, and use less energy to remove moisture. Qualified models remove the same amount of moisture as a similarly-sized standard unit, but use 10 percent to 20 percent less energy. The baseline for this measure is a standard dehumidifier.[10]

DVD, ENERGY STAR. ENERGY STAR®-qualified DVD products meeting the new requirements use up to 60 percent less energy than standard models.[11] ENERGY STAR® DVD players use as little as one-fourth of the energy of standard models in the off mode. The baseline for this measure is a standard DVD player.

Home Audio System, ENERGY STAR. According to ENERGY STAR® products, a 6 percent energy savings can be achieved over standard home audio systems.[12]

Monitor, ENERGY STAR. ENERGY STAR® monitors feature: (1) on mode, where the maximum allowed power varies based on the computer monitor's resolution; (2) sleep mode, where computer monitors must consume 2 watts or less; and, (3) off mode, where computer monitors must consume 1 watt or less. The baseline equipment does not include these features.[13]

Set Top Box, ENERGY STAR. Set top boxes that have earned the ENERGY STAR® rating are at least 30 percent more efficient than conventional models.[14] The baseline measure is a standard receiver.

TV, ENERGY STAR. ENERGY STAR®-qualified TVs use roughly 40 percent less energy than standard units.[15] ENERGY STAR® models are required to consume no more than 1 watt while in sleep mode. The baseline is a standard television, which generally consumes more than 3 watts when turned off.

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10 http://www.energystar.gov/index.cfm?fuseaction=find_a_product.showProductGroup&pgw_code=DE
11 http://www.energystar.gov/index.cfm?fuseaction=find_a_product.showProductGroup&pgw_code=DP
12 http://www.energystar.gov/index.cfm?fuseaction=find_a_product.showProductGroup&pgw_code=HA
13 http://www.energystar.gov/index.cfm?fuseaction=find_a_product.ShowProductGroup&pgw_code=MO
14 http://www.energystar.gov/index.cfm?c=settop_boxes.settop_boxes
15 http://www.energystar.gov/index.cfm?fuseaction=find_a_product.showProductGroup&pgw_code=TV

Other (Pool)

Pool Pumps, Two Speed Motor. This measure enables a pool pump motor to operate at high and low speeds as opposed to constantly running at full power. The baseline for this measure is a standard one speed motor.

Pool Pumps, VSD. This measure enables a pool pump motor to operate at variable speeds as opposed to constantly running at full power. The baseline for this measure is a standard one speed motor.

3. Residential Gas Retrofit Measure Descriptions

Heating

Air-to-Air Heat Exchanger. An air-to-air heat exchanger mechanically ventilates homes in cold climates. During the winter, it transfers heat from the air being exhausted to the fresh, outside air entering the home. Between 50 and 80 percent of the heat normally lost in exhausted air is returned to the house. Air-to-air heat exchangers can be installed as part of a central heating and cooling system or in walls or windows. Wall- and window-mounted units resemble air conditioners and will ventilate one room or area.[16]

Canned Lighting Air-Tight Sealing. Proper sealing around recessed lighting fixtures prevents unwanted heat loss through these air spaces due to air pressure differentials in conditioned and unconditioned spaces in homes. The baseline is no sealing around lighting fixtures.

Ceiling Insulation. This measure represents an increase in R-value. Added ceiling insulation increases the building's thermal performance and brings the resistance value up to and past code, depending on the building vintage. Table B-2.9 summarizes the different resistance values compared in the measure.

Table B-2.9. Ceiling R-Value Comparison

Measure Insulation	Baseline Insulation
R-49	R-0
R-49	R-10
R-60	R-49

Construction, ICF. Building a concrete home with insulating concrete forms (ICFs) saves energy. Greater insulation, tighter construction, and the temperature-moderating mass of the walls conserve heating and cooling energy much better than conventional wood-frame walls.

Construction, SIP. A structural insulated panel (SIP) uses continuous foam insulation throughout the panel, which provides excellent energy efficiency and low levels of air infiltration. The baseline is standard wood framing.

Doors. Composite or steel doors with a foam core increase overall insulation, slowing heat loss. This measure includes adding a thermal door with a resistance value of R-5 or R-11 to houses without a thermal or storm door (R-2.5).

Doors, Weatherization. Mounting weather stripping to the bottom of an exterior door minimizes infiltration door sweep. This type of weatherization consists of an extruded aluminum strip holding a flexible vinyl strip that blocks the air space between the door frame and the door. The baseline for this measure is no weather stripping.

Duct Fittings, Leak-Proof. The majority of duct leakage in residential HVAC systems is due to improperly sealed connections between ductwork and fittings. Even when duct connections are initially well-sealed, leakage may increase over time.

16 http://cipco.apogee.net/res/reevhex.asp

Duct Insulation Upgrade. The addition of insulation around ducts in a heating system reduces heat loss to unconditioned spaces. This measure improves existing duct insulation from R-4 to R-8.

Duct Location. Locating ducts in conditioned spaces reduces wasted heat loss.[17] Many homes have ducts that run through unconditioned areas (such as attics, garages, crawlspaces, and basements) for convenience and practical reasons. Ducts in unconditioned areas lose energy because of the temperature difference between conditioned air in the ducts and the surrounding space.

Duct Sealing. Duct sealing cost-effectively saves energy, improves air and thermal distribution (comfort and ventilation), and reduces cross contamination between different zones in the building (such as smoking vs. non-smoking, bio-aerosols, and localized indoor air pollutants).

Duct Sealing, Aerosol-Based. This aerosol technology seals duct holes up to 1/4-inch in diameter by spraying atomized latex aerosol into the inside of a pressurized duct system. A significant amount of energy use in residential buildings is associated with duct losses due to leakage.

Floor Insulation. The addition of floor insulation increases the overall resistance value of a home and slows heat transfer from the basement to the upper levels. Table B-2.10 summarizes the different resistance values compared in the measure.

Table B-2.10. Floor R-Value Comparison

Measure Insulation	Baseline Insulation
R-30	R-0
R-38	R-30

Green Roof. The added mass and thermal resistance of green roofs reduces the heating and cooling loads of the building. These roofs reduce the ambient temperature of the roof surface and slow the transfer of heat into the building, which reduces cooling costs. They also add insulation to the roof structure, reducing heating requirements in the winter.[18] Additionally, they reduce the ambient temperature around the roof, which decreases the building's urban heat island effect.

HVAC Unit, Proper Sizing. Correctly-sized HVAC systems operate for longer periods of time (instead of cycling on and off frequently), which results in optimum equipment operating efficiency and better control.[19]

Infiltration Control (Caulk, Weather Strip, etc*.) ***Blower Door Test. Sealing air leaks in windows, doors, the roof, crawlspaces, and outside walls prevents drafts and reduces overall heating and cooling losses.

Radiant Barrier, Ceiling. A radiant barrier generally consists of a thin piece of aluminum installed in a ceiling that reduces the solar heat gain from the sun during the summer and traps

[17] http://www.toolbase.org/pdf/techinv/ductsinconditionedspace_techspec.pdf
[18] http://www.toolbase.org/Technology-Inventory/Roofs/green-roofs
[19] http://www.toolbase.org/Technology-Inventory/HVAC/hvac-sizing-practice

heat in during the winter. These barriers reduce heat transfer between the air space of the roof deck and the attic floor.

Smart Siting. This measure, which applies only to new construction, entails optimizing the building orientation to minimize the heating and cooling load on the HVAC system.

Thermal Shell, Infiltration at 0.2 ACH w/ HRV. Heat recovery ventilation (HRV) provides fresh air and improved climate control, while also saving energy by reducing the heating (or cooling) requirements of a building. Combining this feature with better infiltration control (0.2 air changes per hour) minimizes the energy needed to maintain a healthy level of fresh air and reduces heat loss due to air leakage.

Thermostat, Multi-Zone. A multi-zone programmable thermostat automatically controls the set point temperatures for multiple areas (rooms or zones), ensuring the HVAC system is not running during low-occupancy hours. The baseline for this measure is a programmable thermostat with central control only.

Wall Insulation, 2x4 and 2x6. The presence of wall insulation slows the transfer of heat and reduces the heating and cooling loads in a house. Table B-2.11 compares the different insulation levels for 2x4 and 2x6 framing.

Table B-2.11. Wall Insulation Measures

Construction Type	Measure Insulation	Baseline Insulation
2x4	R-13	R-0
2x6	R-21	R-0
	R-21 + R-5 Sheathing	R-21

Windows. This measure provides increased building performance by reducing the U-value in existing and new construction windows, as shown in Table B-2.12.

Table B-2.12. High Efficiency Window Measures

Measure U-Value	Baseline U-Value
0.30	Single Pane
0.30	Double Pane
0.25	0.30
0.22	0.30

Water Heat

Clothes Washer, ENERGY STAR®. This clothes washer uses less energy and water than regular washers.[20] Three levels of efficiency—in units of the corresponding Modified Energy Factor (MEF) —are shown in Table B-2.13. The baseline MEF represents the average MEF of non-ENERGY STAR®-qualified models.

[20] http://www.energystar.gov/index.cfm?fuseaction=find_a_product.showProductGroup&pgw_code=CW

Table B-2.13. Clothes Washer Modified Energy Factor Comparisons

Measure Level	Measure MEF	Baseline MEF
ENERGY STAR	2.0-2.19	1.66
CEE Tier 2	2.2-2.45	1.66
CEE Tier 3	2.46 +	1.66

Dishwasher, ENERGY STAR®. This dishwasher uses advanced technology to clean dishes with less water and energy. The efficient model uses less than 307 kWh/year (including standby consumption) and less than 5 gallons of water per cycle. The baseline model consumes 340 kWh/year.

Drain Water Heat Recovery. Also called gravity film heat exchanges, this device recovers heat energy from domestic drain water, which is then used to pre-heat cold water entering the hot water tank. This minimizes the temperature difference between the heating set point and the temperature of the water entering the system.

Hot Water Pipe Insulation. The addition of R-4 insulation around pipes decreases heat loss. The baseline is a hot water pipe without insulation.

Low-Flow Showerheads. Low-flow showerheads mix water and air to reduce the amount of water that flows through the showerhead. The showerhead creates a fine water spray through an inserted screen in the showerhead. This measure reduces a showerhead's flow rate from 2.5 gallons per minute to 2.0 gallons per minute.

Water Heater Tank Blanket. The installation of R-5 insulation on older models of water heaters helps reduce standby losses.

Water Heater Thermostat Setback. This measure generates savings by reducing the thermostat set point temperature from 135° to 120°F. The set point temperature on hot water systems is often set higher than necessary.

4. Residential Gas Equip Measure Descriptions

Heating

Gas Boiler. Boilers are classified as condensing or non-condensing. Condensing boilers condense the flue gas and water vapor, extracting useful heat and improving the boiler efficiency. This measure compares several boilers with different thermal efficiencies and is applicable to both new and existing construction. The overall efficiency of the boiler is defined as the gross energy output divided by the energy input, and is affected by combustion efficiency, standby losses, cycling losses, and heat transfer. Table B-2.14 displays the measure and baseline thermal efficiencies.

Table B-2.14. Gas Boiler Efficiency Comparison

Measure AFUE	Baseline AFUE
90%	82%
94%	

Gas Furnace. Improvements in furnace technology, such as new ignition and heat exchange design, have led to increased furnace efficiency. The AFUE levels considered in this measure are shown in Table B-2.15.

Table B-2.15. Gas Furnace Efficiency Comparison

Measure AFUE	Baseline AFUE
90%	80%
95%	

Water Heat

Water Heater, Storage. A high-efficiency water heater reduces standby loss and is more efficient than a standard electric water heater. The energy factors (EF) considered in this measure are shown in Table B-2.16.

Table B-2.16. Water Heater EF Comparison

Measure EF	Baseline EF
0.67	0.62
0.80	

Water Heater, Tankless. This measure provides hot water at a preset temperature as needed without storage, thereby reducing or eliminating standby losses. Tankless systems have an EF of 0.82, compared to standard water heaters with an EF of 0.62.[21]

[21] http://www.toolbase.org/Technology-Inventory/Plumbing/tankless-water-heaters

Appliances

High Efficiency Dryer. High efficiency dryers have features, such as moisture sensors, that minimize energy usage while retaining performance. The efficiency levels for this measure are shown in Table B-2.17.

Table B-2.17. Dryer EF Comparison

Measure	Baseline
2.74 EF	
2.83 EF	2.67 EF
2.93 EF	

Other (Pool)

Energy Efficient Pool Heater. Gas pool heaters use natural gas or propane. The water circulated by the pump passes through a filter and then travels to the heater. Gas burns in the heater combustion chamber, generating heat that warms the water returning to the pool. This measure assumes an efficiency level of 88 percent, compared to a standard 83 percent efficient pool heater.

5. Commercial Electric Retrofit Measure Descriptions

HVAC (and Envelope)

Automated Ventilation Variable Frequency Drive (VFD) Control, Occupancy/CO_2 sensors. This measure is also known as demand-control ventilation (DCV), where the ventilation system automatically adjusts air flow when CO_2 is above a specified level. CO_2 controls maintain a minimum ventilation rate at all times to control non-occupant contaminants, such as off-gassing from furniture, equipment, and building components. The baseline of this measure is a ventilation system that runs constantly.

Chilled Water/Condenser Water Settings, Optimization. Making adjustments to the chilled and condenser water system settings to better match the building load will reduce unnecessary use of the compressor and pumps.

Chilled Water Piping Loop with Variable Speed Drive (VSD) Control. A VSD controller, with two-way valves at the cooling coils, controls the chilled water pump speed to vary based on the cooling load, thus reducing pumping energy requirements. The baseline is a constant speed pump with three-way valves.

Chiller Water-Side Economizer. This measure consists of a heat exchanger attached to a condenser water piping loop that operates when outdoor conditions can produce colder condenser water than the mixed air temperature. A water side economizer is used when an outdoor-air economizer is not practical. The baseline measure is no economizer.

Convert Constant Volume Air System to Variable Air Volume (VAV). This measure allows the airflow volume of a HVAC system to vary the heating or cooling load rather than over-conditioning and short-cycling. The baseline is a constant volume system.

Cooling Tower, Decrease Approach Temperature. An oversized cooling tower allows a reduced approach temperature, which saves energy. The approach temperature is the difference between the water leaving the tower and the wet-bulb temperature. This measure assumes a 6 degree delta compared to the baseline of a 10 degree delta.

Cooling Tower, Two-Speed Fan Motor. A two-speed fan cycles between off, low, and high speeds to maintain the tower set point. The low-speed setting uses less energy than a single, high speed fan. The baseline measure is a single-speed fan motor.

Cooling Tower, Variable Speed Drive (VSD) Fan Control. VSDs modulate the air flow so that heat rejection exactly matches load at the desired set point, which saves energy. The baseline measure is a two-speed fan motor.

Direct Digital Control (DDC) System, Installation. DDC systems allow for both HVAC and lighting to be controlled and monitored. For lighting, the DDC system allows for direct control of lights from a remote location. Entire HVAC systems, including pumps, motors, fans, and set points, can be digitally programmed for tighter control of the system.

Direct Digital Control (DDC) System, Optimization. DDC is also known as an energy management system (EMS), which allows for digital monitoring and control of HVAC and lighting systems. The optimization refers to upgrading a high-efficiency energy management system to a premium efficiency system.

Direct Digital Control (DDS) System, Wireless Performance Monitoring. This second-generation building automation systems allows for wireless optimization and operation of building systems (such as HVAC) through computerized monitoring and control software and interfaces.

Direct Expansion (DX) Package Air-Side Economizer. An air-side economizer mixes return air with outside air to cool indoor spaces, which saves energy as less air needs to be cooled.

Direct Expansion (DX) Tune-Up/Diagnostics. Regular maintenance of DX air-conditioning systems includes checking controls, replacing filters, cleaning coils and blowers, and checking refrigerant levels.

Direct/Indirect Evaporative Cooling, Pre-Cooling. Direct evaporative coolers are low-energy systems that evaporate water into the air stream, thus reducing air temperature and increasing humidity. Indirect evaporative coolers use a secondary air stream that is cooled by water and travels through a heat exchanger with the primary air stream, cooling the air but not affecting the humidity. Direct/indirect systems cool the air stream via the indirect cooler, then cool it further through the direct cooler. Including an evaporative cooler before the DX system reduces the overall cooling load.

Duct Fittings, Leak-Proof. The majority of duct leakage in residential HVAC systems is due to improperly sealed connections between ductwork and fittings. Even when duct connections are initially well-sealed, leakage may increase over time.

Duct Repair and Sealing. This maintenance creates significant energy savings by ensuring conditioned air only goes to occupied spaces, thereby reducing an excessive runtime/load on the HVAC system.

Exhaust Air to Ventilation Air Heat Recovery. This measure captures heated air exhausted out of a building and transfers it to the incoming air, decreasing the overall heating load.

Exhaust Hood Makeup Air. This measure provides exhaust air at the hood instead of allowing the hood to exhaust conditioned air in the room. The baseline measure is for conditioned air to be expelled through exhaust hoods.

Green Roof. The added mass and thermal resistance of green roofs reduces the heating and cooling loads of the building. These roofs reduce the ambient temperature of the roof surface and slow the transfer of heat into the building, which reduces cooling costs. They also add insulation to the roof structure, reducing heating requirements in the winter.[22] Additionally, they reduce the ambient temperature around the roof, which decreases the building's urban heat island effect.

Hotel Key Card Energy Control System. This measure controls room HVAC and lighting during non-occupied periods. Occupancy is determined by the presence of a key card and/or additional sensors. The central system sets heating and cooling to a minimum and turns off lighting when the key card is removed. Once the key card is inserted, the hotel guest has full control of the room systems.

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[22] http://www.toolbase.org/Technology-Inventory/Roofs/green-roofs

Infiltration Reduction (Caulking, Weather Stripping, etc.). Sealing air leaks in windows, doors, the roof, crawlspaces, and outside walls decreases overall heating and cooling losses. Baseline and measure values, in units of air changes per hour (ACH), are presented in Table B-2.18.

Table B-2.18. Infiltration Reduction Measures

Measure (ACH)	Baseline (ACH)
0.65	1.00

Insulation, Ceiling. These measures represent an increase in R-value from existing building conditions to current state code or from current state code to better than code. Baseline and measure values are presented in Table B-2.19.

Table B-2.19. Ceiling Insulation Measures

Measure	Baseline
R-38 (State Code)	R-7
R-38 (State Code)	R-8
R-38 (State Code)	R-11
R-49	R-38 (State Code)

Insulation, Duct. Packaged direct expansion and heat-pump equipment are generally coupled with a ducting system inside the building. Insulating these ducts reduces energy loss to the unconditioned plenum space. This measure assumes that R-7 insulation is installed where no insulation previously existed.

Insulation, Floor (Non-Slab). These measures represent an increase in R-value from existing building conditions to current state code or from current state code to better than code. The baseline and measure R-values are presented in Table B-2.20.

Table B-2.20. Floor Insulation Measures

Measure	Baseline
R-30 (State Code)	R-7
R-30 (State Code)	R-8
R-30 (State Code)	R-11
R-30 (State Code)	R-19
R-38	R-30 (State Code)

Insulation, Wall. These measures represent an increase in R-value from existing building conditions to the current state code value of R-13 + 7.5. The baseline value of R-3 represents the average existing insulation level.

Natural Ventilation System. This measure relies on pressure differences to move fresh air through buildings. Natural ventilation, unlike fan-forced ventilation, uses the natural forces of wind and buoyancy to deliver fresh air into buildings. The specific approach and design varies by building type and local climate. The amount of ventilation depends on internal space design and the size and placement of openings in the building. Natural ventilation offsets the energy required to run forced air ventilation systems. [23]

Pipe Insulation. Adding 1.5-inches of insulation to water pipes yields an approximate R-value of R-6, which decreases temperature losses, thereby reducing demand on chilled water systems.

Programmable Thermostat. This measure controls set point temperature automatically, ensuring the HVAC system is not running during low-occupancy hours.

Retro-Commissioning. Commissioning ensures that energy-using systems are operating in an optimal fashion in order to maximize energy efficiency. This commissioning process can be applied to existing buildings to restore them to optimal performance. Retro-commissioning is a systematic, documented process that identifies low-cost operational and maintenance improvements in existing buildings and brings them up to the design intentions.[24,25] The baseline measure is no commissioning.

Sensible Heat Recovery Devices. This measure preconditions incoming air by transferring energy between the exhaust air stream and the supply air stream. This raises the temperature of incoming air during the winter and decreases it in the summer. Energy savings results from the reduced need for mechanical heating or cooling.

Total Heat Recovery Devices. This measure, also called enthalpy recovery, transfers sensible and latent heat. Latent heat, which is released or absorbed due to a phase change (such as the condensation of water vapor), significantly raises the outdoor air humidity in the winter and reduces it in the summer.[26]

Window Film. Solar control window films applied to existing windows reduces peak demand during hot months and conserves air conditioning energy. The use of these films also reduces exposure to ultraviolet radiation and glare.[27]

Windows, High Efficiency. This measure increases building performance by reducing the U-value, as shown in Table B-2.21.

Table B-2.21. High-efficiency Window Measures

Measure U-Value	Baseline U-Value
0.40 (State Code)	0.68
0.40 (State Code)	0.67
0.40 (State Code)	0.65
0.40 (State Code)	0.60
0.32	0.40 (State Code)

23 National Renewable Energy Laboratory; http://www.nrel.gov/docs/fy03osti/33698.pdf
24 http://www.green.ca.gov/CommissioningGuidelines/default.htm
25 http://cbs.lbl.gov/BPA/cct.html
26 http://www.mcquay.com/mcquaybiz/marketing_tools/mt_corporate/EngNews/0701.pdf
27 http://www.iwfa.com/iwfa/Consumer_Info/windowfilmbenefits.html

Lighting

Bi-Level Control, Stairwell Lighting. This measure allows an occupancy sensor to reduces the light load in an unoccupied stairwell by 50 percent for a set amount of time. The baseline is continuous operation at full power.

Cold Cathode Lighting. This measure is a tubular light or bulb that passes an electrical current through a gas or vapor, much like neon lighting. A cold cathode light is up to five times brighter than neon, and has one of the longest lives of any lighting fixture at roughly 50,000 hours.[28] Cold cathode lighting uses 5 watts compared to 30 watts for an incandescent bulb.

Covered Parking Lighting. This measure reducing the energy use of covered parking garages by replacing inefficient metal halide lamps with LED and replacing high pressure sodium lamps with LED low bay lighting.

Daylighting Controls, Outdoors (Photocell). Exterior photocells adjust lighting levels according to sunlight levels reaching desired set points. This measure achieves savings over time-clock or manual controls through changes in seasonal and site conditions by improving night time durations.

Dimming, Continuous: Fluorescent Fixtures. A continuous dimming switch allows light level brightness to vary from 0 percent to 100 percent, increasing electricity savings. The baseline measure is fluorescent fixtures operating at full power.

Dimming, Stepped: Fluorescent Fixtures. This measure allows the user to vary the light level by a number of specified tiers to adjust for the amount of outside daylight. The baseline measure is fluorescent fixtures operating at full power.

Exit Sign, Light Emitting Diodes (LED). LED exit signs use only 2 watts of power and last over 50,000 hours, compared to CFL exit signs that use 9 watts of power and have a shorter life.

Exit Sign, Photoluminescent or Tritium. This measure uses no energy and provides lighting suitable for exit signage.

Exterior Building Lighting, Package. This measure decreases lighting power density by 30 percent. The baseline lighting technology includes all available technologies in a building that make up the total watts per square foot.

Light Emitting Diodes (LED) Refrigeration Case Lights. These highly efficient bulbs create 55 percent energy savings over standard 60 watt fluorescent refrigeration case light.

Lighting Reduction Package, High Efficiency. This measure results in a 15 percent decrease in lighting power density (W/sqft). The baseline lighting technology includes all available technologies in a building that make up the total watts per square foot. Installation of the lighting reduction package reduces lighting power density with higher efficiency technologies, such as high performance T8 or T5 tubes, high-efficiency ballasts, reflective lighting fixtures, etc.

Lighting Reduction Package, Premium Efficiency. This measure results in a 20 percent decrease in lighting power density (W/sqft). The baseline lighting technology includes all available technologies in a building that make up the total watts per square foot. Installation of

28 Conjecture Corporation of wisegeek.com; http://www.wisegeek.com/what-is-a-cold-cathode-light.htm

the lighting reduction package reduces lighting power density with higher efficiency technologies, such as high performance T8 or T5 tubes, high-efficiency ballasts, reflective lighting fixtures, etc.

Lighting Reduction Package, Super Premium Efficiency. This measure results in a 25 percent decrease in lighting power density (W/sqft). The baseline lighting technology includes all available technologies in a building that make up the total watts per square foot. Installation of the lighting reduction package reduces lighting power density (W/sqft) with higher efficiency technologies, such as high performance T8 or T5 tubes, high-efficiency ballasts, reflective lighting fixtures, etc.

Lighting Reduction Package, Super Premium High Bay. Lighting reduction packages, such as T5HO (High Output) for high bay applications in a warehouse or grocery, can reduce the power density by 35 percent. The baseline lighting technology includes all available technologies in a building that make up the total watts per square foot.

Occupancy Sensor, Fluorescent. This measure turns off fluorescent lights after a space is unoccupied for a designated amount of time. The lights turn on again when the sensor detects a person in the space. Occupancy measures can control single or multiple lighting zones. The controlled lighting wattage varies depending on application. The baseline assumes no lighting controls.

Solid State Light Emitting Diode (LED), White Lighting. LEDs are solid-state devices that convert electricity to light, with very high efficiency and long life. Recently, lighting manufacturers have indirectly produced 'cool' white LED lighting using ultraviolet LEDs to excite phosphors that emit a white-appearing light. This measure applies to exterior lighting for landscape, merchandise, signage, and structures. The baseline for this measure is 50 watts, 10 hrs/day, 365 days/yr.

Surface Parking Lighting. Replacing inefficient metal halide lamps that consume between 100-150 watts with LED lighting that consumes 60-111 watts reduces the energy use of surface parking lots. LED lights also last longer than metal halide lamps, reducing the labor of replace lamps.

Time Clock. This technology allows users to program lights and other loads to be turned on and off automatically in response to a time schedule, an occupancy sensor, or a building automation system.

Water Heat

Clothes Washer, Ozonating. This measure disinfects water with ozone-enriched air, which suppresses subsequent biological activity and controls biological growth within the appliance, thus reducing the need for hot water. The baseline measure is a standard commercial clothes washer.[29]

[29] http://www.patentstorm.us/patents/6607672-description.html

Clothes Washer Commercial, ENERGY STAR®. This measure has more capacity than conventional top-load models with an agitator. Some front-loaders can wash over 20 pounds of laundry at once, compared to 10–15 pounds for a standard top-loader.[30]

Demand-Controlled Circulating Systems. This measure circulates hot water only when required. The baseline measure is a continuously circulating hot water system, resulting in energy loss through pipes.

Dishwasher, Residential ENERGY STAR®. Residential sized ENERGY STAR® dishwashers are often appropriate for smaller commercial buildings, and are 10 percent more efficient than the federal minimum standard used as the baseline.[31]

Dishwasher, Commercial: High Temperature ENERGY STAR®. This measure has a minimal idle rate, consumes a minimal amount of water per rack of loaded dishes, and is on average 25 percent more efficient than standard high temp commercial dishwashers.[32]

Dishwasher, Commercial: Low Temperature ENERGY STAR®. This measure uses chemicals combined with low temperatures to save energy compared to standard high temperature commercial dishwashers.

Drain Water Heat Recovery, Water Heater. This measure recovers heat energy from drain water and uses it to heat water entering the hot water tank, minimizing the temperature rise required to achieve the water heater set point.[33]

Hot Water (SHW) Pipe Insulation. One inch of extra insulation on hot water pipes yields an approximate R-value of R-4, decreasing temperature losses. This measure is only applicable for existing construction. The baseline measure is no insulation.

Low-Flow Faucet Aerators. This measure mixes water and air, reducing the amount of water that flows through the faucet. It creates a fine water spray through an inserted screen in the faucet head. Flow rate requirements for this measure are presented in Table B-2.22.

Table B-2.22. Faucet Aerator Flow Rates

Measure Flow Rate (GPM*)	Baseline Flow Rate (GPM)
2.2	3.0
1.5	2.2
* Gallons per minute	

Low-Flow Pre-Rinse Spray Valves. This measure mixes water and air, reducing the amount of water that flows through the spray head. The head creates a fine water spray through an inserted screen, achieving a flow reduction from 1.6 GPM (federal standard) to 0.6 GPM.

30 http://www.energystar.gov/index.cfm?c=clotheswash.pr_clothes_washers_comm
31 http://www.energystar.gov/index.cfm?fuseaction=find_a_product.showProductGroup&pgw_code=DW
32 http://www.energystar.gov/index.cfm?fuseaction=find_a_product.showProductGroup&pgw_code=COH
33 www.toolbase.org/Techinventory/TechDetails.aspx?ContentDetailID=858&BucketID=6&CategoryID=9

Low-Flow Showerheads. This measure mixes water and air, reducing the amount of water that flows through the showerhead. The showerhead creates a fine water spray through an inserted screen. Flow rate requirements for this measure are presented in Table B-2.23.

Table B-2.23. Low-Flow Showerhead Flow Rates

Measure Flow Rate (GPM)	Baseline Flow Rate (GPM)
2.5	4.5
2.0	2.5

Ultrasonic Faucet Control. Ultrasonic sensors automatically turn faucet water on and off when motion is detected at the sink. This eliminates water running continuously while the sink is in use.

Water Cooled Refrigeration with Heat Recovery. Heat recovery gathers and uses thermal energy for the water heater that would normally be rejected to the ambient environment.

Water Heater Temperature Setback. This measure reduces the set point temperature from 130°F to 120°F.

Refrigeration

Anti-Sweat (Humidistat) Controls. This measure enables the user to turn refrigeration display case anti-sweat heaters off when ambient relative humidity is low enough that sweating will not occur. Without controls, heaters generally run continuously.

Case Electronically Commutated Motor (ECM). A case fan is one component of a refrigeration system. ECMs are smaller variable speed motors that operate from a single-phase power source with an electronic controller in or on the motor. The baseline measure is a standard efficiency motor.

Case Replacement, Low and Medium Temperatures. Efficient refrigerated display cases achieve higher performance efficiency and reduce overall energy consumption by incorporating high performance evaporative fans, such as ECMs, energy-efficient double-pane glass doors, anti-sweat controls, high efficiency lighting and ballast, such as T8 or LED lamps, and improved insulation.

Compressor VSD Retrofit. This measure modulates motor speed in response to load changes. When low-load conditions exist, current to the compressor motor is decreased, slowing the compressor motor. Baseline is a constant-speed compressor.

Demand Control Defrost, Hot Gas. Evaporator frost reduces coil capacity by acting as a layer of insulation and reducing the airflow between fins. With hot gas defrost, refrigerant vapor from the compressor discharge or the high pressure receiver is used to warm the evaporator coil and melt the frost.[34]

Evaporative Condenser, High Efficiency. This water cooled measure can cycle a refrigerator with less energy than a standard air-cooled system.

[34] Parker Refrigeration Specialists; http://www.parker.com/literature/Refrigerating%20Specialties%20Division/90-11a.pdf

Floating Condenser Head Pressure Controls. This measure adds controls to float head pressure temperature down during periods of low load. The base case is a standard multiplex system with a fixed condensing set point.

Glass Door, ENERGY STAR® Refrigerators/Freezers. Low-E, double-pane thermal glass doors reduce cooling loses in refrigerated reach-in cases.

High Efficiency Compressors. A component of refrigeration systems, this measure operates up to 15 percent more efficiently than standard-efficiency compressors.

Night Covers for Display Cases. This measure eliminates wasted refrigeration cooling by insulating display cases. In addition, it reduces the heating load of buildings by allowing less refrigerated air to escape and need reheated.

Refrigeration Commissioning or Re-Commissioning. Commissioning ensures that refrigeration systems are operating in an optimal fashion in order to maximize energy efficiency. Retro-commissioning checks previously commissioned equipment to ensure that it is continuing to run efficiently. The baseline measure is no commissioning.[35]

Refrigerator eCube. Refrigerators monitor circulating air temperatures to determine when to switch on and off. When the refrigerator door is opened, circulating air temperature increases more rapidly than food temperature, causing the equipment to work harder to maintain the set point. Instead of measuring air temperature, the eCube, a device with similar heat transfer characteristics to food, allows the refrigerator to monitor the more stable food temperature, resulting in less frequent cycling of the compressor.

Solid-Door Refrigerators/Freezers, ENERGY STAR®. This measure is designed with high efficiency components such as an ECM evaporator, condenser fan motors, hot gas anti-sweat heaters, or high-efficiency compressors, saving energy compared to standard models.[36]

Standalone to Multiplex Compressor. This measure consists of multiple compressors drawing from a common suction header, serving any number of refrigerated display fixtures. The suction group is controlled to satisfy the lowest temperature required by any of the attached display fixtures, and therefore the fixtures served by a given suction group usually have similar temperature requirements. Baseline is a single dedicated compressor system for each refrigeration load.[37, 38]

Strip Curtains on Walk-In Refrigerators. This measure reduces the infiltration of warm air into the refrigerated space by improving the barrier between the refrigerated and the ambient air.

Walk-In Electronically Commutated Motor (ECM). A walk-in fan is one component of refrigeration systems. ECMs typically have small horse power motors (less than 1 HP) that are factory programmed to run at certain speeds. ECMs operate from a single-phase power source

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35 http://cbs.lbl.gov/BPA/cct.html
36 http://www.energystar.gov/index.cfm?fuseaction=find_a_product.showProductGroup&pgw_code=CRF
37 http://www.energysmartgrocer.org/pdfs/PGE/BridgeEquipment%20SpecificationTandCs.pdf
38 http://www.bizlink.com/HPAC_articles/March2007/306.pdf

with an electronic controller in or on the motor. The baseline measure is a standard efficiency motor.[39]

Other

Battery Charger, ENERGY STAR®. On average, these battery chargers use 35 percent less energy than conventional battery chargers, which draw as much as five to 20 times more energy than is actually stored in the battery (even when not actively charging a product). Battery charging systems recharge a variety of cordless products, including power tools, small household appliances, and electric shavers. The baseline is a standard battery charger.[40]

Combination Oven. This measure uses both dry heat and steam, which are injected into the oven when the food being cooked needs it. High efficiency combination ovens with 60 percent efficiency use roughly half the energy of standard combination ovens.[41]

Cooking Hood Controls. Utilizing sensors and two-speed or variable speed fans, hood controls reduce exhaust (and makeup) airflow when appliances are not at capacity (or have been turned off). The baseline for this measure is no hood controls.

Copier, ENERGY STAR®. This measure delivers the same performance as conventional equipment, powers down when not in use, and averages 40 percent more efficiency. The baseline measure is a non-ENERGY STAR® copier.[42]

Deep Fat Fryer, Consortium for Energy Efficiency (CEE). Commercial, 15 inch CEE rated electric fryers have a heavy load cooking efficiency of 80 percent or better, and use less than 1,000 watts when idle.[43] The baseline is standard electric deep fat fryer.

Fax, ENERGY STAR®. This measure enters sleep mode after inactivity, reducing total power consumption by 40 percent.[44]

Griddle, ENERGY STAR®. This measure is approximately 10 percent more efficient than standard models, and must have a minimum cooking efficiency of 38 percent. They must use less than 0.026 therm/hour/ft^2 when idle. The baseline measure is a standard grill at 32 percent efficiency.[45]

High Efficiency Convection Oven, ENERGY STAR®. This measure must meet the specification requirements of 70 percent cooking energy efficiency and an idle energy rate of 1.6 kW. Standard electric convection ovens have a 65 percent cooking energy efficiency and an idle energy rate of 2 kW.[46]

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39 http://www.fishnick.com/publications/appliancereports/refrigeration/GE_ECM_revised.pdf
40 http://www.energystar.gov/index.cfm?c=battery_chargers.pr_battery_chargers
41 http://www.energystar.gov/ia/partners/publications/pubdocs/restaurants_guide.pdf
42 http://www.energystar.gov/index.cfm?fuseaction=find_a_product.showProductGroup&pgw_code=IEQ
43 http://www.energystar.gov/index.cfm?c=fryers.pr_fryers
44 http://www.energystar.gov/ia/products/fap/IE_Prog_Req.pdf
45 http://www.energystar.gov/index.cfm?fuseaction=find_a_product.showProductGroup&pgw_code=COG
46 http://www.energystar.gov/index.cfm?c=ovens.pr_comm_ovens

High Efficiency Ice Maker. This measure uses high efficiency compressors, fan motors, and thicker insulation to achieve 15 percent more efficiency than the baseline measure, which is a conventional automatic commercial ice maker.[47]

Hot Food Holding Cabinet, ENERGY STAR®. This measure uses a maximum of 40 watts/cubic foot. The baseline measure is a conventional holding cabinet.[48]

Low Pressure Air Distribution Complex HVAC. This under-floor measure introduces air into occupancy zones at relatively low velocities. The decrease in pressure differentials and, therefore in air velocity, results in lower energy consumption by the air handlers. The baseline for this measure is a variable air volume or constant volume HVAC system.

Monitor, ENERGY STAR®. This measure enters sleep mode and consumes less than 2 watts. The sleep mode needs to be enabled.

Motor, Consortium for Energy Efficiency (CEE) Premium-Efficiency Plus. These motors (also known as "super" or "enhanced") are more efficient than standard NEMA premium efficiency motors.[49] This measure specifically relates to HVAC motors ranging from 1 HP to 200 HP.

Motor, Pump and Fan System: Variable Speed Control. This measure allows pump and fan motors to operate at a lower speed while still maintaining set points during partial load conditions. This reduces energy consumption as motor operation can vary with load rather than frequently cycling on and off at constant speed.

Motor Rewind. This measure follows the Green Motors Practices Group™ recommendations of best practices to maintain original efficiency, commonly called a Green Rewind.[50, 51] A failed motor can be rewound to a lower efficiency, rewound to maintain the original efficiency, or replaced.

Motor: Variable Air Volume (VAV) Box High Efficiency Electronically Commutated Motor (ECM). High efficiency fan-powered boxes prevent hot and cold spots by maintaining room air circulation while modulating supply-air temperature to match load. This measure applies to a motor efficiency upgrade. An ECM powers the fan in each VAV box. An ECM is a brushless DC motor with electronically built-in speed and torque controls, which allows the motor speed to adjust for optimal airflow. The baseline assumes a standard VAV with induction motors including silicon controlled rectifier speed control.[52]

Network PC Power Management. This software tool intelligently manages computer powers remotely and automatically across a network overnight, on weekends, and when not in use. This significantly lowers energy consumption without impacting user productivity, desktop maintenance, or upgrades. Workstations operating on a local area network or a wide area

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47 Consortium for Energy Efficiency (CEE); http://www.cee1.org/com/com-kit/com-kit-equip.php3

48 http://www.energystar.gov/index.cfm?c=hfhc.pr_hfhc

49 CEE motor nominal efficiencies are higher than the NEMA federal minimum efficiency levels that became effective in December 2010. On December 19, 2010, the 2007 Energy Independence and Security Act updated the minimum efficiency standards for motors, and the previous NEMA premium efficiency specifications became the federal standard.

50 http://www.bpa.gov/energy/n/industrial/Green_motors/

51 http://www.greenmotors.org/downloads/RTFSubmittalMay_08%20_2_.pdf

52 LEED-qualified Justice Center, reported by DCJ.com and the Minnesota Power Incentive Program.

network can implement PC power-management policies across a network to maximize energy savings .

Optimized Variable Volume Lab Hood Design. This measure allows volumetric flow rate to vary, which causes a constant speed through the duct regardless of sash opening. The baseline measure is a constant volume lab hood.

Power Supply Transformer/Converter. This measure applies to the 80 PLUS performance specification requirements for power in computers and servers. 80 PLUS specifies 80 percent or greater efficiency at 20 percent, 50 percent, and 100 percent of rated load with a true power factor of 0.9 or greater.[53] The baseline assumes an 85 percent efficient power supply (>51 watts).

Printer, ENERGY STAR®. This measure deploys a maximum time delay to sleep depending on the size of the equipment, which reduces power consumption during periods of inactivity.[54]

Residential Refrigerator, ENERGY STAR®.This measure uses at least 20 percent less energy than required by current federal standards.[55]

Residential Refrigerator/Freezer Recycling. This refers to the environmentally-friendly disposal of unneeded appliances such as secondary refrigerators or stand-alone freezers.

Residential-Size Refrigerator/Freezer: Early Replacement, ENERGY STAR®. Replacing equipment before the end of its useful life is advantageous because of significant inefficiencies in older models.

Scanner, ENERGY STAR®. This measure enters a low power sleep mode after inactivity.[56]

Server Virtualization. This measure replaces multiple under-utilized servers with one server. Many data center servers operate at 10 percent capacity or less, allowing their functions to be consolidated onto one virtual server that operates in the range of 85 percent capacity. This measure applies to the plug load end use, although it has a savings effect on the cooling load by reducing power and, therefore, the heat generated by equipment.

Smart Strip. Power strips with an occupancy sensor will turn power to all devices plugged into the strip on and off, such as computers, desk lights, and audio equipment, based on occupancy within the work area.

Steam Cooker, ENERGY STAR®. This measure has a cooking efficiency of 50 percent, with idle energy rates that vary depending upon pan size.[57] The baseline efficiency is a standard commercial steam cooker with 35 percent efficiency.

Vending Machines, High Efficiency ENERGY STAR®. New and rebuilt refrigerated beverage vending machines are 50 percent more energy efficient than the standard model, through more

[53] www.80PLUS.org
[54] http://www.energystar.gov/ia/products/fap/IE_Prog_Req.pdf
[55] http://www.energystar.gov/index.cfm?fuseaction=find_a_product.showProductGroup&pgw_code=RF
[56] http://www.energystar.gov.au/products/scanners.html
[57] http://www.energystar.gov/index.cfm?c=steamcookers.pr_steamcookers

efficient compressors, fan motors, lighting systems, and low-power mode options during non-use periods.[58]

Vending Miser. This measure senses occupancy and cycles the vending machine cooling off when no occupancy is detected.

Water Cooler, ENERGY STAR®. This measure provides only cold water and consumes less than 0.16 kWh per day. A unit providing hot and cold water consumes less than 1.20 kWh per day. ENERGY STAR®-qualified water coolers consume 45 percent less energy than standard models.[59]

58 http://www.energystar.gov/index.cfm?fuseaction=find_a_product.showProductGroup&pgw_code=VMCc
59 http://www.energystar.gov/index.cfm?c=water_coolers.pr_water_coolers

6. Commercial Electric Equipment Measure Descriptions

HVAC

Air or Ground Source Heat Pump (ASHP or GSHP). Electric heat pumps move heat to or from the air or the ground to cool and heat a home. Table B-2.24 displays the different efficiency levels we compared for this measure. The baseline size is the same as the measure size.

Table B-2.24. Heat Pump SEER/HSPF Comparisons

Measure Efficiency	Baseline SEER & HSPF
ASHP 14 SEER, 8.5 HSPF	ASHP 13 SEER, 7.7 HSPF
ASHP 16 SEER, 8.8 HSPF	
GSHP 16.2 EER, 8.8 HSPF	

Centrifugal Chiller. This measure uses the vapor compression cycle to chill water and rejects heat from the chilled water and from the compressor to a second water loop cooled by a cooling tower. The advantage of centrifugal compressors is their high flow rate capability and good efficiency. Table B-2.25compares different efficiencies greater than 300 tons, rated in kW/ton.

Table B-2.25. Centrifugal Chiller kW/ton Comparison

Measure kW / ton	Baseline kW / ton
0.55	0.576 (State Code)
0.52	0.576 (State Code)
0.47	0.576 (State Code)

Direct Expansion (DX) Package. DX systems transfer heat with a refrigerant piping circuit, compressor, and refrigerant coils. All components are in a single package typically installed on the building roof. Commercial-sized units are normally rated by their Energy Efficient Ratio (EER). Table B-2.26 displays the different models compared in this measure.

Table B-2.26. DX AC Unit EER / Advanced Technology Comparisons

kBTU / hr	Measure EER	Baseline EER
65 – 135	11.5	11.2 (State Code)
65 – 135	12.0	11.2 (State Code)
135 – 240	11.5	11.0 (State Code)
135 – 240	12.0	11.0 (State Code)
240 – 760	10.5	10.0 (State Code)
240 – 760	10.8	10.0 (State Code)

Screw Chiller. Screw compressors are positive displacement devices. The refrigerant chamber actively compresses to a smaller volume by the twisting motion of two interlocking, rotating screws. Refrigerant trapped in the space between the two rotating screws is compressed as it travels from the inlet to the outlet of the compressor. A slide valve adjusts the compression effect by varying the amount of compression that occurs before the refrigerant is discharged. Screw chillers are generally used for small- to medium-sized buildings. Table B-2.27compares different efficiencies, rated in kW/ton.

Table B-2.27. Screw Chiller kW/ton Comparison

Tons	Measure kW / ton	Baseline kW / ton
<150	0.71	0.79 (State Code)
<150	0.63	0.79 (State Code)
<150	0.58	0.79 (State Code)
150-300	0.65	0.68 (State Code)
150-300	0.57	0.68 (State Code)
150-300	0.50	0.68 (State Code)

Water Heating

Water Heater, Heat Pump. This measure moves heat from a warm reservoir (such as air) into the hot water system.[60] Baseline and efficient measure EF values are given in Table B-2.28.

Table B-2.28. Water Heater EF Comparisons

Water Heater Type	Measure EF	Baseline EF
Electric Storage Water Heater	0.95	0.92
Heat Pump Water Heater	2.2	0.92

Other

Computer, ENERGY STAR. This measure consumes less than 2 watts in sleep and off modes, and is more efficient than conventional units in idle mode, resulting in 30 to 65 percent energy savings.

60 Description source: U.S. Department of Energy; http://www.energysavers.gov/your_home/water_heating/index.cfm/mytopic=12840

7. Commercial Gas Retrofit Measure Descriptions

HVAC (and Envelope)

Automated Ventilation Variable Frequency Drive (VFD) Control, Occupancy/CO_2 sensors. This measure is also known as demand-control ventilation (DCV), where the ventilation system automatically adjusts air flow when CO_2 is above a specified level. CO_2 controls maintain a minimum ventilation rate at all times to control non-occupant contaminants, such as off-gassing from furniture, equipment, and building components. The baseline of this measure is a ventilation system that runs constantly.

Boiler Economizer. This measure recovers heat energy that would otherwise be lost out the boiler stack by using a heat exchanger located on the stack to preheat boiler feed water.

Convert Constant Volume Air System to Variable Air Volume (VAV). TThis measure allows the airflow volume of a HVAC system to vary the heating or cooling load rather than over-conditioning and short-cycling. The baseline is a constant volume system.

Direct Digital Control (DDC) System, Installation. DDC systems allow for both HVAC and lighting to be controlled and monitored. For lighting, the DDC system allows for direct control of lights from a remote location. Entire HVAC systems, including pumps, motors, fans, and set points, can be digitally programmed for tighter control of the system.

Direct Digital Control (DDC) System, Optimization. DDC is also known as an energy management system (EMS), which allows for digital monitoring and control of HVAC and lighting systems. The optimization refers to upgrading a high-efficiency energy management system to a premium efficiency system.

Direct Digital Control (DDS) System, Wireless Performance Monitoring. This second-generation building automation systems allows for wireless optimization and operation of building systems (such as HVAC) through computerized monitoring and control software and interfaces.

Duct Fittings, Leak-Proof. The majority of duct leakage in residential HVAC systems is due to improperly sealed connections between ductwork and fittings. Even when duct connections are initially well-sealed, leakage may increase over time.

Duct Repair and Sealing. This maintenance creates significant energy savings by ensuring conditioned air only goes to occupied spaces, thereby reducing an excessive runtime/load on the HVAC system.

Exhaust Air to Ventilation Air Heat Recovery. This measure captures heated air exhausted out of a building and transfers it to the incoming air, decreasing the overall heating load.

Exhaust Hood Makeup Air. This measure provides exhaust air at the hood instead of allowing the hood to exhaust conditioned air in the room. The baseline measure is for conditioned air to be expelled through exhaust hoods.

Infiltration Reduction (Caulking, Weather Stripping, etc.). Sealing air leaks in windows, doors, the roof, crawlspaces, and outside walls decreases overall heating and cooling losses. This measure reduces the number of air changes per hour from 1.00 to 0.65.

Insulation, Ceiling. These measures represent an increase in R-value from existing building conditions to current state code or from current state code to better than code. Baseline and measure values are presented in Table B-2.29.

Table B-2.29. Ceiling Insulation Measures

Measure	Baseline
R-38 (State Code)	R-7
R-38 (State Code)	R-8
R-38 (State Code)	R-11
R-49	R-38 (State Code)

Insulation, Duct. Packaged direct expansion and heat-pump equipment are generally coupled with a ducting system inside the building. Insulating these ducts reduces energy loss to the unconditioned plenum space. This measure assumes that R-7 insulation is installed where no insulation previously existed.

Insulation, Floor (Non-Slab). These measures represent an increase in R-value from existing building conditions to current state code or from current state code to better than code. Baseline and measure values are presented in Table B-2.30.

Table B-2.30. Floor Insulation Measures

Measure	Baseline
R-30 (State Code)	R-7
R-30 (State Code)	R-8
R-30 (State Code)	R-11
R-30 (State Code)	R-19
R-38	R-30 (State Code)

Insulation, Wall. These measures represent an increase in R-value from existing building conditions to the current state code value of R-13 + 7.5. The baseline value of R-3 represents the average existing insulation level.

Programmable Thermostat. This measure controls set point temperature automatically, ensuring the HVAC system is not running during low-occupancy hours.

Retro-Commissioning. Commissioning ensures that energy-using systems are operating in an optimal fashion in order to maximize energy efficiency. This commissioning process can be applied to existing buildings to restore them to optimal performance. Retro-commissioning is a systematic, documented process that identifies low-cost operational and maintenance improvements in existing buildings and brings them up to the design intentions.[61,62] The baseline measure is no commissioning.

Sensible Heat Recovery Devices. This measure preconditions incoming air by transferring energy between the exhaust air stream and the supply air stream. This raises the temperature of

61 http://www.green.ca.gov/CommissioningGuidelines/default.htm
62 http://cbs.lbl.gov/BPA/cct.html

incoming air during the winter and decreases it in the summer. Energy savings results from the reduced need for mechanical heating or cooling.

Total Heat Recovery Devices. This measure, also called enthalpy recovery, transfers sensible and latent heat. Latent heat, which is released or absorbed due to a phase change (such as the condensation of water vapor), significantly raises the outdoor air humidity in the winter and reduces it in the summer.[63]

Steam Pipe Insulation. R-4 insulation reduces heat loss from a steam pipe. The loss size depends on the pipe diameter and steam temperature.

Steam Trap Maintenance. This measure prevents the dirt created by chemical treatments or pipe scaling from becoming plugged. In most cases, plugging prevents the valve from closing, allowing live steam to escape into the condensate return line or atmosphere, wasting energy.[64]

Windows, High Efficiency. This measure increases building performance by reducing the U-value, as shown in Table B-2.31.

Table B-2.31. High-efficiency Window Measures

Measure U-Value	Baseline U-Value
0.40 (State Code)	0.68
0.40 (State Code)	0.67
0.40 (State Code)	0.65

Water Heat

Clothes Washer, Ozonating. This measure disinfects water with ozone-enriched air, which suppresses subsequent biological activity and controls biological growth within the appliance, thus reducing the need for hot water. The baseline measure is a standard commercial clothes washer.[65]

Demand-Controlled Circulating Systems. This measure circulates hot water only when required. The baseline measure is a continuously circulating hot water system, resulting in energy loss through pipes.

Dishwasher, Commercial: High Temperature ENERGY STAR®. This measure has a minimal idle rate, consumes a minimal amount of water per rack of loaded dishes, and is on average 25 percent more efficient than standard high temp commercial dishwashers.[66]

Dishwasher, Commercial: Low Temperature ENERGY STAR®. This measure uses chemicals combined with low temperatures to save energy compared to standard high temperature commercial dishwashers.

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63 http://www.mcquay.com/mcquaybiz/marketing_tools/mt_corporate/EngNews/0701.pdf
64 http://www.steamtraptesting.com/
65 http://www.patentstorm.us/patents/6607672-description.html
66 http://www.energystar.gov/index.cfm?fuseaction=find_a_product.showProductGroup&pgw_code=COH

Dishwasher, Residential ENERGY STAR®. Residential sized ENERGY STAR® dishwashers are often appropriate for smaller commercial buildings, and are 10 percent more efficient than the federal minimum standard used as the baseline.[67]

Drain Water Heat Recovery, Water Heater. This measure recovers heat energy from drain water and uses it to heat water entering the hot water tank, minimizing the temperature rise required to achieve the water heater set point.[68]

Hot Water (SHW) Pipe Insulation. One inch of extra insulation on hot water pipes yields an approximate R-value of R-4, decreasing temperature losses. This measure is only applicable for existing construction. The baseline measure is no insulation.

Integrated Space Heating/Water Heating. These systems provide space conditioning and hot water heating in one appliance/energy source. Domestic hot water is heated directly and space is heated by a hot water heat exchanger coil piped to the forced air heating system. This combination space/water heating system provides high efficiency heating for the cost of one high efficiency appliance.

Low-Flow Faucet Aerators. This measure mixes water and air, reducing the amount of water that flows through the faucet. It creates a fine water spray through an inserted screen in the faucet head. Flow rate requirements for this measure are presented in Table B-2.32.

Table B-2.32. Faucet Aerator Flow Rates

Measure Flow Rate (GPM*)	Baseline Flow Rate (GPM)
2.2	3.0
1.5	2.2
* Gallons per minute	

Low-Flow Pre-Rinse Spray Valves. This measure mixes water and air, reducing the amount of water that flows through the spray head. The head creates a fine water spray through an inserted screen, achieving a flow reduction from 1.6 GPM (federal standard) to 0.6 GPM.

Low-Flow Showerheads. Low-flow showerheads mix water and air to reduce the amount of water that flows through the showerhead. The showerhead creates a fine water spray through an inserted screen in the showerhead. Flow rate requirements for this measure are presented in Table B-2.33.

Table B-2.33. Low-Flow Showerhead Flow Rates

Measure Flow Rate (GPM)	Baseline Flow Rate (GPM)
2.5	4.5
2.0	2.5

Ultrasonic Faucet Control. Ultrasonic sensors automatically turn faucet water on and off when motion is detected at the sink. This eliminates water running continuously while the sink is in use.

67 http://www.energystar.gov/index.cfm?fuseaction=find_a_product.showProductGroup&pgw_code=DW
68 www.toolbase.org/Techinventory/TechDetails.aspx?ContentDetailID=858&BucketID=6&CategoryID=9

Water Cooled Refrigeration with Heat Recovery. Heat recovery gathers and uses thermal energy for the water heater that would normally be rejected to the ambient environment.

Water Heater Temperature Setback. This measure reduces the set point temperature from 130°F to 120°F.

Other

Broiler. High efficiency broiler ovens have rigorous start-up, shut down, and turn down schedules for additional energy savings over standard units. Improved efficiency broilers have an efficiency of 34 percent, compared to baseline models at 15 percent.

Convection Oven, High Efficiency ENERGY STAR®. This measure must meet the specification requirements of 70 percent cooking energy efficiency and an idle energy rate of 18,000 Btu/h. Standard electric convection ovens have a 65 percent cooking energy efficiency and an idle energy rate of 13,000 Btu/h.[69]

Fryers, Commercial Gas Cooking ENERGY STAR®. These measures are 50 percent efficient, and when idle use less than 9,000 Btu/hr.[70] The baseline efficiency is 35 percent for a non-ENERGY STAR® commercial fryer.

Griddle, ENERGY STAR®. This measure is approximately 10 percent more efficient than standard models, and must have a minimum cooking efficiency of 38 percent. They must use less than 0.026 therm/hour/ft^2 when idle. The baseline measure is a standard grill at 32 percent efficiency.[71]

Oven, Conveyor. A high efficiency conveyor oven is 23 percent efficient, compared to a standard conveyor oven with 15 percent efficiency.

Oven, Power Burner. A power burner incorporates a larger burner and is often sold on range-oven combination units. This measure mixes a greater percentage of air to the gas to increase the overall combustion efficiency of the burner from 40 to 50 percent efficiency to 60 percent efficiency.

Steam Cooker, ENERGY STAR®. This measure has a cooking efficiency of 50 percent, with idle energy rates that vary depending upon pan size.[72] The baseline efficiency is a standard commercial steam cooker with 35 percent efficiency.

Swimming Pool/Spa Covers. This measure reduces evaporation, which is the largest source of pool/spa energy loss. It takes one British thermal unit (Btu) to raise one pound of water by one degree. Each pound of 80º F water that evaporates takes 1,048 Btus of heat out of the pool.[73] The baseline measure is an uncovered pool or spa.

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69 http://www.energystar.gov/index.cfm?c=ovens.pr_comm_ovens
70 http://www.energystar.gov/index.cfm?c=fryers.pr_fryers
71 http://www.energystar.gov/index.cfm?fuseaction=find_a_product.showProductGroup&pgw_code=COG
72 http://www.energystar.gov/index.cfm?c=steamcookers.pr_steamcookers
73 http://www.eere.energy.gov/consumer/your_home/water_heating/index.cfm/mytopic=13140

8. Commercial Gas Equipment Measure Descriptions

HVAC

Gas Boiler. Boilers are classified as condensing or non-condensing. Condensing boilers condense the flue gas and water vapor, extracting useful heat and improving the boiler efficiency. This measure compares several boilers with different thermal efficiencies and is applicable to both new and existing construction. The overall efficiency of the boiler is defined as the gross energy output divided by the energy input, and is affected by combustion efficiency, standby losses, cycling losses, and heat transfer. Table B-2.34 displays the measure and baseline thermal efficiencies.

Table B-2.34. Gas Boiler Efficiency Comparison

Measure AFUE	Baseline AFUE
90%	82%
94%	

Gas Furnace. Improvements in furnace technology, such as new ignition and heat exchange design, have led to increased furnace efficiency. The AFUE levels considered in this measure are shown in Table B-2.15.

Table B-2.35. Gas Furnace Efficiency Comparison

Measure AFUE	Baseline AFUE
90%	80%
95%	

Water Heat

Water Heater. This measure has a range of thermal efficiencies as shown in Table B-2.36. High efficiency models have better insulation, which reduces standby losses.

Table B-2.36. Commercial Gas Water Heater Comparison

Measure Efficiency	Baseline Efficiency
0.82 EF	0.67 EF
0.90 EF	

9. Industrial Electric Measure Descriptions

Air Compressor Improvements (Demand Reduction, Optimization, Equipment). These measures improve the overall compressed air system by improved system design, leak repair, usage practices, more efficient dryer and storage systems, and compressor upgrades.

Clean Room Improvements (Change Filter Strategy, Chiller Optimize, HVAC). These measures aim to save energy through improved clean room equipment and practices. Savings are attributable to optimization of chiller operating parameters, upgrading to more efficient equipment, and improving filter replacement strategies.

Efficiency Centrifugal Fan. This measure achieves energy savings through improved fan design.

Electric Chip Fab Improvements (Eliminate Exhaust, Exhaust Injector, Reduce Gas Pressure, Solid-state Chiller). These measures are general improvements that increase efficiency in the electric chip fabrication process.

Fan System Optimization. This measure involves the overall optimization of the fan system with improved system design, enhanced flow design, better maintenance practices, and adjustments to system parameters.

Food Manufacturing (Cooling and Storage, Refrigerator Storage Tune-up). These measures maintain and enhance the cooling equipment for each facility type. Tune-ups may include refrigerant charge, equipment cleaning, general maintenance, and improved practices.

General Process Improvements (Paper: Premium Fan, Paper: Large Material Handling, Paper: Material Handling, Paper: Premium Control Large Material, Efficient Pulp Screen, Wood: Replace Pneumatic Conveyor, Metal: New Arc Furnace). These measures include upgrading equipment, replacing hydraulic/pneumatic equipment with electrical equipment, and using optimum size and capacity equipment.

High Efficiency Fans (Fan Equipment Upgrade). This measure involves upgrading motors to higher efficiency. Since NEMA Premium motors are becoming the baseline code requirement in 2010, this measure is based off of super premium motors with efficiency levels at least one efficiency band above NEMA premium.

Lighting Improvements (Efficient Lighting 1, 2, and 3 Shift; HighBay Lighting 1, 2, and 3 Shift; Lighting Controls). Changes to overall illumination levels, use of natural lighting, or technology improvements to more efficient bulbs or ballasts will decrease the overall lighting energy consumption. These measures include upgrades from T12 to T8 systems, T8 to high-performance T8 systems, HID to fluorescent conversions, standard HID to high-efficiency HID systems, and occupancy and day lighting controls.

Material Handling (Material Handling Variable Speed Drive (VFD) 1 and 2, Material Handling 1 and 2). This measure includes equipment upgrades (such as to VSDs) and enhanced system design or practices.

Motor Rewind. This measure follows the Green Motors Practices Group™ recommendations of best practices to maintain original efficiency, commonly called a Green Rewind.[74, 75] A failed motor can be rewound to a lower efficiency, rewound to maintain the original efficiency, or replaced.

Pump Equipment Upgrade. This measure achieves energy savings through improved pump design and sizing.

Pump Improvements (Pump Energy Management, Pump System Optimization). This measure involves optimizing the overall pump system with improved system design, enhanced flow design, better maintenance practices, and adjustments to system parameters.

Synchronous Belts. This measure contains mating, corresponding grooves in the drive sprocket, preventing slip and thus reducing energy losses.

Transformers (New & Retrofit). Energy efficient transformers provide improved power quality while minimizing losses.

Whole Plant Improvements (Fan Energy Management, Plant Energy Management, Integrated Plant Energy Management, Energy Project Management). These measures include synergistic savings of plant-wide energy management and improvements across multiple systems such as compressed air, pumping, and fan systems.

74 http://www.bpa.gov/energy/n/industrial/Green_motors/
75 http://www.greenmotors.org/downloads/RTFSubmittalMay_08%20_2_.pdf

10. Industrial Gas Measure Descriptions

Boiler Improvements. A boiler generally creates steam or hot water for process or non-process applications. Savings are generated by installation of a waste heat boiler to provide direct power or use of flue gas heat to preheat boiler feed water.

Boiler Operation and Maintenance. This measure includes analyzing flue gas for proper air/fuel ration, establishing maintenance schedules, or reducing excessive boiler blow down.

HVAC Improvements. Many measures can reduce a plants' HVAC energy consumption, such as conditioning only space in use, installing timers and/or thermostats, lowering ceilings to reduce conditioned space, and installing or upgrading insulation on distribution systems.

HVAC Operation and Maintenance. These measures include sizing air handling grills/ducts/coils to minimize air resistance, adjusting vents to minimize energy use, and maintaining air filters by cleaning or replacing.

Other Process Improvements/Operation and Maintenance. These measures include upgrading obsolete equipment, reducing fluid flow rates, and using optimum size and capacity equipment.

Process Heating Improvements. These measures decrease the energy required for process-related heating. Examples include optimizing the drying oven schedule, reducing the temperature of process equipment when on standby, and modifying equipment to improve the drying process.

Process Heating Operation and Maintenance. These measures improve the a plants overall energy efficiency. Examples include repairing faulty insulation, adjusting burners for efficient operation, and eliminating leaks in combustible gas lines.

Steam Distribution Systems. These measures include leak elimination and improved duct insulation to reduce distribution system loss.

Table B-2.1. Residential Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Manufactured	Cool Central	Air-to-Air Heat Exchangers	Air-to-Air Heat Exchangers	No Air to Air Heat Exchangers	Per Home	Existing	39	5	$576	25%	95%	$2.41	126
Electric	Manufactured	Cool Central	Ceiling Fan	Ceiling Fan (no lighting kit)	No Ceiling Fan	Per Fan	Existing	31	10	$93	85%	35%	$0.45	126
Electric	Manufactured	Cool Central	Ceiling Insulation	R-49 (WA Code - Single Family and Manufactured Homes Only)	R-0 (Zero Insulation - Single Family and Manufactured Homes Only)	Per Home	Existing	209	25	$1,598	75%	1%	$0.22	16
Electric	Manufactured	Cool Central	Ceiling Insulation	R-49 (WA Code - Single Family and Manufactured Homes Only)	R-10 (Existing Insulation - Single Family and Manufactured Homes Only)	Per Home	Existing	156	25	$1,598	75%	35%	$0.30	425
Electric	Manufactured	Cool Central	Ceiling Insulation	R-60 (Above WA Code - Single Family and Manufactured Homes Only)	R-49 (WA Code - Single Family and Manufactured Homes Only)	Per Home	Existing	3	25	$1,976	40%	95%	$29.57	10
Electric	Manufactured	Cool Central	Duct Insulation Upgrade	R-8 (WA Code)	R-4 (Existing Insulation)	Per Home	Existing	8	20	$534	75%	75%	$-6.89	44
Electric	Manufactured	Cool Central	Duct Sealing - Aerosol-Based	Spray-in ductwork sealant to minimize duct leaks	No Duct Sealing	Per Home	Existing	20	18	$827	50%	60%	$-0.86	54
Electric	Manufactured	Cool Central	Leak Proof Duct Fittings	Quick connect fittings that do not require mastic or drawbands (5 per unit)	standard ducts with 13 SEER HVAC	Per Home	Existing	60	30	$1,114	5.0%	95%	$-0.32	26
Electric	Manufactured	Cool Central	Programmable Thermostat	Programmable Thermostat	Manual Thermostat	Per House	Existing	14	15	$33	95%	64%	$-7.11	91
Electric	Manufactured	Cool Central	Proper Sizing - HVAC Unit	Proper Sizing - HVAC Unit	Oversized HVAC Unit	Per AC Unit	Existing	37	15	$5	95%	65%	$-2.75	301
Electric	Manufactured	Cool Central	Radiant Barrier (Ceiling)	Install Radiant Barrier	No Radiant Barrier	Per Home	Existing	23	25	$732	10%	90%	$-2.04	19
Electric	Manufactured	Cool Central	Solar Attic Fan	Solar electric attic ventilation	Standard passive ventilation	Per Home	Existing	11	10	$478	25%	95%	$6.24	37
Electric	Manufactured	Cool Central	Thermostat - Multi-Zone	Individual Room Temperature Control for Major Occupied Rooms	Programmable Thermostat - Central Control Only	Per Home	Existing	27	11	$890	10%	95%	$1.76	29
Electric	Manufactured	Cool Central	Wall Insulation 2x4	R-13 (Below WA Code - Maximum Insulation Feasible)	R-0 (Zero Insulation)	Per Home	Existing	24	25	$1,694	60%	15%	$2.35	19
Electric	Manufactured	Cool Central	Whole-House Dehumidifier	Whole-House Dehumidifier	No Dehumidifier	Per Home	Existing	7	12	$1,372	2.0%	95%	$24.61	2
Electric	Manufactured	Cool Central	Whole-House Fan	Whole-House Fan	No Whole-House Fan	Per Home	Existing	59	20	$1,647	50%	95%	$3.08	378
Electric	Manufactured	Cool Central	Window Overhang	Overhangs over windows for shading	No window overhangs	Per Home	Existing	29	25	$204	50%	50%	$0.75	79
Electric	Manufactured	Cool Room	Ceiling Fan	Ceiling Fan (no lighting kit)	No Ceiling Fan	Per Fan	Existing	11	10	$93	85%	35%	$1.25	35
Electric	Manufactured	Cool Room	Ceiling Insulation	R-49 (WA Code - Single Family and Manufactured Homes Only)	R-0 (Zero Insulation - Single Family and Manufactured Homes Only)	Per Home	Existing	79	25	$1,598	75%	1%	$0.59	5
Electric	Manufactured	Cool Room	Ceiling Insulation	R-49 (WA Code - Single Family and Manufactured Homes Only)	R-10 (Existing Insulation - Single Family and Manufactured Homes Only)	Per Home	Existing	59	25	$1,598	75%	35%	$0.80	151
Electric	Manufactured	Cool Room	Ceiling Insulation	R-60 (Above WA Code - Single Family and Manufactured Homes Only)	R-49 (WA Code - Single Family and Manufactured Homes Only)	Per Home	Existing	1	25	$1,976	40%	95%	$86.05	3
Electric	Manufactured	Cool Room	Radiant Barrier (Ceiling)	Install Radiant Barrier	No Radiant Barrier	Per Home	Existing	8	25	$732	10%	90%	$-5.57	6

Table B-2.1. Residential Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Manufactured	Cool Room	Room AC conversion to Ductless Heat Pump	Ductless Heat Pump Federal Standard	Room AC Federal Standard 9.8 EER; 8,000-13,999 Btuh	Per Home	Existing	4	20	$2,042	18%	95%	$52.73	7
Electric	Manufactured	Cool Room	Wall Insulation 2x4	R-13 (Below WA Code - Maximum Insulation Feasible)	R-0 (Zero Insulation)	Per Home	Existing	11	25	$1,694	60%	15%	$5.21	8
Electric	Manufactured	Cool Room	Window Overhang	Overhangs over windows for shading	No window overhangs	Per Home	Existing	10	25	$204	50%	50%	$2.07	27
Electric	Manufactured	Freezer	Stand-Alone Freezer - Removal	Proper Disposal of Freezer	Existing Non-Efficient Freezer	Per Home	Existing	555	8	$30	54%	100%	$0.00	7,049
Electric	Manufactured	Heat Central	Air-to-Air Heat Exchangers	Air-to-Air Heat Exchangers	No Air to Air Heat Exchangers	Per Home	Existing	820	5	$576	25%	95%	$0.16	6,000
Electric	Manufactured	Heat Central	Canned Lighting Air Tight Sealing	Canned Lighting Air Tight Sealing	No Air tight Sealing	Per Fixture	Existing	44	30	$127	95%	50%	$0.29	465
Electric	Manufactured	Heat Central	Ceiling Insulation	R-49 (WA Code - Single Family and Manufactured Homes Only)	R-0 (Zero Insulation - Single Family and Manufactured Homes Only)	Per Home	Existing	4,486	25	$1,598	75%	1%	$0.02	736
Electric	Manufactured	Heat Central	Ceiling Insulation	R-49 (WA Code - Single Family and Manufactured Homes Only)	R-10 (Existing Insulation - Single Family and Manufactured Homes Only)	Per Home	Existing	3,546	25	$1,598	75%	35%	$0.04	20,299
Electric	Manufactured	Heat Central	Ceiling Insulation	R-60 (Above WA Code - Single Family and Manufactured Homes Only)	R-49 (WA Code - Single Family and Manufactured Homes Only)	Per Home	Existing	85	25	$1,976	40%	95%	$2.55	628
Electric	Manufactured	Heat Central	Conversion Electric Furnace to ASHP	Air Source Heat Pump Seer 14 HSPF 8.2	Electric Furnace HSPF 1	Per Furnace	Existing	3,223	20	$6,249	65%	95%	$0.20	60,863
Electric	Manufactured	Heat Central	Doors	R-10 (Doors with foam core) (Above WA Code - Single Family and Manufactured Homes Only)	R-5 (Composite Doors with foam core) (WA Code Single Family and Manufactured Homes Only)	Per Door	Existing	111	20	$326	25%	95%	$0.31	509
Electric	Manufactured	Heat Central	Doors	R-5 (Composite Doors with foam core) (WA Code - Single Family and Manufactured Homes Only)	R-2.5 (Standard non-thermal wood door) (Below WA Code - Single Family and Manufactured Homes Only)	Per Door	Existing	217	20	$126	85%	75%	$0.05	2,657
Electric	Manufactured	Heat Central	Doors - Weatherization	Weatherstripping And Adding Door Sweeps	Existing Non-Efficient door	Per Door	Existing	49	6	$25	85%	50%	$0.10	397
Electric	Manufactured	Heat Central	Duct Insulation Upgrade	R-8 (WA Code)	R-4 (Existing Insulation)	Per Home	Existing	402	20	$534	75%	75%	$0.13	4,258
Electric	Manufactured	Heat Central	Duct Sealing - Aerosol-Based	Spray-in ductwork sealant to minimize duct leaks	No Duct Sealing	Per Home	Existing	440	18	$827	50%	60%	$0.21	2,421
Electric	Manufactured	Heat Central	Floor Insulation	R-30 (WA Code)	R-0 (Zero Insulation)	Per Home	Existing	4,723	25	$1,610	20%	25%	$0.02	4,245
Electric	Manufactured	Heat Central	Floor Insulation	R-30 (WA Code)	R-15 (Existing Insulation)	Per Home	Existing	479	25	$1,610	25%	50%	$0.36	1,044
Electric	Manufactured	Heat Central	Floor Insulation	R-38 (Above WA Code)	R-30 (WA Code)	Per Home	Existing	121	25	$429	25%	85%	$0.38	447
Electric	Manufactured	Heat Central	Infiltration Control (Caulk, Weather Strip, etc.) Blower-Door test	Install Caulking And Weatherstripping	Existing Infiltration Conditions	Per Home	Existing	299	11	$450	75%	50%	$0.21	1,942
Electric	Manufactured	Heat Central	Leak Proof Duct Fittings	Quick connect fittings that do not require mastic or drawbands (5 per unit)	standard ducts with 13 SEER HVAC	Per Home	Existing	1,722	30	$1,114	5.0%	15%	$0.05	220
Electric	Manufactured	Heat Central	Programmable Thermostat	Programmable Thermostat	Manual Thermostat	Per House	Existing	287	15	$33	95%	52%	$0.00	2,850
Electric	Manufactured	Heat Central	Proper Sizing - HVAC Unit	Proper Sizing - HVAC Unit	Oversized HVAC Unit	Per Heater Unit	Existing	745	15	$430	15%	65%	$0.06	1,647

Table B-2.1. Residential Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Manufactured	Heat Central	Thermostat - Multi-Zone	Individual Room Temperature Control for Major Occupied Rooms	Programmable Thermostat - Central Control Only	Per Home	Existing	557	11	$890	10%	95%	$0.23	1,171
Electric	Manufactured	Heat Central	Wall Insulation 2x4	R-13 (Below WA Code - Maximum Insulation Feasible)	R-0 (Zero Insulation)	Per Home	Existing	2,604	25	$1,694	60%	15%	$0.06	3,995
Electric	Manufactured	Heat Central	Windows	U-value = 0.22 (Above WA Code)	U-value = 0.32 (WA Code)	Per Home	Existing	517	25	$3,187	50%	85%	$0.67	3,636
Electric	Manufactured	Heat Central	Windows	U-value = 0.32 (WA Code)	Double Pane (Existing Window)	Per Home	Existing	2,518	25	$3,761	50%	15%	$0.15	3,035
Electric	Manufactured	Heat Central	Windows	U-value = 0.32 (WA Code)	Single Pane (Existing Window)	Per Home	Existing	3,080	25	$3,761	50%	5%	$0.12	1,209
Electric	Manufactured	Heat Pump	Air-to-Air Heat Exchangers	Air-to-Air Heat Exchangers	No Air to Air Heat Exchangers	Per Home	Existing	409	5	$576	25%	95%	$0.34	840
Electric	Manufactured	Heat Pump	Canned Lighting Air Tight Sealing	Canned Lighting Air Tight Sealing	No Air tight Sealing	Per Fixture	Existing	24	30	$127	95%	50%	$0.54	87
Electric	Manufactured	Heat Pump	Ceiling Fan	Ceiling Fan (no lighting kit)	No Ceiling Fan	Per Fan	Existing	38	10	$93	85%	35%	$0.37	99
Electric	Manufactured	Heat Pump	Ceiling Insulation	R-49 (WA Code - Single Family and Manufactured Homes Only)	R-0 (Zero Insulation - Single Family and Manufactured Homes Only)	Per Home	Existing	2,047	25	$1,598	75%	1%	$0.07	115
Electric	Manufactured	Heat Pump	Ceiling Insulation	R-49 (WA Code - Single Family and Manufactured Homes Only)	R-10 (Existing Insulation - Single Family and Manufactured Homes Only)	Per Home	Existing	1,437	25	$1,598	75%	35%	$0.11	2,839
Electric	Manufactured	Heat Pump	Ceiling Insulation	R-60 (Above WA Code - Single Family and Manufactured Homes Only)	R-49 (WA Code - Single Family and Manufactured Homes Only)	Per Home	Existing	45	25	$1,976	40%	95%	$4.77	119
Electric	Manufactured	Heat Pump	Check Me! O&M Tune-up	Tune-up/Maintenance	No Tune-up Maintenance	Per Heat Pump Unit	Existing	43	5	$204	95%	75%	$1.16	269
Electric	Manufactured	Heat Pump	Doors	R-10 (Doors with foam core) (Above WA Code - Single Family and Manufactured Homes Only)	R-5 (Composite Doors with foam core) (WA Code Single Family and Manufactured Homes Only)	Per Door	Existing	45	20	$326	25%	95%	$0.80	72
Electric	Manufactured	Heat Pump	Doors	R-5 (Composite Doors with foam core) (WA Code - Single Family and Manufactured Homes Only)	R-2.5 (Standard non-thermal wood door) (Below WA Code - Single Family and Manufactured Homes Only)	Per Door	Existing	89	20	$126	85%	75%	$0.15	384
Electric	Manufactured	Heat Pump	Doors - Weatherization	Weatherstripping And Adding Door Sweeps	Existing Non-Efficient door	Per Door	Existing	27	6	$25	85%	50%	$0.20	77
Electric	Manufactured	Heat Pump	Duct Insulation Upgrade	R-8 (WA Code)	R-4 (Existing Insulation)	Per Home	Existing	329	20	$534	75%	75%	$0.17	1,235
Electric	Manufactured	Heat Pump	Duct Sealing - Aerosol-Based	Spray-in ductwork sealant to minimize duct leaks	No Duct Sealing	Per Home	Existing	292	18	$827	50%	60%	$0.32	558
Electric	Manufactured	Heat Pump	Floor Insulation	R-30 (WA Code)	R-0 (Zero Insulation)	Per Home	Existing	1,731	25	$1,610	20%	25%	$0.09	539
Electric	Manufactured	Heat Pump	Floor Insulation	R-30 (WA Code)	R-15 (Existing Insulation)	Per Home	Existing	160	25	$1,610	25%	50%	$1.10	122
Electric	Manufactured	Heat Pump	Floor Insulation	R-38 (Above WA Code)	R-30 (WA Code)	Per Home	Existing	40	25	$429	25%	85%	$1.17	51
Electric	Manufactured	Heat Pump	Infiltration Control (Caulk, Weather Strip, etc.) Blower-Door test	Install Caulking And Weatherstripping	Existing Infiltration Conditions	Per Home	Existing	164	11	$450	75%	50%	$0.40	373
Electric	Manufactured	Heat Pump	Leak Proof Duct Fittings	Quick connect fittings that do not require mastic or drawbands (5 per unit)	standard ducts with 13 SEER HVAC	Per Home	Existing	859	30	$1,114	5.0%	95%	$0.12	243

Table B-2.1. Residential Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Manufactured	Heat Pump	Programmable Thermostat	Programmable Thermostat	Manual Thermostat	Per House	Existing	143	15	$33	95%	64%	$0.02	617
Electric	Manufactured	Heat Pump	Proper Sizing - HVAC Unit	Proper Sizing - HVAC Unit	Oversized HVAC Unit	Per Heat Pump	Existing	385	15	$5	95%	65%	$-0.01	1,996
Electric	Manufactured	Heat Pump	Solar Attic Fan	Solar electric attic ventilation	Standard passive ventilation	Per Home	Existing	14	10	$478	25%	95%	$5.12	29
Electric	Manufactured	Heat Pump	Thermostat - Multi-Zone	Individual Room Temperature Control for Major Occupied Rooms	Programmable Thermostat - Central Control Only	Per Home	Existing	278	11	$890	10%	95%	$0.47	203
Electric	Manufactured	Heat Pump	Wall Insulation 2x4	R-13 (Below WA Code - Maximum Insulation Feasible)	R-0 (Zero Insulation)	Per Home	Existing	1,289	25	$1,694	60%	15%	$0.13	685
Electric	Manufactured	Heat Pump	Whole-House Dehumidifier	Whole-House Dehumidifier	No Dehumidifier	Per Home	Existing	4	12	$1,372	2.0%	95%	$48.01	0.67
Electric	Manufactured	Heat Pump	Whole-House Fan	Whole-House Fan	No Whole-House Fan	Per Home	Existing	72	20	$1,647	50%	95%	$2.52	299
Electric	Manufactured	Heat Pump	Window Overhang	Overhangs over windows for shading	No window overhangs	Per Home	Existing	36	25	$204	50%	50%	$0.61	69
Electric	Manufactured	Heat Pump	Windows	U-value = 0.22 (Above WA Code)	U-value = 0.32 (WA Code)	Per Home	Existing	203	25	$3,187	50%	85%	$1.72	496
Electric	Manufactured	Heat Pump	Windows	U-value = 0.32 (WA Code)	Double Pane (Existing Window)	Per Home	Existing	871	25	$3,761	50%	15%	$0.47	366
Electric	Manufactured	Heat Pump	Windows	U-value = 0.32 (WA Code)	Single Pane (Existing Window)	Per Home	Existing	1,163	25	$3,761	50%	5%	$0.35	160
Electric	Manufactured	Heat Room	Canned Lighting Air Tight Sealing	Canned Lighting Air Tight Sealing	No Air tight Sealing	Per Fixture	Existing	40	30	$127	95%	50%	$0.32	56
Electric	Manufactured	Heat Room	Ceiling Insulation	R-49 (WA Code - Single Family and Manufactured Homes Only)	R-0 (Zero Insulation - Single Family and Manufactured Homes Only)	Per Home	Existing	3,712	25	$1,598	75%	1%	$0.03	82
Electric	Manufactured	Heat Room	Ceiling Insulation	R-49 (WA Code - Single Family and Manufactured Homes Only)	R-10 (Existing Insulation - Single Family and Manufactured Homes Only)	Per Home	Existing	2,936	25	$1,598	75%	35%	$0.05	2,268
Electric	Manufactured	Heat Room	Ceiling Insulation	R-60 (Above WA Code - Single Family and Manufactured Homes Only)	R-49 (WA Code - Single Family and Manufactured Homes Only)	Per Home	Existing	70	25	$1,976	40%	95%	$3.08	70
Electric	Manufactured	Heat Room	Conversion Baseboard Heating to DHP	Ductless Heat Pump HSPF 7.7	Baseboard Heating HSPF = 1	Per Home	Existing	2,098	20	$2,042	15%	95%	$0.09	899
Electric	Manufactured	Heat Room	Doors	R-10 (Doors with foam core) (Above WA Code - Single Family and Manufactured Homes Only)	R-5 (Composite Doors with foam core) (WA Code Single Family and Manufactured Homes Only)	Per Door	Existing	93	20	$326	25%	95%	$0.38	57
Electric	Manufactured	Heat Room	Doors	R-5 (Composite Doors with foam core) (WA Code - Single Family and Manufactured Homes Only)	R-2.5 (Standard non-thermal wood door) (Below WA Code - Single Family and Manufactured Homes Only)	Per Door	Existing	181	20	$126	85%	75%	$0.06	298
Electric	Manufactured	Heat Room	Doors - Weatherization	Weatherstripping And Adding Door Sweeps	Existing Non-Efficient door	Per Door	Existing	44	6	$25	85%	50%	$0.11	48
Electric	Manufactured	Heat Room	Floor Insulation	R-30 (WA Code)	R-0 (Zero Insulation)	Per Home	Existing	4,570	25	$1,610	20%	25%	$0.02	579
Electric	Manufactured	Heat Room	Floor Insulation	R-30 (WA Code)	R-15 (Existing Insulation)	Per Home	Existing	440	25	$1,610	25%	50%	$0.39	134
Electric	Manufactured	Heat Room	Floor Insulation	R-38 (Above WA Code)	R-30 (WA Code)	Per Home	Existing	111	25	$429	25%	85%	$0.41	57
Electric	Manufactured	Heat Room	Infiltration Control (Caulk, Weather Strip, etc.) Blower-Door test	Install Caulking And Weatherstripping	Existing Infiltration Conditions	Per Home	Existing	274	11	$450	75%	50%	$0.23	249

Table B-2.1. Residential Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Manufactured	Heat Room	Wall Insulation 2x4	R-13 (Below WA Code - Maximum Insulation Feasible)	R-0 (Zero Insulation)	Per Home	Existing	2,166	25	$1,694	60%	15%	$0.07	465
Electric	Manufactured	Heat Room	Windows	U-value = 0.22 (Above WA Code)	U-value = 0.32 (WA Code)	Per Home	Existing	431	25	$3,187	50%	85%	$0.81	424
Electric	Manufactured	Heat Room	Windows	U-value = 0.32 (WA Code)	Double Pane (Existing Window)	Per Home	Existing	2,090	25	$3,761	50%	15%	$0.19	352
Electric	Manufactured	Heat Room	Windows	U-value = 0.32 (WA Code)	Single Pane (Existing Window)	Per Home	Existing	2,558	25	$3,761	50%	5%	$0.15	140
Electric	Manufactured	Lighting Exterior	Time Clocks (Exterior Lighting)	Exterior Lighting on a Time Clock	Exterior Lighting (Manual Control)	Per Home	Existing	8	10	$16	80%	85%	$0.29	315
Electric	Manufactured	Lighting Interior Standard	Occupancy Sensors	Wall-Switch Occupancy Sensors	No Occupancy Sensor	Per Sensor	Existing	1	10	$32	20%	95%	$4.17	68
Electric	Manufactured	Plug Load Other	Battery Chargers, ENERGY STAR	ENERGY STAR Battery Chargers	Standard Battery Chargers	Per Device	Existing	12	7	$4	50%	80%	$0.07	321
Electric	Manufactured	Plug Load Other	Smart Strip	Smart Strip	Standard Power Strip	1 Computer or 1 for TV	Existing	43	4	$21	50%	85%	$0.14	1,180
Electric	Manufactured	Refrigerator	Refrigerator/Freezer - Removal of Secondary	Proper Disposal of Refrigerator/Freezer	Existing Non-Efficient Refrigerator/Freezer	Per Home	Existing	481	9	$30	24%	100%	$0.00	7,702
Electric	Manufactured	Water Heat GT 55 Gal	Clothes Washer	Cold Water Only Clothes Washer - Electric Dryer	MEF = 1.66 - Electric DHW & Dryer	Per Unit Each	Existing	237	14	$80	10%	99%	$0.04	59
Electric	Manufactured	Water Heat GT 55 Gal	Clothes Washer	ENERGY STAR - Tier 3 (MEF 2.46 or higher) Top 10% of ENERGY STAR Model - Electric DHW & Dryer	MEF = 1.66 - Electric DHW & Dryer	Per Home	Existing	101	14	$209	100%	95%	$-0.22	219
Electric	Manufactured	Water Heat GT 55 Gal	Dishwasher	RTF ENERGY STAR Dishwasher - 277 kWh/yr and 4.25 gal/cycle	RTF Market Standard 2014 Dishwasher - 289 kWh/yr and 5.0 gal/cycle	Per Home	Existing	12	12	$36	95%	50%	$0.39	14
Electric	Manufactured	Water Heat GT 55 Gal	Drain Water Heat Recovery (GFX)	Gravity Film Heat Exchanger	No Heat Exchanger	Per Home	Existing	363	40	$540	29%	90%	$0.14	230
Electric	Manufactured	Water Heat GT 55 Gal	Faucet Aerators	2.2 GPM	Existing Faucet Aerator (3.0 GPM)	Per Home	Existing	99	9	$2	95%	15%	$-0.00	35
Electric	Manufactured	Water Heat GT 55 Gal	Faucet Aerators - Bathroom Only	0.5 GPM	2.2 GPM	Per Home	Existing	105	9	$2	50%	95%	$-0.00	127
Electric	Manufactured	Water Heat GT 55 Gal	Hot Water Pipe Insulation	R-4 Wrap	No insulation	Per Home	Existing	38	5	$23	95%	75%	$0.15	69
Electric	Manufactured	Water Heat GT 55 Gal	Low-Flow Showerheads	1.5 GPM	2.5 GPM	Per Home	Existing	364	10	$53	95%	85%	$-0.02	530
Electric	Manufactured	Water Heat GT 55 Gal	Low-Flow Showerheads	2.5 GPM	Existing Showerhead (3.0 GPM)	Per Home	Existing	211	10	$34	95%	5%	$-0.01	18
Electric	Manufactured	Water Heat LE 55 Gal	CO2 Heat Pump Water Heater	CO2 Heat Pump Water Heater	Federal Standard 2004 Storage Water Heater - EF 0.871	Per Unit Each	Existing	2,699	15	$6,287	5.0%	100%	$0.29	4,251
Electric	Manufactured	Water Heat LE 55 Gal	Clothes Washer	Cold Water Only Clothes Washer - Electric Dryer	MEF = 1.66 - Electric DHW & Dryer	Per Unit Each	Existing	237	14	$80	10%	99%	$0.04	740
Electric	Manufactured	Water Heat LE 55 Gal	Clothes Washer	ENERGY STAR - Tier 3 (MEF 2.46 or higher) Top 10% of ENERGY STAR Model - Electric DHW & Dryer	MEF = 1.66 - Electric DHW & Dryer	Per Home	Existing	101	14	$209	100%	95%	$-0.22	2,721
Electric	Manufactured	Water Heat LE 55 Gal	Dishwasher	RTF ENERGY STAR Dishwasher - 277 kWh/yr and 4.25 gal/cycle	RTF Market Standard 2014 Dishwasher - 289 kWh/yr and 5.0 gal/cycle	Per Home	Existing	12	12	$36	71%	50%	$0.39	132

Table B-2.1. Residential Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Manufactured	Water Heat LE 55 Gal	Drain Water Heat Recovery (GFX)	Gravity Film Heat Exchanger	No Heat Exchanger	Per Home	Existing	358	40	$540	29%	90%	$0.14	2,817
Electric	Manufactured	Water Heat LE 55 Gal	Faucet Aerators	2.2 GPM	Existing Faucet Aerator (3.0 GPM)	Per Home	Existing	99	9	$2	95%	15%	$-0.00	445
Electric	Manufactured	Water Heat LE 55 Gal	Faucet Aerators - Bathroom Only	0.5 GPM	2.2 GPM	Per Home	Existing	105	9	$2	50%	95%	$-0.00	1,576
Electric	Manufactured	Water Heat LE 55 Gal	Hot Water Pipe Insulation	R-4 Wrap	No insulation	Per Home	Existing	38	5	$23	95%	75%	$0.15	845
Electric	Manufactured	Water Heat LE 55 Gal	Low-Flow Showerheads	1.5 GPM	2.5 GPM	Per Home	Existing	364	10	$53	95%	85%	$-0.02	6,575
Electric	Manufactured	Water Heat LE 55 Gal	Low-Flow Showerheads	2.5 GPM	Existing Showerhead (3.0 GPM)	Per Home	Existing	211	10	$34	95%	5%	$-0.01	225
Electric	Multifamily	Cool Central	Ceiling Fan	Ceiling Fan (no lighting kit)	No Ceiling Fan	Per Fan	Existing	21	10	$93	85%	50%	$0.68	193
Electric	Multifamily	Cool Central	Ceiling Insulation	R-38 (WA Code - Multi Family Only)	R-0 (Zero Insulation - Multi Family Only)	Per Home	Existing	50	25	$456	50%	50%	$-2.63	216
Electric	Multifamily	Cool Central	Ceiling Insulation	R-38 (WA Code - Multi Family Only)	R-10 (Existing Insulation - Multi Family Only)	Per Home	Existing	19	25	$456	50%	50%	$-6.80	79
Electric	Multifamily	Cool Central	Ceiling Insulation	R-49 (Above WA Code - Multi Family Only)	R-38 (WA Code - Multi Family Only)	Per Home	Existing	1	25	$73	15%	95%	$-148.19	2
Electric	Multifamily	Cool Central	Proper Sizing - HVAC Unit	Proper Sizing - HVAC Unit	Oversized HVAC Unit	Per AC Unit	Existing	25	15	$5	95%	65%	$-5.79	330
Electric	Multifamily	Cool Central	Radiant Barrier (Ceiling)	Install Radiant Barrier	No Radiant Barrier	Per Home	Existing	16	30	$261	50%	90%	$-10.37	115
Electric	Multifamily	Cool Central	Solar Attic Fan	Solar electric attic ventilation	Standard passive ventilation	Per Home	Existing	8	10	$478	2.5%	95%	$9.32	4
Electric	Multifamily	Cool Central	Whole-House Dehumidifier	Whole-House Dehumidifier	No Dehumidifier	Per Home	Existing	5	12	$1,372	2.0%	95%	$36.79	2
Electric	Multifamily	Cool Central	Whole-House Fan	Whole-House Fan	No Whole-House Fan	Per Home	Existing	40	20	$1,647	50%	95%	$4.61	404
Electric	Multifamily	Cool Central	Window Overhang	Overhangs over windows for shading	No window overhangs	Per Home	Existing	37	30	$204	50%	50%	$0.57	166
Electric	Multifamily	Cool Room	Ceiling Fan	Ceiling Fan (no lighting kit)	No Ceiling Fan	Per Fan	Existing	7	10	$93	85%	50%	$1.97	56
Electric	Multifamily	Cool Room	Ceiling Insulation	R-38 (WA Code - Multi Family Only)	R-0 (Zero Insulation - Multi Family Only)	Per Home	Existing	25	25	$456	50%	50%	$-5.26	104
Electric	Multifamily	Cool Room	Ceiling Insulation	R-38 (WA Code - Multi Family Only)	R-10 (Existing Insulation - Multi Family Only)	Per Home	Existing	10	25	$456	50%	50%	$-12.86	39
Electric	Multifamily	Cool Room	Ceiling Insulation	R-49 (Above WA Code - Multi Family Only)	R-38 (WA Code - Multi Family Only)	Per Home	Existing	0.64	25	$73	15%	95%	$-271.94	1
Electric	Multifamily	Cool Room	Radiant Barrier (Ceiling)	Install Radiant Barrier	No Radiant Barrier	Per Home	Existing	5	30	$261	50%	90%	$-29.78	37
Electric	Multifamily	Cool Room	Room AC conversion to Ductless Heat Pump	Ductless Heat Pump Federal Standard	Room AC Federal Standard 9.8 EER; 8,000-13,999 Btuh	Per Home	Existing	2	20	$1,439	9.6%	95%	$58.46	4
Electric	Multifamily	Cool Room	Wall Insulation 2x4	R-13 (Below WA Code - Maximum Insulation Feasible)	R-0 (Zero Insulation)	Per Home	Existing	0.07	25	$1,011	60%	15%	$-918.36	0.10
Electric	Multifamily	Cool Room	Window Overhang	Overhangs over windows for shading	No window overhangs	Per Home	Existing	13	30	$204	50%	50%	$1.66	55
Electric	Multifamily	Heat Central	Canned Lighting Air Tight Sealing	Canned Lighting Air Tight Sealing	No Air tight Sealing	Per Fixture	Existing	30	30	$50	95%	50%	$0.17	277
Electric	Multifamily	Heat Central	Ceiling Insulation	R-38 (WA Code - Multi Family Only)	R-0 (Zero Insulation - Multi Family Only)	Per Home	Existing	947	25	$456	50%	50%	$0.04	4,594
Electric	Multifamily	Heat Central	Ceiling Insulation	R-38 (WA Code - Multi Family Only)	R-10 (Existing Insulation - Multi Family Only)	Per Home	Existing	364	25	$456	50%	50%	$0.13	1,702

Table B-2.1. Residential Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Multifamily	Heat Central	Ceiling Insulation	R-49 (Above WA Code - Multi Family Only)	R-38 (WA Code - Multi Family Only)	Per Home	Existing	21	25	$73	15%	95%	$0.36	57
Electric	Multifamily	Heat Central	Conversion Electric Furnace to ASHP	Air Source Heat Pump Seer 14 HSPF 8.2	Electric Furnace HSPF 1	Per Furnace	Existing	1,329	20	$5,071	35%	95%	$0.42	9,201
Electric	Multifamily	Heat Central	Doors - Weatherization	Weatherstripping And Adding Door Sweeps	Existing Non-Efficient door	Per Door	Existing	42	6	$25	95%	50%	$0.12	374
Electric	Multifamily	Heat Central	Floor Insulation	R-30 (WA Code)	R-0 (Zero Insulation)	Per Home	Existing	2,245	25	$579	20%	25%	$0.02	2,052
Electric	Multifamily	Heat Central	Floor Insulation	R-30 (WA Code)	R-15 (Existing Insulation)	Per Home	Existing	226	25	$579	25%	50%	$0.27	507
Electric	Multifamily	Heat Central	Floor Insulation	R-38 (Above WA Code)	R-30 (WA Code)	Per Home	Existing	272	25	$154	25%	85%	$0.05	1,033
Electric	Multifamily	Heat Central	Infiltration Control (Caulk, Weather Strip, etc.) Blower-Door test	Install Caulking And Weatherstripping	Existing Infiltration Conditions	Per Home	Existing	378	11	$358	75%	50%	$0.13	2,522
Electric	Multifamily	Heat Central	Proper Sizing - HVAC Unit	Proper Sizing - HVAC Unit	Oversized HVAC Unit	Per Heater Unit	Existing	537	15	$430	15%	65%	$0.09	1,026
Electric	Multifamily	Heat Central	Wall Insulation 2x4	R-13 (Below WA Code - Maximum Insulation Feasible)	R-0 (Zero Insulation)	Per Home	Existing	2,136	25	$1,011	60%	15%	$0.04	3,357
Electric	Multifamily	Heat Central	Windows	U-value = 0.22 (Above WA Code)	U-value = 0.32 (WA Code)	Per Home	Existing	632	25	$2,272	30%	85%	$0.39	2,712
Electric	Multifamily	Heat Central	Windows	U-value = 0.32 (WA Code)	Double Pane (Existing Window)	Per Home	Existing	2,540	25	$2,682	30%	15%	$0.10	1,869
Electric	Multifamily	Heat Central	Windows	U-value = 0.32 (WA Code)	Single Pane (Existing Window)	Per Home	Existing	3,066	25	$2,682	30%	5%	$0.08	738
Electric	Multifamily	Heat Pump	Canned Lighting Air Tight Sealing	Canned Lighting Air Tight Sealing	No Air tight Sealing	Per Fixture	Existing	12	30	$50	95%	50%	$0.44	8
Electric	Multifamily	Heat Pump	Ceiling Fan	Ceiling Fan (no lighting kit)	No Ceiling Fan	Per Fan	Existing	37	10	$93	85%	50%	$0.38	25
Electric	Multifamily	Heat Pump	Ceiling Insulation	R-38 (WA Code - Multi Family Only)	R-0 (Zero Insulation - Multi Family Only)	Per Home	Existing	535	25	$456	50%	50%	$0.08	190
Electric	Multifamily	Heat Pump	Ceiling Insulation	R-38 (WA Code - Multi Family Only)	R-10 (Existing Insulation - Multi Family Only)	Per Home	Existing	203	25	$456	50%	50%	$0.24	68
Electric	Multifamily	Heat Pump	Ceiling Insulation	R-49 (Above WA Code - Multi Family Only)	R-38 (WA Code - Multi Family Only)	Per Home	Existing	12	25	$73	15%	95%	$0.66	2
Electric	Multifamily	Heat Pump	Check Me! O&M Tune-up	Tune-up/Maintenance	No Tune-up Maintenance	Per Heat Pump Unit	Existing	42	5	$204	95%	75%	$1.20	47
Electric	Multifamily	Heat Pump	Doors - Weatherization	Weatherstripping And Adding Door Sweeps	Existing Non-Efficient door	Per Door	Existing	17	6	$25	95%	50%	$0.31	10
Electric	Multifamily	Heat Pump	Floor Insulation	R-30 (WA Code)	R-15 (Existing Insulation)	Per Home	Existing	179	25	$579	25%	50%	$0.35	29
Electric	Multifamily	Heat Pump	Floor Insulation	R-38 (Above WA Code)	R-30 (WA Code)	Per Home	Existing	215	25	$154	25%	85%	$0.07	60
Electric	Multifamily	Heat Pump	Infiltration Control (Caulk, Weather Strip, etc.) Blower-Door test	Install Caulking And Weatherstripping	Existing Infiltration Conditions	Per Home	Existing	149	11	$358	75%	50%	$0.35	72
Electric	Multifamily	Heat Pump	Proper Sizing - HVAC Unit	Proper Sizing - HVAC Unit	Oversized HVAC Unit	Per Heat Pump	Existing	273	15	$5	95%	65%	$-0.01	261
Electric	Multifamily	Heat Pump	Solar Attic Fan	Solar electric attic ventilation	Standard passive ventilation	Per Home	Existing	14	10	$478	2.5%	95%	$5.28	0.52
Electric	Multifamily	Heat Pump	Wall Insulation 2x4	R-13 (Below WA Code - Maximum Insulation Feasible)	R-0 (Zero Insulation)	Per Home	Existing	762	25	$1,011	60%	15%	$0.14	87
Electric	Multifamily	Heat Pump	Whole-House Dehumidifier	Whole-House Dehumidifier	No Dehumidifier	Per Home	Existing	2	12	$1,372	2.0%	95%	$67.74	0.08
Electric	Multifamily	Heat Pump	Whole-House Fan	Whole-House Fan	No Whole-House Fan	Per Home	Existing	70	20	$1,647	50%	95%	$2.60	52
Electric	Multifamily	Heat Pump	Window Overhang	Overhangs over windows for shading	No window overhangs	Per Home	Existing	65	30	$204	50%	50%	$0.32	23

Table B-2.1. Residential Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Multifamily	Heat Pump	Windows	U-value = 0.22 (Above WA Code)	U-value = 0.32 (WA Code)	Per Home	Existing	144	25	$2,272	30%	85%	$1.74	45
Electric	Multifamily	Heat Pump	Windows	U-value = 0.32 (WA Code)	Double Pane (Existing Window)	Per Home	Existing	745	25	$2,682	30%	15%	$0.39	41
Electric	Multifamily	Heat Pump	Windows	U-value = 0.32 (WA Code)	Single Pane (Existing Window)	Per Home	Existing	985	25	$2,682	30%	5%	$0.29	17
Electric	Multifamily	Heat Room	Canned Lighting Air Tight Sealing	Canned Lighting Air Tight Sealing	No Air tight Sealing	Per Fixture	Existing	24	30	$50	95%	50%	$0.20	1,225
Electric	Multifamily	Heat Room	Ceiling Insulation	R-38 (WA Code - Multi Family Only)	R-0 (Zero Insulation - Multi Family Only)	Per Home	Existing	1,048	25	$456	50%	50%	$0.04	27,180
Electric	Multifamily	Heat Room	Ceiling Insulation	R-38 (WA Code - Multi Family Only)	R-10 (Existing Insulation - Multi Family Only)	Per Home	Existing	407	25	$456	50%	50%	$0.11	9,969
Electric	Multifamily	Heat Room	Ceiling Insulation	R-49 (Above WA Code - Multi Family Only)	R-38 (WA Code - Multi Family Only)	Per Home	Existing	24	25	$73	15%	95%	$0.32	335
Electric	Multifamily	Heat Room	Conversion Baseboard Heating to DHP	Ductless Heat Pump HSPF 7.7	Baseboard Heating HSPF = 1	Per Home	Existing	1,479	20	$1,439	66%	95%	$0.10	121,021
Electric	Multifamily	Heat Room	Doors - Weatherization	Weatherstripping And Adding Door Sweeps	Existing Non-Efficient door	Per Door	Existing	35	6	$25	95%	50%	$0.15	1,619
Electric	Multifamily	Heat Room	Floor Insulation	R-30 (WA Code)	R-0 (Zero Insulation)	Per Home	Existing	1,795	25	$579	20%	25%	$0.02	8,498
Electric	Multifamily	Heat Room	Floor Insulation	R-30 (WA Code)	R-15 (Existing Insulation)	Per Home	Existing	179	25	$579	25%	50%	$0.35	2,083
Electric	Multifamily	Heat Room	Floor Insulation	R-38 (Above WA Code)	R-30 (WA Code)	Per Home	Existing	216	25	$154	25%	85%	$0.07	4,241
Electric	Multifamily	Heat Room	Infiltration Control (Caulk, Weather Strip, etc.) Blower-Door test	Install Caulking And Weatherstripping	Existing Infiltration Conditions	Per Home	Existing	313	11	$358	75%	50%	$0.16	10,776
Electric	Multifamily	Heat Room	Wall Insulation 2x4	R-13 (Below WA Code - Maximum Insulation Feasible)	R-0 (Zero Insulation)	Per Home	Existing	1,555	25	$1,011	60%	15%	$0.06	12,585
Electric	Multifamily	Heat Room	Windows	U-value = 0.22 (Above WA Code)	U-value = 0.32 (WA Code)	Per Home	Existing	458	25	$2,272	30%	85%	$0.54	10,086
Electric	Multifamily	Heat Room	Windows	U-value = 0.32 (WA Code)	Double Pane (Existing Window)	Per Home	Existing	1,835	25	$2,682	30%	15%	$0.15	6,916
Electric	Multifamily	Heat Room	Windows	U-value = 0.32 (WA Code)	Single Pane (Existing Window)	Per Home	Existing	2,216	25	$2,682	30%	5%	$0.12	2,729
Electric	Multifamily	Lighting Exterior	Time Clocks (Exterior Lighting)	Exterior Lighting on a Time Clock	Exterior Lighting (Manual Control)	Per Home	Existing	8	10	$16	80%	85%	$0.29	835
Electric	Multifamily	Lighting Interior Standard	Occupancy Sensors	Wall-Switch Occupancy Sensors	No Occupancy Sensor	Per Sensor	Existing	1	10	$32	20%	95%	$4.40	180
Electric	Multifamily	Plug Load Other	Battery Chargers, ENERGY STAR	ENERGY STAR Battery Chargers	Standard Battery Chargers	Per Device	Existing	5	7	$4	50%	80%	$0.17	461
Electric	Multifamily	Plug Load Other	Smart Strip	Smart Strip	Standard Power Strip	1 Computer or 1 for TV	Existing	43	4	$21	50%	85%	$0.14	3,797
Electric	Multifamily	Water Heat GT 55 Gal	Clothes Washer	Cold Water Only Clothes Washer - Electric Dryer	MEF = 1.66 - Electric DHW & Dryer	Per Unit Each	Existing	237	14	$80	10%	99%	$0.04	153
Electric	Multifamily	Water Heat GT 55 Gal	Clothes Washer	ENERGY STAR - Tier 1 (MEF 2.0 - 2.19) - Electric DHW & Dryer	MEF = 1.66 - Electric DHW & Dryer	Per Home	Existing	66	14	$35	15%	87%	$-0.22	56
Electric	Multifamily	Water Heat GT 55 Gal	Clothes Washer	ENERGY STAR - Tier 2 (MEF 2.2 - 2.45) - Electric DHW & Dryer	MEF = 1.66 - Electric DHW & Dryer	Per Home	Existing	98	14	$102	15%	95%	$-0.16	91
Electric	Multifamily	Water Heat GT 55 Gal	Clothes Washer	ENERGY STAR - Tier 3 (MEF 2.46 or higher) Top 10% of ENERGY STAR Model - Electric DHW & Dryer	MEF = 1.66 - Electric DHW & Dryer	Per Home	Existing	123	14	$209	15%	99%	$-0.18	119

Table B-2.1. Residential Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Multifamily	Water Heat GT 55 Gal	Clothes Washer	ENERGY STAR - Tier 3 (MEF 2.46 or higher) Top 10% of ENERGY STAR Model - Electric DHW & Dryer	RTF Market Standard 2018 Clothes Washer - MEF 2.36 and WF 4.1 (Electric DHW & Dryer)	Per Unit Each	Existing	23	14	$75	15%	95%	$0.02	17
Electric	Multifamily	Water Heat GT 55 Gal	Dishwasher	RTF ENERGY STAR Dishwasher - 277 kWh/yr and 4.25 gal/cycle	RTF Market Standard 2014 Dishwasher - 289 kWh/yr and 5.0 gal/cycle	Per Home	Existing	12	12	$36	95%	50%	$0.39	36
Electric	Multifamily	Water Heat GT 55 Gal	Faucet Aerators	2.2 GPM	Existing Faucet Aerator (3.0 GPM)	Per Home	Existing	121	9	$2	95%	15%	$-0.00	112
Electric	Multifamily	Water Heat GT 55 Gal	Faucet Aerators - Bathroom Only	0.5 GPM	2.2 GPM	Per Home	Existing	128	9	$2	50%	95%	$-0.00	399
Electric	Multifamily	Water Heat GT 55 Gal	Hot Water Pipe Insulation	R-4 Wrap	No insulation	Per Home	Existing	38	5	$23	95%	75%	$0.15	173
Electric	Multifamily	Water Heat GT 55 Gal	Low-Flow Showerheads	1.5 GPM	2.5 GPM	Per Home	Existing	380	10	$45	95%	85%	$-0.02	1,424
Electric	Multifamily	Water Heat GT 55 Gal	Low-Flow Showerheads	2.5 GPM	Existing Showerhead (3.0 GPM)	Per Home	Existing	221	10	$29	95%	5%	$-0.01	48
Electric	Multifamily	Water Heat LE 55 Gal	Clothes Washer	Cold Water Only Clothes Washer - Electric Dryer	MEF = 1.66 - Electric DHW & Dryer	Per Unit Each	Existing	237	14	$80	10%	99%	$0.04	1,881
Electric	Multifamily	Water Heat LE 55 Gal	Clothes Washer	ENERGY STAR - Tier 1 (MEF 2.0 - 2.19) - Electric DHW & Dryer	MEF = 1.66 - Electric DHW & Dryer	Per Home	Existing	66	14	$35	15%	87%	$-0.22	687
Electric	Multifamily	Water Heat LE 55 Gal	Clothes Washer	ENERGY STAR - Tier 2 (MEF 2.2 - 2.45) - Electric DHW & Dryer	MEF = 1.66 - Electric DHW & Dryer	Per Home	Existing	98	14	$102	15%	95%	$-0.16	1,123
Electric	Multifamily	Water Heat LE 55 Gal	Clothes Washer	ENERGY STAR - Tier 3 (MEF 2.46 or higher) Top 10% of ENERGY STAR Model - Electric DHW & Dryer	MEF = 1.66 - Electric DHW & Dryer	Per Home	Existing	123	14	$209	15%	99%	$-0.18	1,468
Electric	Multifamily	Water Heat LE 55 Gal	Clothes Washer	ENERGY STAR - Tier 3 (MEF 2.46 or higher) Top 10% of ENERGY STAR Model - Electric DHW & Dryer	RTF Market Standard 2018 Clothes Washer - MEF 2.36 and WF 4.1 (Electric DHW & Dryer)	Per Unit Each	Existing	23	14	$75	15%	95%	$0.02	217
Electric	Multifamily	Water Heat LE 55 Gal	Dishwasher	RTF ENERGY STAR Dishwasher - 277 kWh/yr and 4.25 gal/cycle	RTF Market Standard 2014 Dishwasher - 289 kWh/yr and 5.0 gal/cycle	Per Home	Existing	12	12	$36	58%	50%	$0.39	273
Electric	Multifamily	Water Heat LE 55 Gal	Faucet Aerators	2.2 GPM	Existing Faucet Aerator (3.0 GPM)	Per Home	Existing	121	9	$2	95%	15%	$-0.00	1,382
Electric	Multifamily	Water Heat LE 55 Gal	Faucet Aerators - Bathroom Only	0.5 GPM	2.2 GPM	Per Home	Existing	128	9	$2	50%	95%	$-0.00	4,896
Electric	Multifamily	Water Heat LE 55 Gal	Hot Water Pipe Insulation	R-4 Wrap	No insulation	Per Home	Existing	38	5	$23	95%	75%	$0.15	2,101
Electric	Multifamily	Water Heat LE 55 Gal	Low-Flow Showerheads	1.5 GPM	2.5 GPM	Per Home	Existing	380	10	$45	95%	85%	$-0.02	17,459
Electric	Multifamily	Water Heat LE 55 Gal	Low-Flow Showerheads	2.5 GPM	Existing Showerhead (3.0 GPM)	Per Home	Existing	221	10	$29	95%	5%	$-0.01	597
Electric	Single Family	Cool Central	Air-to-Air Heat Exchangers	Air-to-Air Heat Exchangers	No Air to Air Heat Exchangers	Per Home	Existing	64	5	$576	50%	95%	$-1.11	4,415
Electric	Single Family	Cool Central	Ceiling Fan	Ceiling Fan (no lighting kit)	No Ceiling Fan	Per Fan	Existing	51	10	$93	85%	50%	$0.28	3,160

Table B-2.1. Residential Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Single Family	Cool Central	Ceiling Insulation	R-49 (WA Code - Single Family and Manufactured Homes Only)	R-0 (Zero Insulation - Single Family and Manufactured Homes Only)	Per Home	Existing	169	45	$1,332	95%	1%	$-3.15	170
Electric	Single Family	Cool Central	Ceiling Insulation	R-49 (WA Code - Single Family and Manufactured Homes Only)	R-10 (Existing Insulation - Single Family and Manufactured Homes Only)	Per Home	Existing	63	45	$1,332	75%	35%	$-8.41	1,758
Electric	Single Family	Cool Central	Ceiling Insulation	R-60 (Above WA Code - Single Family and Manufactured Homes Only)	R-49 (WA Code - Single Family and Manufactured Homes Only)	Per Home	Existing	2	45	$315	75%	95%	$-317.08	146
Electric	Single Family	Cool Central	Duct Insulation Upgrade	R-8 (WA Code)	R-4 (Existing Insulation)	Per Home	Existing	28	20	$1,336	75%	75%	$-13.38	1,668
Electric	Single Family	Cool Central	Duct Sealing - Aerosol-Based	Spray-in ductwork sealant to minimize duct leaks	No Duct Sealing	Per Home	Existing	16	18	$827	50%	60%	$-25.14	495
Electric	Single Family	Cool Central	Leak Proof Duct Fittings	Quick connect fittings that do not require mastic or drawbands (5 per unit)	standard ducts with 13 SEER HVAC	Per Home	Existing	98	30	$1,114	5.0%	95%	$-5.06	465
Electric	Single Family	Cool Central	Programmable Thermostat	Programmable Thermostat	Manual Thermostat	Per House	Existing	22	15	$33	95%	63%	$-20.36	1,509
Electric	Single Family	Cool Central	Proper Sizing - HVAC Unit	Proper Sizing - HVAC Unit	Oversized HVAC Unit	Per AC Unit	Existing	61	15	$5	95%	65%	$-7.64	5,155
Electric	Single Family	Cool Central	Radiant Barrier (Ceiling)	Install Radiant Barrier	No Radiant Barrier	Per Home	Existing	38	30	$610	50%	90%	$-14.25	1,720
Electric	Single Family	Cool Central	Solar Attic Fan	Solar electric attic ventilation	Standard passive ventilation	Per Home	Existing	19	10	$478	25%	95%	$3.84	662
Electric	Single Family	Cool Central	Thermostat - Multi-Zone	Individual Room Temperature Control for Major Occupied Rooms	Programmable Thermostat - Central Control Only	Per Home	Existing	44	11	$890	10%	95%	$-5.78	504
Electric	Single Family	Cool Central	Wall Insulation 2x4	R-13 (Below WA Code - Maximum Insulation Feasible)	R-0 (Zero Insulation)	Per Home	Existing	25	45	$3,094	60%	15%	$-13.88	222
Electric	Single Family	Cool Central	Whole-House Dehumidifier	Whole-House Dehumidifier	No Dehumidifier	Per Home	Existing	12	12	$1,372	2.0%	95%	$15.16	35
Electric	Single Family	Cool Central	Whole-House Fan	Whole-House Fan	No Whole-House Fan	Per Home	Existing	97	20	$1,647	50%	95%	$1.89	6,623
Electric	Single Family	Cool Central	Window Overhang	Overhangs over windows for shading	No window overhangs	Per Home	Existing	90	30	$204	50%	50%	$0.23	2,481
Electric	Single Family	Cool Room	Ceiling Fan	Ceiling Fan (no lighting kit)	No Ceiling Fan	Per Fan	Existing	18	10	$93	85%	50%	$0.77	333
Electric	Single Family	Cool Room	Ceiling Insulation	R-49 (WA Code - Single Family and Manufactured Homes Only)	R-0 (Zero Insulation - Single Family and Manufactured Homes Only)	Per Home	Existing	79	45	$1,332	95%	1%	$-6.77	28
Electric	Single Family	Cool Room	Ceiling Insulation	R-49 (WA Code - Single Family and Manufactured Homes Only)	R-10 (Existing Insulation - Single Family and Manufactured Homes Only)	Per Home	Existing	34	45	$1,332	75%	35%	$-15.62	344
Electric	Single Family	Cool Room	Ceiling Insulation	R-60 (Above WA Code - Single Family and Manufactured Homes Only)	R-49 (WA Code - Single Family and Manufactured Homes Only)	Per Home	Existing	0.86	45	$315	75%	95%	$-732.68	22
Electric	Single Family	Cool Room	Radiant Barrier (Ceiling)	Install Radiant Barrier	No Radiant Barrier	Per Home	Existing	14	30	$610	50%	90%	$-39.00	235
Electric	Single Family	Cool Room	Room AC conversion to Ductless Heat Pump	Ductless Heat Pump Federal Standard	Room AC Federal Standard 9.8 EER; 8,000-13,999 Btuh	Per Home	Existing	7	20	$3,407	7.6%	95%	$54.30	20

Table B-2.1. Residential Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Single Family	Cool Room	Wall Insulation 2x4	R-13 (Below WA Code - Maximum Insulation Feasible)	R-0 (Zero Insulation)	Per Home	Existing	13	45	$3,094	60%	15%	$-26.48	43
Electric	Single Family	Cool Room	Window Overhang	Overhangs over windows for shading	No window overhangs	Per Home	Existing	33	30	$204	50%	50%	$0.65	330
Electric	Single Family	Freezer	Stand-Alone Freezer - Removal	Proper Disposal of Freezer	Existing Non-Efficient Freezer	Per Home	Existing	555	8	$30	56%	100%	$0.00	71,177
Electric	Single Family	Heat Central	Air-to-Air Heat Exchangers	Air-to-Air Heat Exchangers	No Air to Air Heat Exchangers	Per Home	Existing	1,527	5	$576	50%	95%	$0.08	20,900
Electric	Single Family	Heat Central	Canned Lighting Air Tight Sealing	Canned Lighting Air Tight Sealing	No Air tight Sealing	Per Fixture	Existing	117	30	$203	95%	50%	$0.17	1,275
Electric	Single Family	Heat Central	Ceiling Insulation	R-49 (WA Code - Single Family and Manufactured Homes Only)	R-0 (Zero Insulation - Single Family and Manufactured Homes Only)	Per Home	Existing	2,328	45	$1,332	95%	1%	$0.04	503
Electric	Single Family	Heat Central	Ceiling Insulation	R-49 (WA Code - Single Family and Manufactured Homes Only)	R-10 (Existing Insulation - Single Family and Manufactured Homes Only)	Per Home	Existing	917	45	$1,332	75%	35%	$0.13	5,473
Electric	Single Family	Heat Central	Ceiling Insulation	R-60 (Above WA Code - Single Family and Manufactured Homes Only)	R-49 (WA Code - Single Family and Manufactured Homes Only)	Per Home	Existing	26	45	$315	75%	95%	$1.19	416
Electric	Single Family	Heat Central	Conversion Electric Furnace to ASHP	Air Source Heat Pump Seer 14 HSPF 8.2	Electric Furnace HSPF 1	Per Furnace	Existing	3,073	20	$6,835	74%	95%	$0.23	62,205
Electric	Single Family	Heat Central	Doors	R-10 (Doors with foam core) (Above WA Code - Single Family and Manufactured Homes Only)	R-5 (Composite Doors with foam core) (WA Code Single Family and Manufactured Homes Only)	Per Door	Existing	119	20	$200	25%	95%	$0.17	630
Electric	Single Family	Heat Central	Doors	R-5 (Composite Doors with foam core) (WA Code - Single Family and Manufactured Homes Only)	R-2.5 (Standard non-thermal wood door) (Below WA Code - Single Family and Manufactured Homes Only)	Per Door	Existing	234	20	$126	85%	75%	$0.05	3,326
Electric	Single Family	Heat Central	Doors - Weatherization	Weatherstripping And Adding Door Sweeps	Existing Non-Efficient door	Per Door	Existing	81	6	$25	85%	50%	$0.06	766
Electric	Single Family	Heat Central	Duct Insulation Upgrade	R-8 (WA Code)	R-4 (Existing Insulation)	Per Home	Existing	1,114	20	$1,336	75%	75%	$0.12	13,809
Electric	Single Family	Heat Central	Duct Sealing - Aerosol-Based	Spray-in ductwork sealant to minimize duct leaks	No Duct Sealing	Per Home	Existing	849	18	$827	50%	60%	$0.10	5,388
Electric	Single Family	Heat Central	Floor Insulation	R-30 (WA Code)	R-0 (Zero Insulation)	Per Home	Existing	5,267	45	$1,621	20%	25%	$0.01	5,454
Electric	Single Family	Heat Central	Floor Insulation	R-30 (WA Code)	R-15 (Existing Insulation)	Per Home	Existing	510	45	$1,621	25%	50%	$0.30	1,299
Electric	Single Family	Heat Central	Floor Insulation	R-38 (Above WA Code)	R-30 (WA Code)	Per Home	Existing	614	45	$426	25%	85%	$0.05	2,645
Electric	Single Family	Heat Central	Infiltration Control (Caulk, Weather Strip, etc.) Blower-Door test	Install Caulking And Weatherstripping	Existing Infiltration Conditions	Per Home	Existing	836	11	$596	75%	50%	$0.09	6,321
Electric	Single Family	Heat Central	Leak Proof Duct Fittings	Quick connect fittings that do not require mastic or drawbands (5 per unit)	standard ducts with 13 SEER HVAC	Per Home	Existing	3,208	30	$1,114	5.0%	15%	$0.02	475
Electric	Single Family	Heat Central	Programmable Thermostat	Programmable Thermostat	Manual Thermostat	Per House	Existing	536	15	$33	95%	28%	$-0.01	2,949
Electric	Single Family	Heat Central	Proper Sizing - HVAC Unit	Proper Sizing - HVAC Unit	Oversized HVAC Unit	Per Heater Unit	Existing	1,151	15	$430	15%	65%	$0.03	2,622

Table B-2.1. Residential Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Single Family	Heat Central	Thermostat - Multi-Zone	Individual Room Temperature Control for Major Occupied Rooms	Programmable Thermostat - Central Control Only	Per Home	Existing	1,038	11	$890	10%	95%	$0.12	2,269
Electric	Single Family	Heat Central	Wall Insulation 2x4	R-13 (Below WA Code - Maximum Insulation Feasible)	R-0 (Zero Insulation)	Per Home	Existing	6,019	45	$3,094	60%	15%	$0.03	10,683
Electric	Single Family	Heat Central	Windows	U-value = 0.22 (Above WA Code)	U-value = 0.32 (WA Code)	Per Home	Existing	1,286	45	$5,316	50%	75%	$0.40	9,140
Electric	Single Family	Heat Central	Windows	U-value = 0.32 (WA Code)	Double Pane (Existing Window)	Per Home	Existing	5,487	45	$6,274	50%	15%	$0.10	7,530
Electric	Single Family	Heat Central	Windows	U-value = 0.32 (WA Code)	Single Pane (Existing Window)	Per Home	Existing	6,665	45	$6,274	50%	5%	$0.08	2,966
Electric	Single Family	Heat Pump	Air-to-Air Heat Exchangers	Air-to-Air Heat Exchangers	No Air to Air Heat Exchangers	Per Home	Existing	674	5	$576	50%	95%	$0.20	8,732
Electric	Single Family	Heat Pump	Canned Lighting Air Tight Sealing	Canned Lighting Air Tight Sealing	No Air tight Sealing	Per Fixture	Existing	46	30	$203	95%	50%	$0.45	509
Electric	Single Family	Heat Pump	Ceiling Fan	Ceiling Fan (no lighting kit)	No Ceiling Fan	Per Fan	Existing	75	10	$93	85%	50%	$0.18	873
Electric	Single Family	Heat Pump	Ceiling Insulation	R-49 (WA Code - Single Family and Manufactured Homes Only)	R-0 (Zero Insulation - Single Family and Manufactured Homes Only)	Per Home	Existing	1,111	45	$1,332	95%	1%	$0.10	242
Electric	Single Family	Heat Pump	Ceiling Insulation	R-49 (WA Code - Single Family and Manufactured Homes Only)	R-10 (Existing Insulation - Single Family and Manufactured Homes Only)	Per Home	Existing	432	45	$1,332	75%	35%	$0.29	2,606
Electric	Single Family	Heat Pump	Ceiling Insulation	R-60 (Above WA Code - Single Family and Manufactured Homes Only)	R-49 (WA Code - Single Family and Manufactured Homes Only)	Per Home	Existing	12	45	$315	75%	95%	$2.55	196
Electric	Single Family	Heat Pump	Check Me! O&M Tune-up	Tune-up/Maintenance	No Tune-up Maintenance	Per Heat Pump Unit	Existing	84	5	$204	95%	75%	$0.59	1,648
Electric	Single Family	Heat Pump	Doors	R-10 (Doors with foam core) (Above WA Code - Single Family and Manufactured Homes Only)	R-5 (Composite Doors with foam core) (WA Code Single Family and Manufactured Homes Only)	Per Door	Existing	44	20	$200	25%	95%	$0.49	239
Electric	Single Family	Heat Pump	Doors	R-5 (Composite Doors with foam core) (WA Code - Single Family and Manufactured Homes Only)	R-2.5 (Standard non-thermal wood door) (Below WA Code - Single Family and Manufactured Homes Only)	Per Door	Existing	89	20	$126	85%	75%	$0.15	1,279
Electric	Single Family	Heat Pump	Doors - Weatherization	Weatherstripping And Adding Door Sweeps	Existing Non-Efficient door	Per Door	Existing	32	6	$25	85%	50%	$0.16	306
Electric	Single Family	Heat Pump	Duct Insulation Upgrade	R-8 (WA Code)	R-4 (Existing Insulation)	Per Home	Existing	496	20	$1,336	75%	75%	$0.29	6,215
Electric	Single Family	Heat Pump	Duct Sealing - Aerosol-Based	Spray-in ductwork sealant to minimize duct leaks	No Duct Sealing	Per Home	Existing	476	18	$827	50%	60%	$0.19	3,049
Electric	Single Family	Heat Pump	Floor Insulation	R-30 (WA Code)	R-15 (Existing Insulation)	Per Home	Existing	183	45	$1,621	25%	50%	$0.87	479
Electric	Single Family	Heat Pump	Floor Insulation	R-38 (Above WA Code)	R-30 (WA Code)	Per Home	Existing	220	45	$426	25%	85%	$0.18	977
Electric	Single Family	Heat Pump	Infiltration Control (Caulk, Weather Strip, etc.) Blower-Door test	Install Caulking And Weatherstripping	Existing Infiltration Conditions	Per Home	Existing	325	11	$596	75%	50%	$0.26	2,523
Electric	Single Family	Heat Pump	Leak Proof Duct Fittings	Quick connect fittings that do not require mastic or drawbands (5 per unit)	standard ducts with 13 SEER HVAC	Per Home	Existing	1,416	30	$1,114	5.0%	95%	$0.07	1,366

Table B-2.1. Residential Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Single Family	Heat Pump	Programmable Thermostat	Programmable Thermostat	Manual Thermostat	Per House	Existing	236	15	$33	95%	63%	$0.01	3,056
Electric	Single Family	Heat Pump	Proper Sizing - HVAC Unit	Proper Sizing - HVAC Unit	Oversized HVAC Unit	Per Heat Pump	Existing	635	15	$5	95%	65%	$-0.01	10,098
Electric	Single Family	Heat Pump	Solar Attic Fan	Solar electric attic ventilation	Standard passive ventilation	Per Home	Existing	28	10	$478	25%	95%	$2.63	183
Electric	Single Family	Heat Pump	Thermostat - Multi-Zone	Individual Room Temperature Control for Major Occupied Rooms	Programmable Thermostat - Central Control Only	Per Home	Existing	458	11	$890	10%	95%	$0.28	1,028
Electric	Single Family	Heat Pump	Wall Insulation 2x4	R-13 (Below WA Code - Maximum Insulation Feasible)	R-0 (Zero Insulation)	Per Home	Existing	2,270	45	$3,094	60%	15%	$0.12	4,110
Electric	Single Family	Heat Pump	Whole-House Dehumidifier	Whole-House Dehumidifier	No Dehumidifier	Per Home	Existing	18	12	$1,372	2.0%	95%	$10.41	9
Electric	Single Family	Heat Pump	Whole-House Fan	Whole-House Fan	No Whole-House Fan	Per Home	Existing	141	20	$1,647	50%	95%	$1.29	1,830
Electric	Single Family	Heat Pump	Window Overhang	Overhangs over windows for shading	No window overhangs	Per Home	Existing	131	30	$204	50%	50%	$0.15	764
Electric	Single Family	Heat Pump	Windows	U-value = 0.22 (Above WA Code)	U-value = 0.32 (WA Code)	Per Home	Existing	335	45	$5,316	50%	75%	$1.56	2,456
Electric	Single Family	Heat Pump	Windows	U-value = 0.32 (WA Code)	Double Pane (Existing Window)	Per Home	Existing	1,562	45	$6,274	50%	15%	$0.39	2,241
Electric	Single Family	Heat Pump	Windows	U-value = 0.32 (WA Code)	Single Pane (Existing Window)	Per Home	Existing	2,092	45	$6,274	50%	5%	$0.28	983
Electric	Single Family	Heat Room	Canned Lighting Air Tight Sealing	Canned Lighting Air Tight Sealing	No Air tight Sealing	Per Fixture	Existing	101	30	$203	95%	50%	$0.20	1,485
Electric	Single Family	Heat Room	Ceiling Insulation	R-49 (WA Code - Single Family and Manufactured Homes Only)	R-0 (Zero Insulation - Single Family and Manufactured Homes Only)	Per Home	Existing	2,499	45	$1,332	95%	1%	$0.04	727
Electric	Single Family	Heat Room	Ceiling Insulation	R-49 (WA Code - Single Family and Manufactured Homes Only)	R-10 (Existing Insulation - Single Family and Manufactured Homes Only)	Per Home	Existing	992	45	$1,332	75%	35%	$0.12	7,961
Electric	Single Family	Heat Room	Ceiling Insulation	R-60 (Above WA Code - Single Family and Manufactured Homes Only)	R-49 (WA Code - Single Family and Manufactured Homes Only)	Per Home	Existing	28	45	$315	75%	95%	$1.09	604
Electric	Single Family	Heat Room	Conversion Baseboard Heating to DHP	Ductless Heat Pump HSPF 7.7	Baseboard Heating HSPF = 1	Per Home	Existing	3,500	20	$3,407	27%	95%	$0.09	29,467
Electric	Single Family	Heat Room	Doors	R-10 (Doors with foam core) (Above WA Code - Single Family and Manufactured Homes Only)	R-5 (Composite Doors with foam core) (WA Code Single Family and Manufactured Homes Only)	Per Door	Existing	94	20	$200	25%	95%	$0.22	670
Electric	Single Family	Heat Room	Doors	R-5 (Composite Doors with foam core) (WA Code - Single Family and Manufactured Homes Only)	R-2.5 (Standard non-thermal wood door) (Below WA Code - Single Family and Manufactured Homes Only)	Per Door	Existing	186	20	$126	85%	75%	$0.06	3,538
Electric	Single Family	Heat Room	Doors - Weatherization	Weatherstripping And Adding Door Sweeps	Existing Non-Efficient door	Per Door	Existing	70	6	$25	85%	50%	$0.07	886
Electric	Single Family	Heat Room	Floor Insulation	R-30 (WA Code)	R-0 (Zero Insulation)	Per Home	Existing	4,431	45	$1,621	20%	25%	$0.02	6,496
Electric	Single Family	Heat Room	Floor Insulation	R-30 (WA Code)	R-15 (Existing Insulation)	Per Home	Existing	427	45	$1,621	25%	50%	$0.36	1,536
Electric	Single Family	Heat Room	Floor Insulation	R-38 (Above WA Code)	R-30 (WA Code)	Per Home	Existing	514	45	$426	25%	85%	$0.07	3,127
Electric	Single Family	Heat Room	Infiltration Control (Caulk, Weather Strip, etc.) Blower-Door test	Install Caulking And Weatherstripping	Existing Infiltration Conditions	Per Home	Existing	724	11	$596	75%	50%	$0.11	7,739

Table B-2.1. Residential Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Single Family	Heat Room	Wall Insulation 2x4	R-13 (Below WA Code - Maximum Insulation Feasible)	R-0 (Zero Insulation)	Per Home	Existing	4,779	45	$3,094	60%	15%	$0.05	11,983
Electric	Single Family	Heat Room	Windows	U-value = 0.22 (Above WA Code)	U-value = 0.32 (WA Code)	Per Home	Existing	1,023	45	$5,316	50%	75%	$0.50	10,262
Electric	Single Family	Heat Room	Windows	U-value = 0.32 (WA Code)	Double Pane (Existing Window)	Per Home	Existing	4,350	45	$6,274	50%	15%	$0.13	8,414
Electric	Single Family	Heat Room	Windows	U-value = 0.32 (WA Code)	Single Pane (Existing Window)	Per Home	Existing	5,285	45	$6,274	50%	5%	$0.10	3,313
Electric	Single Family	Lighting Exterior	Time Clocks (Exterior Lighting)	Exterior Lighting on a Time Clock	Exterior Lighting (Manual Control)	Per Home	Existing	8	10	$16	80%	85%	$0.29	5,408
Electric	Single Family	Lighting Interior Standard	Occupancy Sensors	Wall-Switch Occupancy Sensors	No Occupancy Sensor	Per Sensor	Existing	1	10	$32	20%	95%	$3.76	1,168
Electric	Single Family	Plug Load Other	Battery Chargers, ENERGY STAR	ENERGY STAR Battery Chargers	Standard Battery Chargers	Per Device	Existing	13	7	$4	50%	80%	$0.07	3,233
Electric	Single Family	Plug Load Other	Smart Strip	Smart Strip	Standard Power Strip	1 Computer or 1 for TV	Existing	43	4	$21	50%	85%	$0.14	11,178
Electric	Single Family	Pool Pump	Pool Pump Timers	Pool Pump Timers	Pool Pump No Timers	Per Pool	Existing	291	10	$56	95%	50%	$0.02	1,008
Electric	Single Family	Refrigerator	Refrigerator/Freezer - Removal of Secondary	Proper Disposal of Refrigerator/Freezer	Existing Non-Efficient Refrigerator/Freezer	Per Home	Existing	481	9	$30	46%	100%	$0.00	164,417
Electric	Single Family	Water Heat GT 55 Gal	Clothes Washer	Cold Water Only Clothes Washer - Electric Dryer	MEF = 1.66 - Electric DHW & Dryer	Per Unit Each	Existing	237	14	$80	10%	99%	$0.04	235
Electric	Single Family	Water Heat GT 55 Gal	Clothes Washer	ENERGY STAR - Tier 3 (MEF 2.46 or higher) Top 10% of ENERGY STAR Model - Electric DHW & Dryer	MEF = 1.66 - Electric DHW & Dryer	Per Home	Existing	135	14	$209	99%	95%	$-0.17	1,158
Electric	Single Family	Water Heat GT 55 Gal	Dishwasher	RTF ENERGY STAR Dishwasher - 277 kWh/yr and 4.25 gal/cycle	RTF Market Standard 2014 Dishwasher - 289 kWh/yr and 5.0 gal/cycle	Per Home	Existing	12	12	$36	95%	50%	$0.39	55
Electric	Single Family	Water Heat GT 55 Gal	Drain Water Heat Recovery (GFX)	Gravity Film Heat Exchanger	No Heat Exchanger	Per Home	Existing	363	40	$540	29%	90%	$0.14	873
Electric	Single Family	Water Heat GT 55 Gal	Faucet Aerators	2.2 GPM	Existing Faucet Aerator (3.0 GPM)	Per Home	Existing	142	9	$4	95%	15%	$-0.00	202
Electric	Single Family	Water Heat GT 55 Gal	Faucet Aerators - Bathroom Only	0.5 GPM	2.2 GPM	Per Home	Existing	201	9	$4	67%	95%	$-0.00	1,277
Electric	Single Family	Water Heat GT 55 Gal	Hot Water Pipe Insulation	R-4 Wrap	No insulation	Per Home	Existing	38	5	$23	95%	75%	$0.15	265
Electric	Single Family	Water Heat GT 55 Gal	Low-Flow Showerheads	1.5 GPM	2.5 GPM	Per Home	Existing	620	10	$68	95%	85%	$-0.01	3,560
Electric	Single Family	Water Heat GT 55 Gal	Low-Flow Showerheads	2.5 GPM	Existing Showerhead (3.0 GPM)	Per Home	Existing	361	10	$44	95%	5%	$-0.00	121
Electric	Single Family	Water Heat LE 55 Gal	Clothes Washer	Cold Water Only Clothes Washer - Electric Dryer	MEF = 1.66 - Electric DHW & Dryer	Per Unit Each	Existing	237	14	$80	10%	99%	$0.04	2,916
Electric	Single Family	Water Heat LE 55 Gal	Clothes Washer	ENERGY STAR - Tier 3 (MEF 2.46 or higher) Top 10% of ENERGY STAR Model - Electric DHW & Dryer	MEF = 1.66 - Electric DHW & Dryer	Per Home	Existing	135	14	$209	99%	95%	$-0.17	14,362
Electric	Single Family	Water Heat LE 55 Gal	Dishwasher	RTF ENERGY STAR Dishwasher - 277 kWh/yr and 4.25 gal/cycle	RTF Market Standard 2014 Dishwasher - 289 kWh/yr and 5.0 gal/cycle	Per Home	Existing	12	12	$36	71%	50%	$0.39	520
Electric	Single Family	Water Heat LE 55 Gal	Drain Water Heat Recovery (GFX)	Gravity Film Heat Exchanger	No Heat Exchanger	Per Home	Existing	358	40	$540	29%	90%	$0.14	10,691

Table B-2.1. Residential Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Single Family	Water Heat LE 55 Gal	Faucet Aerators	2.2 GPM	Existing Faucet Aerator (3.0 GPM)	Per Home	Existing	142	9	$4	95%	15%	$-0.00	2,516
Electric	Single Family	Water Heat LE 55 Gal	Faucet Aerators - Bathroom Only	0.5 GPM	2.2 GPM	Per Home	Existing	201	9	$4	67%	95%	$-0.00	15,844
Electric	Single Family	Water Heat LE 55 Gal	Hot Water Pipe Insulation	R-4 Wrap	No insulation	Per Home	Existing	38	5	$23	95%	75%	$0.15	3,247
Electric	Single Family	Water Heat LE 55 Gal	Low-Flow Showerheads	1.5 GPM	2.5 GPM	Per Home	Existing	620	10	$68	95%	85%	$-0.01	44,147
Electric	Single Family	Water Heat LE 55 Gal	Low-Flow Showerheads	2.5 GPM	Existing Showerhead (3.0 GPM)	Per Home	Existing	361	10	$44	95%	5%	$-0.00	1,511

Table B-2.2. Commercial Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Dry Goods Retail	Cooling Dx	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	Demand Controlled Ventilation (CO2 sensors)	Constant Ventilation	Per Building	Existing	2,169	15	$2,875	25%	94%	$0.16	1,561
Electric	Dry Goods Retail	Cooling Dx	Commissioning of Existing Buildings	Existing Building Commissioning	Average Existing Conditions	Per Building	Existing	2,712	7	$2,267	90%	85%	$0.16	4,711
Electric	Dry Goods Retail	Cooling Dx	Convert Constant Volume Air System to VAV	Variable Volume Air System	Constant Volume Air System	Per Building	Existing	6,509	15	$34,959	15%	67%	$0.68	1,969
Electric	Dry Goods Retail	Cooling Dx	DX Package-Air Side Economizer	Air-Side Economizer	No Economizer	Per Building	Existing	3,254	10	$9,780	10%	80%	$0.47	754
Electric	Dry Goods Retail	Cooling Dx	Direct / Indirect Evaporative Cooling, Pre-Cooling	Evaporative Cooler	Standard DX cooling	Per Building	Existing	5,424	15	$23,958	50%	94%	$0.56	7,250
Electric	Dry Goods Retail	Cooling Dx	Direct Digital Control System-Installation	DDC Retrofit (Morning Warm-Up Control Logic Included in This Measure)	Pneumatic	Per Building	Existing	3,254	5	$11,057	10%	59%	$0.85	483
Electric	Dry Goods Retail	Cooling Dx	Direct Digital Control System-Wireless System	DDC Retrofit - Wireless System	Pneumatic	Per Building	Existing	3,254	5	$2,687	50%	80%	$0.20	2,589
Electric	Dry Goods Retail	Cooling Dx	Duct Repair And Sealing	Reduction In Duct Losses to 5%	No Repair or Sealing, 15% duct losses	Per Building	Existing	542	18	$2,760	45%	65%	$0.59	376
Electric	Dry Goods Retail	Cooling Dx	Economizer Tune-up	Economizer Tune-up	No Economizer Tune-Up	Per Building	Existing	2,169	5	$2,760	10%	75%	$0.32	466
Electric	Dry Goods Retail	Cooling Dx	Green Roof	Vegetation on Roof	Standard Dark Colored Roof	Per Building	Existing	1,775	40	$95,346	3.5%	98%	$5.42	143
Electric	Dry Goods Retail	Cooling Dx	Infiltration Reduction	Install Caulking And Weatherstripping (ACH 0.65)	Infiltration Conditions (ACH 1.0)	Per Building	Existing	1,055	12.5	$322	10%	39%	$0.04	95
Electric	Dry Goods Retail	Cooling Dx	Insulation - Ceiling	R-30 c.i. (WA State Code)	R-7 (Average Existing Conditions)	Per Building	Existing	98	25	$16,780	75%	85%	$18.85	147
Electric	Dry Goods Retail	Cooling Dx	Insulation - Ceiling	R-49 c.i.	R-38 c.i.	Per Building	Existing	1	25	$4,734	25%	98%	$484.80	0.61
Electric	Dry Goods Retail	Cooling Dx	Insulation - Duct	R-7 (WA State Code)	No Insulation	Per Building	Existing	911	20	$2,224	75%	59%	$0.27	936
Electric	Dry Goods Retail	Cooling Dx	Programmable Thermostat - Web Enabled	Programmable Thermostat - Web Enabled	No Programmable Thermostat	Per Building	Existing	650	10	$779	95%	26%	$0.18	364
Electric	Dry Goods Retail	Cooling Dx	RE - Deciduous Trees	Shade Trees	No Trees	Per Building	Existing	167	30	$2,386	75%	55%	$1.51	156
Electric	Dry Goods Retail	Cooling Dx	Window Film	Window Film	No Film	Per Building	Existing	2,079	10	$1,455	90%	66%	$0.11	25
Electric	Dry Goods Retail	Cooling Dx	Windows-High Efficiency	U-0.32	U-0.40 (WA State Code)	Per Building	Existing	2,737	25	$27,894	15%	80%	$1.13	672
Electric	Dry Goods Retail	Cooling Dx	Windows-High Efficiency	U-0.40 (WA State Code)	U-0.68 (Average Existing Conditions)	Per Building	Existing	2,328	25	$60,038	15%	80%	$2.86	562
Electric	Dry Goods Retail	Heat Pump	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	Demand Controlled Ventilation (CO2 sensors)	Constant Ventilation	Per Building	Existing	2,281	15	$2,875	25%	94%	$0.15	316
Electric	Dry Goods Retail	Heat Pump	Commissioning of Existing Buildings	Existing Building Commissioning	Average Existing Conditions	Per Building	Existing	4,176	7	$2,267	90%	85%	$0.10	1,555
Electric	Dry Goods Retail	Heat Pump	Convert Constant Volume Air System to VAV	Variable Volume Air System	Constant Volume Air System	Per Building	Existing	5,346	15	$34,959	15%	67%	$0.82	314
Electric	Dry Goods Retail	Heat Pump	Direct Digital Control System-Installation	DDC Retrofit (Morning Warm-Up Control Logic Included in This Measure)	Pneumatic	Per Building	Existing	5,012	5	$11,057	10%	59%	$0.55	169
Electric	Dry Goods Retail	Heat Pump	Direct Digital Control System-Wireless System	DDC Retrofit - Wireless System	Pneumatic	Per Building	Existing	5,012	5	$2,687	50%	80%	$0.13	909

Table B-2.2. Commercial Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Dry Goods Retail	Heat Pump	Duct Repair And Sealing	Reduction In Duct Losses to 5%	No Repair or Sealing, 15% duct losses	Per Building	Existing	835	18	$2,760	45%	65%	$0.38	132
Electric	Dry Goods Retail	Heat Pump	Exhaust Air to Ventilation Air Heat Recovery	Exhaust Air Heat Recovery	No Heat Recovery	Per Building	Existing	1,590	14	$10,430	5.0%	94%	$0.86	40
Electric	Dry Goods Retail	Heat Pump	Green Roof	Vegetation on Roof	Standard Dark Colored Roof	Per Building	Existing	1,866	40	$95,346	3.5%	98%	$5.15	34
Electric	Dry Goods Retail	Heat Pump	Ground Source Heat Pump > 135 kBTU/hr	High Efficiency Ground Source Heat Pump > 135 kBTU/hr	Water Source Heat Pump > 135 kBTU/hr	Per Building	Existing	3,097	15	$24,113	3.8%	95%	$9.20	47
Electric	Dry Goods Retail	Heat Pump	Infiltration Reduction	Install Caulking And Weatherstripping (ACH 0.65)	Infiltration Conditions (ACH 1.0)	Per Building	Existing	1,546	12.5	$322	10%	39%	$0.02	31
Electric	Dry Goods Retail	Heat Pump	Insulation - Ceiling	R-30 c.i. (WA State Code)	R-7 (Average Existing Conditions)	Per Building	Existing	2,531	25	$16,780	75%	85%	$0.73	859
Electric	Dry Goods Retail	Heat Pump	Insulation - Ceiling	R-38 c.i.	R-30 c.i. (WA State Code)	Per Building	Existing	245	25	$16,780	75%	83%	$7.58	77
Electric	Dry Goods Retail	Heat Pump	Insulation - Ceiling	R-49 c.i.	R-38 c.i.	Per Building	Existing	91	25	$4,734	25%	98%	$5.77	11
Electric	Dry Goods Retail	Heat Pump	Insulation - Duct	R-7 (WA State Code)	No Insulation	Per Building	Existing	1,403	20	$2,224	75%	59%	$0.17	311
Electric	Dry Goods Retail	Heat Pump	Insulation - Floor (non-slab)	R-30 (WA State Code)	R-11 (Average Existing Conditions)	Per Building	Existing	888	25	$8,846	35%	90%	$1.10	138
Electric	Dry Goods Retail	Heat Pump	Insulation - Floor (non-slab)	R-38	R-30 (WA State Code)	Per Building	Existing	175	25	$2,729	35%	90%	$1.72	27
Electric	Dry Goods Retail	Heat Pump	Insulation - Wall	R-16	R-3 (Average Existing Conditions)	Per Building	Existing	1,103	25	$10,857	10%	35%	$1.08	18
Electric	Dry Goods Retail	Heat Pump	Programmable Thermostat - Web Enabled	Programmable Thermostat - Web Enabled	No Programmable Thermostat	Per Building	Existing	1,002	10	$779	95%	26%	$0.11	120
Electric	Dry Goods Retail	Heat Pump	RE - Deciduous Trees	Shade Trees	No Trees	Per Building	Existing	93	30	$1,294	75%	55%	$1.47	18
Electric	Dry Goods Retail	Heat Pump	Window Film	Window Film	No Film	Per Building	Existing	2,079	10	$1,455	90%	66%	$0.10	5
Electric	Dry Goods Retail	Heat Pump	Windows-High Efficiency	U-0.32	U-0.40 (WA State Code)	Per Building	Existing	2,476	25	$27,894	15%	80%	$1.24	130
Electric	Dry Goods Retail	Heat Pump	Windows-High Efficiency	U-0.40 (WA State Code)	U-0.68 (Average Existing Conditions)	Per Building	Existing	2,632	25	$60,038	15%	80%	$2.52	137
Electric	Dry Goods Retail	Lighting Exterior	Covered Parking Lighting	Covered Parking Lighting	Normal Lighting	Per Building	Existing	1,077	9.5	$299	20%	95%	$0.03	1,550
Electric	Dry Goods Retail	Lighting Exterior	Daylighting Controls, Outdoors (Photocell)	Photocell	No Controls	Per Building	Existing	690	8	$106	75%	70%	$0.02	1,034
Electric	Dry Goods Retail	Lighting Exterior	Occupancy Sensor Control	Occupancy Sensor Control	No Occupancy Sensor	Per Building	Existing	1,161	8	$365	90%	75%	$0.05	5,502
Electric	Dry Goods Retail	Lighting Exterior	Solid State LED White Lighting	Landscape, merchandise, signage, structure & task lighting (2.5 W)	50W 10hrs/day, 365 day/yr	Per Building	Existing	672	13.69863	$135	75%	95%	$0.02	155
Electric	Dry Goods Retail	Lighting Exterior	Surface Parking Lighting	Surface Parking Lighting	Normal Lighting	Per Building	Existing	582	18.666667	$786	47%	95%	$0.15	1,854
Electric	Dry Goods Retail	Lighting Exterior	Time Clock	Time Clock	No Controls	Per Building	Existing	622	8	$169	10%	81%	$0.04	325
Electric	Dry Goods Retail	Lighting Interior Fluorescent	Bi-Level Control, Stairwell Lighting	Occupancy Sensor Control, 50% Lighting Power during unoccupied Time	Continuous Full Power Lighting in Stairways	Per Building	Existing	1,225	9	$618	10%	75%	$0.08	496
Electric	Dry Goods Retail	Lighting Interior Fluorescent	Dimming-Continuous, Fluorescent Fixtures	Continuous Dimming, Fluorescent Fixtures (Day-Lighting)	No Dimming Controls	Per Building	Existing	3,340	8	$7,761	30%	84%	$0.41	4,987
Electric	Dry Goods Retail	Lighting Interior Fluorescent	Occupancy Sensor Control	Occupancy Sensor Control	No Occupancy Sensor	Per Building	Existing	5,067	8	$979	45%	56%	$0.03	7,138

Table B-2.2. Commercial Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Dry Goods Retail	Lighting Interior Fluorescent	Time Clock	Time Clock	No Controls	Per Building	Existing	2,714	8	$741	10%	86%	$0.04	1,335
Electric	Dry Goods Retail	Lighting Interior Hid	Occupancy Sensor Control	Occupancy Sensor Control	No Occupancy Sensor	Per Building	Existing	898	8	$979	45%	56%	$0.19	1,449
Electric	Dry Goods Retail	Lighting Interior Hid	Time Clock	Time Clock	No Controls	Per Building	Existing	481	8	$131	10%	86%	$0.04	271
Electric	Dry Goods Retail	Lighting Interior Other	Exit Sign - LED	Two Sided LED Exit Sign (5 Watts)	CFL Exit Sign (9 Watts)	Per Building	Existing	832	16	$138	95%	50%	$0.01	2,851
Electric	Dry Goods Retail	Lighting Interior Other	Exit Sign - Photoluminescent or Tritium	Photoluminescent or Tritium	Two Sided LED Exit Sign (5 Watts)	Per Building	Existing	302	13	$258	95%	98%	$0.11	2,032
Electric	Dry Goods Retail	Lighting Interior Screw Base	Cold Cathode Lighting	Cold Cathode Lighting 5 watts	30 W Incandescent Bulb	Per Building	Existing	158	5	$17	70%	94%	$0.02	201
Electric	Dry Goods Retail	Lighting Interior Screw Base	Occupancy Sensor Control	Occupancy Sensor Control	No Occupancy Sensor	Per Building	Existing	1,725	8	$979	45%	56%	$0.10	802
Electric	Dry Goods Retail	Lighting Interior Screw Base	Time Clock	Time Clock	No Controls	Per Building	Existing	924	8	$251	10%	86%	$0.04	150
Electric	Dry Goods Retail	Other Plug Load	ENERGY STAR - Battery Charging System	ENERGY STAR Battery Charging System	Non-ENERGY STAR Battery Chargers	Per Building	Existing	6	7	$2	20%	20%	$0.07	1
Electric	Dry Goods Retail	Other Plug Load	ENERGY STAR - Water Cooler	ENERGY STAR Water Cooler (Hot/Cold Water)	Non-ENERGY STAR Water Cooler	Per Building	Existing	66	10	$0.00	95%	20%	$-0.01	90
Electric	Dry Goods Retail	Other Plug Load	Power Supply Transformer/Converter	80 Plus	85% efficient power supply (> 51W)	Per Building	Existing	158	4	$2	95%	86%	$0.00	130
Electric	Dry Goods Retail	Other Plug Load	Scanner - ENERGY STAR	ENERGY STAR Scanners	Standard Scanner	Per Building	Existing	17	6	$0.00	95%	20%	$-0.01	23
Electric	Dry Goods Retail	Other Plug Load	Smart Strips	Smart Strip Power Strip	Standard surge protector	Per Building	Existing	230	4	$57	60%	90%	$0.07	895
Electric	Dry Goods Retail	Refrigerator	Residential Refrigerator/Freezer Recycling	Recycling Existing Refrigerator/Freezer	Existing Refrigerator/Freezer	Per Building	Existing	481	9	$130	25%	100%	$0.04	750
Electric	Dry Goods Retail	Space Heat	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	Demand Controlled Ventilation (CO2 sensors)	Constant Ventilation	Per Building	Existing	2,322	15	$2,875	25%	94%	$0.14	726
Electric	Dry Goods Retail	Space Heat	Commissioning of Existing Buildings	Existing Building Commissioning	Average Existing Conditions	Per Building	Existing	2,903	7	$2,267	90%	85%	$0.14	1,932
Electric	Dry Goods Retail	Space Heat	Convert Constant Volume Air System to VAV	Variable Volume Air System	Constant Volume Air System	Per Building	Existing	3,019	15	$34,959	15%	67%	$1.45	397
Electric	Dry Goods Retail	Space Heat	Direct Digital Control System-Installation	DDC Retrofit (Morning Warm-Up Control Logic Included in This Measure)	Pneumatic	Per Building	Existing	3,483	5	$11,057	10%	59%	$0.78	262
Electric	Dry Goods Retail	Space Heat	Direct Digital Control System-Wireless System	DDC Retrofit - Wireless System	Pneumatic	Per Building	Existing	3,483	5	$2,687	50%	80%	$0.18	1,406
Electric	Dry Goods Retail	Space Heat	Duct Repair And Sealing	Reduction In Duct Losses to 5%	No Repair or Sealing, 15% duct losses	Per Building	Existing	580	18	$2,760	45%	65%	$0.54	204
Electric	Dry Goods Retail	Space Heat	Economizer Tune-up	Economizer Tune-up	No Economizer Tune-Up	Per Building	Existing	2,322	5	$2,760	10%	75%	$0.28	223
Electric	Dry Goods Retail	Space Heat	Exhaust Air to Ventilation Air Heat Recovery	Exhaust Air Heat Recovery	No Heat Recovery	Per Building	Existing	3,483	14	$10,430	5.0%	94%	$0.38	195
Electric	Dry Goods Retail	Space Heat	Infiltration Reduction	Install Caulking And Weatherstripping (ACH 0.65)	Infiltration Conditions (ACH 1.0)	Per Building	Existing	2,258	12.5	$322	10%	39%	$0.00	103

Table B-2.2. Commercial Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Dry Goods Retail	Space Heat	Insulation - Ceiling	R-30 c.i. (WA State Code)	R-7 (Average Existing Conditions)	Per Building	Existing	5,341	25	$16,780	75%	85%	$0.33	4,015
Electric	Dry Goods Retail	Space Heat	Insulation - Ceiling	R-38 c.i.	R-30 c.i. (WA State Code)	Per Building	Existing	492	25	$16,780	75%	83%	$3.76	308
Electric	Dry Goods Retail	Space Heat	Insulation - Ceiling	R-49 c.i.	R-38 c.i.	Per Building	Existing	476	25	$4,734	25%	98%	$1.08	115
Electric	Dry Goods Retail	Space Heat	Insulation - Duct	R-7 (WA State Code)	No Insulation	Per Building	Existing	975	20	$2,224	75%	59%	$0.24	424
Electric	Dry Goods Retail	Space Heat	Insulation - Floor (non-slab)	R-30 (WA State Code)	R-11 (Average Existing Conditions)	Per Building	Existing	5,287	25	$8,846	35%	90%	$0.17	1,615
Electric	Dry Goods Retail	Space Heat	Insulation - Floor (non-slab)	R-38	R-30 (WA State Code)	Per Building	Existing	984	25	$2,729	35%	90%	$0.29	279
Electric	Dry Goods Retail	Space Heat	Insulation - Wall	R-16	R-3 (Average Existing Conditions)	Per Building	Existing	10,659	25	$10,857	10%	35%	$0.09	331
Electric	Dry Goods Retail	Space Heat	Programmable Thermostat - Web Enabled	Programmable Thermostat - Web Enabled	No Programmable Thermostat	Per Building	Existing	696	10	$779	95%	26%	$0.16	149
Electric	Dry Goods Retail	Space Heat	Windows-High Efficiency	U-0.40 (WA State Code)	U-0.68 (Average Existing Conditions)	Per Building	Existing	363	25	$60,038	15%	80%	$18.33	34
Electric	Dry Goods Retail	Vending Machines	Vending Miser	Passive Infrared Sensor on Vending Machine Monitoring Vacancy of Area And Cycles Cooling - Controls	No Vending Miser - No controls	Per Building	Existing	1,796	3	$169	5.0%	25%	$0.03	3
Electric	Dry Goods Retail	Ventilation And Circulation	Automated Exhaust VFD Control - Parking Garage CO sensor	CO Sensors	No CO Sensors	Per Building	Existing	13,000	10	$1,410	1.0%	85%	$0.01	336
Electric	Dry Goods Retail	Ventilation And Circulation	Convert Constant Volume Air System to VAV	Variable Volume Air System	Constant Volume Air System	Per Building	Existing	3,746	15	$34,959	15%	67%	$1.18	2,401
Electric	Dry Goods Retail	Ventilation And Circulation	Motor - CEE Premium-Efficiency Plus	CEE PE+ Motor for HVAC Applications	NEMA Efficiency Motors	Per Building	Existing	318	15	$76	95%	76%	$0.02	1,433
Electric	Dry Goods Retail	Ventilation And Circulation	Motor - Pump & Fan System - Variable Speed Control	Pump And Fan System Optimization w/ VSD	No Pump And Fan System VSD Optimization	Per Building	Existing	7,960	20	$1,280	65%	75%	$0.01	24,104
Electric	Dry Goods Retail	Ventilation And Circulation	Motor - VAV Box High Efficiency (ECM)	ECM Motor	Standard Efficiency Motor	Per Building	Existing	1,638	15	$4,200	5.0%	77%	$0.32	340
Electric	Dry Goods Retail	Ventilation And Circulation	Motor Rewind	>15, <500 HP	No Rewind	Per Building	Existing	203	7	$57	65%	25%	$0.05	179
Electric	Dry Goods Retail	Water Heat GT 55 Gal	Demand Controlled Circulating Systems	Demand Controlled Circulating Systems (VFD control by demand)	Constant Circulation	Per Building	Existing	165	10	$3,194	75%	94%	$3.01	261
Electric	Dry Goods Retail	Water Heat GT 55 Gal	Dishwasher Residential	RTF ENERGY STAR Dishwasher - 277 kWh/yr and 4.25 gal/cycle	RTF Market Standard 2014 Dishwasher - 289 kWh/yr and 5.0 gal/cycle	Per Building	Existing	14	12	$44	24%	25%	$0.43	1
Electric	Dry Goods Retail	Water Heat GT 55 Gal	Drainwater Heat Recovery Water Heater	Install (Power-Pipe or GFX) - Heat Recovery Water Heater	No Heat Recovery System	Per Building	Existing	678	25	$1,250	5.0%	92%	$0.20	65
Electric	Dry Goods Retail	Water Heat GT 55 Gal	Low-Flow Faucet Aerators	0.5 GPM	2.2 GPM (Federal Code)	Per Building	Existing	127	9	$4	95%	75%	$-0.03	204
Electric	Dry Goods Retail	Water Heat GT 55 Gal	Low-Flow Faucet Aerators	2.2 GPM (Federal Code)	3.0 GPM	Per Building	Existing	44	9	$3	95%	25%	$-0.06	23
Electric	Dry Goods Retail	Water Heat GT 55 Gal	Pipe Insulation - Hot Water (DWH)	1.0" of Insulation, assuming R-4 (WA State Code)	No Insulation	Per Building	Existing	33	12	$25	80%	90%	$0.11	50
Electric	Dry Goods Retail	Water Heat GT 55 Gal	Ultrasonic Faucet Control	Install Ultrasonic Motion Faucet Control	No Faucet Control	Per Building	Existing	82	10	$317	75%	95%	$0.53	132

Table B-2.2. Commercial Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Dry Goods Retail	Water Heat LE 55 Gal	Demand Controlled Circulating Systems	Demand Controlled Circulating Systems (VFD control by demand)	Constant Circulation	Per Building	Existing	162	10	$3,194	75%	94%	$3.07	252
Electric	Dry Goods Retail	Water Heat LE 55 Gal	Dishwasher Residential	RTF ENERGY STAR Dishwasher - 277 kWh/yr and 4.25 gal/cycle	RTF Market Standard 2014 Dishwasher - 289 kWh/yr and 5.0 gal/cycle	Per Building	Existing	14	12	$44	24%	25%	$0.43	1
Electric	Dry Goods Retail	Water Heat LE 55 Gal	Drainwater Heat Recovery Water Heater	Install (Power-Pipe or GFX) - Heat Recovery Water Heater	No Heat Recovery System	Per Building	Existing	678	25	$1,250	5.0%	92%	$0.20	63
Electric	Dry Goods Retail	Water Heat LE 55 Gal	Low-Flow Faucet Aerators	0.5 GPM	2.2 GPM (Federal Code)	Per Building	Existing	125	9	$4	95%	75%	$-0.03	196
Electric	Dry Goods Retail	Water Heat LE 55 Gal	Low-Flow Faucet Aerators	2.2 GPM (Federal Code)	3.0 GPM	Per Building	Existing	43	9	$3	95%	25%	$-0.06	22
Electric	Dry Goods Retail	Water Heat LE 55 Gal	Pipe Insulation - Hot Water (DWH)	1.0" of Insulation, assuming R-4 (WA State Code)	No Insulation	Per Building	Existing	32	12	$25	80%	90%	$0.11	49
Electric	Dry Goods Retail	Water Heat LE 55 Gal	Ultrasonic Faucet Control	Install Ultrasonic Motion Faucet Control	No Faucet Control	Per Building	Existing	81	10	$317	75%	95%	$0.54	127
Electric	Grocery	Cooking	Combination Oven	60% cooking efficiency	Non ENERGY STAR	Per Building	Existing	622	12	$105	90%	90%	$0.02	112
Electric	Grocery	Cooking	Fryers - New CEE Efficient Electric Deep Fat Fryers	15 inch width Deep Fryer CEE 2006 rating: 80% under heavy load, Less than 1000 watt at idle	15 inch width standard electric deep fat fryers	Per Building	Existing	28	12	$38	35%	35%	$0.19	0.78
Electric	Grocery	Cooking	Griddle	70% cooking efficiency	Non ENERGY STAR	Per Building	Existing	321	12	$112	95%	35%	$0.04	23
Electric	Grocery	Cooking	Hot Food Holding Cabinet	ENERGY STAR Hot Food Holding Cabinet	Non ENERGY STAR Hot Food Holding Cabinet	Per Building	Existing	759	12	$484	55%	21%	$0.08	19
Electric	Grocery	Cooking	Steam Cooker	ENERGY STAR Steam Cooker	Non ENERGY STAR Steam Cooker	Per Building	Existing	237	12	$28	5.0%	35%	$0.01	1
Electric	Grocery	Cooling Dx	Commissioning of Existing Buildings	Existing Building Commissioning	Average Existing Conditions	Per Building	Existing	6,872	7	$6,308	90%	85%	$0.18	846
Electric	Grocery	Cooling Dx	DX Package-Air Side Economizer	Air-Side Economizer	No Economizer	Per Building	Existing	8,247	10	$18,145	10%	90%	$0.34	155
Electric	Grocery	Cooling Dx	Direct / Indirect Evaporative Cooling, Pre-Cooling	Evaporative Cooler	Standard DX cooling	Per Building	Existing	13,745	15	$66,664	50%	94%	$0.61	1,330
Electric	Grocery	Cooling Dx	Direct Digital Control System-Installation	DDC Retrofit (Morning Warm-Up Control Logic Included in This Measure)	Pneumatic	Per Building	Existing	8,247	5	$30,771	10%	61%	$0.93	91
Electric	Grocery	Cooling Dx	Direct Digital Control System-Wireless System	DDC Retrofit - Wireless System	Pneumatic	Per Building	Existing	8,247	5	$7,477	50%	80%	$0.23	474
Electric	Grocery	Cooling Dx	Duct Repair And Sealing	Reduction In Duct Losses to 5%	No Repair or Sealing, 15% duct losses	Per Building	Existing	1,374	18	$7,679	45%	65%	$0.65	69
Electric	Grocery	Cooling Dx	Economizer Tune-up	Economizer Tune-up	No Economizer Tune-Up	Per Building	Existing	5,498	5	$5,120	10%	75%	$0.23	85
Electric	Grocery	Cooling Dx	Exhaust Hood Makeup Air	Provide Makeup Air Directly at Exhaust Hood Instead of Pulling Conditioned Air	Hood Pulls Conditioned Air (No Make-up Air)	Per Building	Existing	657	10	$3,499	64%	85%	$0.83	228
Electric	Grocery	Cooling Dx	Green Roof	Vegetation on Roof	Standard Dark Colored Roof	Per Building	Existing	4,659	40	$74,689	3.5%	98%	$5.95	26
Electric	Grocery	Cooling Dx	Infiltration Reduction	Install Caulking And Weatherstripping (ACH 0.65)	Infiltration Conditions (ACH 1.0)	Per Building	Existing	2,096	12.5	$635	10%	39%	$0.04	13
Electric	Grocery	Cooling Dx	Insulation - Ceiling	R-30 c.i. (WA State Code)	R-7 (Average Existing Conditions)	Per Building	Existing	250	25	$48,345	75%	10%	$21.44	3
Electric	Grocery	Cooling Dx	Insulation - Ceiling	R-49 c.i.	R-38 c.i.	Per Building	Existing	2	25	$13,637	25%	85%	$551.15	0.09

Table B-2.2. Commercial Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Grocery	Cooling Dx	Insulation - Duct	R-7 (WA State Code)	No Insulation	Per Building	Existing	2,309	20	$6,192	75%	60%	$0.30	171
Electric	Grocery	Cooling Dx	Programmable Thermostat - Web Enabled	Programmable Thermostat - Web Enabled	No Programmable Thermostat	Per Building	Existing	1,649	10	$754	95%	31%	$0.07	77
Electric	Grocery	Cooling Dx	RE - Deciduous Trees	Shade Trees	No Trees	Per Building	Existing	52	30	$2,494	75%	55%	$5.03	3
Electric	Grocery	Cooling Dx	Window Film	Window Film	No Film	Per Building	Existing	4,267	10	$2,876	90%	66%	$0.10	3
Electric	Grocery	Cooling Dx	Windows-High Efficiency	U-0.32	U-0.40 (WA State Code)	Per Building	Existing	6,937	25	$55,125	15%	85%	$0.88	128
Electric	Grocery	Cooling Dx	Windows-High Efficiency	U-0.40 (WA State Code)	U-0.65 (Average Existing Conditions)	Per Building	Existing	6,071	25	$18,650	15%	85%	$2.17	110
Electric	Grocery	Heat Pump	Commissioning of Existing Buildings	Existing Building Commissioning	Average Existing Conditions	Per Building	Existing	18,273	7	$6,308	90%	85%	$0.06	526
Electric	Grocery	Heat Pump	Direct Digital Control System-Installation	DDC Retrofit (Morning Warm-Up Control Logic Included in This Measure)	Pneumatic	Per Building	Existing	21,928	5	$30,771	10%	61%	$0.35	59
Electric	Grocery	Heat Pump	Direct Digital Control System-Wireless System	DDC Retrofit - Wireless System	Pneumatic	Per Building	Existing	21,928	5	$7,477	50%	80%	$0.08	310
Electric	Grocery	Heat Pump	Duct Repair And Sealing	Reduction In Duct Losses to 5%	No Repair or Sealing, 15% duct losses	Per Building	Existing	3,654	18	$7,679	45%	65%	$0.24	45
Electric	Grocery	Heat Pump	Exhaust Air to Ventilation Air Heat Recovery	Exhaust Air Heat Recovery	No Heat Recovery	Per Building	Existing	13,968	14	$29,025	5.0%	94%	$0.27	27
Electric	Grocery	Heat Pump	Exhaust Hood Makeup Air	Provide Makeup Air Directly at Exhaust Hood Instead of Pulling Conditioned Air	Hood Pulls Conditioned Air (No Make-up Air)	Per Building	Existing	1,795	10	$3,499	64%	85%	$0.30	149
Electric	Grocery	Heat Pump	Green Roof	Vegetation on Roof	Standard Dark Colored Roof	Per Building	Existing	4,496	40	$74,689	3.5%	98%	$6.16	6
Electric	Grocery	Heat Pump	Ground Source Heat Pump > 135 kBTU/hr	High Efficiency Ground Source Heat Pump > 135 kBTU/hr	Water Source Heat Pump > 135 kBTU/hr	Per Building	Existing	7,206	15	$15,748	3.8%	95%	$7.33	8
Electric	Grocery	Heat Pump	Infiltration Reduction	Install Caulking And Weatherstripping (ACH 0.65)	Infiltration Conditions (ACH 1.0)	Per Building	Existing	10,649	12.5	$635	10%	39%	$0.00	16
Electric	Grocery	Heat Pump	Insulation - Ceiling	R-30 c.i. (WA State Code)	R-7 (Average Existing Conditions)	Per Building	Existing	21,873	25	$48,345	75%	10%	$0.24	66
Electric	Grocery	Heat Pump	Insulation - Ceiling	R-38 c.i.	R-30 c.i. (WA State Code)	Per Building	Existing	2,189	25	$48,345	75%	70%	$2.45	46
Electric	Grocery	Heat Pump	Insulation - Ceiling	R-49 c.i.	R-38 c.i.	Per Building	Existing	1,272	25	$13,637	25%	85%	$1.18	10
Electric	Grocery	Heat Pump	Insulation - Duct	R-7 (WA State Code)	No Insulation	Per Building	Existing	6,139	20	$6,192	75%	60%	$0.11	109
Electric	Grocery	Heat Pump	Insulation - Floor (non-slab)	R-30 (WA State Code)	R-11 (Average Existing Conditions)	Per Building	Existing	16,614	25	$25,490	35%	45%	$0.16	101
Electric	Grocery	Heat Pump	Insulation - Floor (non-slab)	R-38	R-30 (WA State Code)	Per Building	Existing	3,236	25	$7,862	35%	45%	$0.26	19
Electric	Grocery	Heat Pump	Insulation - Wall	R-16	R-3 (Average Existing Conditions)	Per Building	Existing	18,069	25	$27,368	10%	35%	$0.16	24
Electric	Grocery	Heat Pump	Programmable Thermostat - Web Enabled	Programmable Thermostat - Web Enabled	No Programmable Thermostat	Per Building	Existing	4,385	10	$754	95%	31%	$0.02	48
Electric	Grocery	Heat Pump	RE - Deciduous Trees	Shade Trees	No Trees	Per Building	Existing	253	30	$5,313	75%	55%	$2.21	3
Electric	Grocery	Heat Pump	Variable Refrigerant Flow Cooling System	Variable Refrigerant Flow Cooling System	Standard Refrigeration System	Per Building	Existing	39,470	15	$7,807	25%	95%	$0.02	418
Electric	Grocery	Heat Pump	Window Film	Window Film	No Film	Per Building	Existing	4,267	10	$2,876	90%	66%	$0.10	0.86
Electric	Grocery	Heat Pump	Windows-High Efficiency	U-0.32	U-0.40 (WA State Code)	Per Building	Existing	3,168	25	$55,125	15%	85%	$1.93	13
Electric	Grocery	Heat Pump	Windows-High Efficiency	U-0.40 (WA State Code)	U-0.65 (Average Existing Conditions)	Per Building	Existing	6,742	25	$18,650	15%	85%	$1.95	29
Electric	Grocery	Lighting Exterior	Covered Parking Lighting	Covered Parking Lighting	Normal Lighting	Per Building	Existing	2,997	9.5	$834	20%	95%	$0.03	238
Electric	Grocery	Lighting Exterior	Daylighting Controls, Outdoors (Photocell)	Photocell	No Controls	Per Building	Existing	1,172	8	$179	75%	70%	$0.02	150

Table B-2.2. Commercial Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Grocery	Lighting Exterior	Occupancy Sensor Control	Occupancy Sensor Control	No Occupancy Sensor	Per Building	Existing	3,057	8	$545	90%	75%	$0.03	799
Electric	Grocery	Lighting Exterior	Solid State LED White Lighting	Landscape, merchandise, signage, structure & task lighting (2.5 W)	50W 10hrs/day, 365 day/yr	Per Building	Existing	1,141	13.69863	$227	75%	95%	$0.02	22
Electric	Grocery	Lighting Exterior	Surface Parking Lighting	Surface Parking Lighting	Normal Lighting	Per Building	Existing	1,619	18.666667	$2,186	47%	95%	$0.15	285
Electric	Grocery	Lighting Exterior	Time Clock	Time Clock	No Controls	Per Building	Existing	1,638	8	$449	10%	81%	$0.04	47
Electric	Grocery	Lighting Interior Fluorescent	Bi-Level Control, Stairwell Lighting	Occupancy Sensor Control, 50% Lighting Power during unoccupied Time	Continuous Full Power Lighting in Stairways	Per Building	Existing	5,156	9	$1,720	75%	75%	$0.05	884
Electric	Grocery	Lighting Interior Fluorescent	Dimming-Continuous, Fluorescent Fixtures	Continuous Dimming, Fluorescent Fixtures (Day-Lighting)	No Dimming Controls	Per Building	Existing	13,562	8	$13,172	30%	96%	$0.17	1,343
Electric	Grocery	Lighting Interior Fluorescent	LED Refrigeration Case Lights	LED Refrigeration Case Lights	Fluorescent Refrigeration Case	Per Building	Existing	40,036	6	$14,857	95%	80%	$0.06	13,222
Electric	Grocery	Lighting Interior Fluorescent	Occupancy Sensor Control	Occupancy Sensor Control	No Occupancy Sensor	Per Building	Existing	20,569	8	$2,725	45%	57%	$0.02	1,717
Electric	Grocery	Lighting Interior Fluorescent	Time Clock	Time Clock	No Controls	Per Building	Existing	11,019	8	$3,011	10%	81%	$0.04	295
Electric	Grocery	Lighting Interior Hid	Occupancy Sensor Control	Occupancy Sensor Control	No Occupancy Sensor	Per Building	Existing	2,948	8	$2,725	45%	57%	$0.16	270
Electric	Grocery	Lighting Interior Hid	Time Clock	Time Clock	No Controls	Per Building	Existing	1,579	8	$433	10%	81%	$0.04	46
Electric	Grocery	Lighting Interior Other	Exit Sign - LED	Two Sided LED Exit Sign (5 Watts)	CFL Exit Sign (9 Watts)	Per Building	Existing	1,063	16	$176	95%	50%	$0.01	201
Electric	Grocery	Lighting Interior Other	Exit Sign - Photoluminescent or Tritium	Photoluminescent or Tritium	Two Sided LED Exit Sign (5 Watts)	Per Building	Existing	386	13	$330	95%	98%	$0.11	143
Electric	Grocery	Lighting Interior Screw Base	Cold Cathode Lighting	Cold Cathode Lighting 5 watts	30 W Incandescent Bulb	Per Building	Existing	149	5	$9	70%	94%	$0.01	14
Electric	Grocery	Lighting Interior Screw Base	Occupancy Sensor Control	Occupancy Sensor Control	No Occupancy Sensor	Per Building	Existing	3,267	8	$2,725	45%	57%	$0.14	114
Electric	Grocery	Lighting Interior Screw Base	Time Clock	Time Clock	No Controls	Per Building	Existing	1,750	8	$478	10%	81%	$0.04	19
Electric	Grocery	Other Plug Load	ENERGY STAR - Battery Charging System	ENERGY STAR Battery Charging System	Non-ENERGY STAR Battery Chargers	Per Building	Existing	27	7	$9	20%	20%	$0.06	0.44
Electric	Grocery	Other Plug Load	ENERGY STAR - Water Cooler	ENERGY STAR Water Cooler (Hot/Cold Water)	Non-ENERGY STAR Water Cooler	Per Building	Existing	63	10	$3	95%	20%	$0.00	4
Electric	Grocery	Other Plug Load	Power Supply Transformer/Converter	80 Plus	85% efficient power supply (> 51W)	Per Building	Existing	440	4	$3	95%	86%	$-0.00	30
Electric	Grocery	Other Plug Load	Scanner - ENERGY STAR	ENERGY STAR Scanners	Standard Scanner	Per Building	Existing	16	6	$0.00	95%	20%	$-0.01	1
Electric	Grocery	Other Plug Load	Smart Strips	Smart Strip Power Strip	Standard surge protector	Per Building	Existing	640	4	$163	60%	90%	$0.07	137
Electric	Grocery	Refrigeration	Add Doors to Refrigerated Open Display Cases	Add Doors to Refrigerated Open Display Cases	Standard Refrigerated Open Display Cases	Per Building	Existing	22,142	12	$34,328	15%	95%	$0.22	1,258
Electric	Grocery	Refrigeration	Anti-Sweat (Humidistat) Controls	Anti-Sweat (Humidistat) Controls	No Anti-Sweat (Humidistat) Controls	Per Building	Existing	31,296	12	$2,687	90%	45%	$0.01	5,054
Electric	Grocery	Refrigeration	Case Electronically Commutated Motor	ECM Case Fans	Standard Efficiency Motor	Per Building	Existing	14,486	15	$3,518	100%	77%	$0.02	4,419

Table B-2.2. Commercial Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Grocery	Refrigeration	Case Replacement Low Temp	Case Replacement Low Temp	No replacement	Per Building	Existing	31,278	15	$3,386	100%	98%	$0.01	12,223
Electric	Grocery	Refrigeration	Case Replacement Med Temp	Case Replacement Med Temp	No replacement	Per Building	Existing	2,667	15	$1,756	100%	98%	$0.08	1,042
Electric	Grocery	Refrigeration	Commercial Refrigerator - Semivertical - No Doors - Med Temp	Commercial Refrigerator - Semivertical - No Doors - Med Temp	Standard Case	Per Building	Existing	32,195	10	$26,704	90%	85%	$0.12	9,821
Electric	Grocery	Refrigeration	Commercial Refrigerator - Vertical - No Doors - Med Temp	Commercial Refrigerator - Vertical - No Doors - Med Temp	Standard Case	Per Building	Existing	14,570	10	$12,067	90%	85%	$0.12	4,444
Electric	Grocery	Refrigeration	Compressor VSD Retrofit	VSD Compressor	Constant Speed Compressor	Per Building	Existing	72,351	13	$14,234	60%	77%	$0.02	11,340
Electric	Grocery	Refrigeration	Demand Control Defrost - Hot Gas	Refrigerant Defrost	Defrost - Electric	Per Building	Existing	8,397	10	$115	95%	68%	$-0.00	2,147
Electric	Grocery	Refrigeration	Display Case Motion Sensors	Display Case Motion Sensors	No Motion Sensors	Per Building	Existing	7,747	8	$757	90%	85%	$0.01	1,900
Electric	Grocery	Refrigeration	Evaporative Condenser - High-Efficiency	High-Efficiency Evaporative Condenser	Air-Cooled Condenser	Per Building	Existing	4,673	15	$22,986	90%	65%	$0.62	1,085
Electric	Grocery	Refrigeration	Evaporator Fan Controller	ECM Evaporator Fan Controller	No Controller	Per Building	Existing	491	15	$545	90%	85%	$0.13	118
Electric	Grocery	Refrigeration	Floating Condenser Head Pressure Controls	Floating Condenser Head Pressure Controls	No Floating Condenser Head Pressure Controls	Per Building	Existing	22,159	15	$7,538	50%	81%	$0.04	2,824
Electric	Grocery	Refrigeration	Glass Door ENERGY STAR Refrigerators/Freezers	Glass Door ENERGY STAR Refrigerators/Freezers	Standard Glass Doors	Per Building	Existing	477	12	$452	95%	77%	$0.13	138
Electric	Grocery	Refrigeration	High-Efficiency Compressor	High-Efficiency Compressor (15% More Efficient)	Standard Compressor, 40% Efficiency	Per Building	Existing	23,137	10	$15,037	85%	72%	$0.10	10,371
Electric	Grocery	Refrigeration	Ice Maker	High-Efficiency Ice Maker	Standard Ice Maker	Per Building	Existing	857	10	$0.00	95%	86%	$-0.02	277
Electric	Grocery	Refrigeration	Night Covers for Display Cases	Night Covers for Display Cases	No Night Covers	Per Building	Existing	20,822	5	$3,319	95%	85%	$0.04	6,704
Electric	Grocery	Refrigeration	Refrigeration Commissioning of New or Existing Buildings	New or Existing Building Refrigeration Commissioning	No Commissioning	Per Building	Existing	43,520	3	$6,825	95%	85%	$0.06	10,022
Electric	Grocery	Refrigeration	Refrigerator eCube	Refrigerator eCube	No Refrigerator eCube	Per Building	Existing	259	10	$57	75%	95%	$0.03	2,110
Electric	Grocery	Refrigeration	Solid Door ENERGY STAR Refrigerators/Freezers	Solid Door ENERGY STAR Refrigerators/Freezers	Standard Solid Door	Per Building	Existing	1,503	12	$-353.1453	95%	81%	$-0.04	459
Electric	Grocery	Refrigeration	Standalone to Multiplex Compressor	Standalone to Multiplex Compressor	Standalone compressor	Per Building	Existing	19,675	13	$2,812	80%	90%	$0.01	3,752
Electric	Grocery	Refrigeration	Strip Curtains for Walk-Ins	Strip Curtains for Walk-Ins	No Strip Curtains for Walk-In	Per Building	Existing	819	4	$25	95%	20%	$0.01	62
Electric	Grocery	Refrigeration	VFD Rooftop Unit Supply Fan (Grocery Only)	VFD Rooftop Unit Supply Fan (Grocery Only)	Standard Supply Fan	Per Building	Existing	7,331	15	$2,234	90%	75%	$0.03	1,281
Electric	Grocery	Refrigeration	Visi Cooler	High Efficiency Visi Cooler	Standard Visi Cooler	Per Building	Existing	995	10	$186	95%	85%	$0.02	320
Electric	Grocery	Refrigeration	Walk-In Electronically Commutated Motor	ECM Evaporator Fans	Standard Efficiency Motor	Per Building	Existing	491	15	$545	95%	95%	$0.13	176
Electric	Grocery	Refrigeration	Water Cooled Refrigeration with Heat Recovery	Heat Recovery from refrigeration system. Applied to Water Heating Electric End use	No heat recovery	Per Building	Existing	73,643	10	$29,121	2.5%	94%	$0.06	443
Electric	Grocery	Refrigerator	Residential Refrigerator/Freezer Recycling	Recycling Existing Refrigerator/Freezer	Existing Refrigerator/Freezer	Per Building	Existing	481	9	$128	25%	100%	$0.04	41

Table B-2.2. Commercial Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Grocery	Space Heat	Commissioning of Existing Buildings	Existing Building Commissioning	Average Existing Conditions	Per Building	Existing	8,572	7	$6,308	90%	85%	$0.14	170
Electric	Grocery	Space Heat	Direct Digital Control System-Installation	DDC Retrofit (Morning Warm-Up Control Logic Included in This Measure)	Pneumatic	Per Building	Existing	10,287	5	$30,771	10%	61%	$0.74	20
Electric	Grocery	Space Heat	Direct Digital Control System-Wireless System	DDC Retrofit - Wireless System	Pneumatic	Per Building	Existing	10,287	5	$7,477	50%	80%	$0.17	105
Electric	Grocery	Space Heat	Duct Repair And Sealing	Reduction In Duct Losses to 5%	No Repair or Sealing, 15% duct losses	Per Building	Existing	1,714	18	$7,679	45%	65%	$0.51	15
Electric	Grocery	Space Heat	Economizer Tune-up	Economizer Tune-up	No Economizer Tune-Up	Per Building	Existing	6,858	5	$5,120	10%	75%	$0.18	16
Electric	Grocery	Space Heat	Exhaust Air to Ventilation Air Heat Recovery	Exhaust Air Heat Recovery	No Heat Recovery	Per Building	Existing	10,287	14	$29,025	5.0%	94%	$0.36	14
Electric	Grocery	Space Heat	Exhaust Hood Makeup Air	Provide Makeup Air Directly at Exhaust Hood Instead of Pulling Conditioned Air	Hood Pulls Conditioned Air (No Make-up Air)	Per Building	Existing	767	10	$3,499	64%	85%	$0.70	50
Electric	Grocery	Space Heat	Infiltration Reduction	Install Caulking And Weatherstripping (ACH 0.65)	Infiltration Conditions (ACH 1.0)	Per Building	Existing	5,229	12.5	$635	10%	39%	$0.01	5
Electric	Grocery	Space Heat	Insulation - Ceiling	R-30 c.i. (WA State Code)	R-7 (Average Existing Conditions)	Per Building	Existing	16,000	25	$48,345	75%	10%	$0.32	35
Electric	Grocery	Space Heat	Insulation - Ceiling	R-38 c.i.	R-30 c.i. (WA State Code)	Per Building	Existing	1,476	25	$48,345	75%	70%	$3.63	22
Electric	Grocery	Space Heat	Insulation - Ceiling	R-49 c.i.	R-38 c.i.	Per Building	Existing	1,427	25	$13,637	25%	85%	$1.05	8
Electric	Grocery	Space Heat	Insulation - Duct	R-7 (WA State Code)	No Insulation	Per Building	Existing	2,880	20	$6,192	75%	60%	$0.23	36
Electric	Grocery	Space Heat	Insulation - Floor (non-slab)	R-30 (WA State Code)	R-11 (Average Existing Conditions)	Per Building	Existing	15,803	25	$25,490	35%	45%	$0.17	68
Electric	Grocery	Space Heat	Insulation - Floor (non-slab)	R-38	R-30 (WA State Code)	Per Building	Existing	2,941	25	$7,862	35%	45%	$0.29	12
Electric	Grocery	Space Heat	Insulation - Wall	R-16	R-3 (Average Existing Conditions)	Per Building	Existing	30,748	25	$27,368	10%	35%	$0.09	28
Electric	Grocery	Space Heat	Programmable Thermostat - Web Enabled	Programmable Thermostat - Web Enabled	No Programmable Thermostat	Per Building	Existing	2,057	10	$754	95%	31%	$0.05	15
Electric	Grocery	Space Heat	Windows-High Efficiency	U-0.40 (WA State Code)	U-0.65 (Average Existing Conditions)	Per Building	Existing	514	25	$18,650	15%	85%	$25.63	1
Electric	Grocery	Vending Machines	Vending Miser	Passive Infrared Sensor on Vending Machine Monitoring Vacancy of Area And Cycles Cooling - Controls	No Vending Miser - No controls	Per Building	Existing	1,796	3	$170	75%	25%	$0.03	31
Electric	Grocery	Ventilation And Circulation	Automated Exhaust VFD Control - Parking Garage CO sensor	CO Sensors	No CO Sensors	Per Building	Existing	36,173	10	$3,923	5.0%	85%	$0.01	202
Electric	Grocery	Ventilation And Circulation	Cooking Hood Controls	Demand-Ventilation Control	No Controls	Per Building	Existing	1,119	18	$2,401	95%	65%	$0.24	240
Electric	Grocery	Ventilation And Circulation	Motor - CEE Premium-Efficiency Plus	CEE PE+ Motor for HVAC Applications	NEMA Efficiency Motors	Per Building	Existing	699	15	$211	95%	76%	$0.03	171
Electric	Grocery	Ventilation And Circulation	Motor - Pump & Fan System - Variable Speed Control	Pump And Fan System Optimization w/ VSD	No Pump And Fan System VSD Optimization	Per Building	Existing	17,484	20	$3,563	65%	75%	$0.01	2,889
Electric	Grocery	Ventilation And Circulation	Motor Rewind	>15, <500 HP	No Rewind	Per Building	Existing	565	7	$160	65%	25%	$0.05	27
Electric	Grocery	Water Heat GT 55 Gal	Demand Controlled Circulating Systems	Demand Controlled Circulating Systems (VFD control by demand)	Constant Circulation	Per Building	Existing	485	10	$8,889	75%	94%	$2.85	20

Table B-2.2. Commercial Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Grocery	Water Heat GT 55 Gal	Dishwasher Residential	RTF ENERGY STAR Dishwasher - 277 kWh/yr and 4.25 gal/cycle	RTF Market Standard 2014 Dishwasher - 289 kWh/yr and 5.0 gal/cycle	Per Building	Existing	14	12	$44	24%	25%	$0.45	0.05
Electric	Grocery	Water Heat GT 55 Gal	Dishwashing - Commercial - High Temp	High Efficiency Dishwasher (ENERGY STAR)	Standard High Temp Commercial Dishwasher	Per Building	Existing	74	12	$44	95%	95%	$-4.35	3
Electric	Grocery	Water Heat GT 55 Gal	Drainwater Heat Recovery Water Heater	Install (Power-Pipe or GFX) - Heat Recovery Water Heater	No Heat Recovery System	Per Building	Existing	1,932	25	$8,331	5.0%	92%	$0.47	5
Electric	Grocery	Water Heat GT 55 Gal	Low-Flow Faucet Aerators	0.5 GPM	2.2 GPM (Federal Code)	Per Building	Existing	375	9	$12	95%	75%	$-0.01	15
Electric	Grocery	Water Heat GT 55 Gal	Low-Flow Faucet Aerators	2.2 GPM (Federal Code)	3.0 GPM	Per Building	Existing	129	9	$9	95%	25%	$-0.01	1
Electric	Grocery	Water Heat GT 55 Gal	Low-Flow Pre-Rinse Spray Valves	0.6 GPM	1.6 GPM (Federal Standard)	Per Building	Existing	644	4	$195	95%	74%	$0.08	26
Electric	Grocery	Water Heat GT 55 Gal	Pipe Insulation - Hot Water (DWH)	1.0" of Insulation, assuming R-4 (WA State Code)	No Insulation	Per Building	Existing	97	12	$102	80%	90%	$0.15	3
Electric	Grocery	Water Heat GT 55 Gal	Ultrasonic Faucet Control	Install Ultrasonic Motion Faucet Control	No Faucet Control	Per Building	Existing	242	10	$882	75%	95%	$0.54	10
Electric	Grocery	Water Heat GT 55 Gal	Water Cooled Refrigeration with Heat Recovery	Heat Recovery from refrigeration system. Applied to Water Heating Electric End use	No heat recovery	Per Building	Existing	1,106	10	$29,121	55%	94%	$4.10	29
Electric	Grocery	Water Heat LE 55 Gal	Demand Controlled Circulating Systems	Demand Controlled Circulating Systems (VFD control by demand)	Constant Circulation	Per Building	Existing	476	10	$8,889	75%	94%	$2.91	19
Electric	Grocery	Water Heat LE 55 Gal	Dishwasher Residential	RTF ENERGY STAR Dishwasher - 277 kWh/yr and 4.25 gal/cycle	RTF Market Standard 2014 Dishwasher - 289 kWh/yr and 5.0 gal/cycle	Per Building	Existing	14	12	$44	24%	25%	$0.45	0.04
Electric	Grocery	Water Heat LE 55 Gal	Dishwashing - Commercial - High Temp	High Efficiency Dishwasher (ENERGY STAR)	Standard High Temp Commercial Dishwasher	Per Building	Existing	73	12	$41	95%	95%	$-4.43	3
Electric	Grocery	Water Heat LE 55 Gal	Drainwater Heat Recovery Water Heater	Install (Power-Pipe or GFX) - Heat Recovery Water Heater	No Heat Recovery System	Per Building	Existing	1,932	25	$8,331	5.0%	92%	$0.47	4
Electric	Grocery	Water Heat LE 55 Gal	Low-Flow Faucet Aerators	0.5 GPM	2.2 GPM (Federal Code)	Per Building	Existing	368	9	$12	95%	75%	$-0.01	15
Electric	Grocery	Water Heat LE 55 Gal	Low-Flow Faucet Aerators	2.2 GPM (Federal Code)	3.0 GPM	Per Building	Existing	127	9	$9	95%	25%	$-0.01	1
Electric	Grocery	Water Heat LE 55 Gal	Low-Flow Pre-Rinse Spray Valves	0.6 GPM	1.6 GPM (Federal Standard)	Per Building	Existing	644	4	$195	95%	74%	$0.08	26
Electric	Grocery	Water Heat LE 55 Gal	Pipe Insulation - Hot Water (DWH)	1.0" of Insulation, assuming R-4 (WA State Code)	No Insulation	Per Building	Existing	95	12	$102	80%	90%	$0.15	3
Electric	Grocery	Water Heat LE 55 Gal	Ultrasonic Faucet Control	Install Ultrasonic Motion Faucet Control	No Faucet Control	Per Building	Existing	238	10	$882	75%	95%	$0.55	9
Electric	Grocery	Water Heat LE 55 Gal	Water Cooled Refrigeration with Heat Recovery	Heat Recovery from refrigeration system. Applied to Water Heating Electric End use	No heat recovery	Per Building	Existing	1,087	10	$29,121	55%	94%	$4.18	28
Electric	Hospital	Computers	Network PC Power Management	Network PC Power Management	No Power Management	Per Building	Existing	3,077	4	$270	95%	30%	$0.02	1,344
Electric	Hospital	Cooking	Combination Oven	60% cooking efficiency	Non ENERGY STAR	Per Building	Existing	47	12	$8	90%	90%	$0.02	19

Table B-2.2. Commercial Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Hospital	Cooking	Fryers - New CEE Efficient Electric Deep Fat Fryers	15 inch width Deep Fryer CEE 2006 rating: 80% under heavy load, Less than 1000 watt at idle	15 inch width standard electric deep fat fryers	Per Building	Existing	2	12	$3	25%	35%	$0.22	0.10
Electric	Hospital	Cooking	Griddle	70% cooking efficiency	Non ENERGY STAR	Per Building	Existing	65	12	$22	95%	35%	$0.04	12
Electric	Hospital	Cooking	High Efficiency Convection Oven	Convection Oven	Standard Oven	Per Building	Existing	62	12	$11	7.0%	55%	$0.02	1
Electric	Hospital	Cooking	Hot Food Holding Cabinet	ENERGY STAR Hot Food Holding Cabinet	Non ENERGY STAR Hot Food Holding Cabinet	Per Building	Existing	153	12	$98	15%	21%	$0.09	2
Electric	Hospital	Cooking	Steam Cooker	ENERGY STAR Steam Cooker	Non ENERGY STAR Steam Cooker	Per Building	Existing	48	12	$5	5.0%	35%	$0.01	0.85
Electric	Hospital	Cooling Chillers	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	Demand Controlled Ventilation (CO2 sensors)	Constant Ventilation	Per Building	Existing	2,631	15	$4,249	5.0%	94%	$0.20	41
Electric	Hospital	Cooling Chillers	Chilled Water / Condenser Water Settings-Optimization	Additional Control Features	EMS already installed - No Optimization	Per Building	Existing	328	5	$2,896	95%	81%	$2.20	83
Electric	Hospital	Cooling Chillers	Chilled Water Piping Loop w/ VSD Control	VSD for secondary chilled water loop	Primary loop only w/ constant speed pump	Per Building	Existing	1,989	10	$13,368	25%	70%	$1.04	114
Electric	Hospital	Cooling Chillers	Chiller-Water Side Economizer	Install Economizer	No Economizer	Per Building	Existing	1,315	15	$31,039	45%	90%	$3.00	172
Electric	Hospital	Cooling Chillers	Commissioning of Existing Buildings	Existing Building Commissioning	Average Existing Conditions	Per Building	Existing	3,289	7	$3,352	90%	85%	$0.20	649
Electric	Hospital	Cooling Chillers	Convert Constant Volume Air System to VAV	Variable Volume Air System	Constant Volume Air System	Per Building	Existing	7,894	15	$51,680	15%	67%	$0.83	252
Electric	Hospital	Cooling Chillers	Cooling Tower-Decrease Approach Temperature	6 Deg F	10 Deg F	Per Building	Existing	2,105	7.5	$1,652	10%	94%	$0.10	64
Electric	Hospital	Cooling Chillers	Cooling Tower-Two-Speed Fan Motor	Cooling Tower-Two-Speed Fan Motor	Cooling Tower-One-Speed Fan Motor	Per Building	Existing	3,684	15	$148	75%	35%	$-0.00	295
Electric	Hospital	Cooling Chillers	Cooling Tower-VSD Fan Control	Variable-Speed Tower Fans replace Two-Speed	Cooling Tower-Two-Speed Fan Motor	Per Building	Existing	1,052	13	$1,196	75%	75%	$0.15	174
Electric	Hospital	Cooling Chillers	Direct Digital Control System-Installation	DDC Retrofit (Morning Warm-Up Control Logic Included in This Measure)	Pneumatic	Per Building	Existing	3,947	5	$16,345	20%	26%	$1.03	58
Electric	Hospital	Cooling Chillers	Direct Digital Control System-Wireless System	DDC Retrofit - Wireless System	Pneumatic	Per Building	Existing	3,947	5	$3,971	75%	80%	$0.25	496
Electric	Hospital	Cooling Chillers	Exhaust Hood Makeup Air	Provide Makeup Air Directly at Exhaust Hood Instead of Pulling Conditioned Air	Hood Pulls Conditioned Air (No Make-up Air)	Per Building	Existing	1,461	10	$3,500	62%	85%	$0.37	165
Electric	Hospital	Cooling Chillers	Green Roof	Vegetation on Roof	Standard Dark Colored Roof	Per Building	Existing	1,590	40	$4,066	3.5%	98%	$6.61	14
Electric	Hospital	Cooling Chillers	Infiltration Reduction	Install Caulking And Weatherstripping (ACH 0.65)	Infiltration Conditions (ACH 1.0)	Per Building	Existing	1,315	12.5	$440	10%	39%	$0.04	13
Electric	Hospital	Cooling Chillers	Insulation - Ceiling	R-30 c.i. (WA State Code)	R-11 (Average Existing Conditions)	Per Building	Existing	60	25	$18,315	75%	13%	$33.86	1
Electric	Hospital	Cooling Chillers	Insulation - Ceiling	R-49 c.i.	R-38 c.i.	Per Building	Existing	1	25	$5,166	25%	85%	$436.22	0.07
Electric	Hospital	Cooling Chillers	Pipe Insulation - Chilled Water	1.5" of Insulation, assuming R-6 (WA State Code)	No Insulation	Per Building	Existing	394	15	$348	65%	45%	$0.11	29

Table B-2.2. Commercial Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Hospital	Cooling Chillers	Programmable Thermostat - Web Enabled	Programmable Thermostat - Web Enabled	No Programmable Thermostat	Per Building	Existing	789	10	$1,053	15%	26%	$0.20	7
Electric	Hospital	Cooling Chillers	RE - Deciduous Trees	Shade Trees	No Trees	Per Building	Existing	212	30	$3,010	75%	55%	$1.50	22
Electric	Hospital	Cooling Chillers	Sensible And Total Heat Recovery Devices	Install Heat Recovery Devices - rotary air-to-air enthalpy heat recovery- 50% sensible and latent recovery effectiveness	No Heat Recovery	Per Building	Existing	7,885	10	$35,871	25%	98%	$0.71	374
Electric	Hospital	Cooling Chillers	Window Film	Window Film	No Film	Per Building	Existing	2,854	10	$1,991	90%	66%	$0.10	3
Electric	Hospital	Cooling Chillers	Windows-High Efficiency	U-0.32	U-0.40 (WA State Code)	Per Building	Existing	3,320	25	$38,170	15%	60%	$1.27	65
Electric	Hospital	Cooling Chillers	Windows-High Efficiency	U-0.40 (WA State Code)	U-0.67 (Average Existing Conditions)	Per Building	Existing	2,844	25	$82,156	15%	60%	$3.20	55
Electric	Hospital	Cooling Dx	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	Demand Controlled Ventilation (CO2 sensors)	Constant Ventilation	Per Building	Existing	3,214	15	$4,249	5.0%	94%	$0.16	115
Electric	Hospital	Cooling Dx	Commissioning of Existing Buildings	Existing Building Commissioning	Average Existing Conditions	Per Building	Existing	4,018	7	$3,352	90%	85%	$0.16	1,729
Electric	Hospital	Cooling Dx	Convert Constant Volume Air System to VAV	Variable Volume Air System	Constant Volume Air System	Per Building	Existing	9,644	15	$51,680	15%	67%	$0.68	741
Electric	Hospital	Cooling Dx	DX Package-Air Side Economizer	Air-Side Economizer	No Economizer	Per Building	Existing	4,822	10	$9,638	10%	30%	$0.31	106
Electric	Hospital	Cooling Dx	Direct / Indirect Evaporative Cooling, Pre-Cooling	Evaporative Cooler	Standard DX cooling	Per Building	Existing	8,036	15	$35,416	50%	94%	$0.55	2,761
Electric	Hospital	Cooling Dx	Direct Digital Control System-Installation	DDC Retrofit (Morning Warm-Up Control Logic Included in This Measure)	Pneumatic	Per Building	Existing	4,822	5	$16,345	20%	26%	$0.85	160
Electric	Hospital	Cooling Dx	Direct Digital Control System-Wireless System	DDC Retrofit - Wireless System	Pneumatic	Per Building	Existing	4,822	5	$3,971	75%	80%	$0.20	1,357
Electric	Hospital	Cooling Dx	Duct Repair And Sealing	Reduction In Duct Losses to 5%	No Repair or Sealing, 15% duct losses	Per Building	Existing	803	18	$4,079	45%	65%	$0.59	141
Electric	Hospital	Cooling Dx	Economizer Tune-up	Economizer Tune-up	No Economizer Tune-Up	Per Building	Existing	3,214	5	$2,721	10%	75%	$0.21	177
Electric	Hospital	Cooling Dx	Exhaust Hood Makeup Air	Provide Makeup Air Directly at Exhaust Hood Instead of Pulling Conditioned Air	Hood Pulls Conditioned Air (No Make-up Air)	Per Building	Existing	1,592	10	$3,500	62%	85%	$0.34	448
Electric	Hospital	Cooling Dx	Green Roof	Vegetation on Roof	Standard Dark Colored Roof	Per Building	Existing	1,942	40	$4,066	3.5%	98%	$5.41	38
Electric	Hospital	Cooling Dx	Infiltration Reduction	Install Caulking And Weatherstripping (ACH 0.65)	Infiltration Conditions (ACH 1.0)	Per Building	Existing	1,607	12.5	$440	10%	39%	$0.03	36
Electric	Hospital	Cooling Dx	Insulation - Ceiling	R-30 c.i. (WA State Code)	R-11 (Average Existing Conditions)	Per Building	Existing	73	25	$18,315	75%	13%	$27.72	4
Electric	Hospital	Cooling Dx	Insulation - Ceiling	R-49 c.i.	R-38 c.i.	Per Building	Existing	1	25	$5,166	25%	85%	$357.10	0.19
Electric	Hospital	Cooling Dx	Insulation - Duct	R-7 (WA State Code)	No Insulation	Per Building	Existing	1,350	20	$3,289	75%	60%	$0.27	350
Electric	Hospital	Cooling Dx	Programmable Thermostat - Web Enabled	Programmable Thermostat - Web Enabled	No Programmable Thermostat	Per Building	Existing	964	10	$1,053	95%	24%	$0.17	122
Electric	Hospital	Cooling Dx	RE - Deciduous Trees	Shade Trees	No Trees	Per Building	Existing	144	30	$2,271	75%	55%	$1.66	33
Electric	Hospital	Cooling Dx	Window Film	Window Film	No Film	Per Building	Existing	2,854	10	$1,991	90%	66%	$0.10	8
Electric	Hospital	Cooling Dx	Windows-High Efficiency	U-0.32	U-0.40 (WA State Code)	Per Building	Existing	4,056	25	$38,170	15%	60%	$1.04	185

Table B-2.2. Commercial Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Hospital	Cooling Dx	Windows-High Efficiency	U-0.40 (WA State Code)	U-0.67 (Average Existing Conditions)	Per Building	Existing	3,474	25	$82,156	15%	60%	$2.62	156
Electric	Hospital	Heat Pump	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	Demand Controlled Ventilation (CO2 sensors)	Constant Ventilation	Per Building	Existing	3,162	15	$4,249	5.0%	94%	$0.16	14
Electric	Hospital	Heat Pump	Commissioning of Existing Buildings	Existing Building Commissioning	Average Existing Conditions	Per Building	Existing	7,706	7	$3,352	90%	85%	$0.08	478
Electric	Hospital	Heat Pump	Convert Constant Volume Air System to VAV	Variable Volume Air System	Constant Volume Air System	Per Building	Existing	9,863	15	$51,680	15%	67%	$0.66	96
Electric	Hospital	Heat Pump	Direct Digital Control System-Installation	DDC Retrofit (Morning Warm-Up Control Logic Included in This Measure)	Pneumatic	Per Building	Existing	9,247	5	$16,345	20%	26%	$0.44	45
Electric	Hospital	Heat Pump	Direct Digital Control System-Wireless System	DDC Retrofit - Wireless System	Pneumatic	Per Building	Existing	9,247	5	$3,971	75%	80%	$0.10	385
Electric	Hospital	Heat Pump	Duct Repair And Sealing	Reduction In Duct Losses to 5%	No Repair or Sealing, 15% duct losses	Per Building	Existing	1,541	18	$4,079	45%	65%	$0.30	40
Electric	Hospital	Heat Pump	Exhaust Air to Ventilation Air Heat Recovery	Exhaust Air Heat Recovery	No Heat Recovery	Per Building	Existing	4,503	14	$15,419	5.0%	94%	$0.44	18
Electric	Hospital	Heat Pump	Exhaust Hood Makeup Air	Provide Makeup Air Directly at Exhaust Hood Instead of Pulling Conditioned Air	Hood Pulls Conditioned Air (No Make-up Air)	Per Building	Existing	3,132	10	$3,500	62%	85%	$0.17	127
Electric	Hospital	Heat Pump	Green Roof	Vegetation on Roof	Standard Dark Colored Roof	Per Building	Existing	1,911	40	$4,066	3.5%	98%	$5.49	5
Electric	Hospital	Heat Pump	Ground Source Heat Pump > 135 kBTU/hr	High Efficiency Ground Source Heat Pump > 135 kBTU/hr	Water Source Heat Pump > 135 kBTU/hr	Per Building	Existing	4,295	15	$20,863	3.8%	95%	$6.53	11
Electric	Hospital	Heat Pump	Infiltration Reduction	Install Caulking And Weatherstripping (ACH 0.65)	Infiltration Conditions (ACH 1.0)	Per Building	Existing	4,503	12.5	$440	10%	39%	$0.01	14
Electric	Hospital	Heat Pump	Insulation - Ceiling	R-30 c.i. (WA State Code)	R-11 (Average Existing Conditions)	Per Building	Existing	4,510	25	$18,315	75%	13%	$0.44	37
Electric	Hospital	Heat Pump	Insulation - Ceiling	R-38 c.i.	R-30 c.i. (WA State Code)	Per Building	Existing	607	25	$18,315	75%	70%	$3.34	26
Electric	Hospital	Heat Pump	Insulation - Ceiling	R-49 c.i.	R-38 c.i.	Per Building	Existing	351	25	$5,166	25%	85%	$1.62	6
Electric	Hospital	Heat Pump	Insulation - Duct	R-7 (WA State Code)	No Insulation	Per Building	Existing	2,589	20	$3,289	75%	60%	$0.13	97
Electric	Hospital	Heat Pump	Insulation - Floor (non-slab)	R-30 (WA State Code)	R-19 (Average Existing Conditions)	Per Building	Existing	2,018	25	$9,655	35%	35%	$0.52	20
Electric	Hospital	Heat Pump	Insulation - Floor (non-slab)	R-38	R-30 (WA State Code)	Per Building	Existing	831	25	$2,979	35%	35%	$0.39	8
Electric	Hospital	Heat Pump	Insulation - Wall	R-16	R-3 (Average Existing Conditions)	Per Building	Existing	6,901	25	$11,248	10%	35%	$0.17	19
Electric	Hospital	Heat Pump	Programmable Thermostat - Web Enabled	Programmable Thermostat - Web Enabled	No Programmable Thermostat	Per Building	Existing	1,849	10	$1,053	95%	24%	$0.08	33
Electric	Hospital	Heat Pump	RE - Deciduous Trees	Shade Trees	No Trees	Per Building	Existing	145	30	$3,629	75%	55%	$2.64	4
Electric	Hospital	Heat Pump	Variable Refrigerant Flow Cooling System	Variable Refrigerant Flow Cooling System	Standard Refrigeration System	Per Building	Existing	16,645	15	$4,148	25%	95%	$0.02	384
Electric	Hospital	Heat Pump	Window Film	Window Film	No Film	Per Building	Existing	2,854	10	$1,991	90%	66%	$0.10	1
Electric	Hospital	Heat Pump	Windows-High Efficiency	U-0.32	U-0.40 (WA State Code)	Per Building	Existing	2,853	25	$38,170	15%	60%	$1.48	18
Electric	Hospital	Heat Pump	Windows-High Efficiency	U-0.40 (WA State Code)	U-0.67 (Average Existing Conditions)	Per Building	Existing	3,862	25	$82,156	15%	60%	$2.35	25
Electric	Hospital	Lighting Exterior	Covered Parking Lighting	Covered Parking Lighting	Normal Lighting	Per Building	Existing	1,592	9.5	$442	20%	95%	$0.03	554
Electric	Hospital	Lighting Exterior	Daylighting Controls, Outdoors (Photocell)	Photocell	No Controls	Per Building	Existing	721	8	$112	75%	70%	$0.02	190

Table B-2.2. Commercial Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Hospital	Lighting Exterior	Occupancy Sensor Control	Occupancy Sensor Control	No Occupancy Sensor	Per Building	Existing	793	8	$730	90%	75%	$0.16	896
Electric	Hospital	Lighting Exterior	Solid State LED White Lighting	Landscape, merchandise, signage, structure & task lighting (2.5 W)	50W 10hrs/day, 365 day/yr	Per Building	Existing	702	13.69863	$141	75%	95%	$0.02	29
Electric	Hospital	Lighting Exterior	Surface Parking Lighting	Surface Parking Lighting	Normal Lighting	Per Building	Existing	860	18.666667	$1,162	47%	95%	$0.15	663
Electric	Hospital	Lighting Exterior	Time Clock	Time Clock	No Controls	Per Building	Existing	480	8	$131	10%	81%	$0.04	59
Electric	Hospital	Lighting Interior Fluorescent	Bi-Level Control, Stairwell Lighting	Occupancy Sensor Control, 50% Lighting Power during unoccupied Time	Continuous Full Power Lighting in Stairways	Per Building	Existing	1,547	9	$913	85%	75%	$0.09	1,711
Electric	Hospital	Lighting Interior Fluorescent	Dimming-Stepped, Fluorescent Fixtures	3-stepped Dimming of Fluorescent Fixtures (Day-Lighting)	No Dimming Controls	Per Building	Existing	11,328	8	$6,080	30%	51%	$0.09	2,740
Electric	Hospital	Lighting Interior Fluorescent	LED Refrigeration Case Lights	LED Refrigeration Case Lights	Fluorescent Refrigeration Case	Per Building	Existing	521	6	$193	15%	80%	$0.06	125
Electric	Hospital	Lighting Interior Fluorescent	Occupancy Sensor Control	Occupancy Sensor Control	No Occupancy Sensor	Per Building	Existing	6,755	8	$1,448	90%	42%	$0.03	3,782
Electric	Hospital	Lighting Interior Fluorescent	Time Clock	Time Clock	No Controls	Per Building	Existing	4,090	8	$1,118	10%	100%	$0.04	614
Electric	Hospital	Lighting Interior Hid	Occupancy Sensor Control	Occupancy Sensor Control	No Occupancy Sensor	Per Building	Existing	156	8	$1,448	90%	42%	$1.67	89
Electric	Hospital	Lighting Interior Hid	Time Clock	Time Clock	No Controls	Per Building	Existing	94	8	$25	10%	100%	$0.04	14
Electric	Hospital	Lighting Interior Other	Exit Sign - LED	Two Sided LED Exit Sign (5 Watts)	CFL Exit Sign (9 Watts)	Per Building	Existing	949	16	$158	95%	50%	$0.01	787
Electric	Hospital	Lighting Interior Other	Exit Sign - Photoluminescent or Tritium	Photoluminescent or Tritium	Two Sided LED Exit Sign (5 Watts)	Per Building	Existing	345	13	$296	95%	98%	$0.11	561
Electric	Hospital	Lighting Interior Screw Base	Cold Cathode Lighting	Cold Cathode Lighting 5 watts	30 W Incandescent Bulb	Per Building	Existing	528	5	$34	70%	94%	$0.01	196
Electric	Hospital	Lighting Interior Screw Base	Occupancy Sensor Control	Occupancy Sensor Control	No Occupancy Sensor	Per Building	Existing	2,554	8	$1,448	90%	42%	$0.10	515
Electric	Hospital	Lighting Interior Screw Base	Time Clock	Time Clock	No Controls	Per Building	Existing	1,546	8	$422	10%	100%	$0.04	83
Electric	Hospital	Other Plug Load	ENERGY STAR - Battery Charging System	ENERGY STAR Battery Charging System	Non-ENERGY STAR Battery Chargers	Per Building	Existing	52	7	$18	20%	20%	$0.07	3
Electric	Hospital	Other Plug Load	ENERGY STAR - Water Cooler	ENERGY STAR Water Cooler (Hot/Cold Water)	Non-ENERGY STAR Water Cooler	Per Building	Existing	269	10	$1	95%	20%	$-0.01	89
Electric	Hospital	Other Plug Load	Power Supply Transformer/Converter	80 Plus	85% efficient power supply (> 51W)	Per Building	Existing	233	4	$1	95%	86%	$-0.00	255
Electric	Hospital	Other Plug Load	Scanner - ENERGY STAR	ENERGY STAR Scanners	Standard Scanner	Per Building	Existing	23	6	$0.00	95%	20%	$-0.01	7
Electric	Hospital	Other Plug Load	Smart Strips	Smart Strip Power Strip	Standard surge protector	Per Building	Existing	566	4	$144	60%	90%	$0.07	534
Electric	Hospital	Refrigeration	Add Doors to Refrigerated Open Display Cases	Add Doors to Refrigerated Open Display Cases	Standard Refrigerated Open Display Cases	Per Building	Existing	288	12	$447	15%	95%	$0.22	71
Electric	Hospital	Refrigeration	Anti-Sweat (Humidistat) Controls	Anti-Sweat (Humidistat) Controls	No Anti-Sweat (Humidistat) Controls	Per Building	Existing	407	12	$34	15%	45%	$0.01	48
Electric	Hospital	Refrigeration	Case Electronically Commutated Motor	ECM Case Fans	Standard Efficiency Motor	Per Building	Existing	769	15	$187	5.0%	77%	$0.02	51

Table B-2.2. Commercial Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Hospital	Refrigeration	Case Replacement Low Temp	Case Replacement Low Temp	No replacement	Per Building	Existing	16,616	15	$1,800	5.0%	98%	$0.01	28
Electric	Hospital	Refrigeration	Case Replacement Med Temp	Case Replacement Med Temp	No replacement	Per Building	Existing	1,417	15	$932	5.0%	98%	$0.08	2
Electric	Hospital	Refrigeration	Commercial Refrigerator - Semivertical - No Doors - Med Temp	Commercial Refrigerator - Semivertical - No Doors - Med Temp	Standard Case	Per Building	Existing	419	10	$347	90%	85%	$0.12	560
Electric	Hospital	Refrigeration	Commercial Refrigerator - Vertical - No Doors - Med Temp	Commercial Refrigerator - Vertical - No Doors - Med Temp	Standard Case	Per Building	Existing	189	10	$156	90%	85%	$0.12	253
Electric	Hospital	Refrigeration	Demand Control Defrost - Hot Gas	Refrigerant Defrost	Defrost - Electric	Per Building	Existing	97	10	$61	5.0%	68%	$0.09	5
Electric	Hospital	Refrigeration	Display Case Motion Sensors	Display Case Motion Sensors	No Motion Sensors	Per Building	Existing	100	8	$10	90%	85%	$0.01	124
Electric	Hospital	Refrigeration	Evaporative Condenser - High-Efficiency	High-Efficiency Evaporative Condenser	Air-Cooled Condenser	Per Building	Existing	60	15	$299	90%	65%	$0.62	55
Electric	Hospital	Refrigeration	Evaporator Fan Controller	ECM Evaporator Fan Controller	No Controller	Per Building	Existing	163	15	$182	90%	85%	$0.13	199
Electric	Hospital	Refrigeration	Glass Door ENERGY STAR Refrigerators/Freezers	Glass Door ENERGY STAR Refrigerators/Freezers	Standard Glass Doors	Per Building	Existing	10	12	$10	95%	77%	$0.13	13
Electric	Hospital	Refrigeration	High-Efficiency Compressor	High-Efficiency Compressor (15% More Efficient)	Standard Compressor, 40% Efficiency	Per Building	Existing	12,291	10	$7,987	85%	72%	$0.10	604
Electric	Hospital	Refrigeration	Ice Maker	High-Efficiency Ice Maker	Standard Ice Maker	Per Building	Existing	47	10	$0.00	95%	86%	$-0.03	67
Electric	Hospital	Refrigeration	Night Covers for Display Cases	Night Covers for Display Cases	No Night Covers	Per Building	Existing	271	5	$42	15%	85%	$0.03	60
Electric	Hospital	Refrigeration	Refrigeration Commissioning of New or Existing Buildings	New or Existing Building Refrigeration Commissioning	No Commissioning	Per Building	Existing	566	3	$88	10%	85%	$0.06	70
Electric	Hospital	Refrigeration	Refrigerator eCube	Refrigerator eCube	No Refrigerator eCube	Per Building	Existing	624	10	$81	75%	95%	$0.01	107
Electric	Hospital	Refrigeration	Solid Door ENERGY STAR Refrigerators/Freezers	Solid Door ENERGY STAR Refrigerators/Freezers	Standard Solid Door	Per Building	Existing	32	12	$-8.5087092	95%	81%	$-0.04	43
Electric	Hospital	Refrigeration	Strip Curtains for Walk-Ins	Strip Curtains for Walk-Ins	No Strip Curtains for Walk-In	Per Building	Existing	133	4	$8	15%	20%	$0.01	7
Electric	Hospital	Refrigeration	Visi Cooler	High Efficiency Visi Cooler	Standard Visi Cooler	Per Building	Existing	528	10	$98	95%	85%	$0.02	745
Electric	Hospital	Refrigeration	Walk-In Electronically Commutated Motor	ECM Evaporator Fans	Standard Efficiency Motor	Per Building	Existing	163	15	$182	5.0%	95%	$0.13	13
Electric	Hospital	Refrigerator	Residential Refrigerator/Freezer Recycling	Recycling Existing Refrigerator/Freezer	Existing Refrigerator/Freezer	Per Building	Existing	481	9	$129	25%	100%	$0.04	181
Electric	Hospital	Servers	Server Virtualization	Server Virtualization	No Virtualization	Per Building	Existing	360	4	$338	72%	85%	$0.30	307
Electric	Hospital	Space Heat	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	Demand Controlled Ventilation (CO2 sensors)	Constant Ventilation	Per Building	Existing	2,145	15	$4,249	5.0%	94%	$0.24	72
Electric	Hospital	Space Heat	Commissioning of Existing Buildings	Existing Building Commissioning	Average Existing Conditions	Per Building	Existing	2,681	7	$3,352	90%	85%	$0.24	1,174
Electric	Hospital	Space Heat	Convert Constant Volume Air System to VAV	Variable Volume Air System	Constant Volume Air System	Per Building	Existing	2,788	15	$51,680	15%	67%	$2.35	201
Electric	Hospital	Space Heat	Direct Digital Control System-Installation	DDC Retrofit (Morning Warm-Up Control Logic Included in This Measure)	Pneumatic	Per Building	Existing	3,217	5	$16,345	20%	26%	$1.27	116

Table B-2.2. Commercial Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Hospital	Space Heat	Direct Digital Control System-Wireless System	DDC Retrofit - Wireless System	Pneumatic	Per Building	Existing	3,217	5	$3,971	75%	80%	$0.30	987
Electric	Hospital	Space Heat	Duct Repair And Sealing	Reduction In Duct Losses to 5%	No Repair or Sealing, 15% duct losses	Per Building	Existing	536	18	$4,079	45%	65%	$0.88	102
Electric	Hospital	Space Heat	Economizer Tune-up	Economizer Tune-up	No Economizer Tune-Up	Per Building	Existing	2,145	5	$2,721	10%	75%	$0.31	113
Electric	Hospital	Space Heat	Exhaust Air to Ventilation Air Heat Recovery	Exhaust Air Heat Recovery	No Heat Recovery	Per Building	Existing	3,217	14	$15,419	5.0%	94%	$0.62	97
Electric	Hospital	Space Heat	Exhaust Hood Makeup Air	Provide Makeup Air Directly at Exhaust Hood Instead of Pulling Conditioned Air	Hood Pulls Conditioned Air (No Make-up Air)	Per Building	Existing	993	10	$3,500	62%	85%	$0.54	324
Electric	Hospital	Space Heat	Infiltration Reduction	Install Caulking And Weatherstripping (ACH 0.65)	Infiltration Conditions (ACH 1.0)	Per Building	Existing	2,145	12.5	$440	10%	39%	$0.02	52
Electric	Hospital	Space Heat	Insulation - Ceiling	R-30 c.i. (WA State Code)	R-11 (Average Existing Conditions)	Per Building	Existing	3,157	25	$18,315	75%	13%	$0.63	192
Electric	Hospital	Space Heat	Insulation - Ceiling	R-38 c.i.	R-30 c.i. (WA State Code)	Per Building	Existing	397	25	$18,315	75%	70%	$5.11	128
Electric	Hospital	Space Heat	Insulation - Ceiling	R-49 c.i.	R-38 c.i.	Per Building	Existing	384	25	$5,166	25%	85%	$1.48	49
Electric	Hospital	Space Heat	Insulation - Duct	R-7 (WA State Code)	No Insulation	Per Building	Existing	900	20	$3,289	75%	60%	$0.40	245
Electric	Hospital	Space Heat	Insulation - Floor (non-slab)	R-30 (WA State Code)	R-19 (Average Existing Conditions)	Per Building	Existing	1,945	25	$9,655	35%	35%	$0.54	141
Electric	Hospital	Space Heat	Insulation - Floor (non-slab)	R-38	R-30 (WA State Code)	Per Building	Existing	812	25	$2,979	35%	35%	$0.40	58
Electric	Hospital	Space Heat	Insulation - Wall	R-16	R-3 (Average Existing Conditions)	Per Building	Existing	11,829	25	$11,248	10%	35%	$0.10	242
Electric	Hospital	Space Heat	Programmable Thermostat - Web Enabled	Programmable Thermostat - Web Enabled	No Programmable Thermostat	Per Building	Existing	643	10	$1,053	95%	24%	$0.25	83
Electric	Hospital	Space Heat	Sensible And Total Heat Recovery Devices	Install Heat Recovery Devices - rotary air-to-air enthalpy heat recovery- 50% sensible and latent recovery effectiveness	No Heat Recovery	Per Building	Existing	5,363	10	$35,871	25%	98%	$1.04	678
Electric	Hospital	Space Heat	Windows-High Efficiency	U-0.40 (WA State Code)	U-0.67 (Average Existing Conditions)	Per Building	Existing	277	25	$82,156	15%	60%	$32.86	12
Electric	Hospital	Vending Machines	Vending Miser	Passive Infrared Sensor on Vending Machine Monitoring Vacancy of Area And Cycles Cooling - Controls	No Vending Miser - No controls	Per Building	Existing	1,796	3	$170	50%	25%	$0.03	4
Electric	Hospital	Ventilation And Circulation	Automated Exhaust VFD Control - Parking Garage CO sensor	CO Sensors	No CO Sensors	Per Building	Existing	19,217	10	$2,084	20%	85%	$0.01	5,064
Electric	Hospital	Ventilation And Circulation	Convert Constant Volume Air System to VAV	Variable Volume Air System	Constant Volume Air System	Per Building	Existing	10,964	15	$51,680	15%	67%	$0.59	1,741
Electric	Hospital	Ventilation And Circulation	Cooking Hood Controls	Demand-Ventilation Control	No Controls	Per Building	Existing	130	18	$297	95%	85%	$0.26	171
Electric	Hospital	Ventilation And Circulation	Motor - CEE Premium-Efficiency Plus	CEE PE+ Motor for HVAC Applications	NEMA Efficiency Motors	Per Building	Existing	931	15	$112	95%	76%	$0.01	1,042
Electric	Hospital	Ventilation And Circulation	Motor - Pump & Fan System - Variable Speed Control	Pump And Fan System Optimization w/ VSD	No Pump And Fan System VSD Optimization	Per Building	Existing	23,298	20	$1,892	65%	75%	$0.00	17,519
Electric	Hospital	Ventilation And Circulation	Motor - VAV Box High Efficiency (ECM)	ECM Motor	Standard Efficiency Motor	Per Building	Existing	4,796	15	$6,207	8.0%	77%	$0.16	396

Table B-2.2. Commercial Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Hospital	Ventilation And Circulation	Motor Rewind	>15, <500 HP	No Rewind	Per Building	Existing	300	7	$86	65%	25%	$0.05	65
Electric	Hospital	Ventilation And Circulation	Optimized Variable Volume Lab Hood Design	Optimized Variable Volume Lab Hood Design	Constant Volume Lab Hood Design	Per Building	Existing	1,461	13	$1,705	65%	59%	$0.15	918
Electric	Hospital	Water Heat GT 55 Gal	Clothes Washer - Ozonating	Ozonating Clothes Washer	2013 Federal Standard Clothes Washer - MEF = 1.6, WF = 8.5	Per Building	Existing	3,617	10	$8,285	0.8%	95%	$0.23	9
Electric	Hospital	Water Heat GT 55 Gal	Clothes Washer Commercial	ENERGY STAR Commercial Clothes Washer - MEF = 2.43, WF = 4.0	2013 Federal Standard Clothes Washer - MEF = 1.6, WF = 8.5	Per Building	Existing	112	7	$42	95%	80%	$-0.75	32
Electric	Hospital	Water Heat GT 55 Gal	Demand Controlled Circulating Systems	Demand Controlled Circulating Systems (VFD control by demand)	Constant Circulation	Per Building	Existing	1,195	10	$4,722	55%	94%	$0.61	234
Electric	Hospital	Water Heat GT 55 Gal	Dishwasher Residential	RTF ENERGY STAR Dishwasher - 277 kWh/yr and 4.25 gal/cycle	RTF Market Standard 2014 Dishwasher - 289 kWh/yr and 5.0 gal/cycle	Per Building	Existing	19	12	$61	11%	25%	$0.43	0.20
Electric	Hospital	Water Heat GT 55 Gal	Dishwashing - Commercial - High Temp	High Efficiency Dishwasher (ENERGY STAR)	Standard High Temp Commercial Dishwasher	Per Building	Existing	115	12	$64	95%	95%	$-2.79	39
Electric	Hospital	Water Heat GT 55 Gal	Drainwater Heat Recovery Water Heater	Install (Power-Pipe or GFX) - Heat Recovery Water Heater	No Heat Recovery System	Per Building	Existing	4,682	25	$12,082	5.0%	92%	$0.28	80
Electric	Hospital	Water Heat GT 55 Gal	Low-Flow Faucet Aerators	0.5 GPM	2.2 GPM (Federal Code)	Per Building	Existing	924	9	$17	95%	75%	$-0.01	250
Electric	Hospital	Water Heat GT 55 Gal	Low-Flow Faucet Aerators	2.2 GPM (Federal Code)	3.0 GPM	Per Building	Existing	318	9	$13	95%	25%	$-0.02	28
Electric	Hospital	Water Heat GT 55 Gal	Low-Flow Pre-Rinse Spray Valves	0.6 GPM	1.6 GPM (Federal Standard)	Per Building	Existing	128	4	$39	95%	83%	$0.07	38
Electric	Hospital	Water Heat GT 55 Gal	Low-Flow Showerheads	1.5 GPM	2.5 GPM (Federal Code)	Per Building	Existing	170	10	$62	95%	73%	$-0.05	44
Electric	Hospital	Water Heat GT 55 Gal	Low-Flow Showerheads	2.5 GPM (Federal Code)	4.5 GPM	Per Building	Existing	340	10	$51	95%	35%	$-0.09	43
Electric	Hospital	Water Heat GT 55 Gal	Pipe Insulation - Hot Water (DWH)	1.0" of Insulation, assuming R-4 (WA State Code)	No Insulation	Per Building	Existing	239	12	$148	80%	70%	$0.08	48
Electric	Hospital	Water Heat GT 55 Gal	Ultrasonic Faucet Control	Install Ultrasonic Motion Faucet Control	No Faucet Control	Per Building	Existing	597	10	$1,172	75%	90%	$0.28	153
Electric	Hospital	Water Heat LE 55 Gal	Clothes Washer - Ozonating	Ozonating Clothes Washer	2013 Federal Standard Clothes Washer - MEF = 1.6, WF = 8.5	Per Building	Existing	3,553	10	$8,285	0.8%	95%	$0.24	9
Electric	Hospital	Water Heat LE 55 Gal	Clothes Washer Commercial	ENERGY STAR Commercial Clothes Washer - MEF = 2.43, WF = 4.0	2013 Federal Standard Clothes Washer - MEF = 1.6, WF = 8.5	Per Building	Existing	112	7	$42	95%	80%	$-0.75	31
Electric	Hospital	Water Heat LE 55 Gal	Demand Controlled Circulating Systems	Demand Controlled Circulating Systems (VFD control by demand)	Constant Circulation	Per Building	Existing	1,174	10	$4,722	55%	94%	$0.62	225
Electric	Hospital	Water Heat LE 55 Gal	Dishwasher Residential	RTF ENERGY STAR Dishwasher - 277 kWh/yr and 4.25 gal/cycle	RTF Market Standard 2014 Dishwasher - 289 kWh/yr and 5.0 gal/cycle	Per Building	Existing	19	12	$61	11%	25%	$0.43	0.19
Electric	Hospital	Water Heat LE 55 Gal	Dishwashing - Commercial - High Temp	High Efficiency Dishwasher (ENERGY STAR)	Standard High Temp Commercial Dishwasher	Per Building	Existing	113	12	$64	95%	95%	$-2.84	38

Table B-2.2. Commercial Electric Measure Details

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Electric	Hospital	Water Heat LE 55 Gal	Drainwater Heat Recovery Water Heater	Install (Power-Pipe or GFX) - Heat Recovery Water Heater	No Heat Recovery System	Per Building	Existing	4,682	25	$12,082	5.0%	92%	$0.28	77
Electric	Hospital	Water Heat LE 55 Gal	Low-Flow Faucet Aerators	0.5 GPM	2.2 GPM (Federal Code)	Per Building	Existing	907	9	$17	95%	75%	$-0.01	241
Electric	Hospital	Water Heat LE 55 Gal	Low-Flow Faucet Aerators	2.2 GPM (Federal Code)	3.0 GPM	Per Building	Existing	313	9	$13	95%	25%	$-0.02	27
Electric	Hospital	Water Heat LE 55 Gal	Low-Flow Pre-Rinse Spray Valves	0.6 GPM	1.6 GPM (Federal Standard)	Per Building	Existing	128	4	$39	95%	83%	$0.07	38
Electric	Hospital	Water Heat LE 55 Gal	Low-Flow Showerheads	1.5 GPM	2.5 GPM (Federal Code)	Per Building	Existing	170	10	$62	95%	73%	$-0.05	44
Electric	Hospital	Water Heat LE 55 Gal	Low-Flow Showerheads	2.5 GPM (Federal Code)	4.5 GPM	Per Building	Existing	340	10	$51	95%	35%	$-0.09	42
Electric	Hospital	Water Heat LE 55 Gal	Pipe Insulation - Hot Water (DWH)	1.0" of Insulation, assuming R-4 (WA State Code)	No Insulation	Per Building	Existing	234	12	$148	80%	70%	$0.08	46
Electric	Hospital	Water Heat LE 55 Gal	Ultrasonic Faucet Control	Install Ultrasonic Motion Faucet Control	No Faucet Control	Per Building	Existing	587	10	$1,172	75%	90%	$0.29	148
Electric	Hotel Motel	Cooking	Combination Oven	60% cooking efficiency	Non ENERGY STAR	Per Building	Existing	151	12	$26	90%	90%	$0.02	9
Electric	Hotel Motel	Cooking	Fryers - New CEE Efficient Electric Deep Fat Fryers	15 inch width Deep Fryer CEE 2006 rating: 80% under heavy load, Less than 1000 watt at idle	15 inch width standard electric deep fat fryers	Per Building	Existing	6	12	$10	55%	35%	$0.21	0.10
Electric	Hotel Motel	Cooking	Griddle	70% cooking efficiency	Non ENERGY STAR	Per Building	Existing	78	12	$27	95%	35%	$0.04	2
Electric	Hotel Motel	Cooking	Hot Food Holding Cabinet	ENERGY STAR Hot Food Holding Cabinet	Non ENERGY STAR Hot Food Holding Cabinet	Per Building	Existing	184	12	$118	55%	21%	$0.08	1
Electric	Hotel Motel	Cooking	Steam Cooker	ENERGY STAR Steam Cooker	Non ENERGY STAR Steam Cooker	Per Building	Existing	57	12	$6	2.5%	35%	$0.01	0.07
Electric	Hotel Motel	Cooling Chillers	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	Demand Controlled Ventilation (CO2 sensors)	Constant Ventilation	Per Building	Existing	476	15	$4,375	50%	94%	$1.16	50
Electric	Hotel Motel	Cooling Chillers	Chilled Water / Condenser Water Settings-Optimization	Additional Control Features	EMS already installed - No Optimization	Per Building	Existing	297	5	$2,980	95%	81%	$2.51	51
Electric	Hotel Motel	Cooling Chillers	Chilled Water Piping Loop w/ VSD Control	VSD for secondary chilled water loop	Primary loop only w/ constant speed pump	Per Building	Existing	1,800	10	$13,761	25%	70%	$1.19	70
Electric	Hotel Motel	Cooling Chillers	Chiller-Water Side Economizer	Install Economizer	No Economizer	Per Building	Existing	1,191	15	$31,953	45%	30%	$3.41	35
Electric	Hotel Motel	Cooling Chillers	Commissioning of Existing Buildings	Existing Building Commissioning	Average Existing Conditions	Per Building	Existing	2,977	7	$3,450	90%	85%	$0.23	409
Electric	Hotel Motel	Cooling Chillers	Convert Constant Volume Air System to VAV	Variable Volume Air System	Constant Volume Air System	Per Building	Existing	7,146	15	$53,200	15%	67%	$0.94	157
Electric	Hotel Motel	Cooling Chillers	Cooling Tower-Decrease Approach Temperature	6 Deg F	10 Deg F	Per Building	Existing	1,905	7.5	$1,700	10%	94%	$0.12	39
Electric	Hotel Motel	Cooling Chillers	Cooling Tower-Two-Speed Fan Motor	Cooling Tower-Two-Speed Fan Motor	Cooling Tower-One-Speed Fan Motor	Per Building	Existing	3,335	15	$152	75%	35%	$0.00	183
Electric	Hotel Motel	Cooling Chillers	Cooling Tower-VSD Fan Control	Variable-Speed Tower Fans replace Two-Speed	Cooling Tower-Two-Speed Fan Motor	Per Building	Existing	952	13	$1,231	75%	75%	$0.17	108
Electric	Hotel Motel	Cooling Chillers	Direct Digital Control System-Installation	DDC Retrofit (Morning Warm-Up Control Logic Included in This Measure)	Pneumatic	Per Building	Existing	3,573	5	$16,826	10%	52%	$1.18	37

Table B-2.2. Commercial Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Hotel Motel	Cooling Chillers	Direct Digital Control System-Wireless System	DDC Retrofit - Wireless System	Pneumatic	Per Building	Existing	3,573	5	$4,088	50%	80%	$0.28	224
Electric	Hotel Motel	Cooling Chillers	Exhaust Hood Makeup Air	Provide Makeup Air Directly at Exhaust Hood Instead of Pulling Conditioned Air	Hood Pulls Conditioned Air (No Make-up Air)	Per Building	Existing	1,259	10	$3,499	58%	85%	$0.43	98
Electric	Hotel Motel	Cooling Chillers	Green Roof	Vegetation on Roof	Standard Dark Colored Roof	Per Building	Existing	868	40	$64,610	3.5%	98%	$7.51	5
Electric	Hotel Motel	Cooling Chillers	Infiltration Reduction	Install Caulking And Weatherstripping (ACH 0.65)	Infiltration Conditions (ACH 1.0)	Per Building	Existing	1,191	12.5	$933	10%	39%	$0.11	8
Electric	Hotel Motel	Cooling Chillers	Insulation - Ceiling	R-30 c.i. (WA State Code)	R-11 (Average Existing Conditions)	Per Building	Existing	54	25	$11,371	75%	25%	$23.22	1
Electric	Hotel Motel	Cooling Chillers	Insulation - Ceiling	R-49 c.i.	R-38 c.i.	Per Building	Existing	1	25	$3,208	25%	85%	$299.23	0.04
Electric	Hotel Motel	Cooling Chillers	Pipe Insulation - Chilled Water	1.5" of Insulation, assuming R-6 (WA State Code)	No Insulation	Per Building	Existing	357	15	$359	65%	45%	$0.12	19
Electric	Hotel Motel	Cooling Chillers	Programmable Thermostat - Web Enabled	Programmable Thermostat - Web Enabled	No Programmable Thermostat	Per Building	Existing	714	10	$1,749	15%	26%	$0.38	5
Electric	Hotel Motel	Cooling Chillers	RE - Deciduous Trees	Shade Trees	No Trees	Per Building	Existing	482	30	$4,707	75%	55%	$1.03	35
Electric	Hotel Motel	Cooling Chillers	Sensible And Total Heat Recovery Devices	Install Heat Recovery Devices - rotary air-to-air enthalpy heat recovery- 50% sensible and latent recovery effectiveness	No Heat Recovery	Per Building	Existing	7,653	10	$36,924	25%	98%	$0.75	236
Electric	Hotel Motel	Cooling Chillers	Window Film	Window Film	No Film	Per Building	Existing	6,237	10	$4,221	90%	66%	$0.10	5
Electric	Hotel Motel	Cooling Chillers	Windows-High Efficiency	U-0.32	U-0.40 (WA State Code)	Per Building	Existing	3,005	25	$80,903	15%	50%	$2.98	34
Electric	Hotel Motel	Cooling Chillers	Windows-High Efficiency	U-0.40 (WA State Code)	U-0.65 (Average Existing Conditions)	Per Building	Existing	2,630	25	$74,129	15%	50%	$7.35	29
Electric	Hotel Motel	Cooling Dx	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	Demand Controlled Ventilation (CO2 sensors)	Constant Ventilation	Per Building	Existing	585	15	$4,375	50%	94%	$0.95	39
Electric	Hotel Motel	Cooling Dx	Commissioning of Existing Buildings	Existing Building Commissioning	Average Existing Conditions	Per Building	Existing	3,659	7	$3,450	90%	85%	$0.18	258
Electric	Hotel Motel	Cooling Dx	Convert Constant Volume Air System to VAV	Variable Volume Air System	Constant Volume Air System	Per Building	Existing	8,783	15	$53,200	15%	67%	$0.77	125
Electric	Hotel Motel	Cooling Dx	DX Package-Air Side Economizer	Air-Side Economizer	No Economizer	Per Building	Existing	4,391	10	$9,923	10%	30%	$0.35	18
Electric	Hotel Motel	Cooling Dx	Direct / Indirect Evaporative Cooling, Pre-Cooling	Evaporative Cooler	Standard DX cooling	Per Building	Existing	7,319	15	$36,458	50%	94%	$0.63	465
Electric	Hotel Motel	Cooling Dx	Direct Digital Control System-Installation	DDC Retrofit (Morning Warm-Up Control Logic Included in This Measure)	Pneumatic	Per Building	Existing	4,391	5	$16,826	10%	52%	$0.96	27
Electric	Hotel Motel	Cooling Dx	Direct Digital Control System-Wireless System	DDC Retrofit - Wireless System	Pneumatic	Per Building	Existing	4,391	5	$4,088	50%	80%	$0.23	166
Electric	Hotel Motel	Cooling Dx	Duct Repair And Sealing	Reduction In Duct Losses to 5%	No Repair or Sealing, 15% duct losses	Per Building	Existing	731	18	$4,198	45%	65%	$0.67	24
Electric	Hotel Motel	Cooling Dx	Economizer Tune-up	Economizer Tune-up	No Economizer Tune-Up	Per Building	Existing	2,927	5	$2,799	10%	75%	$0.24	29

Table B-2.2. Commercial Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Hotel Motel	Cooling Dx	Exhaust Hood Makeup Air	Provide Makeup Air Directly at Exhaust Hood Instead of Pulling Conditioned Air	Hood Pulls Conditioned Air (No Make-up Air)	Per Building	Existing	1,372	10	$3,499	58%	85%	$0.39	72
Electric	Hotel Motel	Cooling Dx	Green Roof	Vegetation on Roof	Standard Dark Colored Roof	Per Building	Existing	1,067	40	$64,610	3.5%	98%	$6.11	4
Electric	Hotel Motel	Cooling Dx	Hotel Occupancy Control System	Includes multiple hotel control schemes including: Key card system, room occupancy sensors, and front desk control to control room HVAC and lighting during non-occupied periods	325 sqft room, $100/room; No HVAC or lighting occupancy controls	Per Building	Existing	34,504	15	$6,783	60%	97%	$0.02	416
Electric	Hotel Motel	Cooling Dx	Infiltration Reduction	Install Caulking And Weatherstripping (ACH 0.65)	Infiltration Conditions (ACH 1.0)	Per Building	Existing	1,463	12.5	$933	10%	39%	$0.09	5
Electric	Hotel Motel	Cooling Dx	Insulation - Ceiling	R-30 c.i. (WA State Code)	R-11 (Average Existing Conditions)	Per Building	Existing	66	25	$11,371	75%	25%	$18.89	1
Electric	Hotel Motel	Cooling Dx	Insulation - Ceiling	R-49 c.i.	R-38 c.i.	Per Building	Existing	1	25	$3,208	25%	85%	$243.46	0.02
Electric	Hotel Motel	Cooling Dx	Insulation - Duct	R-7 (WA State Code)	No Insulation	Per Building	Existing	1,229	20	$3,386	75%	60%	$0.30	52
Electric	Hotel Motel	Cooling Dx	Programmable Thermostat - Web Enabled	Programmable Thermostat - Web Enabled	No Programmable Thermostat	Per Building	Existing	878	10	$1,749	95%	31%	$0.31	24
Electric	Hotel Motel	Cooling Dx	RE - Deciduous Trees	Shade Trees	No Trees	Per Building	Existing	225	30	$2,437	75%	55%	$1.14	8
Electric	Hotel Motel	Cooling Dx	Window Film	Window Film	No Film	Per Building	Existing	6,237	10	$4,221	90%	66%	$0.10	3
Electric	Hotel Motel	Cooling Dx	Windows-High Efficiency	U-0.32	U-0.40 (WA State Code)	Per Building	Existing	3,694	25	$80,903	15%	50%	$2.43	22
Electric	Hotel Motel	Cooling Dx	Windows-High Efficiency	U-0.40 (WA State Code)	U-0.65 (Average Existing Conditions)	Per Building	Existing	3,233	25	$74,129	15%	50%	$5.98	19
Electric	Hotel Motel	Heat Pump	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	Demand Controlled Ventilation (CO2 sensors)	Constant Ventilation	Per Building	Existing	551	15	$4,375	50%	94%	$1.00	59
Electric	Hotel Motel	Heat Pump	Commissioning of Existing Buildings	Existing Building Commissioning	Average Existing Conditions	Per Building	Existing	8,310	7	$3,450	90%	85%	$0.08	1,044
Electric	Hotel Motel	Heat Pump	Convert Constant Volume Air System to VAV	Variable Volume Air System	Constant Volume Air System	Per Building	Existing	10,637	15	$53,200	15%	67%	$0.63	243
Electric	Hotel Motel	Heat Pump	Direct Digital Control System-Installation	DDC Retrofit (Morning Warm-Up Control Logic Included in This Measure)	Pneumatic	Per Building	Existing	9,972	5	$16,826	10%	52%	$0.42	117
Electric	Hotel Motel	Heat Pump	Direct Digital Control System-Wireless System	DDC Retrofit - Wireless System	Pneumatic	Per Building	Existing	9,972	5	$4,088	50%	80%	$0.10	708
Electric	Hotel Motel	Heat Pump	Duct Repair And Sealing	Reduction In Duct Losses to 5%	No Repair or Sealing, 15% duct losses	Per Building	Existing	1,662	18	$4,198	45%	65%	$0.29	103
Electric	Hotel Motel	Heat Pump	Exhaust Air to Ventilation Air Heat Recovery	Exhaust Air Heat Recovery	No Heat Recovery	Per Building	Existing	5,839	14	$15,872	5.0%	94%	$0.35	57
Electric	Hotel Motel	Heat Pump	Exhaust Hood Makeup Air	Provide Makeup Air Directly at Exhaust Hood Instead of Pulling Conditioned Air	Hood Pulls Conditioned Air (No Make-up Air)	Per Building	Existing	3,065	10	$3,499	58%	85%	$0.17	306
Electric	Hotel Motel	Heat Pump	Green Roof	Vegetation on Roof	Standard Dark Colored Roof	Per Building	Existing	1,004	40	$64,610	3.5%	98%	$6.49	7
Electric	Hotel Motel	Heat Pump	Ground Source Heat Pump > 135 kBTU/hr	High Efficiency Ground Source Heat Pump > 135 kBTU/hr	Water Source Heat Pump > 135 kBTU/hr	Per Building	Existing	3,741	15	$27,360	3.8%	95%	$7.72	19

Table B-2.2. Commercial Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Hotel Motel	Heat Pump	Hotel Occupancy Control System	Includes multiple hotel control schemes including: Key card system, room occupancy sensors, and front desk control to control room HVAC and lighting during non-occupied periods	325 sqft room, $100/room; No HVAC or lighting occupancy controls	Per Building	Existing	34,504	15	$6,783	60%	97%	$0.02	1,766
Electric	Hotel Motel	Heat Pump	Infiltration Reduction	Install Caulking And Weatherstripping (ACH 0.65)	Infiltration Conditions (ACH 1.0)	Per Building	Existing	5,839	12.5	$933	10%	39%	$0.02	40
Electric	Hotel Motel	Heat Pump	Insulation - Ceiling	R-30 c.i. (WA State Code)	R-11 (Average Existing Conditions)	Per Building	Existing	4,425	25	$11,371	75%	25%	$0.28	146
Electric	Hotel Motel	Heat Pump	Insulation - Ceiling	R-38 c.i.	R-30 c.i. (WA State Code)	Per Building	Existing	597	25	$11,371	75%	70%	$2.11	54
Electric	Hotel Motel	Heat Pump	Insulation - Ceiling	R-49 c.i.	R-38 c.i.	Per Building	Existing	425	25	$3,208	25%	85%	$0.83	15
Electric	Hotel Motel	Heat Pump	Insulation - Duct	R-7 (WA State Code)	No Insulation	Per Building	Existing	2,792	20	$3,386	75%	60%	$0.13	217
Electric	Hotel Motel	Heat Pump	Insulation - Floor (non-slab)	R-30 (WA State Code)	R-7 (Average Existing Conditions)	Per Building	Existing	7,704	25	$5,995	35%	45%	$0.08	206
Electric	Hotel Motel	Heat Pump	Insulation - Floor (non-slab)	R-38	R-30 (WA State Code)	Per Building	Existing	1,096	25	$1,850	35%	45%	$0.18	28
Electric	Hotel Motel	Heat Pump	Insulation - Wall	R-16	R-3 (Average Existing Conditions)	Per Building	Existing	14,781	25	$17,675	10%	35%	$0.12	86
Electric	Hotel Motel	Heat Pump	Programmable Thermostat - Web Enabled	Programmable Thermostat - Web Enabled	No Programmable Thermostat	Per Building	Existing	1,994	10	$1,749	95%	31%	$0.13	97
Electric	Hotel Motel	Heat Pump	RE - Deciduous Trees	Shade Trees	No Trees	Per Building	Existing	313	30	$5,677	75%	55%	$1.91	21
Electric	Hotel Motel	Heat Pump	Window Film	Window Film	No Film	Per Building	Existing	6,237	10	$4,221	90%	66%	$0.10	5
Electric	Hotel Motel	Heat Pump	Windows-High Efficiency	U-0.32	U-0.40 (WA State Code)	Per Building	Existing	2,002	25	$80,903	15%	50%	$4.48	22
Electric	Hotel Motel	Heat Pump	Windows-High Efficiency	U-0.40 (WA State Code)	U-0.65 (Average Existing Conditions)	Per Building	Existing	3,411	25	$74,129	15%	50%	$5.66	37
Electric	Hotel Motel	Lighting Exterior	Covered Parking Lighting	Covered Parking Lighting	Normal Lighting	Per Building	Existing	1,639	9.5	$456	20%	95%	$0.03	326
Electric	Hotel Motel	Lighting Exterior	Daylighting Controls, Outdoors (Photocell)	Photocell	No Controls	Per Building	Existing	568	8	$87	75%	70%	$0.02	128
Electric	Hotel Motel	Lighting Exterior	Occupancy Sensor Control	Occupancy Sensor Control	No Occupancy Sensor	Per Building	Existing	1,819	8	$365	90%	75%	$0.03	1,180
Electric	Hotel Motel	Lighting Exterior	Solid State LED White Lighting	Landscape, merchandise, signage, structure & task lighting (2.5 W)	50W 10hrs/day, 365 day/yr	Per Building	Existing	553	13.69863	$111	75%	95%	$0.02	19
Electric	Hotel Motel	Lighting Exterior	Surface Parking Lighting	Surface Parking Lighting	Normal Lighting	Per Building	Existing	885	18.666667	$1,195	47%	95%	$0.15	390
Electric	Hotel Motel	Lighting Exterior	Time Clock	Time Clock	No Controls	Per Building	Existing	563	8	$153	10%	81%	$0.04	37
Electric	Hotel Motel	Lighting Interior Fluorescent	Bi-Level Control, Stairwell Lighting	Occupancy Sensor Control, 50% Lighting Power during unoccupied Time	Continuous Full Power Lighting in Stairways	Per Building	Existing	1,004	9	$940	85%	75%	$0.15	196
Electric	Hotel Motel	Lighting Interior Fluorescent	Dimming-Continuous, Fluorescent Fixtures	Continuous Dimming, Fluorescent Fixtures (Day-Lighting)	No Dimming Controls	Per Building	Existing	1,114	8	$6,389	30%	92%	$1.03	250
Electric	Hotel Motel	Lighting Interior Fluorescent	Occupancy Sensor Control	Occupancy Sensor Control	No Occupancy Sensor	Per Building	Existing	2,925	8	$1,490	90%	58%	$0.09	1,175
Electric	Hotel Motel	Lighting Interior Fluorescent	Time Clock	Time Clock	No Controls	Per Building	Existing	905	8	$248	10%	100%	$0.04	67
Electric	Hotel Motel	Lighting Interior Hid	Occupancy Sensor Control	Occupancy Sensor Control	No Occupancy Sensor	Per Building	Existing	101	8	$1,490	90%	58%	$2.65	47
Electric	Hotel Motel	Lighting Interior Hid	Time Clock	Time Clock	No Controls	Per Building	Existing	31	8	$8	10%	100%	$0.04	2

Table B-2.2. Commercial Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Hotel Motel	Lighting Interior Other	Exit Sign - LED	Two Sided LED Exit Sign (5 Watts)	CFL Exit Sign (9 Watts)	Per Building	Existing	192	16	$31	95%	50%	$0.01	91
Electric	Hotel Motel	Lighting Interior Other	Exit Sign - Photoluminescent or Tritium	Photoluminescent or Tritium	Two Sided LED Exit Sign (5 Watts)	Per Building	Existing	70	13	$59	95%	98%	$0.11	65
Electric	Hotel Motel	Lighting Interior Screw Base	Cold Cathode Lighting	Cold Cathode Lighting 5 watts	30 W Incandescent Bulb	Per Building	Existing	255	5	$13	70%	94%	$0.01	48
Electric	Hotel Motel	Lighting Interior Screw Base	Occupancy Sensor Control	Occupancy Sensor Control	No Occupancy Sensor	Per Building	Existing	9,650	8	$1,490	90%	58%	$0.02	1,382
Electric	Hotel Motel	Lighting Interior Screw Base	Time Clock	Time Clock	No Controls	Per Building	Existing	2,986	8	$816	10%	100%	$0.04	79
Electric	Hotel Motel	Other Plug Load	ENERGY STAR - Battery Charging System	ENERGY STAR Battery Charging System	Non-ENERGY STAR Battery Chargers	Per Building	Existing	11	7	$3	20%	20%	$0.05	0.47
Electric	Hotel Motel	Other Plug Load	ENERGY STAR - Water Cooler	ENERGY STAR Water Cooler (Hot/Cold Water)	Non-ENERGY STAR Water Cooler	Per Building	Existing	49	10	$0.00	95%	20%	$-0.01	9
Electric	Hotel Motel	Other Plug Load	Power Supply Transformer/Converter	80 Plus	85% efficient power supply (> 51W)	Per Building	Existing	240	4	$3	95%	86%	$0.00	33
Electric	Hotel Motel	Other Plug Load	Scanner - ENERGY STAR	ENERGY STAR Scanners	Standard Scanner	Per Building	Existing	38	6	$0.00	95%	20%	$-0.01	7
Electric	Hotel Motel	Other Plug Load	Smart Strips	Smart Strip Power Strip	Standard surge protector	Per Building	Existing	437	4	$111	60%	90%	$0.07	236
Electric	Hotel Motel	Refrigerator	Residential Refrigerator/Freezer Recycling	Recycling Existing Refrigerator/Freezer	Existing Refrigerator/Freezer	Per Building	Existing	481	9	$129	25%	100%	$0.04	103
Electric	Hotel Motel	Space Heat	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	Demand Controlled Ventilation (CO2 sensors)	Constant Ventilation	Per Building	Existing	1,405	15	$4,375	50%	94%	$0.39	196
Electric	Hotel Motel	Space Heat	Commissioning of Existing Buildings	Existing Building Commissioning	Average Existing Conditions	Per Building	Existing	8,781	7	$3,450	90%	85%	$0.07	1,352
Electric	Hotel Motel	Space Heat	Convert Constant Volume Air System to VAV	Variable Volume Air System	Constant Volume Air System	Per Building	Existing	9,132	15	$53,200	15%	67%	$0.73	271
Electric	Hotel Motel	Space Heat	Direct Digital Control System-Installation	DDC Retrofit (Morning Warm-Up Control Logic Included in This Measure)	Pneumatic	Per Building	Existing	10,538	5	$16,826	10%	52%	$0.39	159
Electric	Hotel Motel	Space Heat	Direct Digital Control System-Wireless System	DDC Retrofit - Wireless System	Pneumatic	Per Building	Existing	10,538	5	$4,088	50%	80%	$0.09	966
Electric	Hotel Motel	Space Heat	Duct Repair And Sealing	Reduction In Duct Losses to 5%	No Repair or Sealing, 15% duct losses	Per Building	Existing	1,756	18	$4,198	45%	65%	$0.27	140
Electric	Hotel Motel	Space Heat	Economizer Tune-up	Economizer Tune-up	No Economizer Tune-Up	Per Building	Existing	7,025	5	$2,799	10%	75%	$0.09	153
Electric	Hotel Motel	Space Heat	Exhaust Air to Ventilation Air Heat Recovery	Exhaust Air Heat Recovery	No Heat Recovery	Per Building	Existing	10,538	14	$15,872	5.0%	94%	$0.19	134
Electric	Hotel Motel	Space Heat	Exhaust Hood Makeup Air	Provide Makeup Air Directly at Exhaust Hood Instead of Pulling Conditioned Air	Hood Pulls Conditioned Air (No Make-up Air)	Per Building	Existing	2,890	10	$3,499	58%	85%	$0.18	417

Table B-2.2. Commercial Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Hotel Motel	Space Heat	Hotel Occupancy Control System	Includes multiple hotel control schemes including: Key card system, room occupancy sensors, and front desk control to control room HVAC and lighting during non-occupied periods	325 sqft room, $100/room; No HVAC or lighting occupancy controls	Per Building	Existing	34,504	15	$6,783	60%	97%	$0.01	2,406
Electric	Hotel Motel	Space Heat	Infiltration Reduction	Install Caulking And Weatherstripping (ACH 0.65)	Infiltration Conditions (ACH 1.0)	Per Building	Existing	7,025	12.5	$933	10%	39%	$0.01	62
Electric	Hotel Motel	Space Heat	Insulation - Ceiling	R-30 c.i. (WA State Code)	R-11 (Average Existing Conditions)	Per Building	Existing	7,837	25	$11,371	75%	25%	$0.15	335
Electric	Hotel Motel	Space Heat	Insulation - Ceiling	R-38 c.i.	R-30 c.i. (WA State Code)	Per Building	Existing	986	25	$11,371	75%	70%	$1.27	115
Electric	Hotel Motel	Space Heat	Insulation - Ceiling	R-49 c.i.	R-38 c.i.	Per Building	Existing	953	25	$3,208	25%	85%	$0.36	44
Electric	Hotel Motel	Space Heat	Insulation - Duct	R-7 (WA State Code)	No Insulation	Per Building	Existing	2,950	20	$3,386	75%	60%	$0.12	292
Electric	Hotel Motel	Space Heat	Insulation - Floor (non-slab)	R-30 (WA State Code)	R-7 (Average Existing Conditions)	Per Building	Existing	16,626	25	$5,995	35%	45%	$0.03	567
Electric	Hotel Motel	Space Heat	Insulation - Floor (non-slab)	R-38	R-30 (WA State Code)	Per Building	Existing	2,129	25	$1,850	35%	45%	$0.09	70
Electric	Hotel Motel	Space Heat	Insulation - Wall	R-16	R-3 (Average Existing Conditions)	Per Building	Existing	49,572	25	$17,675	10%	35%	$0.03	360
Electric	Hotel Motel	Space Heat	Programmable Thermostat - Web Enabled	Programmable Thermostat - Web Enabled	No Programmable Thermostat	Per Building	Existing	2,107	10	$1,749	95%	31%	$0.12	125
Electric	Hotel Motel	Space Heat	Sensible And Total Heat Recovery Devices	Install Heat Recovery Devices - rotary air-to-air enthalpy heat recovery- 50% sensible and latent recovery effectiveness	No Heat Recovery	Per Building	Existing	17,563	10	$36,924	25%	98%	$0.32	781
Electric	Hotel Motel	Space Heat	Windows-High Efficiency	U-0.40 (WA State Code)	U-0.65 (Average Existing Conditions)	Per Building	Existing	526	25	$74,129	15%	50%	$36.73	6
Electric	Hotel Motel	Vending Machines	Vending Miser	Passive Infrared Sensor on Vending Machine Monitoring Vacancy of Area And Cycles Cooling - Controls	No Vending Miser - No controls	Per Building	Existing	1,796	3	$169	90%	25%	$0.03	13
Electric	Hotel Motel	Ventilation And Circulation	Automated Exhaust VFD Control - Parking Garage CO sensor	CO Sensors	No CO Sensors	Per Building	Existing	19,782	10	$2,145	20%	85%	$0.01	1,731
Electric	Hotel Motel	Ventilation And Circulation	Convert Constant Volume Air System to VAV	Variable Volume Air System	Constant Volume Air System	Per Building	Existing	6,811	15	$53,200	15%	67%	$0.99	597
Electric	Hotel Motel	Ventilation And Circulation	Cooking Hood Controls	Demand-Ventilation Control	No Controls	Per Building	Existing	1,119	18	$5,250	95%	45%	$0.54	429
Electric	Hotel Motel	Ventilation And Circulation	Motor - CEE Premium-Efficiency Plus	CEE PE+ Motor for HVAC Applications	NEMA Efficiency Motors	Per Building	Existing	578	15	$115	95%	76%	$0.02	353
Electric	Hotel Motel	Ventilation And Circulation	Motor - Pump & Fan System - Variable Speed Control	Pump And Fan System Optimization w/ VSD	No Pump And Fan System VSD Optimization	Per Building	Existing	14,474	20	$1,948	65%	75%	$0.01	5,945
Electric	Hotel Motel	Ventilation And Circulation	Motor - VAV Box High Efficiency (ECM)	ECM Motor	Standard Efficiency Motor	Per Building	Existing	2,979	15	$6,389	5.0%	77%	$0.27	84
Electric	Hotel Motel	Ventilation And Circulation	Motor Rewind	>15, <500 HP	No Rewind	Per Building	Existing	309	7	$87	65%	25%	$0.05	36
Electric	Hotel Motel	Water Heat GT 55 Gal	Clothes Washer - Ozonating	Ozonating Clothes Washer	2013 Federal Standard Clothes Washer - MEF = 1.6, WF = 8.5	Per Building	Existing	4,596	10	$8,285	1.8%	95%	$0.15	13

Table B-2.2. Commercial Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Hotel Motel	Water Heat GT 55 Gal	Clothes Washer Commercial	ENERGY STAR Commercial Clothes Washer - MEF = 2.43, WF = 4.0	2013 Federal Standard Clothes Washer - MEF = 1.6, WF = 8.5	Per Building	Existing	1,050	7	$401	95%	80%	$-0.02	140
Electric	Hotel Motel	Water Heat GT 55 Gal	Demand Controlled Circulating Systems	Demand Controlled Circulating Systems (VFD control by demand)	Constant Circulation	Per Building	Existing	1,519	10	$4,861	55%	80%	$0.49	114
Electric	Hotel Motel	Water Heat GT 55 Gal	Dishwasher Residential	RTF ENERGY STAR Dishwasher - 277 kWh/yr and 4.25 gal/cycle	RTF Market Standard 2014 Dishwasher - 289 kWh/yr and 5.0 gal/cycle	Per Building	Existing	32	12	$101	24%	25%	$0.43	0.35
Electric	Hotel Motel	Water Heat GT 55 Gal	Dishwashing - Commercial - High Temp	High Efficiency Dishwasher (ENERGY STAR)	Standard High Temp Commercial Dishwasher	Per Building	Existing	256	12	$146	95%	95%	$-1.21	40
Electric	Hotel Motel	Water Heat GT 55 Gal	Drainwater Heat Recovery Water Heater	Install (Power-Pipe or GFX) - Heat Recovery Water Heater	No Heat Recovery System	Per Building	Existing	6,099	25	$11,458	5.0%	92%	$0.20	46
Electric	Hotel Motel	Water Heat GT 55 Gal	Low-Flow Faucet Aerators	0.5 GPM	2.2 GPM (Federal Code)	Per Building	Existing	1,174	9	$69	95%	75%	$0.00	147
Electric	Hotel Motel	Water Heat GT 55 Gal	Low-Flow Faucet Aerators	2.2 GPM (Federal Code)	3.0 GPM	Per Building	Existing	405	9	$59	95%	25%	$0.02	16
Electric	Hotel Motel	Water Heat GT 55 Gal	Low-Flow Pre-Rinse Spray Valves	0.6 GPM	1.6 GPM (Federal Standard)	Per Building	Existing	644	4	$195	95%	93%	$0.08	100
Electric	Hotel Motel	Water Heat GT 55 Gal	Low-Flow Showerheads	1.5 GPM	2.5 GPM (Federal Code)	Per Building	Existing	5,530	10	$1,591	95%	73%	$0.03	677
Electric	Hotel Motel	Water Heat GT 55 Gal	Low-Flow Showerheads	2.5 GPM (Federal Code)	4.5 GPM	Per Building	Existing	11,060	10	$1,324	95%	35%	$0.01	649
Electric	Hotel Motel	Water Heat GT 55 Gal	Pipe Insulation - Hot Water (DWH)	1.0" of Insulation, assuming R-4 (WA State Code)	No Insulation	Per Building	Existing	303	12	$139	80%	90%	$0.06	30
Electric	Hotel Motel	Water Heat GT 55 Gal	Ultrasonic Faucet Control	Install Ultrasonic Motion Faucet Control	No Faucet Control	Per Building	Existing	759	10	$4,831	75%	85%	$0.98	85
Electric	Hotel Motel	Water Heat LE 55 Gal	Clothes Washer - Ozonating	Ozonating Clothes Washer	2013 Federal Standard Clothes Washer - MEF = 1.6, WF = 8.5	Per Building	Existing	4,513	10	$8,285	1.8%	95%	$0.16	13
Electric	Hotel Motel	Water Heat LE 55 Gal	Clothes Washer Commercial	ENERGY STAR Commercial Clothes Washer - MEF = 2.43, WF = 4.0	2013 Federal Standard Clothes Washer - MEF = 1.6, WF = 8.5	Per Building	Existing	1,050	7	$401	95%	80%	$-0.02	138
Electric	Hotel Motel	Water Heat LE 55 Gal	Demand Controlled Circulating Systems	Demand Controlled Circulating Systems (VFD control by demand)	Constant Circulation	Per Building	Existing	1,492	10	$4,861	55%	80%	$0.50	110
Electric	Hotel Motel	Water Heat LE 55 Gal	Dishwasher Residential	RTF ENERGY STAR Dishwasher - 277 kWh/yr and 4.25 gal/cycle	RTF Market Standard 2014 Dishwasher - 289 kWh/yr and 5.0 gal/cycle	Per Building	Existing	32	12	$101	24%	25%	$0.43	0.34
Electric	Hotel Motel	Water Heat LE 55 Gal	Dishwashing - Commercial - High Temp	High Efficiency Dishwasher (ENERGY STAR)	Standard High Temp Commercial Dishwasher	Per Building	Existing	252	12	$143	95%	95%	$-1.24	39
Electric	Hotel Motel	Water Heat LE 55 Gal	Drainwater Heat Recovery Water Heater	Install (Power-Pipe or GFX) - Heat Recovery Water Heater	No Heat Recovery System	Per Building	Existing	6,099	25	$11,458	5.0%	92%	$0.20	44
Electric	Hotel Motel	Water Heat LE 55 Gal	Low-Flow Faucet Aerators	0.5 GPM	2.2 GPM (Federal Code)	Per Building	Existing	1,153	9	$69	95%	75%	$0.00	142
Electric	Hotel Motel	Water Heat LE 55 Gal	Low-Flow Faucet Aerators	2.2 GPM (Federal Code)	3.0 GPM	Per Building	Existing	397	9	$59	95%	25%	$0.02	16
Electric	Hotel Motel	Water Heat LE 55 Gal	Low-Flow Pre-Rinse Spray Valves	0.6 GPM	1.6 GPM (Federal Standard)	Per Building	Existing	644	4	$195	95%	93%	$0.08	98
Electric	Hotel Motel	Water Heat LE 55 Gal	Low-Flow Showerheads	1.5 GPM	2.5 GPM (Federal Code)	Per Building	Existing	5,530	10	$1,591	95%	73%	$0.03	664

Table B-2.2. Commercial Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Hotel Motel	Water Heat LE 55 Gal	Low-Flow Showerheads	2.5 GPM (Federal Code)	4.5 GPM	Per Building	Existing	11,060	10	$1,324	95%	35%	$0.01	637
Electric	Hotel Motel	Water Heat LE 55 Gal	Pipe Insulation - Hot Water (DWH)	1.0" of Insulation, assuming R-4 (WA State Code)	No Insulation	Per Building	Existing	298	12	$139	80%	90%	$0.06	29
Electric	Hotel Motel	Water Heat LE 55 Gal	Ultrasonic Faucet Control	Install Ultrasonic Motion Faucet Control	No Faucet Control	Per Building	Existing	746	10	$4,831	75%	85%	$1.00	82
Electric	Office	Computers	Network PC Power Management	Network PC Power Management	No Power Management	Per Building	Existing	5,455	4	$446	95%	30%	$0.02	23,818
Electric	Office	Cooling Chillers	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	Demand Controlled Ventilation (CO2 sensors)	Constant Ventilation	Per Building	Existing	2,517	15	$3,875	75%	94%	$0.19	5,960
Electric	Office	Cooling Chillers	Chilled Water / Condenser Water Settings-Optimization	Additional Control Features	EMS already installed - No Optimization	Per Building	Existing	314	5	$2,640	95%	81%	$2.10	753
Electric	Office	Cooling Chillers	Chilled Water Piping Loop w/ VSD Control	VSD for secondary chilled water loop	Primary loop only w/ constant speed pump	Per Building	Existing	1,903	10	$12,189	25%	70%	$1.00	1,029
Electric	Office	Cooling Chillers	Chiller-Water Side Economizer	Install Economizer	No Economizer	Per Building	Existing	1,258	15	$28,301	45%	45%	$2.86	777
Electric	Office	Cooling Chillers	Commissioning of Existing Buildings	Existing Building Commissioning	Average Existing Conditions	Per Building	Existing	3,146	7	$3,056	90%	85%	$0.19	6,036
Electric	Office	Cooling Chillers	Convert Constant Volume Air System to VAV	Variable Volume Air System	Constant Volume Air System	Per Building	Existing	7,552	15	$47,120	15%	67%	$0.79	2,308
Electric	Office	Cooling Chillers	Cooling Tower-Decrease Approach Temperature	6 Deg F	10 Deg F	Per Building	Existing	2,013	7.5	$1,508	10%	94%	$0.10	582
Electric	Office	Cooling Chillers	Cooling Tower-Two-Speed Fan Motor	Cooling Tower-Two-Speed Fan Motor	Cooling Tower-One-Speed Fan Motor	Per Building	Existing	3,524	15	$134	75%	35%	$0.00	2,688
Electric	Office	Cooling Chillers	Cooling Tower-VSD Fan Control	Variable-Speed Tower Fans replace Two-Speed	Cooling Tower-Two-Speed Fan Motor	Per Building	Existing	1,006	13	$1,090	75%	75%	$0.14	1,585
Electric	Office	Cooling Chillers	Direct Digital Control System-Installation	DDC Retrofit (Morning Warm-Up Control Logic Included in This Measure)	Pneumatic	Per Building	Existing	3,776	5	$14,904	20%	28%	$0.99	574
Electric	Office	Cooling Chillers	Direct Digital Control System-Wireless System	DDC Retrofit - Wireless System	Pneumatic	Per Building	Existing	3,776	5	$3,622	75%	80%	$0.24	4,508
Electric	Office	Cooling Chillers	Green Roof	Vegetation on Roof	Standard Dark Colored Roof	Per Building	Existing	1,384	40	$86,347	3.5%	98%	$6.30	120
Electric	Office	Cooling Chillers	Infiltration Reduction	Install Caulking And Weatherstripping (ACH 0.65)	Infiltration Conditions (ACH 1.0)	Per Building	Existing	1,258	12.5	$502	10%	39%	$0.05	123
Electric	Office	Cooling Chillers	Insulation - Ceiling	R-30 c.i. (WA State Code)	R-11 (Average Existing Conditions)	Per Building	Existing	57	25	$15,196	75%	4%	$29.37	4
Electric	Office	Cooling Chillers	Insulation - Ceiling	R-49 c.i.	R-38 c.i.	Per Building	Existing	1	25	$4,286	25%	65%	$378.36	0.51
Electric	Office	Cooling Chillers	Pipe Insulation - Chilled Water	1.5" of Insulation, assuming R-6 (WA State Code)	No Insulation	Per Building	Existing	377	15	$318	65%	45%	$0.10	278
Electric	Office	Cooling Chillers	Programmable Thermostat - Web Enabled	Programmable Thermostat - Web Enabled	No Programmable Thermostat	Per Building	Existing	755	10	$1,158	15%	26%	$0.24	73
Electric	Office	Cooling Chillers	RE - Deciduous Trees	Shade Trees	No Trees	Per Building	Existing	245	30	$1,979	75%	55%	$0.85	253

Table B-2.2. Commercial Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Office	Cooling Chillers	Sensible And Total Heat Recovery Devices	Install Heat Recovery Devices - rotary air-to-air enthalpy heat recovery- 50% sensible and latent recovery effectiveness	No Heat Recovery	Per Building	Existing	6,277	10	$32,704	25%	98%	$0.81	3,485
Electric	Office	Cooling Chillers	Window Film	Window Film	No Film	Per Building	Existing	2,692	10	$2,275	90%	66%	$0.13	33
Electric	Office	Cooling Chillers	Windows-High Efficiency	U-0.32	U-0.40 (WA State Code)	Per Building	Existing	3,176	25	$43,618	15%	95%	$1.52	959
Electric	Office	Cooling Chillers	Windows-High Efficiency	U-0.40 (WA State Code)	U-0.6 (Average Existing Conditions)	Per Building	Existing	2,897	25	$93,882	15%	95%	$3.59	859
Electric	Office	Cooling Dx	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	Demand Controlled Ventilation (CO2 sensors)	Constant Ventilation	Per Building	Existing	2,369	15	$3,875	75%	94%	$0.20	10,185
Electric	Office	Cooling Dx	Commissioning of Existing Buildings	Existing Building Commissioning	Average Existing Conditions	Per Building	Existing	2,962	7	$3,056	90%	85%	$0.20	9,629
Electric	Office	Cooling Dx	Convert Constant Volume Air System to VAV	Variable Volume Air System	Constant Volume Air System	Per Building	Existing	7,109	15	$47,120	15%	67%	$0.84	4,077
Electric	Office	Cooling Dx	DX Package-Air Side Economizer	Air-Side Economizer	No Economizer	Per Building	Existing	3,554	10	$8,788	10%	20%	$0.38	390
Electric	Office	Cooling Dx	Direct / Indirect Evaporative Cooling, Pre-Cooling	Evaporative Cooler	Standard DX cooling	Per Building	Existing	5,924	15	$32,291	50%	94%	$0.69	15,147
Electric	Office	Cooling Dx	Direct Digital Control System-Installation	DDC Retrofit (Morning Warm-Up Control Logic Included in This Measure)	Pneumatic	Per Building	Existing	3,554	5	$14,904	20%	28%	$1.05	948
Electric	Office	Cooling Dx	Direct Digital Control System-Wireless System	DDC Retrofit - Wireless System	Pneumatic	Per Building	Existing	3,554	5	$3,622	75%	80%	$0.25	7,441
Electric	Office	Cooling Dx	Duct Repair And Sealing	Reduction In Duct Losses to 5%	No Repair or Sealing, 15% duct losses	Per Building	Existing	592	18	$3,720	45%	65%	$0.73	773
Electric	Office	Cooling Dx	Economizer Tune-up	Economizer Tune-up	No Economizer Tune-Up	Per Building	Existing	2,369	5	$2,480	10%	75%	$0.26	973
Electric	Office	Cooling Dx	Green Roof	Vegetation on Roof	Standard Dark Colored Roof	Per Building	Existing	1,303	40	$86,347	3.5%	98%	$6.69	197
Electric	Office	Cooling Dx	Infiltration Reduction	Install Caulking And Weatherstripping (ACH 0.65)	Infiltration Conditions (ACH 1.0)	Per Building	Existing	1,184	12.5	$502	10%	39%	$0.06	202
Electric	Office	Cooling Dx	Insulation - Ceiling	R-30 c.i. (WA State Code)	R-11 (Average Existing Conditions)	Per Building	Existing	54	25	$15,196	75%	4%	$31.20	7
Electric	Office	Cooling Dx	Insulation - Ceiling	R-49 c.i.	R-38 c.i.	Per Building	Existing	1	25	$4,286	25%	65%	$401.94	0.84
Electric	Office	Cooling Dx	Insulation - Duct	R-7 (WA State Code)	No Insulation	Per Building	Existing	995	20	$2,998	75%	59%	$0.33	1,926
Electric	Office	Cooling Dx	Programmable Thermostat - Web Enabled	Programmable Thermostat - Web Enabled	No Programmable Thermostat	Per Building	Existing	710	10	$1,158	95%	26%	$0.25	750
Electric	Office	Cooling Dx	RE - Deciduous Trees	Shade Trees	No Trees	Per Building	Existing	595	30	$5,313	75%	55%	$0.94	1,050
Electric	Office	Cooling Dx	Window Film	Window Film	No Film	Per Building	Existing	2,692	10	$2,275	90%	66%	$0.13	61
Electric	Office	Cooling Dx	Windows-High Efficiency	U-0.32	U-0.40 (WA State Code)	Per Building	Existing	2,989	25	$43,618	15%	95%	$1.62	1,630
Electric	Office	Cooling Dx	Windows-High Efficiency	U-0.40 (WA State Code)	U-0.6 (Average Existing Conditions)	Per Building	Existing	2,727	25	$93,882	15%	95%	$3.82	1,460
Electric	Office	Heat Pump	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	Demand Controlled Ventilation (CO2 sensors)	Constant Ventilation	Per Building	Existing	2,416	15	$3,875	75%	94%	$0.20	6,924
Electric	Office	Heat Pump	Commissioning of Existing Buildings	Existing Building Commissioning	Average Existing Conditions	Per Building	Existing	5,824	7	$3,056	90%	85%	$0.10	15,052

Table B-2.2. Commercial Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Office	Heat Pump	Convert Constant Volume Air System to VAV	Variable Volume Air System	Constant Volume Air System	Per Building	Existing	7,455	15	$47,120	15%	67%	$0.80	2,954
Electric	Office	Heat Pump	Direct Digital Control System-Installation	DDC Retrofit (Morning Warm-Up Control Logic Included in This Measure)	Pneumatic	Per Building	Existing	6,989	5	$14,904	20%	28%	$0.53	1,497
Electric	Office	Heat Pump	Direct Digital Control System-Wireless System	DDC Retrofit - Wireless System	Pneumatic	Per Building	Existing	6,989	5	$3,622	75%	80%	$0.13	11,748
Electric	Office	Heat Pump	Duct Repair And Sealing	Reduction In Duct Losses to 5%	No Repair or Sealing, 15% duct losses	Per Building	Existing	1,164	18	$3,720	45%	65%	$0.37	1,220
Electric	Office	Heat Pump	Exhaust Air to Ventilation Air Heat Recovery	Exhaust Air Heat Recovery	No Heat Recovery	Per Building	Existing	3,364	14	$14,059	5.0%	94%	$0.54	560
Electric	Office	Heat Pump	Green Roof	Vegetation on Roof	Standard Dark Colored Roof	Per Building	Existing	1,328	40	$86,347	3.5%	98%	$6.56	160
Electric	Office	Heat Pump	Ground Source Heat Pump > 135 kBTU/hr	High Efficiency Ground Source Heat Pump > 135 kBTU/hr	Water Source Heat Pump > 135 kBTU/hr	Per Building	Existing	3,281	15	$1,376	3.8%	95%	$7.80	350
Electric	Office	Heat Pump	Infiltration Reduction	Install Caulking And Weatherstripping (ACH 0.65)	Infiltration Conditions (ACH 1.0)	Per Building	Existing	3,364	12.5	$502	10%	39%	$0.02	459
Electric	Office	Heat Pump	Insulation - Ceiling	R-30 c.i. (WA State Code)	R-11 (Average Existing Conditions)	Per Building	Existing	3,221	25	$15,196	75%	4%	$0.52	339
Electric	Office	Heat Pump	Insulation - Ceiling	R-38 c.i.	R-30 c.i. (WA State Code)	Per Building	Existing	433	25	$15,196	75%	50%	$3.89	570
Electric	Office	Heat Pump	Insulation - Ceiling	R-49 c.i.	R-38 c.i.	Per Building	Existing	260	25	$4,286	25%	65%	$1.82	147
Electric	Office	Heat Pump	Insulation - Duct	R-7 (WA State Code)	No Insulation	Per Building	Existing	1,957	20	$2,998	75%	59%	$0.16	3,012
Electric	Office	Heat Pump	Insulation - Floor (non-slab)	R-30 (WA State Code)	R-11 (Average Existing Conditions)	Per Building	Existing	3,123	25	$8,011	35%	15%	$0.28	562
Electric	Office	Heat Pump	Insulation - Floor (non-slab)	R-38	R-30 (WA State Code)	Per Building	Existing	611	25	$2,471	35%	15%	$0.44	109
Electric	Office	Heat Pump	Insulation - Wall	R-16	R-3 (Average Existing Conditions)	Per Building	Existing	5,636	25	$16,510	10%	35%	$0.32	673
Electric	Office	Heat Pump	Programmable Thermostat - Web Enabled	Programmable Thermostat - Web Enabled	No Programmable Thermostat	Per Building	Existing	1,397	10	$1,158	95%	26%	$0.12	1,163
Electric	Office	Heat Pump	RE - Deciduous Trees	Shade Trees	No Trees	Per Building	Existing	240	30	$2,387	75%	55%	$1.05	334
Electric	Office	Heat Pump	Window Film	Window Film	No Film	Per Building	Existing	2,692	10	$2,275	90%	66%	$0.13	48
Electric	Office	Heat Pump	Windows-High Efficiency	U-0.32	U-0.40 (WA State Code)	Per Building	Existing	2,199	25	$43,618	15%	95%	$2.20	954
Electric	Office	Heat Pump	Windows-High Efficiency	U-0.40 (WA State Code)	U-0.6 (Average Existing Conditions)	Per Building	Existing	2,673	25	$93,882	15%	95%	$3.89	1,151
Electric	Office	Lighting Exterior	Covered Parking Lighting	Covered Parking Lighting	Normal Lighting	Per Building	Existing	1,451	9.5	$403	20%	95%	$0.03	5,052
Electric	Office	Lighting Exterior	Daylighting Controls, Outdoors (Photocell)	Photocell	No Controls	Per Building	Existing	657	8	$100	75%	70%	$0.02	1,519
Electric	Office	Lighting Exterior	Occupancy Sensor Control	Occupancy Sensor Control	No Occupancy Sensor	Per Building	Existing	608	8	$366	90%	75%	$0.10	6,837
Electric	Office	Lighting Exterior	Solid State LED White Lighting	Landscape, merchandise, signage, structure & task lighting (2.5 W)	50W 10hrs/day, 365 day/yr	Per Building	Existing	640	13.69863	$128	75%	95%	$0.02	233
Electric	Office	Lighting Exterior	Surface Parking Lighting	Surface Parking Lighting	Normal Lighting	Per Building	Existing	784	18.666667	$1,059	47%	95%	$0.15	6,044
Electric	Office	Lighting Exterior	Time Clock	Time Clock	No Controls	Per Building	Existing	385	8	$105	10%	81%	$0.04	469
Electric	Office	Lighting Interior Fluorescent	Bi-Level Control, Stairwell Lighting	Occupancy Sensor Control, 50% Lighting Power during unoccupied Time	Continuous Full Power Lighting in Stairways	Per Building	Existing	1,178	9	$833	85%	75%	$0.11	8,920

Table B-2.2. Commercial Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Office	Lighting Interior Fluorescent	Dimming-Continuous, Fluorescent Fixtures	Continuous Dimming, Fluorescent Fixtures (Day-Lighting)	No Dimming Controls	Per Building	Existing	7,195	8	$7,384	30%	78%	$0.18	24,232
Electric	Office	Lighting Interior Fluorescent	Occupancy Sensor Control	Occupancy Sensor Control	No Occupancy Sensor	Per Building	Existing	3,693	8	$1,320	90%	42%	$0.06	18,402
Electric	Office	Lighting Interior Fluorescent	Time Clock	Time Clock	No Controls	Per Building	Existing	2,338	8	$639	10%	88%	$0.04	2,790
Electric	Office	Lighting Interior Hid	Occupancy Sensor Control	Occupancy Sensor Control	No Occupancy Sensor	Per Building	Existing	142	8	$1,320	90%	42%	$1.67	819
Electric	Office	Lighting Interior Hid	Time Clock	Time Clock	No Controls	Per Building	Existing	90	8	$24	10%	88%	$0.04	124
Electric	Office	Lighting Interior Other	Exit Sign - LED	Two Sided LED Exit Sign (5 Watts)	CFL Exit Sign (9 Watts)	Per Building	Existing	192	16	$32	95%	50%	$0.01	1,596
Electric	Office	Lighting Interior Other	Exit Sign - Photoluminescent or Tritium	Photoluminescent or Tritium	Two Sided LED Exit Sign (5 Watts)	Per Building	Existing	70	13	$60	95%	98%	$0.11	1,138
Electric	Office	Lighting Interior Screw Base	Cold Cathode Lighting	Cold Cathode Lighting 5 watts	30 W Incandescent Bulb	Per Building	Existing	63	5	$7	70%	94%	$0.03	203
Electric	Office	Lighting Interior Screw Base	Occupancy Sensor Control	Occupancy Sensor Control	No Occupancy Sensor	Per Building	Existing	587	8	$1,320	90%	42%	$0.40	1,019
Electric	Office	Lighting Interior Screw Base	Time Clock	Time Clock	No Controls	Per Building	Existing	371	8	$100	10%	88%	$0.04	154
Electric	Office	Other Plug Load	ENERGY STAR - Battery Charging System	ENERGY STAR Battery Charging System	Non-ENERGY STAR Battery Chargers	Per Building	Existing	5	7	$1	20%	20%	$0.05	3
Electric	Office	Other Plug Load	ENERGY STAR - Water Cooler	ENERGY STAR Water Cooler (Hot/Cold Water)	Non-ENERGY STAR Water Cooler	Per Building	Existing	427	10	$1	95%	20%	$-0.01	1,415
Electric	Office	Other Plug Load	Power Supply Transformer/Converter	80 Plus	85% efficient power supply (> 51W)	Per Building	Existing	213	4	$1	95%	86%	$-0.00	252
Electric	Office	Other Plug Load	Scanner - ENERGY STAR	ENERGY STAR Scanners	Standard Scanner	Per Building	Existing	25	6	$0.00	95%	20%	$-0.01	85
Electric	Office	Other Plug Load	Smart Strips	Smart Strip Power Strip	Standard surge protector	Per Building	Existing	1,033	4	$262	60%	90%	$0.07	9,733
Electric	Office	Refrigerator	Residential Refrigerator/Freezer Recycling	Recycling Existing Refrigerator/Freezer	Existing Refrigerator/Freezer	Per Building	Existing	481	9	$130	25%	100%	$0.04	1,813
Electric	Office	Servers	Server Virtualization	Server Virtualization	No Virtualization	Per Building	Existing	360	4	$338	72%	85%	$0.29	3,072
Electric	Office	Space Heat	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	Demand Controlled Ventilation (CO2 sensors)	Constant Ventilation	Per Building	Existing	4,978	15	$3,875	75%	94%	$0.09	21,028
Electric	Office	Space Heat	Commissioning of Existing Buildings	Existing Building Commissioning	Average Existing Conditions	Per Building	Existing	6,222	7	$3,056	90%	85%	$0.09	22,027
Electric	Office	Space Heat	Convert Constant Volume Air System to VAV	Variable Volume Air System	Constant Volume Air System	Per Building	Existing	6,471	15	$47,120	15%	67%	$0.92	3,647
Electric	Office	Space Heat	Direct Digital Control System-Installation	DDC Retrofit (Morning Warm-Up Control Logic Included in This Measure)	Pneumatic	Per Building	Existing	7,467	5	$14,904	20%	28%	$0.50	2,265
Electric	Office	Space Heat	Direct Digital Control System-Wireless System	DDC Retrofit - Wireless System	Pneumatic	Per Building	Existing	7,467	5	$3,622	75%	80%	$0.12	17,772
Electric	Office	Space Heat	Duct Repair And Sealing	Reduction In Duct Losses to 5%	No Repair or Sealing, 15% duct losses	Per Building	Existing	1,244	18	$3,720	45%	65%	$0.34	1,846

Table B-2.2. Commercial Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Office	Space Heat	Economizer Tune-up	Economizer Tune-up	No Economizer Tune-Up	Per Building	Existing	4,978	5	$2,480	10%	75%	$0.12	2,051
Electric	Office	Space Heat	Exhaust Air to Ventilation Air Heat Recovery	Exhaust Air Heat Recovery	No Heat Recovery	Per Building	Existing	7,467	14	$14,059	5.0%	94%	$0.24	1,760
Electric	Office	Space Heat	Infiltration Reduction	Install Caulking And Weatherstripping (ACH 0.65)	Infiltration Conditions (ACH 1.0)	Per Building	Existing	4,978	12.5	$502	10%	39%	$0.01	960
Electric	Office	Space Heat	Insulation - Ceiling	R-30 c.i. (WA State Code)	R-11 (Average Existing Conditions)	Per Building	Existing	6,996	25	$15,196	75%	4%	$0.23	1,041
Electric	Office	Space Heat	Insulation - Ceiling	R-38 c.i.	R-30 c.i. (WA State Code)	Per Building	Existing	880	25	$15,196	75%	50%	$1.91	1,631
Electric	Office	Space Heat	Insulation - Ceiling	R-49 c.i.	R-38 c.i.	Per Building	Existing	851	25	$4,286	25%	65%	$0.55	678
Electric	Office	Space Heat	Insulation - Duct	R-7 (WA State Code)	No Insulation	Per Building	Existing	2,090	20	$2,998	75%	59%	$0.15	4,507
Electric	Office	Space Heat	Insulation - Floor (non-slab)	R-30 (WA State Code)	R-11 (Average Existing Conditions)	Per Building	Existing	9,747	25	$8,011	35%	15%	$0.08	2,457
Electric	Office	Space Heat	Insulation - Floor (non-slab)	R-38	R-30 (WA State Code)	Per Building	Existing	1,814	25	$2,471	35%	15%	$0.14	452
Electric	Office	Space Heat	Insulation - Wall	R-16	R-3 (Average Existing Conditions)	Per Building	Existing	28,883	25	$16,510	10%	35%	$0.05	4,795
Electric	Office	Space Heat	Programmable Thermostat - Web Enabled	Programmable Thermostat - Web Enabled	No Programmable Thermostat	Per Building	Existing	1,493	10	$1,158	95%	26%	$0.11	1,699
Electric	Office	Space Heat	Sensible And Total Heat Recovery Devices	Install Heat Recovery Devices - rotary air-to-air enthalpy heat recovery- 50% sensible and latent recovery effectiveness	No Heat Recovery	Per Building	Existing	12,445	10	$32,704	25%	98%	$0.40	12,718
Electric	Office	Vending Machines	Vending Miser	Passive Infrared Sensor on Vending Machine Monitoring Vacancy of Area And Cycles Cooling - Controls	No Vending Miser - No controls	Per Building	Existing	1,796	3	$170	10%	25%	$0.03	46
Electric	Office	Ventilation And Circulation	Automated Exhaust VFD Control - Parking Garage CO sensor	CO Sensors	No CO Sensors	Per Building	Existing	17,521	10	$1,900	20%	85%	$0.01	11,980
Electric	Office	Ventilation And Circulation	Convert Constant Volume Air System to VAV	Variable Volume Air System	Constant Volume Air System	Per Building	Existing	2,849	15	$47,120	15%	67%	$2.10	4,134
Electric	Office	Ventilation And Circulation	Motor - CEE Premium-Efficiency Plus	CEE PE+ Motor for HVAC Applications	NEMA Efficiency Motors	Per Building	Existing	242	15	$102	95%	76%	$0.05	2,468
Electric	Office	Ventilation And Circulation	Motor - Pump & Fan System - Variable Speed Control	Pump And Fan System Optimization w/ VSD	No Pump And Fan System VSD Optimization	Per Building	Existing	6,055	20	$1,725	65%	75%	$0.02	41,492
Electric	Office	Ventilation And Circulation	Motor - VAV Box High Efficiency (ECM)	ECM Motor	Standard Efficiency Motor	Per Building	Existing	1,246	15	$5,659	11%	77%	$0.57	1,291
Electric	Office	Ventilation And Circulation	Motor Rewind	>15, <500 HP	No Rewind	Per Building	Existing	273	7	$79	65%	25%	$0.05	545
Electric	Office	Water Heat GT 55 Gal	Demand Controlled Circulating Systems	Demand Controlled Circulating Systems (VFD control by demand)	Constant Circulation	Per Building	Existing	363	10	$4,305	55%	80%	$1.84	1,046
Electric	Office	Water Heat GT 55 Gal	Dishwasher Residential	RTF ENERGY STAR Dishwasher - 277 kWh/yr and 4.25 gal/cycle	RTF Market Standard 2014 Dishwasher - 289 kWh/yr and 5.0 gal/cycle	Per Building	Existing	21	12	$66	8.1%	25%	$0.43	2
Electric	Office	Water Heat GT 55 Gal	Drainwater Heat Recovery Water Heater	Install (Power-Pipe or GFX) - Heat Recovery Water Heater	No Heat Recovery System	Per Building	Existing	1,501	25	$2,083	5.0%	92%	$0.15	428

Table B-2.2. Commercial Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Office	Water Heat GT 55 Gal	Low-Flow Faucet Aerators	0.5 GPM	2.2 GPM (Federal Code)	Per Building	Existing	280	9	$6	95%	75%	$-0.02	1,309
Electric	Office	Water Heat GT 55 Gal	Low-Flow Faucet Aerators	2.2 GPM (Federal Code)	3.0 GPM	Per Building	Existing	96	9	$4	95%	25%	$-0.05	150
Electric	Office	Water Heat GT 55 Gal	Low-Flow Showerheads	1.5 GPM	2.5 GPM (Federal Code)	Per Building	Existing	25	10	$13	95%	73%	$-0.38	116
Electric	Office	Water Heat GT 55 Gal	Low-Flow Showerheads	2.5 GPM (Federal Code)	4.5 GPM	Per Building	Existing	51	10	$12	95%	35%	$-0.43	111
Electric	Office	Water Heat GT 55 Gal	Pipe Insulation - Hot Water (DWH)	1.0" of Insulation, assuming R-4 (WA State Code)	No Insulation	Per Building	Existing	72	12	$24	80%	30%	$0.04	110
Electric	Office	Water Heat GT 55 Gal	Ultrasonic Faucet Control	Install Ultrasonic Motion Faucet Control	No Faucet Control	Per Building	Existing	181	10	$428	75%	85%	$0.31	758
Electric	Office	Water Heat LE 55 Gal	Demand Controlled Circulating Systems	Demand Controlled Circulating Systems (VFD control by demand)	Constant Circulation	Per Building	Existing	357	10	$4,305	55%	80%	$1.88	1,009
Electric	Office	Water Heat LE 55 Gal	Dishwasher Residential	RTF ENERGY STAR Dishwasher - 277 kWh/yr and 4.25 gal/cycle	RTF Market Standard 2014 Dishwasher - 289 kWh/yr and 5.0 gal/cycle	Per Building	Existing	21	12	$66	8.1%	25%	$0.43	2
Electric	Office	Water Heat LE 55 Gal	Drainwater Heat Recovery Water Heater	Install (Power-Pipe or GFX) - Heat Recovery Water Heater	No Heat Recovery System	Per Building	Existing	1,501	25	$2,083	5.0%	92%	$0.15	412
Electric	Office	Water Heat LE 55 Gal	Low-Flow Faucet Aerators	0.5 GPM	2.2 GPM (Federal Code)	Per Building	Existing	275	9	$6	95%	75%	$-0.02	1,262
Electric	Office	Water Heat LE 55 Gal	Low-Flow Faucet Aerators	2.2 GPM (Federal Code)	3.0 GPM	Per Building	Existing	95	9	$4	95%	25%	$-0.04	145
Electric	Office	Water Heat LE 55 Gal	Low-Flow Showerheads	1.5 GPM	2.5 GPM (Federal Code)	Per Building	Existing	25	10	$13	95%	73%	$-0.38	114
Electric	Office	Water Heat LE 55 Gal	Low-Flow Showerheads	2.5 GPM (Federal Code)	4.5 GPM	Per Building	Existing	51	10	$12	95%	35%	$-0.43	109
Electric	Office	Water Heat LE 55 Gal	Pipe Insulation - Hot Water (DWH)	1.0" of Insulation, assuming R-4 (WA State Code)	No Insulation	Per Building	Existing	71	12	$24	80%	30%	$0.04	106
Electric	Office	Water Heat LE 55 Gal	Ultrasonic Faucet Control	Install Ultrasonic Motion Faucet Control	No Faucet Control	Per Building	Existing	178	10	$428	75%	85%	$0.32	731
Electric	Other	Computers	Network PC Power Management	Network PC Power Management	No Power Management	Per Building	Existing	969	4	$84	95%	30%	$0.02	2,763
Electric	Other	Cooking	Combination Oven	60% cooking efficiency	Non ENERGY STAR	Per Building	Existing	90	12	$15	90%	90%	$0.02	447
Electric	Other	Cooking	Fryers - New CEE Efficient Electric Deep Fat Fryers	15 inch width Deep Fryer CEE 2006 rating: 80% under heavy load, Less than 1000 watt at idle	15 inch width standard electric deep fat fryers	Per Building	Existing	5	12	$8	35%	35%	$0.20	4
Electric	Other	Cooking	Griddle	70% cooking efficiency	Non ENERGY STAR	Per Building	Existing	46	12	$16	95%	35%	$0.04	94
Electric	Other	Cooking	Hot Food Holding Cabinet	ENERGY STAR Hot Food Holding Cabinet	Non ENERGY STAR Hot Food Holding Cabinet	Per Building	Existing	110	12	$70	15%	21%	$0.08	21
Electric	Other	Cooking	Steam Cooker	ENERGY STAR Steam Cooker	Non ENERGY STAR Steam Cooker	Per Building	Existing	34	12	$3	5.0%	35%	$0.01	6
Electric	Other	Cooling Chillers	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	Demand Controlled Ventilation (CO2 sensors)	Constant Ventilation	Per Building	Existing	1,768	15	$3,000	50%	94%	$0.21	536
Electric	Other	Cooling Chillers	Chilled Water / Condenser Water Settings-Optimization	Additional Control Features	EMS already installed - No Optimization	Per Building	Existing	221	5	$2,043	95%	81%	$2.31	104
Electric	Other	Cooling Chillers	Chilled Water Piping Loop w/ VSD Control	VSD for secondary chilled water loop	Primary loop only w/ constant speed pump	Per Building	Existing	1,337	10	$10,617	25%	70%	$1.24	142

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Electric	Other	Cooling Chillers	Chiller-Water Side Economizer	Install Economizer	No Economizer	Per Building	Existing	884	15	$24,650	45%	30%	$3.54	71
Electric	Other	Cooling Chillers	Commissioning of Existing Buildings	Existing Building Commissioning	Average Existing Conditions	Per Building	Existing	2,210	7	$2,366	90%	85%	$0.21	822
Electric	Other	Cooling Chillers	Convert Constant Volume Air System to VAV	Variable Volume Air System	Constant Volume Air System	Per Building	Existing	5,306	15	$36,479	15%	67%	$0.87	319
Electric	Other	Cooling Chillers	Cooling Tower-Decrease Approach Temperature	6 Deg F	10 Deg F	Per Building	Existing	1,414	7.5	$1,312	10%	94%	$0.12	80
Electric	Other	Cooling Chillers	Cooling Tower-Two-Speed Fan Motor	Cooling Tower-Two-Speed Fan Motor	Cooling Tower-One-Speed Fan Motor	Per Building	Existing	2,476	15	$118	75%	35%	$0.00	373
Electric	Other	Cooling Chillers	Cooling Tower-VSD Fan Control	Variable-Speed Tower Fans replace Two-Speed	Cooling Tower-Two-Speed Fan Motor	Per Building	Existing	707	13	$950	75%	75%	$0.18	220
Electric	Other	Cooling Chillers	Direct Digital Control System-Installation	DDC Retrofit (Morning Warm-Up Control Logic Included in This Measure)	Pneumatic	Per Building	Existing	2,653	5	$11,538	10%	66%	$1.09	94
Electric	Other	Cooling Chillers	Direct Digital Control System-Wireless System	DDC Retrofit - Wireless System	Pneumatic	Per Building	Existing	2,653	5	$2,804	50%	80%	$0.26	455
Electric	Other	Cooling Chillers	Exhaust Hood Makeup Air	Provide Makeup Air Directly at Exhaust Hood Instead of Pulling Conditioned Air	Hood Pulls Conditioned Air (No Make-up Air)	Per Building	Existing	440	10	$3,499	100%	85%	$1.24	345
Electric	Other	Cooling Chillers	Green Roof	Vegetation on Roof	Standard Dark Colored Roof	Per Building	Existing	1,448	40	$99,561	3.5%	98%	$6.94	24
Electric	Other	Cooling Chillers	Infiltration Reduction	Install Caulking And Weatherstripping (ACH 0.65)	Infiltration Conditions (ACH 1.0)	Per Building	Existing	578	12.5	$172	10%	39%	$0.04	10
Electric	Other	Cooling Chillers	Insulation - Ceiling	R-30 c.i. (WA State Code)	R-11 (Average Existing Conditions)	Per Building	Existing	40	25	$17,522	75%	30%	$48.20	4
Electric	Other	Cooling Chillers	Insulation - Ceiling	R-49 c.i.	R-38 c.i.	Per Building	Existing	0.88	25	$4,943	25%	85%	$621.00	0.09
Electric	Other	Cooling Chillers	Pipe Insulation - Chilled Water	1.5" of Insulation, assuming R-6 (WA State Code)	No Insulation	Per Building	Existing	265	15	$246	65%	45%	$0.11	37
Electric	Other	Cooling Chillers	Programmable Thermostat - Web Enabled	Programmable Thermostat - Web Enabled	No Programmable Thermostat	Per Building	Existing	530	10	$778	15%	26%	$0.23	9
Electric	Other	Cooling Chillers	RE - Deciduous Trees	Shade Trees	No Trees	Per Building	Existing	109	30	$4,049	75%	55%	$3.91	21
Electric	Other	Cooling Chillers	Sensible And Total Heat Recovery Devices	Install Heat Recovery Devices - rotary air-to-air enthalpy heat recovery- 50% sensible and latent recovery effectiveness	No Heat Recovery	Per Building	Existing	5,340	10	$25,319	25%	98%	$0.74	474
Electric	Other	Cooling Chillers	Window Film	Window Film	No Film	Per Building	Existing	1,063	10	$777	90%	66%	$0.11	2
Electric	Other	Cooling Chillers	Windows-High Efficiency	U-0.32	U-0.40 (WA State Code)	Per Building	Existing	2,231	25	$14,893	15%	70%	$0.74	96
Electric	Other	Cooling Chillers	Windows-High Efficiency	U-0.40 (WA State Code)	U-0.65 (Average Existing Conditions)	Per Building	Existing	1,953	25	$32,054	15%	70%	$1.82	83
Electric	Other	Cooling Dx	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	Demand Controlled Ventilation (CO2 sensors)	Constant Ventilation	Per Building	Existing	2,213	15	$3,000	50%	94%	$0.17	3,073
Electric	Other	Cooling Dx	Commissioning of Existing Buildings	Existing Building Commissioning	Average Existing Conditions	Per Building	Existing	2,767	7	$2,366	90%	85%	$0.17	4,540

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Electric	Other	Cooling Dx	Convert Constant Volume Air System to VAV	Variable Volume Air System	Constant Volume Air System	Per Building	Existing	6,641	15	$36,479	15%	67%	$0.69	1,885
Electric	Other	Cooling Dx	DX Package-Air Side Economizer	Air-Side Economizer	No Economizer	Per Building	Existing	3,320	10	$7,655	10%	70%	$0.36	634
Electric	Other	Cooling Dx	Direct / Indirect Evaporative Cooling, Pre-Cooling	Evaporative Cooler	Standard DX cooling	Per Building	Existing	5,534	15	$24,999	50%	94%	$0.57	6,977
Electric	Other	Cooling Dx	Direct Digital Control System-Installation	DDC Retrofit (Morning Warm-Up Control Logic Included in This Measure)	Pneumatic	Per Building	Existing	3,320	5	$11,538	10%	66%	$0.87	514
Electric	Other	Cooling Dx	Direct Digital Control System-Wireless System	DDC Retrofit - Wireless System	Pneumatic	Per Building	Existing	3,320	5	$2,804	50%	80%	$0.21	2,489
Electric	Other	Cooling Dx	Duct Repair And Sealing	Reduction In Duct Losses to 5%	No Repair or Sealing, 15% duct losses	Per Building	Existing	553	18	$2,880	45%	65%	$0.60	362
Electric	Other	Cooling Dx	Economizer Tune-up	Economizer Tune-up	No Economizer Tune-Up	Per Building	Existing	2,213	5	$2,159	10%	75%	$0.24	448
Electric	Other	Cooling Dx	Exhaust Hood Makeup Air	Provide Makeup Air Directly at Exhaust Hood Instead of Pulling Conditioned Air	Hood Pulls Conditioned Air (No Make-up Air)	Per Building	Existing	480	10	$3,499	5.0%	85%	$1.13	93
Electric	Other	Cooling Dx	Green Roof	Vegetation on Roof	Standard Dark Colored Roof	Per Building	Existing	1,813	40	$99,561	3.5%	98%	$5.54	137
Electric	Other	Cooling Dx	Infiltration Reduction	Install Caulking And Weatherstripping (ACH 0.65)	Infiltration Conditions (ACH 1.0)	Per Building	Existing	723	12.5	$172	10%	39%	$0.03	61
Electric	Other	Cooling Dx	Insulation - Ceiling	R-30 c.i. (WA State Code)	R-11 (Average Existing Conditions)	Per Building	Existing	50	25	$17,522	75%	30%	$38.51	25
Electric	Other	Cooling Dx	Insulation - Ceiling	R-49 c.i.	R-38 c.i.	Per Building	Existing	1	25	$4,943	25%	85%	$496.13	0.51
Electric	Other	Cooling Dx	Insulation - Duct	R-7 (WA State Code)	No Insulation	Per Building	Existing	929	20	$2,320	75%	59%	$0.27	902
Electric	Other	Cooling Dx	Programmable Thermostat - Web Enabled	Programmable Thermostat - Web Enabled	No Programmable Thermostat	Per Building	Existing	664	10	$778	95%	28%	$0.18	387
Electric	Other	Cooling Dx	RE - Deciduous Trees	Shade Trees	No Trees	Per Building	Existing	64	30	$2,438	75%	55%	$3.99	57
Electric	Other	Cooling Dx	Window Film	Window Film	No Film	Per Building	Existing	1,063	10	$777	90%	66%	$0.11	12
Electric	Other	Cooling Dx	Windows-High Efficiency	U-0.32	U-0.40 (WA State Code)	Per Building	Existing	2,793	25	$14,893	15%	70%	$0.59	566
Electric	Other	Cooling Dx	Windows-High Efficiency	U-0.40 (WA State Code)	U-0.65 (Average Existing Conditions)	Per Building	Existing	2,444	25	$32,054	15%	70%	$1.45	489
Electric	Other	Heat Pump	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	Demand Controlled Ventilation (CO2 sensors)	Constant Ventilation	Per Building	Existing	2,160	15	$3,000	50%	94%	$0.17	880
Electric	Other	Heat Pump	Commissioning of Existing Buildings	Existing Building Commissioning	Average Existing Conditions	Per Building	Existing	4,512	7	$2,366	90%	85%	$0.10	2,498
Electric	Other	Heat Pump	Convert Constant Volume Air System to VAV	Variable Volume Air System	Constant Volume Air System	Per Building	Existing	5,775	15	$36,479	15%	67%	$0.80	490
Electric	Other	Heat Pump	Direct Digital Control System-Installation	DDC Retrofit (Morning Warm-Up Control Logic Included in This Measure)	Pneumatic	Per Building	Existing	5,414	5	$11,538	10%	66%	$0.53	294
Electric	Other	Heat Pump	Direct Digital Control System-Wireless System	DDC Retrofit - Wireless System	Pneumatic	Per Building	Existing	5,414	5	$2,804	50%	80%	$0.12	1,422
Electric	Other	Heat Pump	Duct Repair And Sealing	Reduction In Duct Losses to 5%	No Repair or Sealing, 15% duct losses	Per Building	Existing	902	18	$2,880	45%	65%	$0.36	207
Electric	Other	Heat Pump	Exhaust Air to Ventilation Air Heat Recovery	Exhaust Air Heat Recovery	No Heat Recovery	Per Building	Existing	2,174	14	$10,883	5.0%	94%	$0.65	79

Table B-2.2. Commercial Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Other	Heat Pump	Exhaust Hood Makeup Air	Provide Makeup Air Directly at Exhaust Hood Instead of Pulling Conditioned Air	Hood Pulls Conditioned Air (No Make-up Air)	Per Building	Existing	822	10	$3,499	5.0%	85%	$0.66	53
Electric	Other	Heat Pump	Green Roof	Vegetation on Roof	Standard Dark Colored Roof	Per Building	Existing	1,769	40	$99,561	3.5%	98%	$5.68	46
Electric	Other	Heat Pump	Ground Source Heat Pump > 135 kBTU/hr	High Efficiency Ground Source Heat Pump > 135 kBTU/hr	Water Source Heat Pump > 135 kBTU/hr	Per Building	Existing	2,933	15	$75,392	3.8%	95%	$7.60	67
Electric	Other	Heat Pump	Infiltration Reduction	Install Caulking And Weatherstripping (ACH 0.65)	Infiltration Conditions (ACH 1.0)	Per Building	Existing	1,421	12.5	$172	10%	39%	$0.01	42
Electric	Other	Heat Pump	Insulation - Ceiling	R-30 c.i. (WA State Code)	R-11 (Average Existing Conditions)	Per Building	Existing	2,504	25	$17,522	75%	30%	$0.77	433
Electric	Other	Heat Pump	Insulation - Ceiling	R-38 c.i.	R-30 c.i. (WA State Code)	Per Building	Existing	336	25	$17,522	75%	70%	$5.78	133
Electric	Other	Heat Pump	Insulation - Ceiling	R-49 c.i.	R-38 c.i.	Per Building	Existing	143	25	$4,943	25%	85%	$3.81	23
Electric	Other	Heat Pump	Insulation - Duct	R-7 (WA State Code)	No Insulation	Per Building	Existing	1,516	20	$2,320	75%	59%	$0.16	503
Electric	Other	Heat Pump	Insulation - Floor (non-slab)	R-30 (WA State Code)	R-7 (Average Existing Conditions)	Per Building	Existing	2,173	25	$9,238	35%	50%	$0.46	281
Electric	Other	Heat Pump	Insulation - Floor (non-slab)	R-38	R-30 (WA State Code)	Per Building	Existing	314	25	$2,849	35%	50%	$1.00	40
Electric	Other	Heat Pump	Insulation - Wall	R-16	R-3 (Average Existing Conditions)	Per Building	Existing	1,900	25	$8,620	10%	35%	$0.49	48
Electric	Other	Heat Pump	Programmable Thermostat - Web Enabled	Programmable Thermostat - Web Enabled	No Programmable Thermostat	Per Building	Existing	1,082	10	$778	95%	28%	$0.10	213
Electric	Other	Heat Pump	RE - Deciduous Trees	Shade Trees	No Trees	Per Building	Existing	142	30	$5,313	75%	55%	$3.95	42
Electric	Other	Heat Pump	Variable Refrigerant Flow Cooling System	Variable Refrigerant Flow Cooling System	Standard Refrigeration System	Per Building	Existing	9,746	15	$3,294	25%	95%	$0.03	2,006
Electric	Other	Heat Pump	Window Film	Window Film	No Film	Per Building	Existing	1,063	10	$777	90%	66%	$0.11	4
Electric	Other	Heat Pump	Windows-High Efficiency	U-0.32	U-0.40 (WA State Code)	Per Building	Existing	2,176	25	$14,893	15%	70%	$0.75	149
Electric	Other	Heat Pump	Windows-High Efficiency	U-0.40 (WA State Code)	U-0.65 (Average Existing Conditions)	Per Building	Existing	2,522	25	$32,054	15%	70%	$1.40	171
Electric	Other	Lighting Exterior	Covered Parking Lighting	Covered Parking Lighting	Normal Lighting	Per Building	Existing	1,124	9.5	$313	20%	95%	$0.03	2,554
Electric	Other	Lighting Exterior	Daylighting Controls, Outdoors (Photocell)	Photocell	No Controls	Per Building	Existing	705	8	$108	75%	70%	$0.02	1,891
Electric	Other	Lighting Exterior	Occupancy Sensor Control	Occupancy Sensor Control	No Occupancy Sensor	Per Building	Existing	1,343	8	$365	90%	75%	$0.04	10,060
Electric	Other	Lighting Exterior	Solid State LED White Lighting	Landscape, merchandise, signage, structure & task lighting (2.5 W)	50W 10hrs/day, 365 day/yr	Per Building	Existing	687	13.69863	$138	75%	95%	$0.02	284
Electric	Other	Lighting Exterior	Surface Parking Lighting	Surface Parking Lighting	Normal Lighting	Per Building	Existing	607	18.666667	$820	47%	95%	$0.15	3,055
Electric	Other	Lighting Exterior	Time Clock	Time Clock	No Controls	Per Building	Existing	719	8	$197	10%	81%	$0.04	596
Electric	Other	Lighting Interior Fluorescent	Bi-Level Control, Stairwell Lighting	Occupancy Sensor Control, 50% Lighting Power during unoccupied Time	Continuous Full Power Lighting in Stairways	Per Building	Existing	660	9	$644	25%	75%	$0.16	1,075
Electric	Other	Lighting Interior Fluorescent	Dimming-Continuous, Fluorescent Fixtures	Continuous Dimming, Fluorescent Fixtures (Day-Lighting)	No Dimming Controls	Per Building	Existing	4,539	8	$7,931	30%	84%	$0.31	10,791
Electric	Other	Lighting Interior Fluorescent	LED Refrigeration Case Lights	LED Refrigeration Case Lights	Fluorescent Refrigeration Case	Per Building	Existing	147	6	$55	10%	80%	$0.06	139
Electric	Other	Lighting Interior Fluorescent	Occupancy Sensor Control	Occupancy Sensor Control	No Occupancy Sensor	Per Building	Existing	2,754	8	$1,022	90%	52%	$0.06	11,281

Table B-2.2. Commercial Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Other	Lighting Interior Fluorescent	Time Clock	Time Clock	No Controls	Per Building	Existing	1,475	8	$402	10%	100%	$0.04	1,285
Electric	Other	Lighting Interior Hid	Occupancy Sensor Control	Occupancy Sensor Control	No Occupancy Sensor	Per Building	Existing	971	8	$1,022	90%	52%	$0.18	4,631
Electric	Other	Lighting Interior Hid	Time Clock	Time Clock	No Controls	Per Building	Existing	520	8	$142	10%	100%	$0.04	527
Electric	Other	Lighting Interior Other	Exit Sign - LED	Two Sided LED Exit Sign (5 Watts)	CFL Exit Sign (9 Watts)	Per Building	Existing	337	16	$56	95%	50%	$0.01	1,828
Electric	Other	Lighting Interior Other	Exit Sign - Photoluminescent or Tritium	Photoluminescent or Tritium	Two Sided LED Exit Sign (5 Watts)	Per Building	Existing	122	13	$105	95%	98%	$0.11	1,303
Electric	Other	Lighting Interior Screw Base	Cold Cathode Lighting	Cold Cathode Lighting 5 watts	30 W Incandescent Bulb	Per Building	Existing	151	5	$17	70%	94%	$0.03	316
Electric	Other	Lighting Interior Screw Base	Occupancy Sensor Control	Occupancy Sensor Control	No Occupancy Sensor	Per Building	Existing	826	8	$1,022	90%	52%	$0.22	1,169
Electric	Other	Lighting Interior Screw Base	Time Clock	Time Clock	No Controls	Per Building	Existing	442	8	$120	10%	100%	$0.04	133
Electric	Other	Other Plug Load	ENERGY STAR - Battery Charging System	ENERGY STAR Battery Charging System	Non-ENERGY STAR Battery Chargers	Per Building	Existing	6	7	$2	20%	20%	$0.07	2
Electric	Other	Other Plug Load	ENERGY STAR - Water Cooler	ENERGY STAR Water Cooler (Hot/Cold Water)	Non-ENERGY STAR Water Cooler	Per Building	Existing	44	10	$1	95%	20%	$-0.00	95
Electric	Other	Other Plug Load	Power Supply Transformer/Converter	80 Plus	85% efficient power supply (> 51W)	Per Building	Existing	165	4	$2	95%	86%	$0.00	191
Electric	Other	Other Plug Load	Scanner - ENERGY STAR	ENERGY STAR Scanners	Standard Scanner	Per Building	Existing	17	6	$1	95%	20%	$0.01	37
Electric	Other	Other Plug Load	Smart Strips	Smart Strip Power Strip	Standard surge protector	Per Building	Existing	240	4	$60	60%	90%	$0.07	1,476
Electric	Other	Refrigeratio n	Add Doors to Refrigerated Open Display Cases	Add Doors to Refrigerated Open Display Cases	Standard Refrigerated Open Display Cases	Per Building	Existing	81	12	$126	15%	95%	$0.22	132
Electric	Other	Refrigeratio n	Anti-Sweat (Humidistat) Controls	Anti-Sweat (Humidistat) Controls	No Anti-Sweat (Humidistat) Controls	Per Building	Existing	115	12	$9	15%	45%	$0.01	88
Electric	Other	Refrigeratio n	Case Electronically Commutated Motor	ECM Case Fans	Standard Efficiency Motor	Per Building	Existing	543	15	$131	2.5%	77%	$0.02	118
Electric	Other	Refrigeratio n	Case Replacement Low Temp	Case Replacement Low Temp	No replacement	Per Building	Existing	11,729	15	$1,269	2.5%	98%	$0.01	65
Electric	Other	Refrigeratio n	Case Replacement Med Temp	Case Replacement Med Temp	No replacement	Per Building	Existing	1,000	15	$657	2.5%	98%	$0.08	5
Electric	Other	Refrigeratio n	Commercial Refrigerator - Semivertical - No Doors - Med Temp	Commercial Refrigerator - Semivertical - No Doors - Med Temp	Standard Case	Per Building	Existing	118	10	$98	90%	85%	$0.12	1,031
Electric	Other	Refrigeratio n	Commercial Refrigerator - Vertical - No Doors - Med Temp	Commercial Refrigerator - Vertical - No Doors - Med Temp	Standard Case	Per Building	Existing	53	10	$44	90%	85%	$0.12	466
Electric	Other	Refrigeratio n	Compressor VSD Retrofit	VSD Compressor	Constant Speed Compressor	Per Building	Existing	154	13	$52	60%	77%	$0.04	717
Electric	Other	Refrigeratio n	Demand Control Defrost - Hot Gas	Refrigerant Defrost	Defrost - Electric	Per Building	Existing	17	10	$43	5.0%	68%	$0.37	6
Electric	Other	Refrigeratio n	Display Case Motion Sensors	Display Case Motion Sensors	No Motion Sensors	Per Building	Existing	28	8	$2	90%	85%	$0.01	208
Electric	Other	Refrigeratio n	Evaporative Condenser - High-Efficiency	High-Efficiency Evaporative Condenser	Air-Cooled Condenser	Per Building	Existing	17	15	$84	90%	65%	$0.62	66
Electric	Other	Refrigeratio n	Evaporator Fan Controller	ECM Evaporator Fan Controller	No Controller	Per Building	Existing	163	15	$181	90%	85%	$0.13	1,175

Table B-2.2. Commercial Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Other	Refrigeration	Floating Condenser Head Pressure Controls	Floating Condenser Head Pressure Controls	No Floating Condenser Head Pressure Controls	Per Building	Existing	81	15	$27	50%	81%	$0.04	280
Electric	Other	Refrigeration	Glass Door ENERGY STAR Refrigerators/Freezers	Glass Door ENERGY STAR Refrigerators/Freezers	Standard Glass Doors	Per Building	Existing	2	12	$2	95%	77%	$0.12	22
Electric	Other	Refrigeration	High-Efficiency Compressor	High-Efficiency Compressor (15% More Efficient)	Standard Compressor, 40% Efficiency	Per Building	Existing	9,761	10	$6,343	85%	72%	$0.10	591
Electric	Other	Refrigeration	Ice Maker	High-Efficiency Ice Maker	Standard Ice Maker	Per Building	Existing	47	10	$0.00	95%	86%	$-0.02	440
Electric	Other	Refrigeration	Night Covers for Display Cases	Night Covers for Display Cases	No Night Covers	Per Building	Existing	76	5	$13	5.0%	85%	$0.04	37
Electric	Other	Refrigeration	Refrigeration Commissioning of New or Existing Buildings	New or Existing Building Refrigeration Commissioning	No Commissioning	Per Building	Existing	160	3	$25	5.0%	85%	$0.06	51
Electric	Other	Refrigeration	Refrigerator eCube	Refrigerator eCube	No Refrigerator eCube	Per Building	Existing	188	10	$59	75%	95%	$0.04	128
Electric	Other	Refrigeration	Solid Door ENERGY STAR Refrigerators/Freezers	Solid Door ENERGY STAR Refrigerators/Freezers	Standard Solid Door	Per Building	Existing	8	12	$-2.3914952	95%	81%	$-0.05	74
Electric	Other	Refrigeration	Standalone to Multiplex Compressor	Standalone to Multiplex Compressor	Standalone compressor	Per Building	Existing	37	13	$5	2.5%	90%	$0.01	6
Electric	Other	Refrigeration	Strip Curtains for Walk-Ins	Strip Curtains for Walk-Ins	No Strip Curtains for Walk-In	Per Building	Existing	133	4	$8	5.0%	20%	$0.01	15
Electric	Other	Refrigeration	VFD Rooftop Unit Supply Fan (Grocery Only)	VFD Rooftop Unit Supply Fan (Grocery Only)	Standard Supply Fan	Per Building	Existing	366	15	$111	25%	95%	$0.03	638
Electric	Other	Refrigeration	Visi Cooler	High Efficiency Visi Cooler	Standard Visi Cooler	Per Building	Existing	373	10	$70	95%	85%	$0.02	3,432
Electric	Other	Refrigeration	Walk-In Electronically Commutated Motor	ECM Evaporator Fans	Standard Efficiency Motor	Per Building	Existing	163	15	$181	2.5%	95%	$0.13	44
Electric	Other	Refrigeration	Water Cooled Refrigeration with Heat Recovery	Heat Recovery from refrigeration system. Applied to Water Heating Electric End use	No heat recovery	Per Building	Existing	1	10	$106	2.5%	94%	$10.76	0.15
Electric	Other	Refrigerator	Residential Refrigerator/Freezer Recycling	Recycling Existing Refrigerator/Freezer	Existing Refrigerator/Freezer	Per Building	Existing	481	9	$130	25%	100%	$0.04	1,184
Electric	Other	Servers	Server Virtualization	Server Virtualization	No Virtualization	Per Building	Existing	360	4	$337	72%	85%	$0.29	2,006
Electric	Other	Space Heat	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	Demand Controlled Ventilation (CO2 sensors)	Constant Ventilation	Per Building	Existing	3,138	15	$3,000	50%	94%	$0.10	5,366
Electric	Other	Space Heat	Commissioning of Existing Buildings	Existing Building Commissioning	Average Existing Conditions	Per Building	Existing	3,923	7	$2,366	90%	85%	$0.10	8,022
Electric	Other	Space Heat	Convert Constant Volume Air System to VAV	Variable Volume Air System	Constant Volume Air System	Per Building	Existing	4,080	15	$36,479	15%	67%	$1.12	1,426
Electric	Other	Space Heat	Direct Digital Control System-Installation	DDC Retrofit (Morning Warm-Up Control Logic Included in This Measure)	Pneumatic	Per Building	Existing	4,708	5	$11,538	10%	66%	$0.60	1,047
Electric	Other	Space Heat	Direct Digital Control System-Wireless System	DDC Retrofit - Wireless System	Pneumatic	Per Building	Existing	4,708	5	$2,804	50%	80%	$0.13	5,065
Electric	Other	Space Heat	Duct Repair And Sealing	Reduction In Duct Losses to 5%	No Repair or Sealing, 15% duct losses	Per Building	Existing	784	18	$2,880	45%	65%	$0.41	737
Electric	Other	Space Heat	Economizer Tune-up	Economizer Tune-up	No Economizer Tune-Up	Per Building	Existing	3,138	5	$2,159	10%	75%	$0.16	805

Table B-2.2. Commercial Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Other	Space Heat	Exhaust Air to Ventilation Air Heat Recovery	Exhaust Air Heat Recovery	No Heat Recovery	Per Building	Existing	4,708	14	$10,883	5.0%	94%	$0.29	703
Electric	Other	Space Heat	Exhaust Hood Makeup Air	Provide Makeup Air Directly at Exhaust Hood Instead of Pulling Conditioned Air	Hood Pulls Conditioned Air (No Make-up Air)	Per Building	Existing	647	10	$3,499	5.0%	85%	$0.83	189
Electric	Other	Space Heat	Infiltration Reduction	Install Caulking And Weatherstripping (ACH 0.65)	Infiltration Conditions (ACH 1.0)	Per Building	Existing	2,052	12.5	$172	10%	39%	$-0.01	250
Electric	Other	Space Heat	Insulation - Ceiling	R-30 c.i. (WA State Code)	R-11 (Average Existing Conditions)	Per Building	Existing	5,293	25	$17,522	75%	30%	$0.35	3,740
Electric	Other	Space Heat	Insulation - Ceiling	R-38 c.i.	R-30 c.i. (WA State Code)	Per Building	Existing	666	25	$17,522	75%	70%	$2.90	1,057
Electric	Other	Space Heat	Insulation - Ceiling	R-49 c.i.	R-38 c.i.	Per Building	Existing	644	25	$4,943	25%	85%	$0.83	409
Electric	Other	Space Heat	Insulation - Duct	R-7 (WA State Code)	No Insulation	Per Building	Existing	1,318	20	$2,320	75%	59%	$0.18	1,731
Electric	Other	Space Heat	Insulation - Floor (non-slab)	R-30 (WA State Code)	R-7 (Average Existing Conditions)	Per Building	Existing	10,386	25	$9,238	35%	50%	$0.08	5,307
Electric	Other	Space Heat	Insulation - Floor (non-slab)	R-38	R-30 (WA State Code)	Per Building	Existing	1,330	25	$2,849	35%	50%	$0.22	640
Electric	Other	Space Heat	Insulation - Wall	R-16	R-3 (Average Existing Conditions)	Per Building	Existing	14,399	25	$8,620	10%	35%	$0.05	1,376
Electric	Other	Space Heat	Programmable Thermostat - Web Enabled	Programmable Thermostat - Web Enabled	No Programmable Thermostat	Per Building	Existing	941	10	$778	95%	28%	$0.11	683
Electric	Other	Space Heat	Sensible And Total Heat Recovery Devices	Install Heat Recovery Devices - rotary air-to-air enthalpy heat recovery- 50% sensible and latent recovery effectiveness	No Heat Recovery	Per Building	Existing	7,847	10	$25,319	25%	98%	$0.49	4,631
Electric	Other	Space Heat	Windows-High Efficiency	U-0.40 (WA State Code)	U-0.65 (Average Existing Conditions)	Per Building	Existing	235	25	$32,054	15%	70%	$15.12	55
Electric	Other	Vending Machines	Vending Miser	Passive Infrared Sensor on Vending Machine Monitoring Vacancy of Area And Cycles Cooling - Controls	No Vending Miser - No controls	Per Building	Existing	1,796	3	$169	10%	25%	$0.03	26
Electric	Other	Ventilation And Circulation	Automated Exhaust VFD Control - Parking Garage CO sensor	CO Sensors	No CO Sensors	Per Building	Existing	13,565	10	$1,470	5.0%	85%	$0.01	2,039
Electric	Other	Ventilation And Circulation	Convert Constant Volume Air System to VAV	Variable Volume Air System	Constant Volume Air System	Per Building	Existing	3,057	15	$36,479	15%	67%	$1.51	2,878
Electric	Other	Ventilation And Circulation	Cooking Hood Controls	Demand-Ventilation Control	No Controls	Per Building	Existing	93	18	$199	95%	65%	$0.24	542
Electric	Other	Ventilation And Circulation	Motor - CEE Premium-Efficiency Plus	CEE PE+ Motor for HVAC Applications	NEMA Efficiency Motors	Per Building	Existing	259	15	$78	95%	76%	$0.03	1,721
Electric	Other	Ventilation And Circulation	Motor - Pump & Fan System - Variable Speed Control	Pump And Fan System Optimization w/ VSD	No Pump And Fan System VSD Optimization	Per Building	Existing	6,497	20	$1,335	65%	75%	$0.01	28,936
Electric	Other	Ventilation And Circulation	Motor - VAV Box High Efficiency (ECM)	ECM Motor	Standard Efficiency Motor	Per Building	Existing	1,337	15	$4,382	13%	77%	$0.41	1,064
Electric	Other	Ventilation And Circulation	Motor Rewind	>15, <500 HP	No Rewind	Per Building	Existing	211	7	$60	65%	25%	$0.05	274
Electric	Other	Ventilation And Circulation	Optimized Variable Volume Lab Hood Design	Optimized Variable Volume Lab Hood Design	Constant Volume Lab Hood Design	Per Building	Existing	407	13	$1,706	5.0%	59%	$0.57	113

Table B-2.2. Commercial Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Other	Water Heat GT 55 Gal	Clothes Washer - Ozonating	Ozonating Clothes Washer	2013 Federal Standard Clothes Washer - MEF = 1.6, WF = 8.5	Per Building	Existing	688	10	$8,285	0.3%	95%	$1.75	5
Electric	Other	Water Heat GT 55 Gal	Clothes Washer Commercial	ENERGY STAR Commercial Clothes Washer - MEF = 2.43, WF = 4.0	2013 Federal Standard Clothes Washer - MEF = 1.6, WF = 8.5	Per Building	Existing	37	7	$14	95%	80%	$-2.40	89
Electric	Other	Water Heat GT 55 Gal	Demand Controlled Circulating Systems	Demand Controlled Circulating Systems (VFD control by demand)	Constant Circulation	Per Building	Existing	227	10	$3,333	55%	94%	$2.28	366
Electric	Other	Water Heat GT 55 Gal	Dishwasher Residential	RTF ENERGY STAR Dishwasher - 277 kWh/yr and 4.25 gal/cycle	RTF Market Standard 2014 Dishwasher - 289 kWh/yr and 5.0 gal/cycle	Per Building	Existing	14	12	$45	5.4%	25%	$0.44	0.61
Electric	Other	Water Heat GT 55 Gal	Dishwashing - Commercial - High Temp	High Efficiency Dishwasher (ENERGY STAR)	Standard High Temp Commercial Dishwasher	Per Building	Existing	4	12	$2	95%	95%	$-74.20	12
Electric	Other	Water Heat GT 55 Gal	Drainwater Heat Recovery Water Heater	Install (Power-Pipe or GFX) - Heat Recovery Water Heater	No Heat Recovery System	Per Building	Existing	909	25	$2,292	5.0%	92%	$0.27	126
Electric	Other	Water Heat GT 55 Gal	Low-Flow Faucet Aerators	0.5 GPM	2.2 GPM (Federal Code)	Per Building	Existing	175	9	$4	95%	75%	$-0.03	392
Electric	Other	Water Heat GT 55 Gal	Low-Flow Faucet Aerators	2.2 GPM (Federal Code)	3.0 GPM	Per Building	Existing	60	9	$3	95%	25%	$-0.05	45
Electric	Other	Water Heat GT 55 Gal	Low-Flow Pre-Rinse Spray Valves	0.6 GPM	1.6 GPM (Federal Standard)	Per Building	Existing	429	4	$130	95%	93%	$0.08	1,183
Electric	Other	Water Heat GT 55 Gal	Low-Flow Showerheads	1.5 GPM	2.5 GPM (Federal Code)	Per Building	Existing	19	10	$10	95%	73%	$-0.49	43
Electric	Other	Water Heat GT 55 Gal	Low-Flow Showerheads	2.5 GPM (Federal Code)	4.5 GPM	Per Building	Existing	39	10	$9	95%	35%	$-0.56	41
Electric	Other	Water Heat GT 55 Gal	Pipe Insulation - Hot Water (DWH)	1.0" of Insulation, assuming R-4 (WA State Code)	No Insulation	Per Building	Existing	45	12	$28	80%	90%	$0.08	89
Electric	Other	Water Heat GT 55 Gal	Ultrasonic Faucet Control	Install Ultrasonic Motion Faucet Control	No Faucet Control	Per Building	Existing	113	10	$331	75%	95%	$0.39	254
Electric	Other	Water Heat GT 55 Gal	Water Cooled Refrigeration with Heat Recovery	Heat Recovery from refrigeration system. Applied to Water Heating Electric End use	No heat recovery	Per Building	Existing	5	10	$106	2.5%	94%	$3.26	0.31
Electric	Other	Water Heat LE 55 Gal	Clothes Washer - Ozonating	Ozonating Clothes Washer	2013 Federal Standard Clothes Washer - MEF = 1.6, WF = 8.5	Per Building	Existing	676	10	$8,285	0.3%	95%	$1.78	4
Electric	Other	Water Heat LE 55 Gal	Clothes Washer Commercial	ENERGY STAR Commercial Clothes Washer - MEF = 2.43, WF = 4.0	2013 Federal Standard Clothes Washer - MEF = 1.6, WF = 8.5	Per Building	Existing	37	7	$14	95%	80%	$-2.40	87
Electric	Other	Water Heat LE 55 Gal	Demand Controlled Circulating Systems	Demand Controlled Circulating Systems (VFD control by demand)	Constant Circulation	Per Building	Existing	223	10	$3,333	55%	94%	$2.32	353
Electric	Other	Water Heat LE 55 Gal	Dishwasher Residential	RTF ENERGY STAR Dishwasher - 277 kWh/yr and 4.25 gal/cycle	RTF Market Standard 2014 Dishwasher - 289 kWh/yr and 5.0 gal/cycle	Per Building	Existing	14	12	$45	5.4%	25%	$0.44	0.60
Electric	Other	Water Heat LE 55 Gal	Dishwashing - Commercial - High Temp	High Efficiency Dishwasher (ENERGY STAR)	Standard High Temp Commercial Dishwasher	Per Building	Existing	4	12	$2	95%	95%	$-75.55	12
Electric	Other	Water Heat LE 55 Gal	Drainwater Heat Recovery Water Heater	Install (Power-Pipe or GFX) - Heat Recovery Water Heater	No Heat Recovery System	Per Building	Existing	909	25	$2,292	5.0%	92%	$0.27	122

Table B-2.2. Commercial Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Other	Water Heat LE 55 Gal	Low-Flow Faucet Aerators	0.5 GPM	2.2 GPM (Federal Code)	Per Building	Existing	172	9	$4	95%	75%	$-0.03	378
Electric	Other	Water Heat LE 55 Gal	Low-Flow Faucet Aerators	2.2 GPM (Federal Code)	3.0 GPM	Per Building	Existing	59	9	$3	95%	25%	$-0.05	43
Electric	Other	Water Heat LE 55 Gal	Low-Flow Pre-Rinse Spray Valves	0.6 GPM	1.6 GPM (Federal Standard)	Per Building	Existing	429	4	$130	95%	93%	$0.08	1,162
Electric	Other	Water Heat LE 55 Gal	Low-Flow Showerheads	1.5 GPM	2.5 GPM (Federal Code)	Per Building	Existing	19	10	$10	95%	73%	$-0.49	42
Electric	Other	Water Heat LE 55 Gal	Low-Flow Showerheads	2.5 GPM (Federal Code)	4.5 GPM	Per Building	Existing	39	10	$9	95%	35%	$-0.56	40
Electric	Other	Water Heat LE 55 Gal	Pipe Insulation - Hot Water (DWH)	1.0" of Insulation, assuming R-4 (WA State Code)	No Insulation	Per Building	Existing	44	12	$28	80%	90%	$0.09	85
Electric	Other	Water Heat LE 55 Gal	Ultrasonic Faucet Control	Install Ultrasonic Motion Faucet Control	No Faucet Control	Per Building	Existing	111	10	$331	75%	95%	$0.40	245
Electric	Other	Water Heat LE 55 Gal	Water Cooled Refrigeration with Heat Recovery	Heat Recovery from refrigeration system. Applied to Water Heating Electric End use	No heat recovery	Per Building	Existing	5	10	$106	2.5%	94%	$3.32	0.30
Electric	Restaurant	Cooking	Combination Oven	60% cooking efficiency	Non ENERGY STAR	Per Building	Existing	4,663	12	$786	90%	90%	$0.02	2,812
Electric	Restaurant	Cooking	Fryers - New CEE Efficient Electric Deep Fat Fryers	15 inch width Deep Fryer CEE 2006 rating: 80% under heavy load, Less than 1000 watt at idle	15 inch width standard electric deep fat fryers	Per Building	Existing	213	12	$299	70%	35%	$0.19	39
Electric	Restaurant	Cooking	Griddle	70% cooking efficiency	Non ENERGY STAR	Per Building	Existing	1,135	12	$400	95%	35%	$0.04	281
Electric	Restaurant	Cooking	Hot Food Holding Cabinet	ENERGY STAR Hot Food Holding Cabinet	Non ENERGY STAR Hot Food Holding Cabinet	Per Building	Existing	2,680	12	$1,713	35%	21%	$0.08	148
Electric	Restaurant	Cooking	Steam Cooker	ENERGY STAR Steam Cooker	Non ENERGY STAR Steam Cooker	Per Building	Existing	839	12	$95	20%	35%	$0.01	79
Electric	Restaurant	Cooling Dx	Commissioning of Existing Buildings	Existing Building Commissioning	Average Existing Conditions	Per Building	Existing	1,801	7	$690	90%	85%	$0.07	1,964
Electric	Restaurant	Cooling Dx	DX Package-Air Side Economizer	Air-Side Economizer	No Economizer	Per Building	Existing	2,161	10	$3,969	10%	50%	$0.28	207
Electric	Restaurant	Cooling Dx	Direct / Indirect Evaporative Cooling, Pre-Cooling	Evaporative Cooler	Standard DX cooling	Per Building	Existing	3,602	15	$7,291	50%	94%	$0.25	3,207
Electric	Restaurant	Cooling Dx	Direct Digital Control System-Installation	DDC Retrofit (Morning Warm-Up Control Logic Included in This Measure)	Pneumatic	Per Building	Existing	2,161	5	$3,365	10%	100%	$0.39	361
Electric	Restaurant	Cooling Dx	Direct Digital Control System-Wireless System	DDC Retrofit - Wireless System	Pneumatic	Per Building	Existing	2,161	5	$817	50%	100%	$0.09	1,423
Electric	Restaurant	Cooling Dx	Duct Repair And Sealing	Reduction In Duct Losses to 5%	No Repair or Sealing, 15% duct losses	Per Building	Existing	360	18	$840	45%	65%	$0.27	163
Electric	Restaurant	Cooling Dx	Economizer Tune-up	Economizer Tune-up	No Economizer Tune-Up	Per Building	Existing	1,440	5	$1,119	10%	75%	$0.19	206
Electric	Restaurant	Cooling Dx	Exhaust Hood Makeup Air	Provide Makeup Air Directly at Exhaust Hood Instead of Pulling Conditioned Air	Hood Pulls Conditioned Air (No Make-up Air)	Per Building	Existing	990	10	$3,500	100%	85%	$0.55	846
Electric	Restaurant	Cooling Dx	Green Roof	Vegetation on Roof	Standard Dark Colored Roof	Per Building	Existing	1,138	40	$28,009	3.5%	98%	$2.48	57
Electric	Restaurant	Cooling Dx	Infiltration Reduction	Install Caulking And Weatherstripping (ACH 0.65)	Infiltration Conditions (ACH 1.0)	Per Building	Existing	720	12.5	$142	10%	39%	$0.02	41
Electric	Restaurant	Cooling Dx	Insulation - Ceiling	R-30 c.i. (WA State Code)	R-11 (Average Existing Conditions)	Per Building	Existing	32	25	$4,929	75%	85%	$16.64	30
Electric	Restaurant	Cooling Dx	Insulation - Ceiling	R-49 c.i.	R-38 c.i.	Per Building	Existing	0.72	25	$1,390	25%	98%	$214.45	0.25

Table B-2.2. Commercial Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Restaurant	Cooling Dx	Insulation - Duct	R-7 (WA State Code)	No Insulation	Per Building	Existing	605	20	$677	75%	56%	$0.12	371
Electric	Restaurant	Cooling Dx	Programmable Thermostat - Web Enabled	Programmable Thermostat - Web Enabled	No Programmable Thermostat	Per Building	Existing	432	10	$807	95%	25%	$0.29	150
Electric	Restaurant	Cooling Dx	RE - Deciduous Trees	Shade Trees	No Trees	Per Building	Existing	257	30	$3,629	75%	55%	$1.49	152
Electric	Restaurant	Cooling Dx	Window Film	Window Film	No Film	Per Building	Existing	733	10	$645	90%	66%	$0.13	5
Electric	Restaurant	Cooling Dx	Windows-High Efficiency	U-0.32	U-0.40 (WA State Code)	Per Building	Existing	1,817	25	$12,372	15%	80%	$0.75	280
Electric	Restaurant	Cooling Dx	Windows-High Efficiency	U-0.40 (WA State Code)	U-0.65 (Average Existing Conditions)	Per Building	Existing	1,591	25	$26,631	15%	80%	$1.85	241
Electric	Restaurant	Heat Pump	Commissioning of Existing Buildings	Existing Building Commissioning	Average Existing Conditions	Per Building	Existing	2,076	7	$690	90%	85%	$0.06	640
Electric	Restaurant	Heat Pump	Direct Digital Control System-Installation	DDC Retrofit (Morning Warm-Up Control Logic Included in This Measure)	Pneumatic	Per Building	Existing	2,491	5	$3,365	10%	100%	$0.34	120
Electric	Restaurant	Heat Pump	Direct Digital Control System-Wireless System	DDC Retrofit - Wireless System	Pneumatic	Per Building	Existing	2,491	5	$817	50%	100%	$0.08	473
Electric	Restaurant	Heat Pump	Duct Repair And Sealing	Reduction In Duct Losses to 5%	No Repair or Sealing, 15% duct losses	Per Building	Existing	415	18	$840	45%	65%	$0.23	54
Electric	Restaurant	Heat Pump	Exhaust Air to Ventilation Air Heat Recovery	Exhaust Air Heat Recovery	No Heat Recovery	Per Building	Existing	413	14	$6,019	5.0%	94%	$1.91	8
Electric	Restaurant	Heat Pump	Exhaust Hood Makeup Air	Provide Makeup Air Directly at Exhaust Hood Instead of Pulling Conditioned Air	Hood Pulls Conditioned Air (No Make-up Air)	Per Building	Existing	1,228	10	$3,500	100%	85%	$0.44	281
Electric	Restaurant	Heat Pump	Green Roof	Vegetation on Roof	Standard Dark Colored Roof	Per Building	Existing	1,094	40	$28,009	3.5%	98%	$2.58	15
Electric	Restaurant	Heat Pump	Ground Source Heat Pump > 135 kBTU/hr	High Efficiency Ground Source Heat Pump > 135 kBTU/hr	Water Source Heat Pump > 135 kBTU/hr	Per Building	Existing	1,880	15	$90,944	3.8%	95%	$6.15	23
Electric	Restaurant	Heat Pump	Infiltration Reduction	Install Caulking And Weatherstripping (ACH 0.65)	Infiltration Conditions (ACH 1.0)	Per Building	Existing	413	12.5	$142	10%	39%	$0.04	6
Electric	Restaurant	Heat Pump	Insulation - Ceiling	R-30 c.i. (WA State Code)	R-11 (Average Existing Conditions)	Per Building	Existing	491	25	$4,929	75%	85%	$1.11	133
Electric	Restaurant	Heat Pump	Insulation - Ceiling	R-38 c.i.	R-30 c.i. (WA State Code)	Per Building	Existing	63	25	$4,929	75%	83%	$8.69	16
Electric	Restaurant	Heat Pump	Insulation - Ceiling	R-49 c.i.	R-38 c.i.	Per Building	Existing	18	25	$1,390	25%	98%	$8.56	1
Electric	Restaurant	Heat Pump	Insulation - Duct	R-7 (WA State Code)	No Insulation	Per Building	Existing	697	20	$677	75%	56%	$0.10	121
Electric	Restaurant	Heat Pump	Insulation - Floor (non-slab)	R-30 (WA State Code)	R-11 (Average Existing Conditions)	Per Building	Existing	65	25	$2,598	35%	90%	$4.38	8
Electric	Restaurant	Heat Pump	Insulation - Floor (non-slab)	R-38	R-30 (WA State Code)	Per Building	Existing	14	25	$801	35%	90%	$6.28	1
Electric	Restaurant	Heat Pump	Insulation - Wall	R-16	R-3 (Average Existing Conditions)	Per Building	Existing	140	25	$4,526	10%	35%	$3.57	2
Electric	Restaurant	Heat Pump	Programmable Thermostat - Web Enabled	Programmable Thermostat - Web Enabled	No Programmable Thermostat	Per Building	Existing	498	10	$807	95%	25%	$0.25	49
Electric	Restaurant	Heat Pump	RE - Deciduous Trees	Shade Trees	No Trees	Per Building	Existing	253	30	$4,050	75%	55%	$1.69	42
Electric	Restaurant	Heat Pump	Variable Refrigerant Flow Cooling System	Variable Refrigerant Flow Cooling System	Standard Refrigeration System	Per Building	Existing	4,484	15	$1,708	25%	95%	$0.04	513
Electric	Restaurant	Heat Pump	Window Film	Window Film	No Film	Per Building	Existing	733	10	$645	90%	66%	$0.13	1
Electric	Restaurant	Heat Pump	Windows-High Efficiency	U-0.32	U-0.40 (WA State Code)	Per Building	Existing	1,642	25	$12,372	15%	80%	$0.83	71
Electric	Restaurant	Heat Pump	Windows-High Efficiency	U-0.40 (WA State Code)	U-0.65 (Average Existing Conditions)	Per Building	Existing	1,555	25	$26,631	15%	80%	$1.90	67
Electric	Restaurant	Lighting Exterior	Covered Parking Lighting	Covered Parking Lighting	Normal Lighting	Per Building	Existing	327	9.5	$91	20%	95%	$0.03	276
Electric	Restaurant	Lighting Exterior	Daylighting Controls, Outdoors (Photocell)	Photocell	No Controls	Per Building	Existing	374	8	$57	75%	70%	$0.02	395

Table B-2.2. Commercial Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Restaurant	Lighting Exterior	Occupancy Sensor Control	Occupancy Sensor Control	No Occupancy Sensor	Per Building	Existing	751	8	$273	90%	75%	$0.06	2,103
Electric	Restaurant	Lighting Exterior	Solid State LED White Lighting	Landscape, merchandise, signage, structure & task lighting (2.5 W)	50W 10hrs/day, 365 day/yr	Per Building	Existing	364	13.69863	$73	75%	95%	$0.02	59
Electric	Restaurant	Lighting Exterior	Surface Parking Lighting	Surface Parking Lighting	Normal Lighting	Per Building	Existing	177	18.666667	$239	47%	95%	$0.15	330
Electric	Restaurant	Lighting Exterior	Time Clock	Time Clock	No Controls	Per Building	Existing	402	8	$110	10%	81%	$0.04	125
Electric	Restaurant	Lighting Interior Fluorescent	Bi-Level Control, Stairwell Lighting	Occupancy Sensor Control, 50% Lighting Power during unoccupied Time	Continuous Full Power Lighting in Stairways	Per Building	Existing	399	9	$187	10%	75%	$0.07	64
Electric	Restaurant	Lighting Interior Fluorescent	Dimming-Continuous, Fluorescent Fixtures	Continuous Dimming, Fluorescent Fixtures (Day-Lighting)	No Dimming Controls	Per Building	Existing	721	8	$3,499	30%	98%	$0.87	760
Electric	Restaurant	Lighting Interior Fluorescent	LED Refrigeration Case Lights	LED Refrigeration Case Lights	Fluorescent Refrigeration Case	Per Building	Existing	1,180	6	$438	25%	80%	$0.06	1,060
Electric	Restaurant	Lighting Interior Fluorescent	Occupancy Sensor Control	Occupancy Sensor Control	No Occupancy Sensor	Per Building	Existing	1,094	8	$298	45%	64%	$0.04	1,062
Electric	Restaurant	Lighting Interior Fluorescent	Time Clock	Time Clock	No Controls	Per Building	Existing	586	8	$160	10%	100%	$0.04	201
Electric	Restaurant	Lighting Interior Hid	Occupancy Sensor Control	Occupancy Sensor Control	No Occupancy Sensor	Per Building	Existing	79	8	$298	45%	64%	$0.67	86
Electric	Restaurant	Lighting Interior Hid	Time Clock	Time Clock	No Controls	Per Building	Existing	42	8	$11	10%	100%	$0.04	16
Electric	Restaurant	Lighting Interior Other	Exit Sign - LED	Two Sided LED Exit Sign (5 Watts)	CFL Exit Sign (9 Watts)	Per Building	Existing	337	16	$56	95%	50%	$0.01	677
Electric	Restaurant	Lighting Interior Other	Exit Sign - Photoluminescent or Tritium	Photoluminescent or Tritium	Two Sided LED Exit Sign (5 Watts)	Per Building	Existing	122	13	$105	95%	98%	$0.11	482
Electric	Restaurant	Lighting Interior Screw Base	Cold Cathode Lighting	Cold Cathode Lighting 5 watts	30 W Incandescent Bulb	Per Building	Existing	271	5	$23	70%	94%	$0.02	225
Electric	Restaurant	Lighting Interior Screw Base	Occupancy Sensor Control	Occupancy Sensor Control	No Occupancy Sensor	Per Building	Existing	1,481	8	$298	45%	64%	$0.03	510
Electric	Restaurant	Lighting Interior Screw Base	Time Clock	Time Clock	No Controls	Per Building	Existing	793	8	$216	10%	100%	$0.04	96
Electric	Restaurant	Other Plug Load	ENERGY STAR - Battery Charging System	ENERGY STAR Battery Charging System	Non-ENERGY STAR Battery Chargers	Per Building	Existing	3	7	$1	20%	20%	$0.05	0.66
Electric	Restaurant	Other Plug Load	ENERGY STAR - Water Cooler	ENERGY STAR Water Cooler (Hot/Cold Water)	Non-ENERGY STAR Water Cooler	Per Building	Existing	160	10	$0.37	95%	20%	$-0.01	128
Electric	Restaurant	Other Plug Load	Power Supply Transformer/Converter	80 Plus	85% efficient power supply (> 51W)	Per Building	Existing	48	4	$0.74	95%	86%	$0.00	46
Electric	Restaurant	Other Plug Load	Scanner - ENERGY STAR	ENERGY STAR Scanners	Standard Scanner	Per Building	Existing	17	6	$0.00	95%	20%	$-0.01	14
Electric	Restaurant	Other Plug Load	Smart Strips	Smart Strip Power Strip	Standard surge protector	Per Building	Existing	70	4	$17	60%	90%	$0.07	159
Electric	Restaurant	Refrigeratio n	Add Doors to Refrigerated Open Display Cases	Add Doors to Refrigerated Open Display Cases	Standard Refrigerated Open Display Cases	Per Building	Existing	653	12	$1,012	15%	95%	$0.22	393
Electric	Restaurant	Refrigeratio n	Anti-Sweat (Humidistat) Controls	Anti-Sweat (Humidistat) Controls	No Anti-Sweat (Humidistat) Controls	Per Building	Existing	923	12	$79	25%	45%	$0.01	438
Electric	Restaurant	Refrigeratio n	Case Electronically Commutated Motor	ECM Case Fans	Standard Efficiency Motor	Per Building	Existing	316	15	$76	10%	77%	$0.02	102

Table B-2.2. Commercial Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Restaurant	Refrigeration	Case Replacement Low Temp	Case Replacement Low Temp	No replacement	Per Building	Existing	3,421	15	$370	10%	98%	$0.01	70
Electric	Restaurant	Refrigeration	Case Replacement Med Temp	Case Replacement Med Temp	No replacement	Per Building	Existing	291	15	$192	10%	98%	$0.08	6
Electric	Restaurant	Refrigeration	Commercial Refrigerator - Semivertical - No Doors - Med Temp	Commercial Refrigerator - Semivertical - No Doors - Med Temp	Standard Case	Per Building	Existing	949	10	$787	90%	85%	$0.12	3,070
Electric	Restaurant	Refrigeration	Commercial Refrigerator - Vertical - No Doors - Med Temp	Commercial Refrigerator - Vertical - No Doors - Med Temp	Standard Case	Per Building	Existing	429	10	$355	90%	85%	$0.12	1,389
Electric	Restaurant	Refrigeration	Demand Control Defrost - Hot Gas	Refrigerant Defrost	Defrost - Electric	Per Building	Existing	242	10	$12	5.0%	68%	$0.00	34
Electric	Restaurant	Refrigeration	Display Case Motion Sensors	Display Case Motion Sensors	No Motion Sensors	Per Building	Existing	228	8	$22	90%	85%	$0.01	690
Electric	Restaurant	Refrigeration	Evaporative Condenser - High-Efficiency	High-Efficiency Evaporative Condenser	Air-Cooled Condenser	Per Building	Existing	137	15	$678	90%	65%	$0.62	332
Electric	Restaurant	Refrigeration	Evaporator Fan Controller	ECM Evaporator Fan Controller	No Controller	Per Building	Existing	327	15	$363	90%	85%	$0.13	976
Electric	Restaurant	Refrigeration	Glass Door ENERGY STAR Refrigerators/Freezers	Glass Door ENERGY STAR Refrigerators/Freezers	Standard Glass Doors	Per Building	Existing	126	12	$119	95%	77%	$0.13	387
Electric	Restaurant	Refrigeration	High-Efficiency Compressor	High-Efficiency Compressor (15% More Efficient)	Standard Compressor, 40% Efficiency	Per Building	Existing	9,978	10	$6,484	85%	72%	$0.10	3,680
Electric	Restaurant	Refrigeration	Ice Maker	High-Efficiency Ice Maker	Standard Ice Maker	Per Building	Existing	809	10	$0.74	95%	86%	$-0.02	2,779
Electric	Restaurant	Refrigeration	Night Covers for Display Cases	Night Covers for Display Cases	No Night Covers	Per Building	Existing	614	5	$98	30%	85%	$0.04	661
Electric	Restaurant	Refrigeration	Refrigeration Commissioning of New or Existing Buildings	New or Existing Building Refrigeration Commissioning	No Commissioning	Per Building	Existing	1,283	3	$201	10%	85%	$0.06	376
Electric	Restaurant	Refrigeration	Refrigerator eCube	Refrigerator eCube	No Refrigerator eCube	Per Building	Existing	154	10	$62	75%	95%	$0.06	646
Electric	Restaurant	Refrigeration	Solid Door ENERGY STAR Refrigerators/Freezers	Solid Door ENERGY STAR Refrigerators/Freezers	Standard Solid Door	Per Building	Existing	396	12	$-93.228017	95%	81%	$-0.04	1,286
Electric	Restaurant	Refrigeration	Strip Curtains for Walk-Ins	Strip Curtains for Walk-Ins	No Strip Curtains for Walk-In	Per Building	Existing	133	4	$8	5.0%	20%	$0.02	5
Electric	Restaurant	Refrigeration	Visi Cooler	High Efficiency Visi Cooler	Standard Visi Cooler	Per Building	Existing	108	10	$20	95%	85%	$0.02	371
Electric	Restaurant	Refrigeration	Walk-In Electronically Commutated Motor	ECM Evaporator Fans	Standard Efficiency Motor	Per Building	Existing	327	15	$363	75%	95%	$0.13	986
Electric	Restaurant	Refrigerator	Residential Refrigerator/Freezer Recycling	Recycling Existing Refrigerator/Freezer	Existing Refrigerator/Freezer	Per Building	Existing	481	9	$129	25%	100%	$0.04	439
Electric	Restaurant	Space Heat	Commissioning of Existing Buildings	Existing Building Commissioning	Average Existing Conditions	Per Building	Existing	592	7	$690	90%	85%	$0.23	115
Electric	Restaurant	Space Heat	Direct Digital Control System-Installation	DDC Retrofit (Morning Warm-Up Control Logic Included in This Measure)	Pneumatic	Per Building	Existing	710	5	$3,365	10%	100%	$1.18	26
Electric	Restaurant	Space Heat	Direct Digital Control System-Wireless System	DDC Retrofit - Wireless System	Pneumatic	Per Building	Existing	710	5	$817	50%	100%	$0.29	105
Electric	Restaurant	Space Heat	Duct Repair And Sealing	Reduction In Duct Losses to 5%	No Repair or Sealing, 15% duct losses	Per Building	Existing	118	18	$840	45%	65%	$0.82	12
Electric	Restaurant	Space Heat	Economizer Tune-up	Economizer Tune-up	No Economizer Tune-Up	Per Building	Existing	473	5	$1,119	10%	75%	$0.59	13
Electric	Restaurant	Space Heat	Exhaust Air to Ventilation Air Heat Recovery	Exhaust Air Heat Recovery	No Heat Recovery	Per Building	Existing	710	14	$6,019	5.0%	94%	$1.11	11

Table B-2.2. Commercial Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Restaurant	Space Heat	Exhaust Hood Makeup Air	Provide Makeup Air Directly at Exhaust Hood Instead of Pulling Conditioned Air	Hood Pulls Conditioned Air (No Make-up Air)	Per Building	Existing	304	10	$3,500	100%	85%	$1.79	62
Electric	Restaurant	Space Heat	Infiltration Reduction	Install Caulking And Weatherstripping (ACH 0.65)	Infiltration Conditions (ACH 1.0)	Per Building	Existing	473	12.5	$142	10%	39%	$0.04	6
Electric	Restaurant	Space Heat	Insulation - Ceiling	R-30 c.i. (WA State Code)	R-11 (Average Existing Conditions)	Per Building	Existing	786	25	$4,929	75%	85%	$0.69	164
Electric	Restaurant	Space Heat	Insulation - Ceiling	R-38 c.i.	R-30 c.i. (WA State Code)	Per Building	Existing	99	25	$4,929	75%	83%	$5.52	18
Electric	Restaurant	Space Heat	Insulation - Ceiling	R-49 c.i.	R-38 c.i.	Per Building	Existing	95	25	$1,390	25%	98%	$1.61	6
Electric	Restaurant	Space Heat	Insulation - Duct	R-7 (WA State Code)	No Insulation	Per Building	Existing	198	20	$677	75%	56%	$0.38	24
Electric	Restaurant	Space Heat	Insulation - Floor (non-slab)	R-30 (WA State Code)	R-11 (Average Existing Conditions)	Per Building	Existing	1,064	25	$2,598	35%	90%	$0.27	95
Electric	Restaurant	Space Heat	Insulation - Floor (non-slab)	R-38	R-30 (WA State Code)	Per Building	Existing	198	25	$801	35%	90%	$0.44	16
Electric	Restaurant	Space Heat	Insulation - Wall	R-16	R-3 (Average Existing Conditions)	Per Building	Existing	2,225	25	$4,526	10%	35%	$0.22	20
Electric	Restaurant	Space Heat	Programmable Thermostat - Web Enabled	Programmable Thermostat - Web Enabled	No Programmable Thermostat	Per Building	Existing	142	10	$807	95%	25%	$0.88	8
Electric	Restaurant	Space Heat	Windows-High Efficiency	U-0.40 (WA State Code)	U-0.65 (Average Existing Conditions)	Per Building	Existing	35	25	$26,631	15%	80%	$83.33	0.97
Electric	Restaurant	Ventilation And Circulation	Cooking Hood Controls	Demand-Ventilation Control	No Controls	Per Building	Existing	1,865	18	$6,249	95%	25%	$0.38	1,673
Electric	Restaurant	Ventilation And Circulation	Motor - CEE Premium-Efficiency Plus	CEE PE+ Motor for HVAC Applications	NEMA Efficiency Motors	Per Building	Existing	127	15	$23	95%	76%	$0.02	334
Electric	Restaurant	Ventilation And Circulation	Motor - Pump & Fan System - Variable Speed Control	Pump And Fan System Optimization w/ VSD	No Pump And Fan System VSD Optimization	Per Building	Existing	3,185	20	$389	65%	75%	$0.01	5,616
Electric	Restaurant	Ventilation And Circulation	Motor Rewind	>15, <500 HP	No Rewind	Per Building	Existing	61	7	$17	65%	25%	$0.05	31
Electric	Restaurant	Water Heat GT 55 Gal	Demand Controlled Circulating Systems	Demand Controlled Circulating Systems (VFD control by demand)	Constant Circulation	Per Building	Existing	1,543	10	$972	75%	94%	$0.09	799
Electric	Restaurant	Water Heat GT 55 Gal	Dishwasher Residential	RTF ENERGY STAR Dishwasher - 277 kWh/yr and 4.25 gal/cycle	RTF Market Standard 2014 Dishwasher - 289 kWh/yr and 5.0 gal/cycle	Per Building	Existing	15	12	$46	46%	25%	$0.43	1
Electric	Restaurant	Water Heat GT 55 Gal	Dishwashing - Commercial - High Temp	High Efficiency Dishwasher (ENERGY STAR)	Standard High Temp Commercial Dishwasher	Per Building	Existing	2,898	12	$1,648	95%	95%	$-0.04	1,922
Electric	Restaurant	Water Heat GT 55 Gal	Drainwater Heat Recovery Water Heater	Install (Power-Pipe or GFX) - Heat Recovery Water Heater	No Heat Recovery System	Per Building	Existing	6,088	25	$1,874	5.0%	92%	$0.02	183
Electric	Restaurant	Water Heat GT 55 Gal	Low-Flow Faucet Aerators	0.5 GPM	2.2 GPM (Federal Code)	Per Building	Existing	1,192	9	$4	95%	75%	$-0.04	624
Electric	Restaurant	Water Heat GT 55 Gal	Low-Flow Faucet Aerators	2.2 GPM (Federal Code)	3.0 GPM	Per Building	Existing	411	9	$3	95%	25%	$-0.07	71
Electric	Restaurant	Water Heat GT 55 Gal	Low-Flow Pre-Rinse Spray Valves	0.6 GPM	1.6 GPM (Federal Standard)	Per Building	Existing	816	4	$246	95%	46%	$0.04	263
Electric	Restaurant	Water Heat GT 55 Gal	Pipe Insulation - Hot Water (DWH)	1.0" of Insulation, assuming R-4 (WA State Code)	No Insulation	Per Building	Existing	308	12	$25	80%	90%	$0.00	139
Electric	Restaurant	Water Heat GT 55 Gal	Ultrasonic Faucet Control	Install Ultrasonic Motion Faucet Control	No Faucet Control	Per Building	Existing	771	10	$275	75%	75%	$-0.02	318

Table B-2.2. Commercial Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Restaurant	Water Heat LE 55 Gal	Demand Controlled Circulating Systems	Demand Controlled Circulating Systems (VFD control by demand)	Constant Circulation	Per Building	Existing	1,515	10	$972	75%	94%	$0.09	770
Electric	Restaurant	Water Heat LE 55 Gal	Dishwasher Residential	RTF ENERGY STAR Dishwasher - 277 kWh/yr and 4.25 gal/cycle	RTF Market Standard 2014 Dishwasher - 289 kWh/yr and 5.0 gal/cycle	Per Building	Existing	15	12	$46	46%	25%	$0.43	1
Electric	Restaurant	Water Heat LE 55 Gal	Dishwashing - Commercial - High Temp	High Efficiency Dishwasher (ENERGY STAR)	Standard High Temp Commercial Dishwasher	Per Building	Existing	2,846	12	$1,619	95%	95%	$-0.04	1,853
Electric	Restaurant	Water Heat LE 55 Gal	Drainwater Heat Recovery Water Heater	Install (Power-Pipe or GFX) - Heat Recovery Water Heater	No Heat Recovery System	Per Building	Existing	6,088	25	$1,874	5.0%	92%	$0.02	177
Electric	Restaurant	Water Heat LE 55 Gal	Low-Flow Faucet Aerators	0.5 GPM	2.2 GPM (Federal Code)	Per Building	Existing	1,171	9	$4	95%	75%	$-0.04	601
Electric	Restaurant	Water Heat LE 55 Gal	Low-Flow Faucet Aerators	2.2 GPM (Federal Code)	3.0 GPM	Per Building	Existing	404	9	$3	95%	25%	$-0.07	69
Electric	Restaurant	Water Heat LE 55 Gal	Low-Flow Pre-Rinse Spray Valves	0.6 GPM	1.6 GPM (Federal Standard)	Per Building	Existing	816	4	$246	95%	46%	$0.04	258
Electric	Restaurant	Water Heat LE 55 Gal	Pipe Insulation - Hot Water (DWH)	1.0" of Insulation, assuming R-4 (WA State Code)	No Insulation	Per Building	Existing	303	12	$25	80%	90%	$0.00	134
Electric	Restaurant	Water Heat LE 55 Gal	Ultrasonic Faucet Control	Install Ultrasonic Motion Faucet Control	No Faucet Control	Per Building	Existing	757	10	$275	75%	75%	$-0.02	307
Electric	School	Computers	Network PC Power Management	Network PC Power Management	No Power Management	Per Building	Existing	12,730	4	$1,249	95%	30%	$0.03	3,560
Electric	School	Cooking	Combination Oven	60% cooking efficiency	Non ENERGY STAR	Per Building	Existing	70	12	$10	90%	90%	$0.01	34
Electric	School	Cooking	Fryers - New CEE Efficient Electric Deep Fat Fryers	15 inch width Deep Fryer CEE 2006 rating: 80% under heavy load, Less than 1000 watt at idle	15 inch width standard electric deep fat fryers	Per Building	Existing	3	12	$5	35%	35%	$0.23	0.24
Electric	School	Cooking	Griddle	70% cooking efficiency	Non ENERGY STAR	Per Building	Existing	26	12	$10	95%	35%	$0.05	5
Electric	School	Cooking	Hot Food Holding Cabinet	ENERGY STAR Hot Food Holding Cabinet	Non ENERGY STAR Hot Food Holding Cabinet	Per Building	Existing	62	12	$37	75%	21%	$0.08	6
Electric	School	Cooking	Steam Cooker	ENERGY STAR Steam Cooker	Non ENERGY STAR Steam Cooker	Per Building	Existing	19	12	$5	5.0%	35%	$0.03	0.38
Electric	School	Cooling Chillers	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	Demand Controlled Ventilation (CO2 sensors)	Constant Ventilation	Per Building	Existing	1,608	15	$13,377	25%	94%	$1.05	89
Electric	School	Cooling Chillers	Chilled Water / Condenser Water Settings-Optimization	Additional Control Features	EMS already installed - No Optimization	Per Building	Existing	201	5	$9,112	95%	81%	$11.36	35
Electric	School	Cooling Chillers	Chilled Water Piping Loop w/ VSD Control	VSD for secondary chilled water loop	Primary loop only w/ constant speed pump	Per Building	Existing	1,215	10	$56,104	25%	70%	$7.20	48
Electric	School	Cooling Chillers	Chiller-Water Side Economizer	Install Economizer	No Economizer	Per Building	Existing	804	15	$30,247	45%	90%	$20.60	73
Electric	School	Cooling Chillers	Commissioning of Existing Buildings	Existing Building Commissioning	Average Existing Conditions	Per Building	Existing	2,010	7	$10,545	90%	85%	$1.04	278
Electric	School	Cooling Chillers	Convert Constant Volume Air System to VAV	Variable Volume Air System	Constant Volume Air System	Per Building	Existing	4,824	15	$62,639	15%	67%	$4.28	107
Electric	School	Cooling Chillers	Cooling Tower-Decrease Approach Temperature	6 Deg F	10 Deg F	Per Building	Existing	1,286	7.5	$6,929	10%	94%	$0.73	27

Table B-2.2. Commercial Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	School	Cooling Chillers	Cooling Tower-Two-Speed Fan Motor	Cooling Tower-Two-Speed Fan Motor	Cooling Tower-One-Speed Fan Motor	Per Building	Existing	2,251	15	$622	75%	35%	$0.03	125
Electric	School	Cooling Chillers	Cooling Tower-VSD Fan Control	Variable-Speed Tower Fans replace Two-Speed	Cooling Tower-Two-Speed Fan Motor	Per Building	Existing	643	13	$5,020	75%	75%	$1.06	73
Electric	School	Cooling Chillers	Direct Digital Control System-Installation	DDC Retrofit (Morning Warm-Up Control Logic Included in This Measure)	Pneumatic	Per Building	Existing	2,412	5	$51,438	10%	34%	$5.34	16
Electric	School	Cooling Chillers	Direct Digital Control System-Wireless System	DDC Retrofit - Wireless System	Pneumatic	Per Building	Existing	2,412	5	$12,502	50%	80%	$1.30	153
Electric	School	Cooling Chillers	Exhaust Hood Makeup Air	Provide Makeup Air Directly at Exhaust Hood Instead of Pulling Conditioned Air	Hood Pulls Conditioned Air (No Make-up Air)	Per Building	Existing	910	10	$3,502	73%	85%	$0.60	84
Electric	School	Cooling Chillers	Green Roof	Vegetation on Roof	Standard Dark Colored Roof	Per Building	Existing	1,402	40	$72,582	3.5%	98%	$34.05	8
Electric	School	Cooling Chillers	Infiltration Reduction	Install Caulking And Weatherstripping (ACH 0.65)	Infiltration Conditions (ACH 1.0)	Per Building	Existing	804	12.5	$1,410	10%	39%	$0.25	5
Electric	School	Cooling Chillers	Insulation - Ceiling	R-30 c.i. (WA State Code)	R-7 (Average Existing Conditions)	Per Building	Existing	73	25	$83,170	75%	15%	$126.11	1
Electric	School	Cooling Chillers	Insulation - Ceiling	R-49 c.i.	R-38 c.i.	Per Building	Existing	0.80	25	$23,466	25%	85%	$3,242.32	0.03
Electric	School	Cooling Chillers	Pipe Insulation - Chilled Water	1.5" of Insulation, assuming R-6 (WA State Code)	No Insulation	Per Building	Existing	241	15	$1,099	65%	45%	$0.58	12
Electric	School	Cooling Chillers	Programmable Thermostat - Web Enabled	Programmable Thermostat - Web Enabled	No Programmable Thermostat	Per Building	Existing	482	10	$734	15%	26%	$0.23	3
Electric	School	Cooling Chillers	RE - Deciduous Trees	Shade Trees	No Trees	Per Building	Existing	300	30	$3,357	75%	55%	$1.18	22
Electric	School	Cooling Chillers	Sensible And Total Heat Recovery Devices	Install Heat Recovery Devices - rotary air-to-air enthalpy heat recovery- 50% sensible and latent recovery effectiveness	No Heat Recovery	Per Building	Existing	4,832	10	$12,885	25%	98%	$3.64	160
Electric	School	Cooling Chillers	Window Film	Window Film	No Film	Per Building	Existing	7,293	10	$6,377	90%	66%	$0.13	6
Electric	School	Cooling Chillers	Windows-High Efficiency	U-0.32	U-0.40 (WA State Code)	Per Building	Existing	2,029	25	$22,191	15%	60%	$6.68	27
Electric	School	Cooling Chillers	Windows-High Efficiency	U-0.40 (WA State Code)	U-0.67 (Average Existing Conditions)	Per Building	Existing	1,738	25	$63,000	15%	60%	$16.80	23
Electric	School	Cooling Dx	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	Demand Controlled Ventilation (CO2 sensors)	Constant Ventilation	Per Building	Existing	1,819	15	$13,377	25%	94%	$0.93	90
Electric	School	Cooling Dx	Commissioning of Existing Buildings	Existing Building Commissioning	Average Existing Conditions	Per Building	Existing	2,274	7	$10,545	90%	85%	$0.92	268
Electric	School	Cooling Dx	Convert Constant Volume Air System to VAV	Variable Volume Air System	Constant Volume Air System	Per Building	Existing	5,458	15	$62,639	15%	67%	$3.79	113
Electric	School	Cooling Dx	DX Package-Air Side Economizer	Air-Side Economizer	No Economizer	Per Building	Existing	2,729	10	$40,447	10%	60%	$2.31	32
Electric	School	Cooling Dx	Direct / Indirect Evaporative Cooling, Pre-Cooling	Evaporative Cooler	Standard DX cooling	Per Building	Existing	4,549	15	$11,458	50%	94%	$3.11	422
Electric	School	Cooling Dx	Direct Digital Control System-Installation	DDC Retrofit (Morning Warm-Up Control Logic Included in This Measure)	Pneumatic	Per Building	Existing	2,729	5	$51,438	10%	34%	$4.72	16

Table B-2.2. Commercial Electric Measure Details

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Electric	School	Cooling Dx	Direct Digital Control System-Wireless System	DDC Retrofit - Wireless System	Pneumatic	Per Building	Existing	2,729	5	$12,502	50%	80%	$1.15	151
Electric	School	Cooling Dx	Duct Repair And Sealing	Reduction In Duct Losses to 5%	No Repair or Sealing, 15% duct losses	Per Building	Existing	454	18	$12,840	45%	65%	$3.30	22
Electric	School	Cooling Dx	Economizer Tune-up	Economizer Tune-up	No Economizer Tune-Up	Per Building	Existing	1,819	5	$11,414	10%	75%	$1.57	27
Electric	School	Cooling Dx	Exhaust Hood Makeup Air	Provide Makeup Air Directly at Exhaust Hood Instead of Pulling Conditioned Air	Hood Pulls Conditioned Air (No Make-up Air)	Per Building	Existing	992	10	$3,502	73%	85%	$0.55	82
Electric	School	Cooling Dx	Green Roof	Vegetation on Roof	Standard Dark Colored Roof	Per Building	Existing	1,586	40	$72,582	3.5%	98%	$30.09	8
Electric	School	Cooling Dx	Infiltration Reduction	Install Caulking And Weatherstripping (ACH 0.65)	Infiltration Conditions (ACH 1.0)	Per Building	Existing	909	12.5	$1,410	10%	39%	$0.22	5
Electric	School	Cooling Dx	Insulation - Ceiling	R-30 c.i. (WA State Code)	R-7 (Average Existing Conditions)	Per Building	Existing	82	25	$83,170	75%	15%	$111.46	1
Electric	School	Cooling Dx	Insulation - Ceiling	R-49 c.i.	R-38 c.i.	Per Building	Existing	0.90	25	$23,466	25%	85%	$2,865.56	0.03
Electric	School	Cooling Dx	Insulation - Duct	R-7 (WA State Code)	No Insulation	Per Building	Existing	764	20	$10,352	75%	55%	$1.51	50
Electric	School	Cooling Dx	Programmable Thermostat - Web Enabled	Programmable Thermostat - Web Enabled	No Programmable Thermostat	Per Building	Existing	545	10	$734	95%	21%	$0.21	16
Electric	School	Cooling Dx	RE - Deciduous Trees	Shade Trees	No Trees	Per Building	Existing	192	30	$2,386	75%	55%	$1.31	12
Electric	School	Cooling Dx	Window Film	Window Film	No Film	Per Building	Existing	7,293	10	$6,377	90%	66%	$0.13	6
Electric	School	Cooling Dx	Windows-High Efficiency	U-0.32	U-0.40 (WA State Code)	Per Building	Existing	2,295	25	$22,191	15%	60%	$5.91	28
Electric	School	Cooling Dx	Windows-High Efficiency	U-0.40 (WA State Code)	U-0.67 (Average Existing Conditions)	Per Building	Existing	1,966	25	$63,000	15%	60%	$14.85	24
Electric	School	Heat Pump	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	Demand Controlled Ventilation (CO2 sensors)	Constant Ventilation	Per Building	Existing	1,760	15	$13,377	25%	94%	$0.96	97
Electric	School	Heat Pump	Commissioning of Existing Buildings	Existing Building Commissioning	Average Existing Conditions	Per Building	Existing	18,023	7	$10,545	90%	85%	$0.11	2,617
Electric	School	Heat Pump	Convert Constant Volume Air System to VAV	Variable Volume Air System	Constant Volume Air System	Per Building	Existing	23,069	15	$62,639	15%	67%	$0.89	548
Electric	School	Heat Pump	Direct Digital Control System-Installation	DDC Retrofit (Morning Warm-Up Control Logic Included in This Measure)	Pneumatic	Per Building	Existing	21,627	5	$51,438	10%	34%	$0.59	172
Electric	School	Heat Pump	Direct Digital Control System-Wireless System	DDC Retrofit - Wireless System	Pneumatic	Per Building	Existing	21,627	5	$12,502	50%	80%	$0.14	1,598
Electric	School	Heat Pump	Duct Repair And Sealing	Reduction In Duct Losses to 5%	No Repair or Sealing, 15% duct losses	Per Building	Existing	3,604	18	$12,840	45%	65%	$0.41	232
Electric	School	Heat Pump	Exhaust Air to Ventilation Air Heat Recovery	Exhaust Air Heat Recovery	No Heat Recovery	Per Building	Existing	18,987	14	$48,525	5.0%	94%	$0.33	194
Electric	School	Heat Pump	Exhaust Hood Makeup Air	Provide Makeup Air Directly at Exhaust Hood Instead of Pulling Conditioned Air	Hood Pulls Conditioned Air (No Make-up Air)	Per Building	Existing	7,659	10	$3,502	73%	85%	$0.06	869
Electric	School	Heat Pump	Green Roof	Vegetation on Roof	Standard Dark Colored Roof	Per Building	Existing	1,534	40	$72,582	3.5%	98%	$31.10	11
Electric	School	Heat Pump	Ground Source Heat Pump > 135 kBTU/hr	High Efficiency Ground Source Heat Pump > 135 kBTU/hr	Water Source Heat Pump > 135 kBTU/hr	Per Building	Existing	2,390	15	$26,768	3.8%	95%	$49.31	14
Electric	School	Heat Pump	Infiltration Reduction	Install Caulking And Weatherstripping (ACH 0.65)	Infiltration Conditions (ACH 1.0)	Per Building	Existing	18,987	12.5	$1,410	10%	39%	$0.00	155

Table B-2.2. Commercial Electric Measure Details

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Electric	School	Heat Pump	Insulation - Ceiling	R-30 c.i. (WA State Code)	R-7 (Average Existing Conditions)	Per Building	Existing	29,832	25	$83,170	75%	15%	$0.30	703
Electric	School	Heat Pump	Insulation - Ceiling	R-38 c.i.	R-30 c.i. (WA State Code)	Per Building	Existing	3,011	25	$83,170	75%	70%	$3.06	323
Electric	School	Heat Pump	Insulation - Ceiling	R-49 c.i.	R-38 c.i.	Per Building	Existing	2,258	25	$23,466	25%	85%	$1.14	97
Electric	School	Heat Pump	Insulation - Duct	R-7 (WA State Code)	No Insulation	Per Building	Existing	6,055	20	$10,352	75%	55%	$0.18	507
Electric	School	Heat Pump	Insulation - Floor (non-slab)	R-30 (WA State Code)	R-11 (Average Existing Conditions)	Per Building	Existing	31,444	25	$43,848	35%	35%	$0.14	764
Electric	School	Heat Pump	Insulation - Floor (non-slab)	R-38	R-30 (WA State Code)	Per Building	Existing	6,110	25	$13,532	35%	35%	$0.24	144
Electric	School	Heat Pump	Insulation - Wall	R-16	R-3 (Average Existing Conditions)	Per Building	Existing	32,629	25	$20,366	10%	35%	$0.06	219
Electric	School	Heat Pump	Programmable Thermostat - Web Enabled	Programmable Thermostat - Web Enabled	No Programmable Thermostat	Per Building	Existing	4,325	10	$734	95%	21%	$0.02	161
Electric	School	Heat Pump	RE - Deciduous Trees	Shade Trees	No Trees	Per Building	Existing	212	30	$2,488	75%	55%	$1.23	16
Electric	School	Heat Pump	Variable Refrigerant Flow Cooling System	Variable Refrigerant Flow Cooling System	Standard Refrigeration System	Per Building	Existing	38,929	15	$15,624	25%	95%	$0.04	2,187
Electric	School	Heat Pump	Window Film	Window Film	No Film	Per Building	Existing	7,293	10	$6,377	90%	66%	$0.13	7
Electric	School	Heat Pump	Windows-High Efficiency	U-0.40 (WA State Code)	U-0.67 (Average Existing Conditions)	Per Building	Existing	3,776	25	$63,000	15%	60%	$7.73	58
Electric	School	Lighting Exterior	Covered Parking Lighting	Covered Parking Lighting	Normal Lighting	Per Building	Existing	5,011	9.5	$1,394	20%	95%	$0.03	1,117
Electric	School	Lighting Exterior	Daylighting Controls, Outdoors (Photocell)	Photocell	No Controls	Per Building	Existing	1,537	8	$236	75%	70%	$0.02	506
Electric	School	Lighting Exterior	Occupancy Sensor Control	Occupancy Sensor Control	No Occupancy Sensor	Per Building	Existing	2,561	8	$729	90%	75%	$0.05	1,865
Electric	School	Lighting Exterior	Solid State LED White Lighting	Landscape, merchandise, signage, structure & task lighting (2.5 W)	50W 10hrs/day, 365 day/yr	Per Building	Existing	1,497	13.69863	$300	75%	95%	$0.02	76
Electric	School	Lighting Exterior	Surface Parking Lighting	Surface Parking Lighting	Normal Lighting	Per Building	Existing	2,707	18.666667	$3,658	47%	95%	$0.15	1,336
Electric	School	Lighting Exterior	Time Clock	Time Clock	No Controls	Per Building	Existing	1,982	8	$541	10%	81%	$0.04	160
Electric	School	Lighting Interior Fluorescent	Bi-Level Control, Stairwell Lighting	Occupancy Sensor Control, 50% Lighting Power during unoccupied Time	Continuous Full Power Lighting in Stairways	Per Building	Existing	2,921	9	$2,874	50%	75%	$0.16	1,104
Electric	School	Lighting Interior Fluorescent	Dimming-Continuous, Fluorescent Fixtures	Continuous Dimming, Fluorescent Fixtures (Day-Lighting)	No Dimming Controls	Per Building	Existing	22,302	8	$17,281	30%	81%	$0.14	5,346
Electric	School	Lighting Interior Fluorescent	LED Refrigeration Case Lights	LED Refrigeration Case Lights	Fluorescent Refrigeration Case	Per Building	Existing	1,641	6	$611	10%	80%	$0.07	162
Electric	School	Lighting Interior Fluorescent	Occupancy Sensor Control	Occupancy Sensor Control	No Occupancy Sensor	Per Building	Existing	9,367	8	$4,559	90%	35%	$0.08	2,674
Electric	School	Lighting Interior Fluorescent	Time Clock	Time Clock	No Controls	Per Building	Existing	7,248	8	$1,984	10%	95%	$0.04	639
Electric	School	Lighting Interior Hid	Occupancy Sensor Control	Occupancy Sensor Control	No Occupancy Sensor	Per Building	Existing	968	8	$4,559	90%	35%	$0.85	295
Electric	School	Lighting Interior Hid	Time Clock	Time Clock	No Controls	Per Building	Existing	749	8	$203	10%	95%	$0.04	70
Electric	School	Lighting Interior Other	Exit Sign - LED	Two Sided LED Exit Sign (5 Watts)	CFL Exit Sign (9 Watts)	Per Building	Existing	217	16	$37	95%	50%	$0.01	115
Electric	School	Lighting Interior Other	Exit Sign - Photoluminescent or Tritium	Photoluminescent or Tritium	Two Sided LED Exit Sign (5 Watts)	Per Building	Existing	79	13	$69	95%	98%	$0.11	82

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Electric	School	Lighting Interior Screw Base	Cold Cathode Lighting	Cold Cathode Lighting 5 watts	30 W Incandescent Bulb	Per Building	Existing	32	5	$5	70%	94%	$0.04	9
Electric	School	Lighting Interior Screw Base	Occupancy Sensor Control	Occupancy Sensor Control	No Occupancy Sensor	Per Building	Existing	498	8	$4,559	90%	35%	$1.65	62
Electric	School	Lighting Interior Screw Base	Time Clock	Time Clock	No Controls	Per Building	Existing	385	8	$107	10%	95%	$0.05	14
Electric	School	Other Plug Load	ENERGY STAR - Battery Charging System	ENERGY STAR Battery Charging System	Non-ENERGY STAR Battery Chargers	Per Building	Existing	0.93	7	$0.00	20%	20%	$-0.01	0.04
Electric	School	Other Plug Load	ENERGY STAR - Water Cooler	ENERGY STAR Water Cooler (Hot/Cold Water)	Non-ENERGY STAR Water Cooler	Per Building	Existing	41	10	$0.00	95%	20%	$-0.01	8
Electric	School	Other Plug Load	Power Supply Transformer/Converter	80 Plus	85% efficient power supply (> 51W)	Per Building	Existing	735	4	$5	95%	86%	$-0.00	2
Electric	School	Other Plug Load	Scanner - ENERGY STAR	ENERGY STAR Scanners	Standard Scanner	Per Building	Existing	16	6	$0.00	95%	20%	$-0.01	3
Electric	School	Other Plug Load	Smart Strips	Smart Strip Power Strip	Standard surge protector	Per Building	Existing	535	4	$134	60%	90%	$0.07	322
Electric	School	Refrigeration	Add Doors to Refrigerated Open Display Cases	Add Doors to Refrigerated Open Display Cases	Standard Refrigerated Open Display Cases	Per Building	Existing	907	12	$1,405	15%	95%	$0.22	144
Electric	School	Refrigeration	Anti-Sweat (Humidistat) Controls	Anti-Sweat (Humidistat) Controls	No Anti-Sweat (Humidistat) Controls	Per Building	Existing	1,282	12	$107	15%	45%	$0.01	96
Electric	School	Refrigeration	Case Electronically Commutated Motor	ECM Case Fans	Standard Efficiency Motor	Per Building	Existing	2,421	15	$590	5.0%	77%	$0.02	103
Electric	School	Refrigeration	Case Replacement Low Temp	Case Replacement Low Temp	No replacement	Per Building	Existing	52,294	15	$5,664	5.0%	98%	$0.01	143
Electric	School	Refrigeration	Case Replacement Med Temp	Case Replacement Med Temp	No replacement	Per Building	Existing	4,460	15	$2,933	5.0%	98%	$0.08	12
Electric	School	Refrigeration	Commercial Refrigerator - Semivertical - No Doors - Med Temp	Commercial Refrigerator - Semivertical - No Doors - Med Temp	Standard Case	Per Building	Existing	1,319	10	$1,094	90%	85%	$0.12	1,128
Electric	School	Refrigeration	Commercial Refrigerator - Vertical - No Doors - Med Temp	Commercial Refrigerator - Vertical - No Doors - Med Temp	Standard Case	Per Building	Existing	597	10	$493	90%	85%	$0.12	510
Electric	School	Refrigeration	Demand Control Defrost - Hot Gas	Refrigerant Defrost	Defrost - Electric	Per Building	Existing	287	10	$193	5.0%	68%	$0.10	10
Electric	School	Refrigeration	Display Case Motion Sensors	Display Case Motion Sensors	No Motion Sensors	Per Building	Existing	317	8	$32	90%	85%	$0.01	249
Electric	School	Refrigeration	Evaporative Condenser - High-Efficiency	High-Efficiency Evaporative Condenser	Air-Cooled Condenser	Per Building	Existing	191	15	$944	90%	65%	$0.62	104
Electric	School	Refrigeration	Evaporator Fan Controller	ECM Evaporator Fan Controller	No Controller	Per Building	Existing	327	15	$364	90%	85%	$0.13	253
Electric	School	Refrigeration	Glass Door ENERGY STAR Refrigerators/Freezers	Glass Door ENERGY STAR Refrigerators/Freezers	Standard Glass Doors	Per Building	Existing	9	12	$10	95%	77%	$0.15	7
Electric	School	Refrigeration	High-Efficiency Compressor	High-Efficiency Compressor (15% More Efficient)	Standard Compressor, 40% Efficiency	Per Building	Existing	51,577	10	$33,523	85%	72%	$0.10	1,141
Electric	School	Refrigeration	Ice Maker	High-Efficiency Ice Maker	Standard Ice Maker	Per Building	Existing	714	10	$0.00	95%	86%	$-0.02	648
Electric	School	Refrigeration	Night Covers for Display Cases	Night Covers for Display Cases	No Night Covers	Per Building	Existing	853	5	$134	50%	85%	$0.03	405
Electric	School	Refrigeration	Refrigeration Commissioning of New or Existing Buildings	New or Existing Building Refrigeration Commissioning	No Commissioning	Per Building	Existing	1,783	3	$278	10%	85%	$0.06	136
Electric	School	Refrigeration	Refrigerator eCube	Refrigerator eCube	No Refrigerator eCube	Per Building	Existing	553	10	$53	75%	95%	$0.01	202

Table B-2.2. Commercial Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	School	Refrigeration	Solid Door ENERGY STAR Refrigerators/Freezers	Solid Door ENERGY STAR Refrigerators/Freezers	Standard Solid Door	Per Building	Existing	30	12	$-5.3637393	95%	81%	$-0.03	26
Electric	School	Refrigeration	Strip Curtains for Walk-Ins	Strip Curtains for Walk-Ins	No Strip Curtains for Walk-In	Per Building	Existing	133	4	$10	95%	20%	$0.02	28
Electric	School	Refrigeration	Visi Cooler	High Efficiency Visi Cooler	Standard Visi Cooler	Per Building	Existing	1,664	10	$311	95%	85%	$0.02	1,501
Electric	School	Refrigeration	Walk-In Electronically Commutated Motor	ECM Evaporator Fans	Standard Efficiency Motor	Per Building	Existing	327	15	$364	10%	95%	$0.13	34
Electric	School	Refrigerator	Residential Refrigerator/Freezer Recycling	Recycling Existing Refrigerator/Freezer	Existing Refrigerator/Freezer	Per Building	Existing	481	9	$128	25%	100%	$0.04	116
Electric	School	Servers	Server Virtualization	Server Virtualization	No Virtualization	Per Building	Existing	360	4	$337	72%	85%	$0.29	196
Electric	School	Space Heat	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	Demand Controlled Ventilation (CO2 sensors)	Constant Ventilation	Per Building	Existing	30,345	15	$13,377	25%	94%	$0.05	550
Electric	School	Space Heat	Commissioning of Existing Buildings	Existing Building Commissioning	Average Existing Conditions	Per Building	Existing	37,932	7	$10,545	90%	85%	$0.05	1,730
Electric	School	Space Heat	Convert Constant Volume Air System to VAV	Variable Volume Air System	Constant Volume Air System	Per Building	Existing	39,449	15	$62,639	15%	67%	$0.51	299
Electric	School	Space Heat	Direct Digital Control System-Installation	DDC Retrofit (Morning Warm-Up Control Logic Included in This Measure)	Pneumatic	Per Building	Existing	45,518	5	$51,438	10%	34%	$0.28	115
Electric	School	Space Heat	Direct Digital Control System-Wireless System	DDC Retrofit - Wireless System	Pneumatic	Per Building	Existing	45,518	5	$12,502	50%	80%	$0.06	1,070
Electric	School	Space Heat	Duct Repair And Sealing	Reduction In Duct Losses to 5%	No Repair or Sealing, 15% duct losses	Per Building	Existing	7,586	18	$12,840	45%	65%	$0.19	155
Electric	School	Space Heat	Economizer Tune-up	Economizer Tune-up	No Economizer Tune-Up	Per Building	Existing	30,345	5	$11,414	10%	75%	$0.09	169
Electric	School	Space Heat	Exhaust Air to Ventilation Air Heat Recovery	Exhaust Air Heat Recovery	No Heat Recovery	Per Building	Existing	45,518	14	$48,525	5.0%	94%	$0.13	148
Electric	School	Space Heat	Exhaust Hood Makeup Air	Provide Makeup Air Directly at Exhaust Hood Instead of Pulling Conditioned Air	Hood Pulls Conditioned Air (No Make-up Air)	Per Building	Existing	14,293	10	$3,502	73%	85%	$0.03	582
Electric	School	Space Heat	Infiltration Reduction	Install Caulking And Weatherstripping (ACH 0.65)	Infiltration Conditions (ACH 1.0)	Per Building	Existing	30,345	12.5	$1,410	10%	39%	$-0.00	78
Electric	School	Space Heat	Insulation - Ceiling	R-30 c.i. (WA State Code)	R-7 (Average Existing Conditions)	Per Building	Existing	71,633	25	$83,170	75%	15%	$0.12	538
Electric	School	Space Heat	Insulation - Ceiling	R-38 c.i.	R-30 c.i. (WA State Code)	Per Building	Existing	6,610	25	$83,170	75%	70%	$1.39	225
Electric	School	Space Heat	Insulation - Ceiling	R-49 c.i.	R-38 c.i.	Per Building	Existing	6,390	25	$23,466	25%	85%	$0.40	87
Electric	School	Space Heat	Insulation - Duct	R-7 (WA State Code)	No Insulation	Per Building	Existing	12,745	20	$10,352	75%	55%	$0.08	338
Electric	School	Space Heat	Insulation - Floor (non-slab)	R-30 (WA State Code)	R-11 (Average Existing Conditions)	Per Building	Existing	70,620	25	$43,848	35%	35%	$0.06	543
Electric	School	Space Heat	Insulation - Floor (non-slab)	R-38	R-30 (WA State Code)	Per Building	Existing	13,145	25	$13,532	35%	35%	$0.10	98
Electric	School	Space Heat	Insulation - Wall	R-16	R-3 (Average Existing Conditions)	Per Building	Existing	133,406	25	$20,366	10%	35%	$0.01	283
Electric	School	Space Heat	Programmable Thermostat - Web Enabled	Programmable Thermostat - Web Enabled	No Programmable Thermostat	Per Building	Existing	9,103	10	$734	95%	21%	$0.00	106

Table B-2.2. Commercial Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	School	Space Heat	Sensible And Total Heat Recovery Devices	Install Heat Recovery Devices - rotary air-to-air enthalpy heat recovery- 50% sensible and latent recovery effectiveness	No Heat Recovery	Per Building	Existing	75,864	10	$12,885	25%	98%	$0.22	999
Electric	School	Space Heat	Windows-High Efficiency	U-0.40 (WA State Code)	U-0.67 (Average Existing Conditions)	Per Building	Existing	3,928	25	$63,000	15%	60%	$7.43	17
Electric	School	Vending Machines	Vending Miser	Passive Infrared Sensor on Vending Machine Monitoring Vacancy of Area And Cycles Cooling - Controls	No Vending Miser - No controls	Per Building	Existing	1,796	3	$171	75%	25%	$0.03	13
Electric	School	Ventilation And Circulation	Automated Exhaust VFD Control - Parking Garage CO sensor	CO Sensors	No CO Sensors	Per Building	Existing	60,478	10	$6,559	1.0%	85%	$0.01	133
Electric	School	Ventilation And Circulation	Convert Constant Volume Air System to VAV	Variable Volume Air System	Constant Volume Air System	Per Building	Existing	8,505	15	$62,639	15%	67%	$2.42	947
Electric	School	Ventilation And Circulation	Cooking Hood Controls	Demand-Ventilation Control	No Controls	Per Building	Existing	1,119	18	$2,703	95%	85%	$0.27	1,000
Electric	School	Ventilation And Circulation	Motor - CEE Premium-Efficiency Plus	CEE PE+ Motor for HVAC Applications	NEMA Efficiency Motors	Per Building	Existing	722	15	$354	95%	76%	$0.05	560
Electric	School	Ventilation And Circulation	Motor - Pump & Fan System - Variable Speed Control	Pump And Fan System Optimization w/ VSD	No Pump And Fan System VSD Optimization	Per Building	Existing	18,074	20	$5,959	65%	75%	$0.03	9,427
Electric	School	Ventilation And Circulation	Motor - VAV Box High Efficiency (ECM)	ECM Motor	Standard Efficiency Motor	Per Building	Existing	3,721	15	$19,534	11%	77%	$0.66	293
Electric	School	Ventilation And Circulation	Motor Rewind	>15, <500 HP	No Rewind	Per Building	Existing	944	7	$268	65%	25%	$0.05	143
Electric	School	Ventilation And Circulation	Optimized Variable Volume Lab Hood Design	Optimized Variable Volume Lab Hood Design	Constant Volume Lab Hood Design	Per Building	Existing	1,134	13	$1,705	65%	59%	$0.20	483
Electric	School	Water Heat GT 55 Gal	Clothes Washer - Ozonating	Ozonating Clothes Washer	2013 Federal Standard Clothes Washer - MEF = 1.6, WF = 8.5	Per Building	Existing	12,173	10	$8,281	1.8%	95%	$-0.02	34
Electric	School	Water Heat GT 55 Gal	Clothes Washer Commercial	ENERGY STAR Commercial Clothes Washer - MEF = 2.43, WF = 4.0	2013 Federal Standard Clothes Washer - MEF = 1.6, WF = 8.5	Per Building	Existing	280	7	$107	95%	80%	$-0.25	36
Electric	School	Water Heat GT 55 Gal	Demand Controlled Circulating Systems	Demand Controlled Circulating Systems (VFD control by demand)	Constant Circulation	Per Building	Existing	4,024	10	$14,862	55%	94%	$0.57	356
Electric	School	Water Heat GT 55 Gal	Dishwasher Residential	RTF ENERGY STAR Dishwasher - 277 kWh/yr and 4.25 gal/cycle	RTF Market Standard 2014 Dishwasher - 289 kWh/yr and 5.0 gal/cycle	Per Building	Existing	13	12	$42	35%	25%	$0.44	0.20
Electric	School	Water Heat GT 55 Gal	Dishwashing - Commercial - High Temp	High Efficiency Dishwasher (ENERGY STAR)	Standard High Temp Commercial Dishwasher	Per Building	Existing	420	12	$241	95%	95%	$-0.71	65
Electric	School	Water Heat GT 55 Gal	Drainwater Heat Recovery Water Heater	Install (Power-Pipe or GFX) - Heat Recovery Water Heater	No Heat Recovery System	Per Building	Existing	15,230	25	$7,916	5.0%	92%	$0.05	122
Electric	School	Water Heat GT 55 Gal	Low-Flow Faucet Aerators	0.5 GPM	2.2 GPM (Federal Code)	Per Building	Existing	3,109	9	$21	95%	75%	$-0.00	381
Electric	School	Water Heat GT 55 Gal	Low-Flow Faucet Aerators	2.2 GPM (Federal Code)	3.0 GPM	Per Building	Existing	1,073	9	$16	95%	25%	$-0.01	43

Table B-2.2. Commercial Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	School	Water Heat GT 55 Gal	Low-Flow Pre-Rinse Spray Valves	0.6 GPM	1.6 GPM (Federal Standard)	Per Building	Existing	773	4	$236	95%	65%	$0.08	81
Electric	School	Water Heat GT 55 Gal	Low-Flow Showerheads	1.5 GPM	2.5 GPM (Federal Code)	Per Building	Existing	634	10	$348	95%	73%	$0.07	75
Electric	School	Water Heat GT 55 Gal	Low-Flow Showerheads	2.5 GPM (Federal Code)	4.5 GPM	Per Building	Existing	1,268	10	$289	95%	35%	$0.01	72
Electric	School	Water Heat GT 55 Gal	Pipe Insulation - Hot Water (DWH)	1.0" of Insulation, assuming R-4 (WA State Code)	No Insulation	Per Building	Existing	804	12	$96	80%	8%	$0.01	8
Electric	School	Water Heat GT 55 Gal	Ultrasonic Faucet Control	Install Ultrasonic Motion Faucet Control	No Faucet Control	Per Building	Existing	2,012	10	$1,475	75%	75%	$0.10	194
Electric	School	Water Heat LE 55 Gal	Clothes Washer - Ozonating	Ozonating Clothes Washer	2013 Federal Standard Clothes Washer - MEF = 1.6, WF = 8.5	Per Building	Existing	11,956	10	$8,281	1.8%	95%	$-0.02	33
Electric	School	Water Heat LE 55 Gal	Clothes Washer Commercial	ENERGY STAR Commercial Clothes Washer - MEF = 2.43, WF = 4.0	2013 Federal Standard Clothes Washer - MEF = 1.6, WF = 8.5	Per Building	Existing	280	7	$107	95%	80%	$-0.25	36
Electric	School	Water Heat LE 55 Gal	Demand Controlled Circulating Systems	Demand Controlled Circulating Systems (VFD control by demand)	Constant Circulation	Per Building	Existing	3,952	10	$14,862	55%	94%	$0.58	343
Electric	School	Water Heat LE 55 Gal	Dishwasher Residential	RTF ENERGY STAR Dishwasher - 277 kWh/yr and 4.25 gal/cycle	RTF Market Standard 2014 Dishwasher - 289 kWh/yr and 5.0 gal/cycle	Per Building	Existing	13	12	$42	35%	25%	$0.44	0.20
Electric	School	Water Heat LE 55 Gal	Dishwashing - Commercial - High Temp	High Efficiency Dishwasher (ENERGY STAR)	Standard High Temp Commercial Dishwasher	Per Building	Existing	412	12	$236	95%	95%	$-0.73	62
Electric	School	Water Heat LE 55 Gal	Drainwater Heat Recovery Water Heater	Install (Power-Pipe or GFX) - Heat Recovery Water Heater	No Heat Recovery System	Per Building	Existing	15,230	25	$7,916	5.0%	92%	$0.05	118
Electric	School	Water Heat LE 55 Gal	Low-Flow Faucet Aerators	0.5 GPM	2.2 GPM (Federal Code)	Per Building	Existing	3,054	9	$21	95%	75%	$-0.00	367
Electric	School	Water Heat LE 55 Gal	Low-Flow Faucet Aerators	2.2 GPM (Federal Code)	3.0 GPM	Per Building	Existing	1,053	9	$16	95%	25%	$-0.01	42
Electric	School	Water Heat LE 55 Gal	Low-Flow Pre-Rinse Spray Valves	0.6 GPM	1.6 GPM (Federal Standard)	Per Building	Existing	773	4	$236	95%	65%	$0.08	80
Electric	School	Water Heat LE 55 Gal	Low-Flow Showerheads	1.5 GPM	2.5 GPM (Federal Code)	Per Building	Existing	634	10	$348	95%	73%	$0.07	74
Electric	School	Water Heat LE 55 Gal	Low-Flow Showerheads	2.5 GPM (Federal Code)	4.5 GPM	Per Building	Existing	1,268	10	$289	95%	35%	$0.01	71
Electric	School	Water Heat LE 55 Gal	Pipe Insulation - Hot Water (DWH)	1.0" of Insulation, assuming R-4 (WA State Code)	No Insulation	Per Building	Existing	790	12	$96	80%	8%	$0.01	8
Electric	School	Water Heat LE 55 Gal	Ultrasonic Faucet Control	Install Ultrasonic Motion Faucet Control	No Faucet Control	Per Building	Existing	1,976	10	$1,475	75%	75%	$0.10	187
Electric	University	Computers	Network PC Power Management	Network PC Power Management	No Power Management	Per Building	Existing	13,325	4	$1,304	95%	30%	$0.03	870
Electric	University	Cooking	Combination Oven	60% cooking efficiency	Non ENERGY STAR	Per Building	Existing	134	12	$22	90%	90%	$0.02	15
Electric	University	Cooking	Fryers - New CEE Efficient Electric Deep Fat Fryers	15 inch width Deep Fryer CEE 2006 rating: 80% under heavy load, Less than 1000 watt at idle	15 inch width standard electric deep fat fryers	Per Building	Existing	6	12	$11	35%	35%	$0.25	0.10
Electric	University	Cooking	Griddle	70% cooking efficiency	Non ENERGY STAR	Per Building	Existing	50	12	$16	95%	35%	$0.04	2
Electric	University	Cooking	Hot Food Holding Cabinet	ENERGY STAR Hot Food Holding Cabinet	Non ENERGY STAR Hot Food Holding Cabinet	Per Building	Existing	119	12	$78	75%	21%	$0.09	2
Electric	University	Cooking	Steam Cooker	ENERGY STAR Steam Cooker	Non ENERGY STAR Steam Cooker	Per Building	Existing	37	12	$5	5.0%	35%	$0.01	0.16

Table B-2.2. Commercial Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	University	Cooling Chillers	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	Demand Controlled Ventilation (CO2 sensors)	Constant Ventilation	Per Building	Existing	1,683	15	$13,996	25%	94%	$1.05	3
Electric	University	Cooling Chillers	Chilled Water / Condenser Water Settings-Optimization	Additional Control Features	EMS already installed - No Optimization	Per Building	Existing	210	5	$9,539	95%	81%	$11.36	1
Electric	University	Cooling Chillers	Chilled Water Piping Loop w/ VSD Control	VSD for secondary chilled water loop	Primary loop only w/ constant speed pump	Per Building	Existing	1,272	10	$58,724	25%	70%	$7.20	1
Electric	University	Cooling Chillers	Chiller-Water Side Economizer	Install Economizer	No Economizer	Per Building	Existing	841	15	$36,336	45%	90%	$20.60	2
Electric	University	Cooling Chillers	Commissioning of Existing Buildings	Existing Building Commissioning	Average Existing Conditions	Per Building	Existing	2,104	7	$11,040	90%	85%	$1.04	9
Electric	University	Cooling Chillers	Convert Constant Volume Air System to VAV	Variable Volume Air System	Constant Volume Air System	Per Building	Existing	5,049	15	$70,238	15%	67%	$4.28	3
Electric	University	Cooling Chillers	Cooling Tower-Decrease Approach Temperature	6 Deg F	10 Deg F	Per Building	Existing	1,346	7.5	$7,256	10%	94%	$0.73	0.92
Electric	University	Cooling Chillers	Cooling Tower-Two-Speed Fan Motor	Cooling Tower-Two-Speed Fan Motor	Cooling Tower-One-Speed Fan Motor	Per Building	Existing	2,356	15	$652	75%	35%	$0.03	4
Electric	University	Cooling Chillers	Cooling Tower-VSD Fan Control	Variable-Speed Tower Fans replace Two-Speed	Cooling Tower-Two-Speed Fan Motor	Per Building	Existing	673	13	$5,250	75%	75%	$1.06	2
Electric	University	Cooling Chillers	Direct Digital Control System-Installation	DDC Retrofit (Morning Warm-Up Control Logic Included in This Measure)	Pneumatic	Per Building	Existing	2,524	5	$53,845	10%	34%	$5.34	0.56
Electric	University	Cooling Chillers	Direct Digital Control System-Wireless System	DDC Retrofit - Wireless System	Pneumatic	Per Building	Existing	2,524	5	$13,086	50%	80%	$1.30	5
Electric	University	Cooling Chillers	Exhaust Hood Makeup Air	Provide Makeup Air Directly at Exhaust Hood Instead of Pulling Conditioned Air	Hood Pulls Conditioned Air (No Make-up Air)	Per Building	Existing	1,024	10	$3,502	73%	85%	$0.53	2
Electric	University	Cooling Chillers	Green Roof	Vegetation on Roof	Standard Dark Colored Roof	Per Building	Existing	654	40	$20,480	3.5%	98%	$34.05	0.13
Electric	University	Cooling Chillers	Infiltration Reduction	Install Caulking And Weatherstripping (ACH 0.65)	Infiltration Conditions (ACH 1.0)	Per Building	Existing	841	12.5	$1,472	10%	39%	$0.25	0.19
Electric	University	Cooling Chillers	Insulation - Ceiling	R-30 c.i. (WA State Code)	R-7 (Average Existing Conditions)	Per Building	Existing	76	25	$38,808	75%	13%	$56.22	0.04
Electric	University	Cooling Chillers	Insulation - Ceiling	R-49 c.i.	R-38 c.i.	Per Building	Existing	0.84	25	$10,944	25%	85%	$1,444.68	0.00
Electric	University	Cooling Chillers	Pipe Insulation - Chilled Water	1.5" of Insulation, assuming R-6 (WA State Code)	No Insulation	Per Building	Existing	252	15	$1,146	65%	45%	$0.57	0.44
Electric	University	Cooling Chillers	Programmable Thermostat - Web Enabled	Programmable Thermostat - Web Enabled	No Programmable Thermostat	Per Building	Existing	504	10	$1,641	15%	26%	$0.50	0.11
Electric	University	Cooling Chillers	RE - Deciduous Trees	Shade Trees	No Trees	Per Building	Existing	197	30	$2,068	75%	55%	$1.11	0.48
Electric	University	Cooling Chillers	Sensible And Total Heat Recovery Devices	Install Heat Recovery Devices - rotary air-to-air enthalpy heat recovery- 50% sensible and latent recovery effectiveness	No Heat Recovery	Per Building	Existing	5,058	10	$18,163	25%	98%	$3.64	5
Electric	University	Cooling Chillers	Window Film	Window Film	No Film	Per Building	Existing	7,634	10	$6,677	90%	66%	$0.13	0.22
Electric	University	Cooling Chillers	Windows-High Efficiency	U-0.32	U-0.40 (WA State Code)	Per Building	Existing	2,123	25	$27,899	15%	60%	$6.68	0.95

Table B-2.2. Commercial Electric Measure Details

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Electric	University	Cooling Chillers	Windows-High Efficiency	U-0.40 (WA State Code)	U-0.67 (Average Existing Conditions)	Per Building	Existing	1,819	25	$75,287	15%	60%	$16.80	0.81
Electric	University	Cooling Dx	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	Demand Controlled Ventilation (CO2 sensors)	Constant Ventilation	Per Building	Existing	1,904	15	$13,996	25%	94%	$0.93	4
Electric	University	Cooling Dx	Commissioning of Existing Buildings	Existing Building Commissioning	Average Existing Conditions	Per Building	Existing	2,380	7	$11,040	90%	85%	$0.92	14
Electric	University	Cooling Dx	Convert Constant Volume Air System to VAV	Variable Volume Air System	Constant Volume Air System	Per Building	Existing	5,713	15	$70,238	15%	67%	$3.79	6
Electric	University	Cooling Dx	DX Package-Air Side Economizer	Air-Side Economizer	No Economizer	Per Building	Existing	2,856	10	$42,338	10%	60%	$2.31	1
Electric	University	Cooling Dx	Direct / Indirect Evaporative Cooling, Pre-Cooling	Evaporative Cooler	Standard DX cooling	Per Building	Existing	4,761	15	$16,668	50%	94%	$3.11	22
Electric	University	Cooling Dx	Direct Digital Control System-Installation	DDC Retrofit (Morning Warm-Up Control Logic Included in This Measure)	Pneumatic	Per Building	Existing	2,856	5	$53,845	10%	34%	$4.72	0.86
Electric	University	Cooling Dx	Direct Digital Control System-Wireless System	DDC Retrofit - Wireless System	Pneumatic	Per Building	Existing	2,856	5	$13,086	50%	80%	$1.15	8
Electric	University	Cooling Dx	Duct Repair And Sealing	Reduction In Duct Losses to 5%	No Repair or Sealing, 15% duct losses	Per Building	Existing	476	18	$13,440	45%	65%	$3.30	1
Electric	University	Cooling Dx	Economizer Tune-up	Economizer Tune-up	No Economizer Tune-Up	Per Building	Existing	1,904	5	$11,945	10%	75%	$1.57	1
Electric	University	Cooling Dx	Exhaust Hood Makeup Air	Provide Makeup Air Directly at Exhaust Hood Instead of Pulling Conditioned Air	Hood Pulls Conditioned Air (No Make-up Air)	Per Building	Existing	1,116	10	$3,502	73%	85%	$0.49	4
Electric	University	Cooling Dx	Green Roof	Vegetation on Roof	Standard Dark Colored Roof	Per Building	Existing	740	40	$20,480	3.5%	98%	$30.09	0.20
Electric	University	Cooling Dx	Infiltration Reduction	Install Caulking And Weatherstripping (ACH 0.65)	Infiltration Conditions (ACH 1.0)	Per Building	Existing	952	12.5	$1,472	10%	39%	$0.22	0.29
Electric	University	Cooling Dx	Insulation - Ceiling	R-30 c.i. (WA State Code)	R-7 (Average Existing Conditions)	Per Building	Existing	86	25	$38,808	75%	13%	$49.68	0.06
Electric	University	Cooling Dx	Insulation - Ceiling	R-49 c.i.	R-38 c.i.	Per Building	Existing	0.95	25	$10,944	25%	85%	$1,276.80	0.00
Electric	University	Cooling Dx	Insulation - Duct	R-7 (WA State Code)	No Insulation	Per Building	Existing	799	20	$10,832	75%	55%	$1.51	2
Electric	University	Cooling Dx	Programmable Thermostat - Web Enabled	Programmable Thermostat - Web Enabled	No Programmable Thermostat	Per Building	Existing	571	10	$1,641	95%	21%	$0.45	0.88
Electric	University	Cooling Dx	RE - Deciduous Trees	Shade Trees	No Trees	Per Building	Existing	215	30	$2,495	75%	55%	$1.23	0.69
Electric	University	Cooling Dx	Window Film	Window Film	No Film	Per Building	Existing	7,634	10	$6,677	90%	66%	$0.13	0.32
Electric	University	Cooling Dx	Windows-High Efficiency	U-0.32	U-0.40 (WA State Code)	Per Building	Existing	2,403	25	$27,899	15%	60%	$5.91	1
Electric	University	Cooling Dx	Windows-High Efficiency	U-0.40 (WA State Code)	U-0.67 (Average Existing Conditions)	Per Building	Existing	2,058	25	$75,287	15%	60%	$14.85	1
Electric	University	Heat Pump	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	Demand Controlled Ventilation (CO2 sensors)	Constant Ventilation	Per Building	Existing	1,842	15	$13,996	25%	94%	$0.96	1
Electric	University	Heat Pump	Commissioning of Existing Buildings	Existing Building Commissioning	Average Existing Conditions	Per Building	Existing	18,865	7	$11,040	90%	85%	$0.11	36
Electric	University	Heat Pump	Convert Constant Volume Air System to VAV	Variable Volume Air System	Constant Volume Air System	Per Building	Existing	24,147	15	$70,238	15%	67%	$0.89	7
Electric	University	Heat Pump	Direct Digital Control System-Installation	DDC Retrofit (Morning Warm-Up Control Logic Included in This Measure)	Pneumatic	Per Building	Existing	22,638	5	$53,845	10%	34%	$0.59	2

Table B-2.2. Commercial Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	University	Heat Pump	Direct Digital Control System-Wireless System	DDC Retrofit - Wireless System	Pneumatic	Per Building	Existing	22,638	5	$13,086	50%	80%	$0.14	21
Electric	University	Heat Pump	Duct Repair And Sealing	Reduction In Duct Losses to 5%	No Repair or Sealing, 15% duct losses	Per Building	Existing	3,773	18	$13,440	45%	65%	$0.41	3
Electric	University	Heat Pump	Exhaust Air to Ventilation Air Heat Recovery	Exhaust Air Heat Recovery	No Heat Recovery	Per Building	Existing	19,874	14	$50,793	5.0%	94%	$0.33	2
Electric	University	Heat Pump	Exhaust Hood Makeup Air	Provide Makeup Air Directly at Exhaust Hood Instead of Pulling Conditioned Air	Hood Pulls Conditioned Air (No Make-up Air)	Per Building	Existing	8,616	10	$3,502	73%	85%	$0.06	11
Electric	University	Heat Pump	Green Roof	Vegetation on Roof	Standard Dark Colored Roof	Per Building	Existing	716	40	$20,480	3.5%	98%	$31.10	0.06
Electric	University	Heat Pump	Ground Source Heat Pump > 135 kBTU/hr	High Efficiency Ground Source Heat Pump > 135 kBTU/hr	Water Source Heat Pump > 135 kBTU/hr	Per Building	Existing	2,502	15	$70,073	3.8%	95%	$49.31	0.20
Electric	University	Heat Pump	Infiltration Reduction	Install Caulking And Weatherstripping (ACH 0.65)	Infiltration Conditions (ACH 1.0)	Per Building	Existing	19,874	12.5	$1,472	10%	39%	$0.00	2
Electric	University	Heat Pump	Insulation - Ceiling	R-30 c.i. (WA State Code)	R-7 (Average Existing Conditions)	Per Building	Existing	20,975	25	$38,808	75%	13%	$0.20	5
Electric	University	Heat Pump	Insulation - Ceiling	R-38 c.i.	R-30 c.i. (WA State Code)	Per Building	Existing	2,114	25	$38,808	75%	70%	$2.03	2
Electric	University	Heat Pump	Insulation - Ceiling	R-49 c.i.	R-38 c.i.	Per Building	Existing	1,690	25	$10,944	25%	85%	$0.71	0.95
Electric	University	Heat Pump	Insulation - Duct	R-7 (WA State Code)	No Insulation	Per Building	Existing	6,338	20	$10,832	75%	55%	$0.18	6
Electric	University	Heat Pump	Insulation - Floor (non-slab)	R-30 (WA State Code)	R-11 (Average Existing Conditions)	Per Building	Existing	25,133	25	$20,461	35%	35%	$0.08	8
Electric	University	Heat Pump	Insulation - Floor (non-slab)	R-38	R-30 (WA State Code)	Per Building	Existing	4,885	25	$6,306	35%	35%	$0.13	1
Electric	University	Heat Pump	Insulation - Wall	R-16	R-3 (Average Existing Conditions)	Per Building	Existing	57,135	25	$21,315	10%	35%	$0.03	5
Electric	University	Heat Pump	Programmable Thermostat - Web Enabled	Programmable Thermostat - Web Enabled	No Programmable Thermostat	Per Building	Existing	4,527	10	$1,641	95%	21%	$0.05	2
Electric	University	Heat Pump	RE - Deciduous Trees	Shade Trees	No Trees	Per Building	Existing	178	30	$1,967	75%	55%	$1.16	0.18
Electric	University	Heat Pump	Variable Refrigerant Flow Cooling System	Variable Refrigerant Flow Cooling System	Standard Refrigeration System	Per Building	Existing	40,748	15	$16,352	25%	95%	$0.04	29
Electric	University	Heat Pump	Window Film	Window Film	No Film	Per Building	Existing	7,634	10	$6,677	90%	66%	$0.13	0.10
Electric	University	Heat Pump	Windows-High Efficiency	U-0.40 (WA State Code)	U-0.67 (Average Existing Conditions)	Per Building	Existing	3,953	25	$75,287	15%	60%	$7.73	0.80
Electric	University	Lighting Exterior	Covered Parking Lighting	Covered Parking Lighting	Normal Lighting	Per Building	Existing	5,245	9.5	$1,461	20%	95%	$0.03	273
Electric	University	Lighting Exterior	Daylighting Controls, Outdoors (Photocell)	Photocell	No Controls	Per Building	Existing	1,050	8	$163	75%	70%	$0.02	123
Electric	University	Lighting Exterior	Occupancy Sensor Control	Occupancy Sensor Control	No Occupancy Sensor	Per Building	Existing	2,681	8	$730	90%	75%	$0.04	456
Electric	University	Lighting Exterior	Solid State LED White Lighting	Landscape, merchandise, signage, structure & task lighting (2.5 W)	50W 10hrs/day, 365 day/yr	Per Building	Existing	1,023	13.69863	$207	75%	95%	$0.02	18
Electric	University	Lighting Exterior	Surface Parking Lighting	Surface Parking Lighting	Normal Lighting	Per Building	Existing	2,834	18.666667	$3,828	47%	95%	$0.15	326
Electric	University	Lighting Exterior	Time Clock	Time Clock	No Controls	Per Building	Existing	2,074	8	$567	10%	81%	$0.04	39
Electric	University	Lighting Interior Fluorescent	Bi-Level Control, Stairwell Lighting	Occupancy Sensor Control, 50% Lighting Power during unoccupied Time	Continuous Full Power Lighting in Stairways	Per Building	Existing	4,244	9	$3,007	50%	75%	$0.11	508
Electric	University	Lighting Interior Fluorescent	Dimming-Continuous, Fluorescent Fixtures	Continuous Dimming, Fluorescent Fixtures (Day-Lighting)	No Dimming Controls	Per Building	Existing	43,904	8	$11,804	30%	81%	$0.04	2,459

Table B-2.2. Commercial Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	University	Lighting Interior Fluorescent	LED Refrigeration Case Lights	LED Refrigeration Case Lights	Fluorescent Refrigeration Case	Per Building	Existing	1,717	6	$635	10%	80%	$0.06	39
Electric	University	Lighting Interior Fluorescent	Occupancy Sensor Control	Occupancy Sensor Control	No Occupancy Sensor	Per Building	Existing	18,440	8	$4,766	90%	35%	$0.04	1,230
Electric	University	Lighting Interior Fluorescent	Time Clock	Time Clock	No Controls	Per Building	Existing	14,269	8	$3,901	10%	95%	$0.04	294
Electric	University	Lighting Interior Hid	Occupancy Sensor Control	Occupancy Sensor Control	No Occupancy Sensor	Per Building	Existing	1,629	8	$4,766	90%	35%	$0.52	116
Electric	University	Lighting Interior Hid	Time Clock	Time Clock	No Controls	Per Building	Existing	1,261	8	$348	10%	95%	$0.05	27
Electric	University	Lighting Interior Other	Exit Sign - LED	Two Sided LED Exit Sign (5 Watts)	CFL Exit Sign (9 Watts)	Per Building	Existing	830	16	$140	95%	50%	$0.01	102
Electric	University	Lighting Interior Other	Exit Sign - Photoluminescent or Tritium	Photoluminescent or Tritium	Two Sided LED Exit Sign (5 Watts)	Per Building	Existing	301	13	$258	95%	98%	$0.11	73
Electric	University	Lighting Interior Screw Base	Cold Cathode Lighting	Cold Cathode Lighting 5 watts	30 W Incandescent Bulb	Per Building	Existing	457	5	$89	70%	94%	$0.05	29
Electric	University	Lighting Interior Screw Base	Occupancy Sensor Control	Occupancy Sensor Control	No Occupancy Sensor	Per Building	Existing	6,921	8	$4,766	90%	35%	$0.12	202
Electric	University	Lighting Interior Screw Base	Time Clock	Time Clock	No Controls	Per Building	Existing	5,355	8	$1,461	10%	95%	$0.04	48
Electric	University	Other Plug Load	ENERGY STAR - Battery Charging System	ENERGY STAR Battery Charging System	Non-ENERGY STAR Battery Chargers	Per Building	Existing	0.97	7	$0.00	20%	20%	$-0.01	0.01
Electric	University	Other Plug Load	ENERGY STAR - Water Cooler	ENERGY STAR Water Cooler (Hot/Cold Water)	Non-ENERGY STAR Water Cooler	Per Building	Existing	92	10	$0.00	95%	20%	$-0.01	4
Electric	University	Other Plug Load	Power Supply Transformer/Converter	80 Plus	85% efficient power supply (> 51W)	Per Building	Existing	770	4	$5	95%	86%	$-0.00	0.71
Electric	University	Other Plug Load	Scanner - ENERGY STAR	ENERGY STAR Scanners	Standard Scanner	Per Building	Existing	36	6	$0.00	95%	20%	$-0.01	1
Electric	University	Other Plug Load	Smart Strips	Smart Strip Power Strip	Standard surge protector	Per Building	Existing	560	4	$140	60%	90%	$0.07	78
Electric	University	Refrigeration	Add Doors to Refrigerated Open Display Cases	Add Doors to Refrigerated Open Display Cases	Standard Refrigerated Open Display Cases	Per Building	Existing	950	12	$1,472	15%	95%	$0.22	35
Electric	University	Refrigeration	Anti-Sweat (Humidistat) Controls	Anti-Sweat (Humidistat) Controls	No Anti-Sweat (Humidistat) Controls	Per Building	Existing	1,342	12	$112	15%	45%	$0.01	23
Electric	University	Refrigeration	Case Electronically Commutated Motor	ECM Case Fans	Standard Efficiency Motor	Per Building	Existing	2,535	15	$618	5.0%	77%	$0.02	25
Electric	University	Refrigeration	Case Replacement Low Temp	Case Replacement Low Temp	No replacement	Per Building	Existing	54,737	15	$5,930	5.0%	98%	$0.01	35
Electric	University	Refrigeration	Case Replacement Med Temp	Case Replacement Med Temp	No replacement	Per Building	Existing	4,668	15	$3,069	5.0%	98%	$0.08	2
Electric	University	Refrigeration	Commercial Refrigerator - Semivertical - No Doors - Med Temp	Commercial Refrigerator - Semivertical - No Doors - Med Temp	Standard Case	Per Building	Existing	1,381	10	$1,146	90%	85%	$0.12	275
Electric	University	Refrigeration	Commercial Refrigerator - Vertical - No Doors - Med Temp	Commercial Refrigerator - Vertical - No Doors - Med Temp	Standard Case	Per Building	Existing	625	10	$517	90%	85%	$0.12	124
Electric	University	Refrigeration	Demand Control Defrost - Hot Gas	Refrigerant Defrost	Defrost - Electric	Per Building	Existing	301	10	$196	5.0%	68%	$0.10	2
Electric	University	Refrigeration	Display Case Motion Sensors	Display Case Motion Sensors	No Motion Sensors	Per Building	Existing	332	8	$33	90%	85%	$0.01	61

Table B-2.2. Commercial Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	University	Refrigeratio n	Evaporative Condenser - High-Efficiency	High-Efficiency Evaporative Condenser	Air-Cooled Condenser	Per Building	Existing	200	15	$983	90%	65%	$0.62	25
Electric	University	Refrigeratio n	Evaporator Fan Controller	ECM Evaporator Fan Controller	No Controller	Per Building	Existing	327	15	$365	90%	85%	$0.13	59
Electric	University	Refrigeratio n	Glass Door ENERGY STAR Refrigerators/Freezers	Glass Door ENERGY STAR Refrigerators/Freezers	Standard Glass Doors	Per Building	Existing	9	12	$11	95%	77%	$0.16	1
Electric	University	Refrigeratio n	High-Efficiency Compressor	High-Efficiency Compressor (15% More Efficient)	Standard Compressor, 40% Efficiency	Per Building	Existing	53,988	10	$35,087	85%	72%	$0.10	279
Electric	University	Refrigeratio n	Ice Maker	High-Efficiency Ice Maker	Standard Ice Maker	Per Building	Existing	714	10	$0.00	95%	86%	$-0.02	151
Electric	University	Refrigeratio n	Night Covers for Display Cases	Night Covers for Display Cases	No Night Covers	Per Building	Existing	893	5	$140	50%	85%	$0.03	99
Electric	University	Refrigeratio n	Refrigeration Commissioning of New or Existing Buildings	New or Existing Building Refrigeration Commissioning	No Commissioning	Per Building	Existing	1,867	3	$292	10%	85%	$0.06	33
Electric	University	Refrigeratio n	Refrigerator eCube	Refrigerator eCube	No Refrigerator eCube	Per Building	Existing	1,025	10	$123	75%	95%	$0.01	49
Electric	University	Refrigeratio n	Solid Door ENERGY STAR Refrigerators/Freezers	Solid Door ENERGY STAR Refrigerators/Freezers	Standard Solid Door	Per Building	Existing	30	12	$-5.6212027	95%	81%	$-0.03	6
Electric	University	Refrigeratio n	Strip Curtains for Walk-Ins	Strip Curtains for Walk-Ins	No Strip Curtains for Walk-In	Per Building	Existing	133	4	$11	95%	20%	$0.02	6
Electric	University	Refrigeratio n	Visi Cooler	High Efficiency Visi Cooler	Standard Visi Cooler	Per Building	Existing	1,741	10	$326	95%	85%	$0.02	367
Electric	University	Refrigeratio n	Walk-In Electronically Commutated Motor	ECM Evaporator Fans	Standard Efficiency Motor	Per Building	Existing	327	15	$365	10%	95%	$0.13	8
Electric	University	Refrigerator	Residential Refrigerator/Freezer Recycling	Recycling Existing Refrigerator/Freezer	Existing Refrigerator/Freezer	Per Building	Existing	481	9	$129	25%	100%	$0.04	27
Electric	University	Servers	Server Virtualization	Server Virtualization	No Virtualization	Per Building	Existing	360	4	$337	72%	85%	$0.29	46
Electric	University	Space Heat	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	Demand Controlled Ventilation (CO2 sensors)	Constant Ventilation	Per Building	Existing	31,763	15	$13,996	25%	94%	$0.05	172
Electric	University	Space Heat	Commissioning of Existing Buildings	Existing Building Commissioning	Average Existing Conditions	Per Building	Existing	39,704	7	$11,040	90%	85%	$0.05	553
Electric	University	Space Heat	Convert Constant Volume Air System to VAV	Variable Volume Air System	Constant Volume Air System	Per Building	Existing	41,292	15	$70,238	15%	67%	$0.51	94
Electric	University	Space Heat	Direct Digital Control System-Installation	DDC Retrofit (Morning Warm-Up Control Logic Included in This Measure)	Pneumatic	Per Building	Existing	47,645	5	$53,845	10%	34%	$0.28	36
Electric	University	Space Heat	Direct Digital Control System-Wireless System	DDC Retrofit - Wireless System	Pneumatic	Per Building	Existing	47,645	5	$13,086	50%	80%	$0.06	336
Electric	University	Space Heat	Duct Repair And Sealing	Reduction In Duct Losses to 5%	No Repair or Sealing, 15% duct losses	Per Building	Existing	7,940	18	$13,440	45%	65%	$0.19	48
Electric	University	Space Heat	Economizer Tune-up	Economizer Tune-up	No Economizer Tune-Up	Per Building	Existing	31,763	5	$11,945	10%	75%	$0.09	53
Electric	University	Space Heat	Exhaust Air to Ventilation Air Heat Recovery	Exhaust Air Heat Recovery	No Heat Recovery	Per Building	Existing	47,645	14	$50,793	5.0%	94%	$0.13	46
Electric	University	Space Heat	Exhaust Hood Makeup Air	Provide Makeup Air Directly at Exhaust Hood Instead of Pulling Conditioned Air	Hood Pulls Conditioned Air (No Make-up Air)	Per Building	Existing	16,080	10	$3,502	73%	85%	$0.02	182
Electric	University	Space Heat	Infiltration Reduction	Install Caulking And Weatherstripping (ACH 0.65)	Infiltration Conditions (ACH 1.0)	Per Building	Existing	31,763	12.5	$1,472	10%	39%	$-0.00	24

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Electric	University	Space Heat	Insulation - Ceiling	R-30 c.i. (WA State Code)	R-7 (Average Existing Conditions)	Per Building	Existing	50,301	25	$38,808	75%	13%	$0.07	98
Electric	University	Space Heat	Insulation - Ceiling	R-38 c.i.	R-30 c.i. (WA State Code)	Per Building	Existing	4,641	25	$38,808	75%	70%	$0.92	48
Electric	University	Space Heat	Insulation - Ceiling	R-49 c.i.	R-38 c.i.	Per Building	Existing	4,487	25	$10,944	25%	85%	$0.26	18
Electric	University	Space Heat	Insulation - Duct	R-7 (WA State Code)	No Insulation	Per Building	Existing	13,340	20	$10,832	75%	55%	$0.08	108
Electric	University	Space Heat	Insulation - Floor (non-slab)	R-30 (WA State Code)	R-11 (Average Existing Conditions)	Per Building	Existing	53,367	25	$20,461	35%	35%	$0.03	125
Electric	University	Space Heat	Insulation - Floor (non-slab)	R-38	R-30 (WA State Code)	Per Building	Existing	9,933	25	$6,306	35%	35%	$0.06	22
Electric	University	Space Heat	Insulation - Wall	R-16	R-3 (Average Existing Conditions)	Per Building	Existing	217,902	25	$21,315	10%	35%	$-0.00	142
Electric	University	Space Heat	Programmable Thermostat - Web Enabled	Programmable Thermostat - Web Enabled	No Programmable Thermostat	Per Building	Existing	9,529	10	$1,641	95%	21%	$0.02	34
Electric	University	Space Heat	Sensible And Total Heat Recovery Devices	Install Heat Recovery Devices - rotary air-to-air enthalpy heat recovery- 50% sensible and latent recovery effectiveness	No Heat Recovery	Per Building	Existing	79,409	10	$18,163	25%	98%	$0.22	319
Electric	University	Space Heat	Windows-High Efficiency	U-0.40 (WA State Code)	U-0.67 (Average Existing Conditions)	Per Building	Existing	4,112	25	$75,287	15%	60%	$7.43	5
Electric	University	Vending Machines	Vending Miser	Passive Infrared Sensor on Vending Machine Monitoring Vacancy of Area And Cycles Cooling - Controls	No Vending Miser - No controls	Per Building	Existing	1,796	3	$168	90%	25%	$0.03	4
Electric	University	Ventilation And Circulation	Automated Exhaust VFD Control - Parking Garage CO sensor	CO Sensors	No CO Sensors	Per Building	Existing	63,304	10	$6,863	20%	85%	$0.01	632
Electric	University	Ventilation And Circulation	Convert Constant Volume Air System to VAV	Variable Volume Air System	Constant Volume Air System	Per Building	Existing	8,903	15	$70,238	15%	67%	$2.42	217
Electric	University	Ventilation And Circulation	Cooking Hood Controls	Demand-Ventilation Control	No Controls	Per Building	Existing	1,119	18	$2,698	95%	85%	$0.27	226
Electric	University	Ventilation And Circulation	Motor - CEE Premium-Efficiency Plus	CEE PE+ Motor for HVAC Applications	NEMA Efficiency Motors	Per Building	Existing	756	15	$370	95%	76%	$0.05	128
Electric	University	Ventilation And Circulation	Motor - Pump & Fan System - Variable Speed Control	Pump And Fan System Optimization w/ VSD	No Pump And Fan System VSD Optimization	Per Building	Existing	18,919	20	$6,233	65%	75%	$0.03	2,163
Electric	University	Ventilation And Circulation	Motor - VAV Box High Efficiency (ECM)	ECM Motor	Standard Efficiency Motor	Per Building	Existing	3,895	15	$20,449	11%	77%	$0.66	67
Electric	University	Ventilation And Circulation	Motor Rewind	>15, <500 HP	No Rewind	Per Building	Existing	988	7	$281	65%	25%	$0.05	32
Electric	University	Ventilation And Circulation	Optimized Variable Volume Lab Hood Design	Optimized Variable Volume Lab Hood Design	Constant Volume Lab Hood Design	Per Building	Existing	1,187	13	$1,703	65%	59%	$0.19	114
Electric	University	Water Heat GT 55 Gal	Clothes Washer - Ozonating	Ozonating Clothes Washer	2013 Federal Standard Clothes Washer - MEF = 1.6, WF = 8.5	Per Building	Existing	12,742	10	$8,280	1.8%	95%	$-0.02	8
Electric	University	Water Heat GT 55 Gal	Clothes Washer Commercial	ENERGY STAR Commercial Clothes Washer - MEF = 2.43, WF = 4.0	2013 Federal Standard Clothes Washer - MEF = 1.6, WF = 8.5	Per Building	Existing	294	7	$118	95%	80%	$-0.24	8
Electric	University	Water Heat GT 55 Gal	Demand Controlled Circulating Systems	Demand Controlled Circulating Systems (VFD control by demand)	Constant Circulation	Per Building	Existing	4,212	10	$15,559	55%	94%	$0.57	87

Table B-2.2. Commercial Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	University	Water Heat GT 55 Gal	Dishwasher Residential	RTF ENERGY STAR Dishwasher - 277 kWh/yr and 4.25 gal/cycle	RTF Market Standard 2014 Dishwasher - 289 kWh/yr and 5.0 gal/cycle	Per Building	Existing	30	12	$89	35%	25%	$0.41	0.10
Electric	University	Water Heat GT 55 Gal	Dishwashing - Commercial - High Temp	High Efficiency Dishwasher (ENERGY STAR)	Standard High Temp Commercial Dishwasher	Per Building	Existing	420	12	$241	95%	95%	$-0.71	15
Electric	University	Water Heat GT 55 Gal	Drainwater Heat Recovery Water Heater	Install (Power-Pipe or GFX) - Heat Recovery Water Heater	No Heat Recovery System	Per Building	Existing	10,306	25	$8,330	5.0%	92%	$0.08	30
Electric	University	Water Heat GT 55 Gal	Low-Flow Faucet Aerators	0.5 GPM	2.2 GPM (Federal Code)	Per Building	Existing	3,255	9	$22	95%	75%	$-0.00	93
Electric	University	Water Heat GT 55 Gal	Low-Flow Faucet Aerators	2.2 GPM (Federal Code)	3.0 GPM	Per Building	Existing	1,123	9	$16	95%	25%	$-0.01	10
Electric	University	Water Heat GT 55 Gal	Low-Flow Pre-Rinse Spray Valves	0.6 GPM	1.6 GPM (Federal Standard)	Per Building	Existing	773	4	$236	95%	65%	$0.09	19
Electric	University	Water Heat GT 55 Gal	Low-Flow Showerheads	1.5 GPM	2.5 GPM (Federal Code)	Per Building	Existing	664	10	$365	95%	73%	$0.07	18
Electric	University	Water Heat GT 55 Gal	Low-Flow Showerheads	2.5 GPM (Federal Code)	4.5 GPM	Per Building	Existing	1,328	10	$303	95%	35%	$0.01	17
Electric	University	Water Heat GT 55 Gal	Pipe Insulation - Hot Water (DWH)	1.0" of Insulation, assuming R-4 (WA State Code)	No Insulation	Per Building	Existing	842	12	$101	80%	8%	$0.01	2
Electric	University	Water Heat GT 55 Gal	Ultrasonic Faucet Control	Install Ultrasonic Motion Faucet Control	No Faucet Control	Per Building	Existing	2,106	10	$1,545	75%	75%	$0.10	47
Electric	University	Water Heat LE 55 Gal	Clothes Washer - Ozonating	Ozonating Clothes Washer	2013 Federal Standard Clothes Washer - MEF = 1.6, WF = 8.5	Per Building	Existing	12,514	10	$8,280	1.8%	95%	$-0.02	8
Electric	University	Water Heat LE 55 Gal	Clothes Washer Commercial	ENERGY STAR Commercial Clothes Washer - MEF = 2.43, WF = 4.0	2013 Federal Standard Clothes Washer - MEF = 1.6, WF = 8.5	Per Building	Existing	294	7	$118	95%	80%	$-0.24	8
Electric	University	Water Heat LE 55 Gal	Demand Controlled Circulating Systems	Demand Controlled Circulating Systems (VFD control by demand)	Constant Circulation	Per Building	Existing	4,137	10	$15,559	55%	94%	$0.58	83
Electric	University	Water Heat LE 55 Gal	Dishwasher Residential	RTF ENERGY STAR Dishwasher - 277 kWh/yr and 4.25 gal/cycle	RTF Market Standard 2014 Dishwasher - 289 kWh/yr and 5.0 gal/cycle	Per Building	Existing	30	12	$89	35%	25%	$0.41	0.10
Electric	University	Water Heat LE 55 Gal	Dishwashing - Commercial - High Temp	High Efficiency Dishwasher (ENERGY STAR)	Standard High Temp Commercial Dishwasher	Per Building	Existing	412	12	$230	95%	95%	$-0.73	14
Electric	University	Water Heat LE 55 Gal	Drainwater Heat Recovery Water Heater	Install (Power-Pipe or GFX) - Heat Recovery Water Heater	No Heat Recovery System	Per Building	Existing	10,306	25	$8,330	5.0%	92%	$0.08	28
Electric	University	Water Heat LE 55 Gal	Low-Flow Faucet Aerators	0.5 GPM	2.2 GPM (Federal Code)	Per Building	Existing	3,196	9	$22	95%	75%	$-0.00	89
Electric	University	Water Heat LE 55 Gal	Low-Flow Faucet Aerators	2.2 GPM (Federal Code)	3.0 GPM	Per Building	Existing	1,103	9	$16	95%	25%	$-0.01	10
Electric	University	Water Heat LE 55 Gal	Low-Flow Pre-Rinse Spray Valves	0.6 GPM	1.6 GPM (Federal Standard)	Per Building	Existing	773	4	$236	95%	65%	$0.09	18
Electric	University	Water Heat LE 55 Gal	Low-Flow Showerheads	1.5 GPM	2.5 GPM (Federal Code)	Per Building	Existing	664	10	$365	95%	73%	$0.07	18
Electric	University	Water Heat LE 55 Gal	Low-Flow Showerheads	2.5 GPM (Federal Code)	4.5 GPM	Per Building	Existing	1,328	10	$303	95%	35%	$0.01	17
Electric	University	Water Heat LE 55 Gal	Pipe Insulation - Hot Water (DWH)	1.0" of Insulation, assuming R-4 (WA State Code)	No Insulation	Per Building	Existing	827	12	$101	80%	8%	$0.01	1
Electric	University	Water Heat LE 55 Gal	Ultrasonic Faucet Control	Install Ultrasonic Motion Faucet Control	No Faucet Control	Per Building	Existing	2,068	10	$1,545	75%	75%	$0.10	45

Table B-2.2. Commercial Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Warehouse	Cooling Chillers	Chilled Water / Condenser Water Settings-Optimization	Additional Control Features	EMS already installed - No Optimization	Per Building	Existing	114	5	$10,303	95%	81%	$22.54	5
Electric	Warehouse	Cooling Chillers	Chilled Water Piping Loop w/ VSD Control	VSD for secondary chilled water loop	Primary loop only w/ constant speed pump	Per Building	Existing	692	10	$35,683	25%	70%	$8.04	8
Electric	Warehouse	Cooling Chillers	Chiller-Water Side Economizer	Install Economizer	No Economizer	Per Building	Existing	458	15	$82,855	45%	90%	$23.00	12
Electric	Warehouse	Cooling Chillers	Commissioning of Existing Buildings	Existing Building Commissioning	Average Existing Conditions	Per Building	Existing	1,145	7	$11,924	90%	85%	$2.06	47
Electric	Warehouse	Cooling Chillers	Cooling Tower-Decrease Approach Temperature	6 Deg F	10 Deg F	Per Building	Existing	733	7.5	$4,416	10%	94%	$0.82	4
Electric	Warehouse	Cooling Chillers	Cooling Tower-Two-Speed Fan Motor	Cooling Tower-Two-Speed Fan Motor	Cooling Tower-One-Speed Fan Motor	Per Building	Existing	1,283	15	$393	75%	35%	$0.03	21
Electric	Warehouse	Cooling Chillers	Cooling Tower-VSD Fan Control	Variable-Speed Tower Fans replace Two-Speed	Cooling Tower-Two-Speed Fan Motor	Per Building	Existing	366	13	$3,194	75%	75%	$1.19	12
Electric	Warehouse	Cooling Chillers	Direct Digital Control System-Installation	DDC Retrofit (Morning Warm-Up Control Logic Included in This Measure)	Pneumatic	Per Building	Existing	1,374	5	$58,171	20%	93%	$10.60	15
Electric	Warehouse	Cooling Chillers	Direct Digital Control System-Wireless System	DDC Retrofit - Wireless System	Pneumatic	Per Building	Existing	1,374	5	$14,139	75%	98%	$2.58	43
Electric	Warehouse	Cooling Chillers	Green Roof	Vegetation on Roof	Standard Dark Colored Roof	Per Building	Existing	806	40	$39,443	3.5%	98%	$67.57	1
Electric	Warehouse	Cooling Chillers	Infiltration Reduction	Install Caulking And Weatherstripping (ACH 0.65)	Infiltration Conditions (ACH 1.0)	Per Building	Existing	143	12.5	$429	10%	39%	$0.42	0.29
Electric	Warehouse	Cooling Chillers	Insulation - Ceiling	R-30 c.i. (WA State Code)	R-8 (Average Existing Conditions)	Per Building	Existing	41	25	$94,937	75%	10%	$252.62	0.16
Electric	Warehouse	Cooling Chillers	Insulation - Ceiling	R-49 c.i.	R-38 c.i.	Per Building	Existing	0.45	25	$26,789	25%	85%	$6,495.30	0.00
Electric	Warehouse	Cooling Chillers	Pipe Insulation - Chilled Water	1.5" of Insulation, assuming R-6 (WA State Code)	No Insulation	Per Building	Existing	137	15	$1,240	65%	45%	$1.14	2
Electric	Warehouse	Cooling Chillers	Programmable Thermostat - Web Enabled	Programmable Thermostat - Web Enabled	No Programmable Thermostat	Per Building	Existing	274	10	$726	15%	26%	$0.41	0.57
Electric	Warehouse	Cooling Chillers	RE - Deciduous Trees	Shade Trees	No Trees	Per Building	Existing	53	30	$1,960	75%	55%	$3.91	1
Electric	Warehouse	Cooling Chillers	Sensible And Total Heat Recovery Devices	Install Heat Recovery Devices - rotary air-to-air enthalpy heat recovery- 50% sensible and latent recovery effectiveness	No Heat Recovery	Per Building	Existing	2,291	10	$27,656	25%	98%	$8.70	27
Electric	Warehouse	Cooling Chillers	Window Film	Window Film	No Film	Per Building	Existing	764	10	$1,923	90%	66%	$0.39	0.20
Electric	Warehouse	Cooling Chillers	Windows-High Efficiency	U-0.32	U-0.40 (WA State Code)	Per Building	Existing	1,156	25	$36,941	15%	70%	$3.54	5
Electric	Warehouse	Cooling Chillers	Windows-High Efficiency	U-0.40 (WA State Code)	U-0.65 (Average Existing Conditions)	Per Building	Existing	1,012	25	$79,510	15%	70%	$8.72	4
Electric	Warehouse	Cooling Dx	Commissioning of Existing Buildings	Existing Building Commissioning	Average Existing Conditions	Per Building	Existing	1,426	7	$11,924	90%	85%	$1.66	193
Electric	Warehouse	Cooling Dx	DX Package-Air Side Economizer	Air-Side Economizer	No Economizer	Per Building	Existing	1,711	10	$25,724	10%	40%	$2.34	16
Electric	Warehouse	Cooling Dx	Direct / Indirect Evaporative Cooling, Pre-Cooling	Evaporative Cooler	Standard DX cooling	Per Building	Existing	2,852	15	$26,041	50%	94%	$5.62	312

Table B-2.2. Commercial Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Warehouse	Cooling Dx	Direct Digital Control System-Installation	DDC Retrofit (Morning Warm-Up Control Logic Included in This Measure)	Pneumatic	Per Building	Existing	1,711	5	$58,171	20%	93%	$8.52	65
Electric	Warehouse	Cooling Dx	Direct Digital Control System-Wireless System	DDC Retrofit - Wireless System	Pneumatic	Per Building	Existing	1,711	5	$14,139	75%	98%	$2.07	184
Electric	Warehouse	Cooling Dx	Duct Repair And Sealing	Reduction In Duct Losses to 5%	No Repair or Sealing, 15% duct losses	Per Building	Existing	285	18	$14,520	45%	65%	$5.95	15
Electric	Warehouse	Cooling Dx	Economizer Tune-up	Economizer Tune-up	No Economizer Tune-Up	Per Building	Existing	1,141	5	$7,260	10%	75%	$1.59	20
Electric	Warehouse	Cooling Dx	Green Roof	Vegetation on Roof	Standard Dark Colored Roof	Per Building	Existing	1,004	40	$39,443	3.5%	98%	$54.26	6
Electric	Warehouse	Cooling Dx	Infiltration Reduction	Install Caulking And Weatherstripping (ACH 0.65)	Infiltration Conditions (ACH 1.0)	Per Building	Existing	178	12.5	$429	10%	39%	$0.34	1
Electric	Warehouse	Cooling Dx	Insulation - Ceiling	R-30 c.i. (WA State Code)	R-8 (Average Existing Conditions)	Per Building	Existing	51	25	$94,937	75%	10%	$202.88	0.70
Electric	Warehouse	Cooling Dx	Insulation - Ceiling	R-49 c.i.	R-38 c.i.	Per Building	Existing	0.57	25	$26,789	25%	85%	$5,216.55	0.02
Electric	Warehouse	Cooling Dx	Insulation - Duct	R-7 (WA State Code)	No Insulation	Per Building	Existing	479	20	$11,700	75%	58%	$2.73	37
Electric	Warehouse	Cooling Dx	Programmable Thermostat - Web Enabled	Programmable Thermostat - Web Enabled	No Programmable Thermostat	Per Building	Existing	342	10	$726	95%	24%	$0.33	13
Electric	Warehouse	Cooling Dx	RE - Deciduous Trees	Shade Trees	No Trees	Per Building	Existing	12	30	$2,268	75%	55%	$19.94	0.88
Electric	Warehouse	Cooling Dx	Window Film	Window Film	No Film	Per Building	Existing	764	10	$1,923	90%	66%	$0.39	0.72
Electric	Warehouse	Cooling Dx	Windows-High Efficiency	U-0.32	U-0.40 (WA State Code)	Per Building	Existing	1,439	25	$36,941	15%	98%	$2.84	33
Electric	Warehouse	Cooling Dx	Windows-High Efficiency	U-0.40 (WA State Code)	U-0.65 (Average Existing Conditions)	Per Building	Existing	1,260	25	$79,510	15%	98%	$7.00	29
Electric	Warehouse	Heat Pump	Commissioning of Existing Buildings	Existing Building Commissioning	Average Existing Conditions	Per Building	Existing	5,516	7	$11,924	90%	85%	$0.42	299
Electric	Warehouse	Heat Pump	Direct Digital Control System-Installation	DDC Retrofit (Morning Warm-Up Control Logic Included in This Measure)	Pneumatic	Per Building	Existing	6,619	5	$58,171	20%	93%	$2.19	109
Electric	Warehouse	Heat Pump	Direct Digital Control System-Wireless System	DDC Retrofit - Wireless System	Pneumatic	Per Building	Existing	6,619	5	$14,139	75%	98%	$0.52	306
Electric	Warehouse	Heat Pump	Duct Repair And Sealing	Reduction In Duct Losses to 5%	No Repair or Sealing, 15% duct losses	Per Building	Existing	1,103	18	$14,520	45%	65%	$1.52	25
Electric	Warehouse	Heat Pump	Exhaust Air to Ventilation Air Heat Recovery	Exhaust Air Heat Recovery	No Heat Recovery	Per Building	Existing	4,948	14	$54,874	5.0%	94%	$1.45	18
Electric	Warehouse	Heat Pump	Green Roof	Vegetation on Roof	Standard Dark Colored Roof	Per Building	Existing	981	40	$39,443	3.5%	98%	$55.55	2
Electric	Warehouse	Heat Pump	Ground Source Heat Pump > 135 kBTU/hr	High Efficiency Ground Source Heat Pump > 135 kBTU/hr	Water Source Heat Pump > 135 kBTU/hr	Per Building	Existing	1,513	15	$89,508	3.8%	95%	$49.53	3
Electric	Warehouse	Heat Pump	Infiltration Reduction	Install Caulking And Weatherstripping (ACH 0.65)	Infiltration Conditions (ACH 1.0)	Per Building	Existing	1,544	12.5	$429	10%	39%	$0.03	4
Electric	Warehouse	Heat Pump	Insulation - Ceiling	R-30 c.i. (WA State Code)	R-8 (Average Existing Conditions)	Per Building	Existing	7,833	25	$94,937	75%	10%	$1.33	45
Electric	Warehouse	Heat Pump	Insulation - Ceiling	R-38 c.i.	R-30 c.i. (WA State Code)	Per Building	Existing	787	25	$94,937	75%	70%	$13.37	31
Electric	Warehouse	Heat Pump	Insulation - Ceiling	R-49 c.i.	R-38 c.i.	Per Building	Existing	514	25	$26,789	25%	85%	$5.77	8
Electric	Warehouse	Heat Pump	Insulation - Duct	R-7 (WA State Code)	No Insulation	Per Building	Existing	1,853	20	$11,700	75%	58%	$0.69	61
Electric	Warehouse	Heat Pump	Insulation - Floor (non-slab)	R-30 (WA State Code)	R-8 (Average Existing Conditions)	Per Building	Existing	9,675	25	$50,058	35%	45%	$0.56	113
Electric	Warehouse	Heat Pump	Insulation - Floor (non-slab)	R-38	R-30 (WA State Code)	Per Building	Existing	1,351	25	$15,445	35%	45%	$1.25	15
Electric	Warehouse	Heat Pump	Insulation - Wall	R-16	R-3 (Average Existing Conditions)	Per Building	Existing	7,185	25	$44,782	10%	35%	$0.68	17

Table B-2.2. Commercial Electric Measure Details

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Electric	Warehouse	Heat Pump	Programmable Thermostat - Web Enabled	Programmable Thermostat - Web Enabled	No Programmable Thermostat	Per Building	Existing	1,323	10	$726	95%	24%	$0.07	21
Electric	Warehouse	Heat Pump	RE - Deciduous Trees	Shade Trees	No Trees	Per Building	Existing	21	30	$2,268	75%	55%	$11.42	0.61
Electric	Warehouse	Heat Pump	Window Film	Window Film	No Film	Per Building	Existing	764	10	$1,923	90%	66%	$0.38	0.29
Electric	Warehouse	Heat Pump	Windows-High Efficiency	U-0.32	U-0.40 (WA State Code)	Per Building	Existing	156	25	$36,941	15%	98%	$26.14	1
Electric	Warehouse	Heat Pump	Windows-High Efficiency	U-0.40 (WA State Code)	U-0.65 (Average Existing Conditions)	Per Building	Existing	1,543	25	$79,510	15%	98%	$5.71	14
Electric	Warehouse	Lighting Exterior	Covered Parking Lighting	Covered Parking Lighting	Normal Lighting	Per Building	Existing	5,666	9.5	$1,579	20%	95%	$0.02	2,108
Electric	Warehouse	Lighting Exterior	Daylighting Controls, Outdoors (Photocell)	Photocell	No Controls	Per Building	Existing	1,643	8	$254	75%	70%	$0.02	337
Electric	Warehouse	Lighting Exterior	Occupancy Sensor Control	Occupancy Sensor Control	No Occupancy Sensor	Per Building	Existing	1,837	8	$550	90%	75%	$0.05	2,141
Electric	Warehouse	Lighting Exterior	Solid State LED White Lighting	Landscape, merchandise, signage, structure & task lighting (2.5 W)	50W 10hrs/day, 365 day/yr	Per Building	Existing	1,600	13.69863	$320	75%	95%	$0.02	53
Electric	Warehouse	Lighting Exterior	Surface Parking Lighting	Surface Parking Lighting	Normal Lighting	Per Building	Existing	3,061	18.666667	$4,132	47%	95%	$0.15	2,522
Electric	Warehouse	Lighting Exterior	Time Clock	Time Clock	No Controls	Per Building	Existing	825	8	$223	10%	81%	$0.04	97
Electric	Warehouse	Lighting Interior Fluorescent	Bi-Level Control, Stairwell Lighting	Occupancy Sensor Control, 50% Lighting Power during unoccupied Time	Continuous Full Power Lighting in Stairways	Per Building	Existing	605	9	$647	10%	75%	$0.17	154
Electric	Warehouse	Lighting Interior Fluorescent	Dimming-Continuous, Fluorescent Fixtures	Continuous Dimming, Fluorescent Fixtures (Day-Lighting)	No Dimming Controls	Per Building	Existing	3,993	8	$18,464	30%	98%	$0.83	1,809
Electric	Warehouse	Lighting Interior Fluorescent	Occupancy Sensor Control	Occupancy Sensor Control	No Occupancy Sensor	Per Building	Existing	7,221	8	$5,154	90%	50%	$0.12	4,708
Electric	Warehouse	Lighting Interior Fluorescent	Time Clock	Time Clock	No Controls	Per Building	Existing	3,244	8	$889	10%	100%	$0.04	469
Electric	Warehouse	Lighting Interior Hid	Occupancy Sensor Control	Occupancy Sensor Control	No Occupancy Sensor	Per Building	Existing	6,241	8	$5,154	90%	50%	$0.14	4,538
Electric	Warehouse	Lighting Interior Hid	Time Clock	Time Clock	No Controls	Per Building	Existing	2,804	8	$768	10%	100%	$0.04	452
Electric	Warehouse	Lighting Interior Other	Exit Sign - LED	Two Sided LED Exit Sign (5 Watts)	CFL Exit Sign (9 Watts)	Per Building	Existing	192	16	$30	95%	50%	$0.01	170
Electric	Warehouse	Lighting Interior Other	Exit Sign - Photoluminescent or Tritium	Photoluminescent or Tritium	Two Sided LED Exit Sign (5 Watts)	Per Building	Existing	70	13	$60	95%	98%	$0.11	121
Electric	Warehouse	Lighting Interior Screw Base	Cold Cathode Lighting	Cold Cathode Lighting 5 watts	30 W Incandescent Bulb	Per Building	Existing	132	5	$12	70%	94%	$0.02	46
Electric	Warehouse	Lighting Interior Screw Base	Occupancy Sensor Control	Occupancy Sensor Control	No Occupancy Sensor	Per Building	Existing	3,439	8	$5,154	90%	50%	$0.26	781
Electric	Warehouse	Lighting Interior Screw Base	Time Clock	Time Clock	No Controls	Per Building	Existing	1,545	8	$423	10%	100%	$0.04	77
Electric	Warehouse	Other Plug Load	ENERGY STAR - Battery Charging System	ENERGY STAR Battery Charging System	Non-ENERGY STAR Battery Chargers	Per Building	Existing	13	7	$6	20%	20%	$0.08	1
Electric	Warehouse	Other Plug Load	ENERGY STAR - Water Cooler	ENERGY STAR Water Cooler (Hot/Cold Water)	Non-ENERGY STAR Water Cooler	Per Building	Existing	307	10	$0.00	95%	20%	$-0.01	109
Electric	Warehouse	Other Plug Load	Power Supply Transformer/Converter	80 Plus	85% efficient power supply (> 51W)	Per Building	Existing	831	4	$6	95%	86%	$-0.00	70

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Electric	Warehouse	Other Plug Load	Scanner - ENERGY STAR	ENERGY STAR Scanners	Standard Scanner	Per Building	Existing	16	6	$0.00	95%	20%	$-0.01	5
Electric	Warehouse	Other Plug Load	Smart Strips	Smart Strip Power Strip	Standard surge protector	Per Building	Existing	403	4	$102	60%	90%	$0.07	406
Electric	Warehouse	Refrigerator	Residential Refrigerator/Freezer Recycling	Recycling Existing Refrigerator/Freezer	Existing Refrigerator/Freezer	Per Building	Existing	481	9	$127	25%	100%	$0.04	193
Electric	Warehouse	Space Heat	Commissioning of Existing Buildings	Existing Building Commissioning	Average Existing Conditions	Per Building	Existing	8,555	7	$11,924	90%	85%	$0.26	1,184
Electric	Warehouse	Space Heat	Direct Digital Control System-Installation	DDC Retrofit (Morning Warm-Up Control Logic Included in This Measure)	Pneumatic	Per Building	Existing	10,266	5	$58,171	20%	93%	$1.41	450
Electric	Warehouse	Space Heat	Direct Digital Control System-Wireless System	DDC Retrofit - Wireless System	Pneumatic	Per Building	Existing	10,266	5	$14,139	75%	98%	$0.33	1,265
Electric	Warehouse	Space Heat	Duct Repair And Sealing	Reduction In Duct Losses to 5%	No Repair or Sealing, 15% duct losses	Per Building	Existing	1,711	18	$14,520	45%	65%	$0.98	105
Electric	Warehouse	Space Heat	Economizer Tune-up	Economizer Tune-up	No Economizer Tune-Up	Per Building	Existing	6,844	5	$7,260	10%	75%	$0.25	121
Electric	Warehouse	Space Heat	Exhaust Air to Ventilation Air Heat Recovery	Exhaust Air Heat Recovery	No Heat Recovery	Per Building	Existing	10,266	14	$54,874	5.0%	94%	$0.69	100
Electric	Warehouse	Space Heat	Infiltration Reduction	Install Caulking And Weatherstripping (ACH 0.65)	Infiltration Conditions (ACH 1.0)	Per Building	Existing	2,136	12.5	$429	10%	39%	$0.01	17
Electric	Warehouse	Space Heat	Insulation - Ceiling	R-30 c.i. (WA State Code)	R-8 (Average Existing Conditions)	Per Building	Existing	16,218	25	$94,937	75%	10%	$0.63	251
Electric	Warehouse	Space Heat	Insulation - Ceiling	R-38 c.i.	R-30 c.i. (WA State Code)	Per Building	Existing	1,496	25	$94,937	75%	70%	$7.03	159
Electric	Warehouse	Space Heat	Insulation - Ceiling	R-49 c.i.	R-38 c.i.	Per Building	Existing	1,446	25	$26,789	25%	85%	$2.04	61
Electric	Warehouse	Space Heat	Insulation - Duct	R-7 (WA State Code)	No Insulation	Per Building	Existing	2,874	20	$11,700	75%	58%	$0.44	250
Electric	Warehouse	Space Heat	Insulation - Floor (non-slab)	R-30 (WA State Code)	R-8 (Average Existing Conditions)	Per Building	Existing	23,220	25	$50,058	35%	45%	$0.22	717
Electric	Warehouse	Space Heat	Insulation - Floor (non-slab)	R-38	R-30 (WA State Code)	Per Building	Existing	2,974	25	$15,445	35%	45%	$0.56	87
Electric	Warehouse	Space Heat	Insulation - Wall	R-16	R-3 (Average Existing Conditions)	Per Building	Existing	29,893	25	$44,782	10%	35%	$0.15	193
Electric	Warehouse	Space Heat	Programmable Thermostat - Web Enabled	Programmable Thermostat - Web Enabled	No Programmable Thermostat	Per Building	Existing	2,053	10	$726	95%	24%	$0.04	84
Electric	Warehouse	Space Heat	Sensible And Total Heat Recovery Devices	Install Heat Recovery Devices - rotary air-to-air enthalpy heat recovery- 50% sensible and latent recovery effectiveness	No Heat Recovery	Per Building	Existing	17,110	10	$27,656	25%	98%	$1.15	684
Electric	Warehouse	Space Heat	Windows-High Efficiency	U-0.40 (WA State Code)	U-0.65 (Average Existing Conditions)	Per Building	Existing	512	25	$79,510	15%	98%	$17.20	11
Electric	Warehouse	Vending Machines	Vending Miser	Passive Infrared Sensor on Vending Machine Monitoring Vacancy of Area And Cycles Cooling - Controls	No Vending Miser - No controls	Per Building	Existing	1,796	3	$169	10%	25%	$0.03	6
Electric	Warehouse	Ventilation And Circulation	Motor - CEE Premium-Efficiency Plus	CEE PE+ Motor for HVAC Applications	NEMA Efficiency Motors	Per Building	Existing	358	15	$399	95%	76%	$0.13	252
Electric	Warehouse	Ventilation And Circulation	Motor - Pump & Fan System - Variable Speed Control	Pump And Fan System Optimization w/ VSD	No Pump And Fan System VSD Optimization	Per Building	Existing	8,963	20	$6,739	65%	75%	$0.07	4,238
Electric	Warehouse	Ventilation And Circulation	Motor Rewind	>15, <500 HP	No Rewind	Per Building	Existing	1,068	7	$302	65%	25%	$0.05	147

Table B-2.2. Commercial Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Warehouse	Water Heat GT 55 Gal	Demand Controlled Circulating Systems	Demand Controlled Circulating Systems (VFD control by demand)	Constant Circulation	Per Building	Existing	601	10	$16,807	55%	94%	$4.35	216
Electric	Warehouse	Water Heat GT 55 Gal	Dishwasher Residential	RTF ENERGY STAR Dishwasher - 277 kWh/yr and 4.25 gal/cycle	RTF Market Standard 2014 Dishwasher - 289 kWh/yr and 5.0 gal/cycle	Per Building	Existing	13	12	$42	2.7%	25%	$0.44	0.06
Electric	Warehouse	Water Heat GT 55 Gal	Drainwater Heat Recovery Water Heater	Install (Power-Pipe or GFX) - Heat Recovery Water Heater	No Heat Recovery System	Per Building	Existing	2,425	25	$1,458	5.0%	92%	$0.06	75
Electric	Warehouse	Water Heat GT 55 Gal	Low-Flow Faucet Aerators	0.5 GPM	2.2 GPM (Federal Code)	Per Building	Existing	464	9	$6	95%	75%	$-0.03	230
Electric	Warehouse	Water Heat GT 55 Gal	Low-Flow Faucet Aerators	2.2 GPM (Federal Code)	3.0 GPM	Per Building	Existing	160	9	$6	95%	25%	$-0.05	26
Electric	Warehouse	Water Heat GT 55 Gal	Pipe Insulation - Hot Water (DWH)	1.0" of Insulation, assuming R-4 (WA State Code)	No Insulation	Per Building	Existing	120	12	$24	80%	90%	$0.02	58
Electric	Warehouse	Water Heat GT 55 Gal	Ultrasonic Faucet Control	Install Ultrasonic Motion Faucet Control	No Faucet Control	Per Building	Existing	300	10	$332	75%	95%	$0.10	149
Electric	Warehouse	Water Heat LE 55 Gal	Demand Controlled Circulating Systems	Demand Controlled Circulating Systems (VFD control by demand)	Constant Circulation	Per Building	Existing	590	10	$16,807	55%	94%	$4.43	208
Electric	Warehouse	Water Heat LE 55 Gal	Dishwasher Residential	RTF ENERGY STAR Dishwasher - 277 kWh/yr and 4.25 gal/cycle	RTF Market Standard 2014 Dishwasher - 289 kWh/yr and 5.0 gal/cycle	Per Building	Existing	13	12	$42	2.7%	25%	$0.44	0.06
Electric	Warehouse	Water Heat LE 55 Gal	Drainwater Heat Recovery Water Heater	Install (Power-Pipe or GFX) - Heat Recovery Water Heater	No Heat Recovery System	Per Building	Existing	2,425	25	$1,458	5.0%	92%	$0.06	72
Electric	Warehouse	Water Heat LE 55 Gal	Low-Flow Faucet Aerators	0.5 GPM	2.2 GPM (Federal Code)	Per Building	Existing	456	9	$6	95%	75%	$-0.03	222
Electric	Warehouse	Water Heat LE 55 Gal	Low-Flow Faucet Aerators	2.2 GPM (Federal Code)	3.0 GPM	Per Building	Existing	157	9	$6	95%	25%	$-0.05	25
Electric	Warehouse	Water Heat LE 55 Gal	Pipe Insulation - Hot Water (DWH)	1.0" of Insulation, assuming R-4 (WA State Code)	No Insulation	Per Building	Existing	118	12	$24	80%	90%	$0.02	55
Electric	Warehouse	Water Heat LE 55 Gal	Ultrasonic Faucet Control	Install Ultrasonic Motion Faucet Control	No Faucet Control	Per Building	Existing	295	10	$332	75%	95%	$0.10	143

Table B-2.3. Industrial Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Chemical Mfg	Fans	Fan Energy Mangement	Fan Energy Mangement		Per Industry	Existing	137,325	10	$0.00	27%	100%	$0.01	32
Electric	Chemical Mfg	Fans	Fan Equipment Upgrade	Fan Equipment Upgrade		Per Industry	Existing	480,637	10	$41,197	23%	100%	$0.03	89
Electric	Chemical Mfg	Fans	Motors: Rewind 101-200 HP	Motors: Rewind 101-200 HP		Per Industry	Existing	6,866	10	$1,579	9.8%	100%	$0.03	0.53
Electric	Chemical Mfg	Fans	Motors: Rewind 20-50 HP	Motors: Rewind 20-50 HP		Per Industry	Existing	12,359	10	$4,449	6.2%	100%	$0.05	0.61
Electric	Chemical Mfg	Fans	Motors: Rewind 201-500 HP	Motors: Rewind 201-500 HP		Per Industry	Existing	6,866	10	$1,029	11%	100%	$0.02	0.66
Electric	Chemical Mfg	Fans	Motors: Rewind 501-5000 HP	Motors: Rewind 501-5000 HP		Per Industry	Existing	6,866	10	$755	7.8%	100%	$0.01	0.46
Electric	Chemical Mfg	Fans	Motors: Rewind 51-100 HP	Motors: Rewind 51-100 HP		Per Industry	Existing	6,866	10	$2,128	6.3%	100%	$0.04	0.34
Electric	Chemical Mfg	Fans	Plant Energy Management	Plant Energy Management		Per Industry	Existing	164,790	10	$3,449	27%	100%	$0.01	37
Electric	Chemical Mfg	Fans	Synchronous Belts	Synchronous Belts		Per Industry	Existing	27,465	10	$5,875	21%	100%	$0.03	4
Electric	Chemical Mfg	Fans	Transformers-New	Transformers-New		Per Industry	Existing	5,630	32	$4,279	37%	100%	$0.07	1
Electric	Chemical Mfg	Fans	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	20,598	10	$2,047	9.4%	100%	$0.01	1
Electric	Chemical Mfg	Hvac	Transformers-New	Transformers-New		Per Industry	Existing	5,078	32	$3,859	37%	100%	$0.07	1
Electric	Chemical Mfg	Hvac	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	18,578	10	$1,846	9.4%	100%	$0.01	1
Electric	Chemical Mfg	Lighting	Efficient Lighting 3 Shift	Efficient Lighting 3 Shift		Per Industry	Existing	517,708	10	$13,075	20%	100%	$-0.00	87
Electric	Chemical Mfg	Lighting	HighBay Lighting 3 Shift	HighBay Lighting 3 Shift		Per Industry	Existing	377,187	10	$29,809	29%	100%	$0.01	82
Electric	Chemical Mfg	Lighting	Lighting Controls	Lighting Controls		Per Industry	Existing	208,602	10	$44,432	15%	100%	$0.03	20
Electric	Chemical Mfg	Lighting	Transformers-New	Transformers-New		Per Industry	Existing	3,032	32	$2,304	37%	100%	$0.07	0.67
Electric	Chemical Mfg	Lighting	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	11,093	10	$1,102	9.4%	100%	$0.01	0.62
Electric	Chemical Mfg	Motors Other	Motors: Rewind 101-200 HP	Motors: Rewind 101-200 HP		Per Industry	Existing	15,405	10	$3,543	9.8%	100%	$0.03	1
Electric	Chemical Mfg	Motors Other	Motors: Rewind 20-50 HP	Motors: Rewind 20-50 HP		Per Industry	Existing	27,730	10	$9,982	6.2%	100%	$0.05	1
Electric	Chemical Mfg	Motors Other	Motors: Rewind 201-500 HP	Motors: Rewind 201-500 HP		Per Industry	Existing	15,405	10	$2,310	11%	100%	$0.02	1
Electric	Chemical Mfg	Motors Other	Motors: Rewind 501-5000 HP	Motors: Rewind 501-5000 HP		Per Industry	Existing	15,405	10	$1,694	7.8%	100%	$0.01	1
Electric	Chemical Mfg	Motors Other	Motors: Rewind 51-100 HP	Motors: Rewind 51-100 HP		Per Industry	Existing	15,405	10	$4,775	6.3%	100%	$0.04	0.74
Electric	Chemical Mfg	Motors Other	Plant Energy Management	Plant Energy Management		Per Industry	Existing	369,738	10	$7,738	27%	100%	$0.01	85
Electric	Chemical Mfg	Motors Other	Synchronous Belts	Synchronous Belts		Per Industry	Existing	61,623	10	$13,183	21%	100%	$0.03	10
Electric	Chemical Mfg	Motors Other	Transformers-New	Transformers-New		Per Industry	Existing	12,632	32	$9,600	37%	100%	$0.07	3
Electric	Chemical Mfg	Motors Other	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	46,217	10	$4,592	9.4%	100%	$0.01	3
Electric	Chemical Mfg	Other	Transformers-New	Transformers-New		Per Industry	Existing	1,991	32	$1,513	37%	100%	$0.07	0.63
Electric	Chemical Mfg	Other	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	7,285	10	$724	9.4%	100%	$0.01	0.58
Electric	Chemical Mfg	Process Aircomp	Air Compressor Demand Reduction	Air Compressor Demand Reduction		Per Industry	Existing	639,311	10	$51,464	26%	100%	$0.02	142
Electric	Chemical Mfg	Process Aircomp	Motors: Rewind 101-200 HP	Motors: Rewind 101-200 HP		Per Industry	Existing	15,982	10	$3,676	9.8%	100%	$0.03	1
Electric	Chemical Mfg	Process Aircomp	Motors: Rewind 20-50 HP	Motors: Rewind 20-50 HP		Per Industry	Existing	28,769	10	$10,356	6.2%	100%	$0.05	1
Electric	Chemical Mfg	Process Aircomp	Motors: Rewind 201-500 HP	Motors: Rewind 201-500 HP		Per Industry	Existing	15,982	10	$2,397	11%	100%	$0.02	1
Electric	Chemical Mfg	Process Aircomp	Motors: Rewind 501-5000 HP	Motors: Rewind 501-5000 HP		Per Industry	Existing	15,982	10	$1,758	7.8%	100%	$0.01	1
Electric	Chemical Mfg	Process Aircomp	Motors: Rewind 51-100 HP	Motors: Rewind 51-100 HP		Per Industry	Existing	15,982	10	$4,954	6.3%	100%	$0.04	0.79

Table B-2.3. Industrial Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Chemical Mfg	Process Aircomp	Plant Energy Management	Plant Energy Management		Per Industry	Existing	383,586	10	$8,028	27%	100%	$0.01	84
Electric	Chemical Mfg	Process Aircomp	Synchronous Belts	Synchronous Belts		Per Industry	Existing	63,931	10	$13,676	21%	100%	$0.03	10
Electric	Chemical Mfg	Process Aircomp	Transformers-New	Transformers-New		Per Industry	Existing	13,105	32	$9,960	37%	100%	$0.07	3
Electric	Chemical Mfg	Process Aircomp	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	47,948	10	$4,765	9.4%	100%	$0.01	3
Electric	Chemical Mfg	Process Heat	Transformers-New	Transformers-New		Per Industry	Existing	3,804	32	$2,891	37%	100%	$0.07	1
Electric	Chemical Mfg	Process Heat	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	13,917	10	$1,383	9.4%	100%	$0.01	1
Electric	Chemical Mfg	Process Other	Motors: Rewind 101-200 HP	Motors: Rewind 101-200 HP		Per Industry	Existing	973	10	$223	9.8%	100%	$0.03	0.07
Electric	Chemical Mfg	Process Other	Motors: Rewind 20-50 HP	Motors: Rewind 20-50 HP		Per Industry	Existing	1,753	10	$631	6.2%	100%	$0.05	0.08
Electric	Chemical Mfg	Process Other	Motors: Rewind 201-500 HP	Motors: Rewind 201-500 HP		Per Industry	Existing	973	10	$146	11%	100%	$0.02	0.09
Electric	Chemical Mfg	Process Other	Motors: Rewind 501-5000 HP	Motors: Rewind 501-5000 HP		Per Industry	Existing	973	10	$107	7.8%	100%	$0.01	0.06
Electric	Chemical Mfg	Process Other	Motors: Rewind 51-100 HP	Motors: Rewind 51-100 HP		Per Industry	Existing	973	10	$301	6.3%	100%	$0.04	0.05
Electric	Chemical Mfg	Process Other	Plant Energy Management	Plant Energy Management		Per Industry	Existing	23,373	10	$489	27%	100%	$0.01	5
Electric	Chemical Mfg	Process Other	Synchronous Belts	Synchronous Belts		Per Industry	Existing	3,895	10	$833	21%	100%	$0.03	0.67
Electric	Chemical Mfg	Process Other	Transformers-New	Transformers-New		Per Industry	Existing	798	32	$606	37%	100%	$0.07	0.24
Electric	Chemical Mfg	Process Other	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	2,921	10	$290	9.4%	100%	$0.01	0.22
Electric	Chemical Mfg	Pumps	Motors: Rewind 101-200 HP	Motors: Rewind 101-200 HP		Per Industry	Existing	15,001	10	$3,450	9.8%	100%	$0.03	1
Electric	Chemical Mfg	Pumps	Motors: Rewind 20-50 HP	Motors: Rewind 20-50 HP		Per Industry	Existing	27,003	10	$9,721	6.2%	100%	$0.05	1
Electric	Chemical Mfg	Pumps	Motors: Rewind 201-500 HP	Motors: Rewind 201-500 HP		Per Industry	Existing	15,001	10	$2,250	11%	100%	$0.02	1
Electric	Chemical Mfg	Pumps	Motors: Rewind 501-5000 HP	Motors: Rewind 501-5000 HP		Per Industry	Existing	15,001	10	$1,650	7.8%	100%	$0.01	1
Electric	Chemical Mfg	Pumps	Motors: Rewind 51-100 HP	Motors: Rewind 51-100 HP		Per Industry	Existing	15,001	10	$4,650	6.3%	100%	$0.04	0.70
Electric	Chemical Mfg	Pumps	Plant Energy Management	Plant Energy Management		Per Industry	Existing	360,045	10	$7,535	27%	100%	$0.01	83
Electric	Chemical Mfg	Pumps	Pump Energy Management	Pump Energy Management		Per Industry	Existing	225,028	10	$0.00	31%	100%	$0.01	57
Electric	Chemical Mfg	Pumps	Pump Equipment Upgrade	Pump Equipment Upgrade		Per Industry	Existing	600,075	10	$75,009	34%	100%	$0.03	149
Electric	Chemical Mfg	Pumps	Pump System Optimization	Pump System Optimization		Per Industry	Existing	1,500,189	12	$81,048	15%	100%	$0.06	186
Electric	Chemical Mfg	Pumps	Synchronous Belts	Synchronous Belts		Per Industry	Existing	60,007	10	$12,837	21%	100%	$0.03	10
Electric	Chemical Mfg	Pumps	Transformers-New	Transformers-New		Per Industry	Existing	12,301	32	$9,349	37%	100%	$0.07	3
Electric	Chemical Mfg	Pumps	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	45,005	10	$4,472	9.4%	100%	$0.01	3
Electric	Computer Electronic Mfg	Fans	Plant Energy Management	Plant Energy Management		Per Industry	Existing	253,056	10	$5,296	27%	100%	$0.01	58
Electric	Computer Electronic Mfg	Fans	Transformers-New	Transformers-New		Per Industry	Existing	8,646	32	$6,571	37%	100%	$0.07	2
Electric	Computer Electronic Mfg	Fans	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	31,632	10	$24,040	9.4%	100%	$0.11	2

Table B-2.3. Industrial Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Computer Electronic Mfg	Hvac	Clean Room: Change Filter Strategy	Clean Room: Change Filter Strategy		Per Industry	Existing	5,811,494	1	$37,698	10%	100%	$-0.00	408
Electric	Computer Electronic Mfg	Hvac	Clean Room: Chiller Optimize	Clean Room: Chiller Optimize		Per Industry	Existing	2,153,570	10	$75,373	28%	100%	$0.01	412
Electric	Computer Electronic Mfg	Hvac	Clean Room: Clean Room HVAC	Clean Room: Clean Room HVAC		Per Industry	Existing	1,307,586	20	$11,696	30%	100%	$0.01	253
Electric	Computer Electronic Mfg	Hvac	Elec Chip Fab: Eliminate Exhaust	Elec Chip Fab: Eliminate Exhaust		Per Industry	Existing	726,436	10	$35,632	80%	100%	$0.02	365
Electric	Computer Electronic Mfg	Hvac	Elec Chip Fab: Solidstate Chiller	Elec Chip Fab: Solidstate Chiller		Per Industry	Existing	13,075,863	10	$49,390	20%	100%	$0.07	2,243
Electric	Computer Electronic Mfg	Hvac	Transformers-New	Transformers-New		Per Industry	Existing	59,567	32	$45,271	37%	100%	$0.07	13
Electric	Computer Electronic Mfg	Hvac	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	217,931	10	$65,627	9.4%	100%	$0.11	12
Electric	Computer Electronic Mfg	Lighting	Lighting Controls	Lighting Controls		Per Industry	Existing	1,691,281	10	$60,243	15%	100%	$0.03	222
Electric	Computer Electronic Mfg	Lighting	Transformers-New	Transformers-New		Per Industry	Existing	24,584	32	$18,684	37%	100%	$0.07	7
Electric	Computer Electronic Mfg	Lighting	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	89,944	10	$68,357	9.4%	100%	$0.11	6
Electric	Computer Electronic Mfg	Motors Other	Plant Energy Management	Plant Energy Management		Per Industry	Existing	501,001	10	$10,485	27%	100%	$0.01	116
Electric	Computer Electronic Mfg	Motors Other	Transformers-New	Transformers-New		Per Industry	Existing	17,117	32	$13,009	37%	100%	$0.07	4
Electric	Computer Electronic Mfg	Motors Other	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	62,625	10	$47,595	9.4%	100%	$0.11	4
Electric	Computer Electronic Mfg	Other	Transformers-New	Transformers-New		Per Industry	Existing	16,607	32	$12,621	37%	100%	$0.07	5
Electric	Computer Electronic Mfg	Other	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	60,759	10	$46,177	9.4%	100%	$0.11	4
Electric	Computer Electronic Mfg	Process Aircomp	Air Compressor Demand Reduction	Air Compressor Demand Reduction		Per Industry	Existing	97,984	10	$7,887	26%	100%	$0.02	21
Electric	Computer Electronic Mfg	Process Aircomp	Elec Chip Fab: Reduce Gas Pressure	Elec Chip Fab: Reduce Gas Pressure		Per Industry	Existing	48,992	10	$0.00	50%	100%	$-0.01	21
Electric	Computer Electronic Mfg	Process Aircomp	Plant Energy Management	Plant Energy Management		Per Industry	Existing	58,790	10	$1,230	27%	100%	$0.01	12
Electric	Computer Electronic Mfg	Process Aircomp	Transformers-New	Transformers-New		Per Industry	Existing	2,008	32	$1,526	37%	100%	$0.07	0.55
Electric	Computer Electronic Mfg	Process Aircomp	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	7,348	10	$5,585	9.4%	100%	$0.11	0.51
Electric	Computer Electronic Mfg	Process Heat	Elec Chip Fab: Exhaust Injector	Elec Chip Fab: Exhaust Injector		Per Industry	Existing	5,608,306	10	$25,522	35%	100%	$0.06	1,683

Table B-2.3. Industrial Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Computer Electronic Mfg	Process Heat	Transformers-New	Transformers-New		Per Industry	Existing	22,994	32	$17,475	37%	100%	$0.07	4
Electric	Computer Electronic Mfg	Process Heat	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	84,124	10	$63,934	9.4%	100%	$0.11	4
Electric	Computer Electronic Mfg	Process Other	Plant Energy Management	Plant Energy Management		Per Industry	Existing	470,782	10	$9,853	27%	100%	$0.01	109
Electric	Computer Electronic Mfg	Process Other	Transformers-New	Transformers-New		Per Industry	Existing	16,085	32	$12,224	37%	100%	$0.07	4
Electric	Computer Electronic Mfg	Process Other	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	58,847	10	$44,724	9.4%	100%	$0.11	4
Electric	Computer Electronic Mfg	Pumps	Plant Energy Management	Plant Energy Management		Per Industry	Existing	401,312	10	$8,399	27%	100%	$0.01	92
Electric	Computer Electronic Mfg	Pumps	Transformers-New	Transformers-New		Per Industry	Existing	13,711	32	$10,420	37%	100%	$0.07	4
Electric	Computer Electronic Mfg	Pumps	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	50,164	10	$38,124	9.4%	100%	$0.11	3
Electric	Electrical Equipment Mfg	Fans	Plant Energy Management	Plant Energy Management		Per Industry	Existing	76,977	10	$1,611	27%	100%	$0.01	17
Electric	Electrical Equipment Mfg	Fans	Transformers-New	Transformers-New		Per Industry	Existing	2,630	32	$1,998	37%	100%	$0.07	0.81
Electric	Electrical Equipment Mfg	Fans	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	9,622	10	$7,312	9.4%	100%	$0.11	0.74
Electric	Electrical Equipment Mfg	Hvac	Clean Room: Change Filter Strategy	Clean Room: Change Filter Strategy		Per Industry	Existing	849,392	1	$5,509	10%	100%	$-0.00	59
Electric	Electrical Equipment Mfg	Hvac	Clean Room: Chiller Optimize	Clean Room: Chiller Optimize		Per Industry	Existing	314,760	10	$25,632	28%	100%	$0.01	60
Electric	Electrical Equipment Mfg	Hvac	Clean Room: Clean Room HVAC	Clean Room: Clean Room HVAC		Per Industry	Existing	191,113	20	$30,940	30%	100%	$0.01	37
Electric	Electrical Equipment Mfg	Hvac	Elec Chip Fab: Eliminate Exhaust	Elec Chip Fab: Eliminate Exhaust		Per Industry	Existing	106,174	10	$19,823	80%	100%	$0.02	53
Electric	Electrical Equipment Mfg	Hvac	Elec Chip Fab: Solidstate Chiller	Elec Chip Fab: Solidstate Chiller		Per Industry	Existing	1,911,133	10	$71,857	20%	100%	$0.07	327
Electric	Electrical Equipment Mfg	Hvac	Transformers-New	Transformers-New		Per Industry	Existing	8,706	32	$6,616	37%	100%	$0.07	1
Electric	Electrical Equipment Mfg	Hvac	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	31,852	10	$24,207	9.4%	100%	$0.11	1
Electric	Electrical Equipment Mfg	Lighting	Lighting Controls	Lighting Controls		Per Industry	Existing	476,888	10	$1,577	15%	100%	$0.03	62
Electric	Electrical Equipment Mfg	Lighting	Transformers-New	Transformers-New		Per Industry	Existing	6,932	32	$5,268	37%	100%	$0.07	2
Electric	Electrical Equipment Mfg	Lighting	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	25,361	10	$19,274	9.4%	100%	$0.11	1

Table B-2.3. Industrial Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Electrical Equipment Mfg	Motors Other	Plant Energy Management	Plant Energy Management		Per Industry	Existing	172,713	10	$3,614	27%	100%	$0.01	40
Electric	Electrical Equipment Mfg	Motors Other	Transformers-New	Transformers-New		Per Industry	Existing	5,901	32	$4,484	37%	100%	$0.07	1
Electric	Electrical Equipment Mfg	Motors Other	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	21,589	10	$16,407	9.4%	100%	$0.11	1
Electric	Electrical Equipment Mfg	Other	Transformers-New	Transformers-New		Per Industry	Existing	2,187	32	$1,662	37%	100%	$0.07	0.69
Electric	Electrical Equipment Mfg	Other	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	8,001	10	$6,081	9.4%	100%	$0.11	0.64
Electric	Electrical Equipment Mfg	Process Aircomp	Air Compressor Demand Reduction	Air Compressor Demand Reduction		Per Industry	Existing	298,636	10	$24,040	26%	100%	$0.02	66
Electric	Electrical Equipment Mfg	Process Aircomp	Elec Chip Fab: Reduce Gas Pressure	Elec Chip Fab: Reduce Gas Pressure		Per Industry	Existing	149,318	10	$0.00	50%	100%	$-0.01	64
Electric	Electrical Equipment Mfg	Process Aircomp	Plant Energy Management	Plant Energy Management		Per Industry	Existing	179,181	10	$3,750	27%	100%	$0.01	37
Electric	Electrical Equipment Mfg	Process Aircomp	Transformers-New	Transformers-New		Per Industry	Existing	6,122	32	$4,652	37%	100%	$0.07	1
Electric	Electrical Equipment Mfg	Process Aircomp	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	22,397	10	$17,022	9.4%	100%	$0.11	1
Electric	Electrical Equipment Mfg	Process Heat	Elec Chip Fab: Exhaust Injector	Elec Chip Fab: Exhaust Injector		Per Industry	Existing	3,299,123	10	$85,655	35%	100%	$0.06	990
Electric	Electrical Equipment Mfg	Process Heat	Transformers-New	Transformers-New		Per Industry	Existing	13,526	32	$10,280	37%	100%	$0.07	2
Electric	Electrical Equipment Mfg	Process Heat	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	49,486	10	$37,610	9.4%	100%	$0.11	2
Electric	Electrical Equipment Mfg	Process Other	Plant Energy Management	Plant Energy Management		Per Industry	Existing	56,320	10	$1,178	27%	100%	$0.01	13
Electric	Electrical Equipment Mfg	Process Other	Transformers-New	Transformers-New		Per Industry	Existing	1,924	32	$1,462	37%	100%	$0.07	0.59
Electric	Electrical Equipment Mfg	Process Other	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	7,040	10	$5,350	9.4%	100%	$0.11	0.54
Electric	Electrical Equipment Mfg	Pumps	Plant Energy Management	Plant Energy Management		Per Industry	Existing	168,185	10	$3,520	27%	100%	$0.01	38
Electric	Electrical Equipment Mfg	Pumps	Transformers-New	Transformers-New		Per Industry	Existing	5,746	32	$4,367	37%	100%	$0.07	1
Electric	Electrical Equipment Mfg	Pumps	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	21,023	10	$15,977	9.4%	100%	$0.11	1
Electric	Fabricated Metal Products	Fans	Fan Energy Mangement	Fan Energy Mangement		Per Industry	Existing	370,315	10	$0.00	27%	100%	$0.01	86
Electric	Fabricated Metal Products	Fans	Motors: Rewind 101-200 HP	Motors: Rewind 101-200 HP		Per Industry	Existing	18,515	10	$4,258	13%	100%	$0.03	2

Table B-2.3. Industrial Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Fabricated Metal Products	Fans	Motors: Rewind 20-50 HP	Motors: Rewind 20-50 HP		Per Industry	Existing	33,328	10	$11,998	20%	100%	$0.05	5
Electric	Fabricated Metal Products	Fans	Motors: Rewind 201-500 HP	Motors: Rewind 201-500 HP		Per Industry	Existing	18,515	10	$2,777	3.6%	100%	$0.02	0.56
Electric	Fabricated Metal Products	Fans	Motors: Rewind 51-100 HP	Motors: Rewind 51-100 HP		Per Industry	Existing	18,515	10	$5,739	5.3%	100%	$0.04	0.82
Electric	Fabricated Metal Products	Fans	Plant Energy Management	Plant Energy Management		Per Industry	Existing	444,378	10	$9,300	27%	100%	$0.01	99
Electric	Fabricated Metal Products	Fans	Synchronous Belts	Synchronous Belts		Per Industry	Existing	74,063	10	$15,844	21%	100%	$0.03	12
Electric	Fabricated Metal Products	Fans	Transformers-New	Transformers-New		Per Industry	Existing	15,182	32	$11,539	37%	100%	$0.07	4
Electric	Fabricated Metal Products	Fans	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	55,547	10	$5,520	9.4%	100%	$0.01	4
Electric	Fabricated Metal Products	Hvac	Transformers-New	Transformers-New		Per Industry	Existing	22,813	32	$17,338	37%	100%	$0.07	7
Electric	Fabricated Metal Products	Hvac	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	83,463	10	$8,294	9.4%	100%	$0.01	6
Electric	Fabricated Metal Products	Lighting	Efficient Lighting 1 Shift	Efficient Lighting 1 Shift		Per Industry	Existing	3,646,784	10	$82,101	1.3%	100%	$0.01	40
Electric	Fabricated Metal Products	Lighting	Efficient Lighting 2 Shift	Efficient Lighting 2 Shift		Per Industry	Existing	3,646,784	10	$65,059	2.9%	100%	$0.00	88
Electric	Fabricated Metal Products	Lighting	Efficient Lighting 3 Shift	Efficient Lighting 3 Shift		Per Industry	Existing	3,646,784	10	$92,101	15%	100%	$-0.00	483
Electric	Fabricated Metal Products	Lighting	HighBay Lighting 1 Shift	HighBay Lighting 1 Shift		Per Industry	Existing	2,656,942	10	$43,154	1.9%	100%	$0.03	37
Electric	Fabricated Metal Products	Lighting	HighBay Lighting 2 Shift	HighBay Lighting 2 Shift		Per Industry	Existing	2,656,942	10	$76,313	4.3%	100%	$0.02	83
Electric	Fabricated Metal Products	Lighting	HighBay Lighting 3 Shift	HighBay Lighting 3 Shift		Per Industry	Existing	2,656,942	10	$9,979	23%	100%	$0.01	441
Electric	Fabricated Metal Products	Lighting	Lighting Controls	Lighting Controls		Per Industry	Existing	1,469,412	10	$12,984	15%	100%	$0.03	142
Electric	Fabricated Metal Products	Lighting	Transformers-New	Transformers-New		Per Industry	Existing	21,359	32	$16,233	37%	100%	$0.07	4
Electric	Fabricated Metal Products	Lighting	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	78,145	10	$7,765	9.4%	100%	$0.01	4
Electric	Fabricated Metal Products	Motors Other	Motors: Rewind 101-200 HP	Motors: Rewind 101-200 HP		Per Industry	Existing	52,709	10	$12,123	13%	100%	$0.03	6
Electric	Fabricated Metal Products	Motors Other	Motors: Rewind 20-50 HP	Motors: Rewind 20-50 HP		Per Industry	Existing	94,876	10	$34,155	20%	100%	$0.05	16
Electric	Fabricated Metal Products	Motors Other	Motors: Rewind 201-500 HP	Motors: Rewind 201-500 HP		Per Industry	Existing	52,709	10	$7,906	3.6%	100%	$0.02	1

Table B-2.3. Industrial Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Fabricated Metal Products	Motors Other	Motors: Rewind 51-100 HP	Motors: Rewind 51-100 HP		Per Industry	Existing	52,709	10	$16,339	5.3%	100%	$0.04	2
Electric	Fabricated Metal Products	Motors Other	Plant Energy Management	Plant Energy Management		Per Industry	Existing	1,265,018	10	$26,476	27%	100%	$0.01	290
Electric	Fabricated Metal Products	Motors Other	Synchronous Belts	Synchronous Belts		Per Industry	Existing	210,836	10	$45,104	21%	100%	$0.03	34
Electric	Fabricated Metal Products	Motors Other	Transformers-New	Transformers-New		Per Industry	Existing	43,221	32	$32,848	37%	100%	$0.07	12
Electric	Fabricated Metal Products	Motors Other	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	158,127	10	$15,714	9.4%	100%	$0.01	11
Electric	Fabricated Metal Products	Other	Transformers-New	Transformers-New		Per Industry	Existing	7,278	32	$5,531	37%	100%	$0.07	2
Electric	Fabricated Metal Products	Other	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	26,628	10	$2,646	9.4%	100%	$0.01	2
Electric	Fabricated Metal Products	Process Aircomp	Air Compressor Demand Reduction	Air Compressor Demand Reduction		Per Industry	Existing	854,157	10	$68,759	26%	100%	$0.02	190
Electric	Fabricated Metal Products	Process Aircomp	Motors: Rewind 101-200 HP	Motors: Rewind 101-200 HP		Per Industry	Existing	21,353	10	$4,911	13%	100%	$0.03	2
Electric	Fabricated Metal Products	Process Aircomp	Motors: Rewind 20-50 HP	Motors: Rewind 20-50 HP		Per Industry	Existing	38,437	10	$13,837	20%	100%	$0.05	6
Electric	Fabricated Metal Products	Process Aircomp	Motors: Rewind 201-500 HP	Motors: Rewind 201-500 HP		Per Industry	Existing	21,353	10	$3,203	3.6%	100%	$0.02	0.65
Electric	Fabricated Metal Products	Process Aircomp	Motors: Rewind 51-100 HP	Motors: Rewind 51-100 HP		Per Industry	Existing	21,353	10	$6,619	5.3%	100%	$0.04	0.92
Electric	Fabricated Metal Products	Process Aircomp	Plant Energy Management	Plant Energy Management		Per Industry	Existing	512,494	10	$10,726	27%	100%	$0.01	112
Electric	Fabricated Metal Products	Process Aircomp	Synchronous Belts	Synchronous Belts		Per Industry	Existing	85,415	10	$18,273	21%	100%	$0.03	14
Electric	Fabricated Metal Products	Process Aircomp	Transformers-New	Transformers-New		Per Industry	Existing	17,510	32	$13,307	37%	100%	$0.07	5
Electric	Fabricated Metal Products	Process Aircomp	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	64,061	10	$6,366	9.4%	100%	$0.01	4
Electric	Fabricated Metal Products	Process Electro Chemical	Transformers-New	Transformers-New		Per Industry	Existing	4,166	32	$3,166	37%	100%	$0.07	1
Electric	Fabricated Metal Products	Process Electro Chemical	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	15,241	10	$1,514	9.4%	100%	$0.01	1
Electric	Fabricated Metal Products	Process Heat	Transformers-New	Transformers-New		Per Industry	Existing	44,691	32	$33,965	37%	100%	$0.07	14
Electric	Fabricated Metal Products	Process Heat	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	163,506	10	$16,248	9.4%	100%	$0.01	13
Electric	Fabricated Metal Products	Process Other	Motors: Rewind 101-200 HP	Motors: Rewind 101-200 HP		Per Industry	Existing	8,045	10	$1,850	13%	100%	$0.03	0.92

Table B-2.3. Industrial Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Fabricated Metal Products	Process Other	Motors: Rewind 20-50 HP	Motors: Rewind 20-50 HP		Per Industry	Existing	14,482	10	$5,213	20%	100%	$0.05	2
Electric	Fabricated Metal Products	Process Other	Motors: Rewind 201-500 HP	Motors: Rewind 201-500 HP		Per Industry	Existing	8,045	10	$1,206	3.6%	100%	$0.02	0.24
Electric	Fabricated Metal Products	Process Other	Motors: Rewind 51-100 HP	Motors: Rewind 51-100 HP		Per Industry	Existing	8,045	10	$2,494	5.3%	100%	$0.04	0.36
Electric	Fabricated Metal Products	Process Other	Plant Energy Management	Plant Energy Management		Per Industry	Existing	193,099	10	$4,041	27%	100%	$0.01	44
Electric	Fabricated Metal Products	Process Other	Synchronous Belts	Synchronous Belts		Per Industry	Existing	32,183	10	$6,884	21%	100%	$0.03	5
Electric	Fabricated Metal Products	Process Other	Transformers-New	Transformers-New		Per Industry	Existing	6,597	32	$5,014	37%	100%	$0.07	2
Electric	Fabricated Metal Products	Process Other	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	24,137	10	$2,398	9.4%	100%	$0.01	1
Electric	Food Mfg	Fans	Energy Project Management	Energy Project Management		Per Industry	Existing	571,120	11	$70,298	27%	100%	$0.03	100
Electric	Food Mfg	Fans	Fan Energy Mangement	Fan Energy Mangement		Per Industry	Existing	196,937	10	$0.00	27%	100%	$0.01	45
Electric	Food Mfg	Fans	Fan Equipment Upgrade	Fan Equipment Upgrade		Per Industry	Existing	689,282	10	$59,081	23%	100%	$0.03	113
Electric	Food Mfg	Fans	Integrated Plant Energy Management	Integrated Plant Energy Management		Per Industry	Existing	984,689	11	$94,113	22%	100%	$0.05	173
Electric	Food Mfg	Fans	Motors: Rewind 101-200 HP	Motors: Rewind 101-200 HP		Per Industry	Existing	9,846	10	$2,264	12%	100%	$0.03	0.99
Electric	Food Mfg	Fans	Motors: Rewind 20-50 HP	Motors: Rewind 20-50 HP		Per Industry	Existing	17,724	10	$6,380	12%	100%	$0.05	1
Electric	Food Mfg	Fans	Motors: Rewind 201-500 HP	Motors: Rewind 201-500 HP		Per Industry	Existing	9,846	10	$1,477	9.7%	100%	$0.02	0.81
Electric	Food Mfg	Fans	Motors: Rewind 501-5000 HP	Motors: Rewind 501-5000 HP		Per Industry	Existing	9,846	10	$1,083	11%	100%	$0.01	0.97
Electric	Food Mfg	Fans	Motors: Rewind 51-100 HP	Motors: Rewind 51-100 HP		Per Industry	Existing	9,846	10	$3,052	11%	100%	$0.04	0.88
Electric	Food Mfg	Fans	Plant Energy Management	Plant Energy Management		Per Industry	Existing	236,325	10	$4,946	27%	100%	$0.01	53
Electric	Food Mfg	Fans	Synchronous Belts	Synchronous Belts		Per Industry	Existing	39,387	10	$8,426	21%	100%	$0.03	6
Electric	Food Mfg	Fans	Transformers-New	Transformers-New		Per Industry	Existing	8,074	32	$6,136	37%	100%	$0.07	2
Electric	Food Mfg	Fans	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	29,540	10	$2,935	9.4%	100%	$0.01	2
Electric	Food Mfg	Hvac	Transformers-New	Transformers-New		Per Industry	Existing	20,144	32	$15,309	37%	100%	$0.07	6
Electric	Food Mfg	Hvac	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	73,698	10	$7,323	9.4%	100%	$0.01	5
Electric	Food Mfg	Lighting	Efficient Lighting 1 Shift	Efficient Lighting 1 Shift		Per Industry	Existing	3,014,762	10	$33,210	4.5%	100%	$0.01	115
Electric	Food Mfg	Lighting	Efficient Lighting 2 Shift	Efficient Lighting 2 Shift		Per Industry	Existing	3,014,762	10	$36,453	3.3%	100%	$0.00	83
Electric	Food Mfg	Lighting	Efficient Lighting 3 Shift	Efficient Lighting 3 Shift		Per Industry	Existing	3,014,762	10	$76,139	12%	100%	$-0.00	304
Electric	Food Mfg	Lighting	HighBay Lighting 1 Shift	HighBay Lighting 1 Shift		Per Industry	Existing	2,196,469	10	$31,689	6.7%	100%	$0.03	109
Electric	Food Mfg	Lighting	HighBay Lighting 2 Shift	HighBay Lighting 2 Shift		Per Industry	Existing	2,196,469	10	$11,095	5.0%	100%	$0.02	78
Electric	Food Mfg	Lighting	HighBay Lighting 3 Shift	HighBay Lighting 3 Shift		Per Industry	Existing	2,196,469	10	$73,588	18%	100%	$0.01	270
Electric	Food Mfg	Lighting	Lighting Controls	Lighting Controls		Per Industry	Existing	1,214,749	10	$58,741	15%	100%	$0.03	118
Electric	Food Mfg	Lighting	Transformers-New	Transformers-New		Per Industry	Existing	17,657	32	$13,420	37%	100%	$0.07	3
Electric	Food Mfg	Lighting	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	64,602	10	$6,420	9.4%	100%	$0.01	3

Table B-2.3. Industrial Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Food Mfg	Motors Other	Energy Project Management	Energy Project Management		Per Industry	Existing	2,969,824	11	$65,551	27%	100%	$0.03	499
Electric	Food Mfg	Motors Other	Integrated Plant Energy Management	Integrated Plant Energy Management		Per Industry	Existing	5,120,387	11	$9,392	22%	100%	$0.05	885
Electric	Food Mfg	Motors Other	Motors: Rewind 101-200 HP	Motors: Rewind 101-200 HP		Per Industry	Existing	51,203	10	$11,776	12%	100%	$0.03	5
Electric	Food Mfg	Motors Other	Motors: Rewind 20-50 HP	Motors: Rewind 20-50 HP		Per Industry	Existing	92,166	10	$33,180	12%	100%	$0.05	9
Electric	Food Mfg	Motors Other	Motors: Rewind 201-500 HP	Motors: Rewind 201-500 HP		Per Industry	Existing	51,203	10	$7,680	9.7%	100%	$0.02	4
Electric	Food Mfg	Motors Other	Motors: Rewind 501-5000 HP	Motors: Rewind 501-5000 HP		Per Industry	Existing	51,203	10	$5,632	11%	100%	$0.01	5
Electric	Food Mfg	Motors Other	Motors: Rewind 51-100 HP	Motors: Rewind 51-100 HP		Per Industry	Existing	51,203	10	$15,873	11%	100%	$0.04	4
Electric	Food Mfg	Motors Other	Plant Energy Management	Plant Energy Management		Per Industry	Existing	1,228,893	10	$25,720	27%	100%	$0.01	282
Electric	Food Mfg	Motors Other	Synchronous Belts	Synchronous Belts		Per Industry	Existing	204,815	10	$43,816	21%	100%	$0.03	34
Electric	Food Mfg	Motors Other	Transformers-New	Transformers-New		Per Industry	Existing	41,987	32	$31,910	37%	100%	$0.07	12
Electric	Food Mfg	Motors Other	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	153,611	10	$15,265	9.4%	100%	$0.01	11
Electric	Food Mfg	Other	Transformers-New	Transformers-New		Per Industry	Existing	10,332	32	$7,852	37%	100%	$0.07	3
Electric	Food Mfg	Other	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	37,801	10	$3,756	9.4%	100%	$0.01	3
Electric	Food Mfg	Process Aircomp	Air Compressor Demand Reduction	Air Compressor Demand Reduction		Per Industry	Existing	404,379	10	$32,552	26%	100%	$0.02	89
Electric	Food Mfg	Process Aircomp	Energy Project Management	Energy Project Management		Per Industry	Existing	586,350	11	$72,172	27%	100%	$0.03	109
Electric	Food Mfg	Process Aircomp	Integrated Plant Energy Management	Integrated Plant Energy Management		Per Industry	Existing	1,010,948	11	$99,290	22%	100%	$0.05	173
Electric	Food Mfg	Process Aircomp	Motors: Rewind 101-200 HP	Motors: Rewind 101-200 HP		Per Industry	Existing	10,109	10	$2,325	12%	100%	$0.03	0.99
Electric	Food Mfg	Process Aircomp	Motors: Rewind 20-50 HP	Motors: Rewind 20-50 HP		Per Industry	Existing	18,197	10	$6,550	12%	100%	$0.05	1
Electric	Food Mfg	Process Aircomp	Motors: Rewind 201-500 HP	Motors: Rewind 201-500 HP		Per Industry	Existing	10,109	10	$1,516	9.7%	100%	$0.02	0.83
Electric	Food Mfg	Process Aircomp	Motors: Rewind 501-5000 HP	Motors: Rewind 501-5000 HP		Per Industry	Existing	10,109	10	$1,112	11%	100%	$0.01	0.99
Electric	Food Mfg	Process Aircomp	Motors: Rewind 51-100 HP	Motors: Rewind 51-100 HP		Per Industry	Existing	10,109	10	$3,133	11%	100%	$0.04	0.88
Electric	Food Mfg	Process Aircomp	Plant Energy Management	Plant Energy Management		Per Industry	Existing	242,627	10	$5,078	27%	100%	$0.01	53
Electric	Food Mfg	Process Aircomp	Synchronous Belts	Synchronous Belts		Per Industry	Existing	40,437	10	$8,650	21%	100%	$0.03	6
Electric	Food Mfg	Process Aircomp	Transformers-New	Transformers-New		Per Industry	Existing	8,289	32	$6,300	37%	100%	$0.07	2
Electric	Food Mfg	Process Aircomp	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	30,328	10	$3,013	9.4%	100%	$0.01	2
Electric	Food Mfg	Process Refrig	Energy Project Management	Energy Project Management		Per Industry	Existing	2,238,791	11	$75,569	27%	100%	$0.03	342
Electric	Food Mfg	Process Refrig	Food: Cooling and Storage	Food: Cooling and Storage		Per Industry	Existing	1,157,995	10	$47,398	100%	100%	$0.04	993
Electric	Food Mfg	Process Refrig	Food: Refrig Storage Tuneup	Food: Refrig Storage Tuneup		Per Industry	Existing	578,997	3	$40,529	100%	100%	$0.02	496
Electric	Food Mfg	Process Refrig	Integrated Plant Energy Management	Integrated Plant Energy Management		Per Industry	Existing	3,859,984	11	$60,926	22%	100%	$0.05	540
Electric	Food Mfg	Process Refrig	Motors: Rewind 101-200 HP	Motors: Rewind 101-200 HP		Per Industry	Existing	38,599	10	$8,877	12%	100%	$0.03	3
Electric	Food Mfg	Process Refrig	Motors: Rewind 20-50 HP	Motors: Rewind 20-50 HP		Per Industry	Existing	69,479	10	$25,012	12%	100%	$0.05	5
Electric	Food Mfg	Process Refrig	Motors: Rewind 201-500 HP	Motors: Rewind 201-500 HP		Per Industry	Existing	38,599	10	$5,789	9.7%	100%	$0.02	3

Table B-2.3. Industrial Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Food Mfg	Process Refrig	Motors: Rewind 501-5000 HP	Motors: Rewind 501-5000 HP		Per Industry	Existing	38,599	10	$4,245	11%	100%	$0.01	3
Electric	Food Mfg	Process Refrig	Motors: Rewind 51-100 HP	Motors: Rewind 51-100 HP		Per Industry	Existing	38,599	10	$11,965	11%	100%	$0.04	2
Electric	Food Mfg	Process Refrig	Plant Energy Management	Plant Energy Management		Per Industry	Existing	926,396	10	$19,389	27%	100%	$0.01	165
Electric	Food Mfg	Process Refrig	Synchronous Belts	Synchronous Belts		Per Industry	Existing	154,399	10	$33,030	21%	100%	$0.03	20
Electric	Food Mfg	Process Refrig	Transformers-New	Transformers-New		Per Industry	Existing	31,651	32	$24,055	37%	100%	$0.07	7
Electric	Food Mfg	Process Refrig	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	115,799	10	$11,507	9.4%	100%	$0.01	6
Electric	Food Mfg	Pumps	Energy Project Management	Energy Project Management		Per Industry	Existing	1,248,849	11	$53,719	27%	100%	$0.03	240
Electric	Food Mfg	Pumps	Integrated Plant Energy Management	Integrated Plant Energy Management		Per Industry	Existing	2,153,188	11	$24,462	22%	100%	$0.05	380
Electric	Food Mfg	Pumps	Motors: Rewind 101-200 HP	Motors: Rewind 101-200 HP		Per Industry	Existing	21,531	10	$4,952	12%	100%	$0.03	2
Electric	Food Mfg	Pumps	Motors: Rewind 20-50 HP	Motors: Rewind 20-50 HP		Per Industry	Existing	38,757	10	$13,952	12%	100%	$0.05	4
Electric	Food Mfg	Pumps	Motors: Rewind 201-500 HP	Motors: Rewind 201-500 HP		Per Industry	Existing	21,531	10	$3,229	9.7%	100%	$0.02	1
Electric	Food Mfg	Pumps	Motors: Rewind 501-5000 HP	Motors: Rewind 501-5000 HP		Per Industry	Existing	21,531	10	$2,368	11%	100%	$0.01	2
Electric	Food Mfg	Pumps	Motors: Rewind 51-100 HP	Motors: Rewind 51-100 HP		Per Industry	Existing	21,531	10	$6,674	11%	100%	$0.04	1
Electric	Food Mfg	Pumps	Plant Energy Management	Plant Energy Management		Per Industry	Existing	516,765	10	$10,815	27%	100%	$0.01	119
Electric	Food Mfg	Pumps	Pump Energy Management	Pump Energy Management		Per Industry	Existing	322,978	10	$0.00	31%	100%	$0.01	82
Electric	Food Mfg	Pumps	Pump Equipment Upgrade	Pump Equipment Upgrade		Per Industry	Existing	861,275	10	$7,659	34%	100%	$0.03	190
Electric	Food Mfg	Pumps	Synchronous Belts	Synchronous Belts		Per Industry	Existing	86,127	10	$18,425	21%	100%	$0.03	14
Electric	Food Mfg	Pumps	Transformers-New	Transformers-New		Per Industry	Existing	17,656	32	$13,418	37%	100%	$0.07	5
Electric	Food Mfg	Pumps	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	64,595	10	$6,419	9.4%	100%	$0.01	4
Electric	Industrial Machinery	Fans	Fan Energy Mangement	Fan Energy Mangement		Per Industry	Existing	511,205	10	$0.00	27%	100%	$0.01	119
Electric	Industrial Machinery	Fans	Fan Equipment Upgrade	Fan Equipment Upgrade		Per Industry	Existing	1,789,219	10	$53,361	23%	100%	$0.03	282
Electric	Industrial Machinery	Fans	Fan System Optimization	Fan System Optimization		Per Industry	Existing	2,556,028	10	$6,723	30%	100%	$0.03	606
Electric	Industrial Machinery	Fans	Motors: Rewind 101-200 HP	Motors: Rewind 101-200 HP		Per Industry	Existing	25,560	10	$5,878	17%	100%	$0.03	3
Electric	Industrial Machinery	Fans	Motors: Rewind 20-50 HP	Motors: Rewind 20-50 HP		Per Industry	Existing	46,008	10	$16,563	11%	100%	$0.05	3
Electric	Industrial Machinery	Fans	Motors: Rewind 51-100 HP	Motors: Rewind 51-100 HP		Per Industry	Existing	25,560	10	$7,923	0.2%	100%	$0.04	0.03
Electric	Industrial Machinery	Fans	Plant Energy Management	Plant Energy Management		Per Industry	Existing	613,446	10	$12,839	27%	100%	$0.01	138
Electric	Industrial Machinery	Fans	Synchronous Belts	Synchronous Belts		Per Industry	Existing	102,241	10	$21,872	21%	100%	$0.03	17
Electric	Industrial Machinery	Fans	Transformers-New	Transformers-New		Per Industry	Existing	20,959	32	$15,929	37%	100%	$0.07	6
Electric	Industrial Machinery	Fans	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	76,680	10	$7,620	9.4%	100%	$0.01	5
Electric	Industrial Machinery	Hvac	Transformers-New	Transformers-New		Per Industry	Existing	75,846	32	$57,643	37%	100%	$0.07	24
Electric	Industrial Machinery	Hvac	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	277,485	10	$27,575	9.4%	100%	$0.01	22
Electric	Industrial Machinery	Lighting	Efficient Lighting 3 Shift	Efficient Lighting 3 Shift		Per Industry	Existing	8,383,951	10	$11,741	13%	100%	$-0.00	908

Table B-2.3. Industrial Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Industrial Machinery	Lighting	HighBay Lighting 3 Shift	HighBay Lighting 3 Shift		Per Industry	Existing	6,108,307	10	$82,742	19%	100%	$0.01	905
Electric	Industrial Machinery	Lighting	Lighting Controls	Lighting Controls		Per Industry	Existing	3,378,176	10	$19,551	15%	100%	$0.03	366
Electric	Industrial Machinery	Lighting	Transformers-New	Transformers-New		Per Industry	Existing	49,106	32	$37,320	37%	100%	$0.07	12
Electric	Industrial Machinery	Lighting	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	179,656	10	$17,853	9.4%	100%	$0.01	11
Electric	Industrial Machinery	Motors Other	Motors: Rewind 101-200 HP	Motors: Rewind 101-200 HP		Per Industry	Existing	72,762	10	$16,735	17%	100%	$0.03	10
Electric	Industrial Machinery	Motors Other	Motors: Rewind 20-50 HP	Motors: Rewind 20-50 HP		Per Industry	Existing	130,973	10	$47,150	11%	100%	$0.05	11
Electric	Industrial Machinery	Motors Other	Motors: Rewind 51-100 HP	Motors: Rewind 51-100 HP		Per Industry	Existing	72,762	10	$22,556	0.2%	100%	$0.04	0.11
Electric	Industrial Machinery	Motors Other	Plant Energy Management	Plant Energy Management		Per Industry	Existing	1,746,308	10	$36,550	27%	100%	$0.01	404
Electric	Industrial Machinery	Motors Other	Synchronous Belts	Synchronous Belts		Per Industry	Existing	291,051	10	$62,264	21%	100%	$0.03	49
Electric	Industrial Machinery	Motors Other	Transformers-New	Transformers-New		Per Industry	Existing	59,665	32	$45,345	37%	100%	$0.07	17
Electric	Industrial Machinery	Motors Other	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	218,288	10	$21,693	9.4%	100%	$0.01	16
Electric	Industrial Machinery	Other	Transformers-New	Transformers-New		Per Industry	Existing	12,532	32	$9,524	37%	100%	$0.07	3
Electric	Industrial Machinery	Other	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	45,849	10	$4,556	9.4%	100%	$0.01	3
Electric	Industrial Machinery	Process Aircomp	Air Compressor Demand Reduction	Air Compressor Demand Reduction		Per Industry	Existing	1,179,131	10	$94,920	26%	100%	$0.02	262
Electric	Industrial Machinery	Process Aircomp	Motors: Rewind 101-200 HP	Motors: Rewind 101-200 HP		Per Industry	Existing	29,478	10	$6,780	17%	100%	$0.03	4
Electric	Industrial Machinery	Process Aircomp	Motors: Rewind 20-50 HP	Motors: Rewind 20-50 HP		Per Industry	Existing	53,060	10	$19,101	11%	100%	$0.05	4
Electric	Industrial Machinery	Process Aircomp	Motors: Rewind 51-100 HP	Motors: Rewind 51-100 HP		Per Industry	Existing	29,478	10	$9,138	0.2%	100%	$0.04	0.04
Electric	Industrial Machinery	Process Aircomp	Plant Energy Management	Plant Energy Management		Per Industry	Existing	707,478	10	$14,807	27%	100%	$0.01	155
Electric	Industrial Machinery	Process Aircomp	Synchronous Belts	Synchronous Belts		Per Industry	Existing	117,913	10	$25,225	21%	100%	$0.03	19
Electric	Industrial Machinery	Process Aircomp	Transformers-New	Transformers-New		Per Industry	Existing	24,172	32	$18,370	37%	100%	$0.07	7
Electric	Industrial Machinery	Process Aircomp	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	88,434	10	$8,788	9.4%	100%	$0.01	6
Electric	Industrial Machinery	Process Heat	Transformers-New	Transformers-New		Per Industry	Existing	23,166	32	$17,606	37%	100%	$0.07	7
Electric	Industrial Machinery	Process Heat	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	84,757	10	$8,422	9.4%	100%	$0.01	6
Electric	Industrial Machinery	Pumps	Motors: Rewind 101-200 HP	Motors: Rewind 101-200 HP		Per Industry	Existing	46,269	10	$10,642	17%	100%	$0.03	6
Electric	Industrial Machinery	Pumps	Motors: Rewind 20-50 HP	Motors: Rewind 20-50 HP		Per Industry	Existing	83,285	10	$29,982	11%	100%	$0.05	7
Electric	Industrial Machinery	Pumps	Motors: Rewind 51-100 HP	Motors: Rewind 51-100 HP		Per Industry	Existing	46,269	10	$14,343	0.2%	100%	$0.04	0.07
Electric	Industrial Machinery	Pumps	Plant Energy Management	Plant Energy Management		Per Industry	Existing	1,110,472	10	$23,242	27%	100%	$0.01	257
Electric	Industrial Machinery	Pumps	Pump Energy Management	Pump Energy Management		Per Industry	Existing	694,045	10	$0.00	31%	100%	$0.01	178
Electric	Industrial Machinery	Pumps	Pump Equipment Upgrade	Pump Equipment Upgrade		Per Industry	Existing	1,850,788	10	$31,348	34%	100%	$0.03	499
Electric	Industrial Machinery	Pumps	Synchronous Belts	Synchronous Belts		Per Industry	Existing	185,078	10	$39,593	21%	100%	$0.03	31
Electric	Industrial Machinery	Pumps	Transformers-New	Transformers-New		Per Industry	Existing	37,941	32	$28,835	37%	100%	$0.07	11

Table B-2.3. Industrial Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Industrial Machinery	Pumps	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	138,809	10	$13,794	9.4%	100%	$0.01	10
Electric	Miscellaneous Mfg	Fans	Fan Energy Mangement	Fan Energy Mangement		Per Industry	Existing	754,021	10	$0.00	27%	100%	$0.01	175
Electric	Miscellaneous Mfg	Fans	Fan Equipment Upgrade	Fan Equipment Upgrade		Per Industry	Existing	2,639,075	10	$26,206	23%	100%	$0.03	417
Electric	Miscellaneous Mfg	Fans	Fan System Optimization	Fan System Optimization		Per Industry	Existing	3,770,108	10	$52,412	30%	100%	$0.03	894
Electric	Miscellaneous Mfg	Fans	Motors: Rewind 101-200 HP	Motors: Rewind 101-200 HP		Per Industry	Existing	37,701	10	$8,671	17%	100%	$0.03	4
Electric	Miscellaneous Mfg	Fans	Motors: Rewind 20-50 HP	Motors: Rewind 20-50 HP		Per Industry	Existing	67,861	10	$24,430	11%	100%	$0.05	5
Electric	Miscellaneous Mfg	Fans	Motors: Rewind 51-100 HP	Motors: Rewind 51-100 HP		Per Industry	Existing	37,701	10	$11,687	0.2%	100%	$0.04	0.05
Electric	Miscellaneous Mfg	Fans	Plant Energy Management	Plant Energy Management		Per Industry	Existing	904,825	10	$18,938	27%	100%	$0.01	203
Electric	Miscellaneous Mfg	Fans	Synchronous Belts	Synchronous Belts		Per Industry	Existing	150,804	10	$32,261	21%	100%	$0.03	25
Electric	Miscellaneous Mfg	Fans	Transformers-New	Transformers-New		Per Industry	Existing	30,914	32	$23,495	37%	100%	$0.07	9
Electric	Miscellaneous Mfg	Fans	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	113,103	10	$11,239	9.4%	100%	$0.01	8
Electric	Miscellaneous Mfg	Hvac	Clean Room: Change Filter Strategy	Clean Room: Change Filter Strategy		Per Industry	Existing	14,826,647	1	$96,179	10%	100%	$-0.00	1,271
Electric	Miscellaneous Mfg	Hvac	Clean Room: Chiller Optimize	Clean Room: Chiller Optimize		Per Industry	Existing	5,494,323	10	$47,424	28%	100%	$0.01	1,282
Electric	Miscellaneous Mfg	Hvac	Clean Room: Clean Room HVAC	Clean Room: Clean Room HVAC		Per Industry	Existing	3,335,995	20	$40,093	30%	100%	$0.01	789
Electric	Miscellaneous Mfg	Hvac	Transformers-New	Transformers-New		Per Industry	Existing	151,973	32	$15,499	37%	100%	$0.07	43
Electric	Miscellaneous Mfg	Hvac	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	555,999	10	$55,254	9.4%	100%	$0.01	40
Electric	Miscellaneous Mfg	Lighting	Efficient Lighting 1 Shift	Efficient Lighting 1 Shift		Per Industry	Existing	17,569,391	10	$59,102	5.2%	100%	$0.01	787
Electric	Miscellaneous Mfg	Lighting	Efficient Lighting 2 Shift	Efficient Lighting 2 Shift		Per Industry	Existing	17,569,391	10	$95,219	1.7%	100%	$0.00	252
Electric	Miscellaneous Mfg	Lighting	Efficient Lighting 3 Shift	Efficient Lighting 3 Shift		Per Industry	Existing	17,569,391	10	$43,725	13%	100%	$-0.00	1,904
Electric	Miscellaneous Mfg	Lighting	HighBay Lighting 1 Shift	HighBay Lighting 1 Shift		Per Industry	Existing	12,800,556	10	$98,574	7.8%	100%	$0.03	742
Electric	Miscellaneous Mfg	Lighting	HighBay Lighting 2 Shift	HighBay Lighting 2 Shift		Per Industry	Existing	12,800,556	10	$12,995	2.6%	100%	$0.02	237
Electric	Miscellaneous Mfg	Lighting	HighBay Lighting 3 Shift	HighBay Lighting 3 Shift		Per Industry	Existing	12,800,556	10	$11,635	19%	100%	$0.01	1,701
Electric	Miscellaneous Mfg	Lighting	Lighting Controls	Lighting Controls		Per Industry	Existing	7,079,299	10	$7,890	15%	100%	$0.03	689
Electric	Miscellaneous Mfg	Lighting	Transformers-New	Transformers-New		Per Industry	Existing	102,906	32	$78,208	37%	100%	$0.07	23
Electric	Miscellaneous Mfg	Lighting	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	376,486	10	$37,414	9.4%	100%	$0.01	21
Electric	Miscellaneous Mfg	Motors Other	Motors: Rewind 101-200 HP	Motors: Rewind 101-200 HP		Per Industry	Existing	151,789	10	$34,911	17%	100%	$0.03	20
Electric	Miscellaneous Mfg	Motors Other	Motors: Rewind 20-50 HP	Motors: Rewind 20-50 HP		Per Industry	Existing	273,221	10	$98,359	11%	100%	$0.05	24
Electric	Miscellaneous Mfg	Motors Other	Motors: Rewind 51-100 HP	Motors: Rewind 51-100 HP		Per Industry	Existing	151,789	10	$47,054	0.2%	100%	$0.04	0.23
Electric	Miscellaneous Mfg	Motors Other	Plant Energy Management	Plant Energy Management		Per Industry	Existing	3,642,959	10	$76,247	27%	100%	$0.01	843
Electric	Miscellaneous Mfg	Motors Other	Synchronous Belts	Synchronous Belts		Per Industry	Existing	607,159	10	$29,889	21%	100%	$0.03	102
Electric	Miscellaneous Mfg	Motors Other	Transformers-New	Transformers-New		Per Industry	Existing	124,467	32	$94,595	37%	100%	$0.07	36

Table B-2.3. Industrial Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Miscellaneous Mfg	Motors Other	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	455,369	10	$45,253	9.4%	100%	$0.01	33
Electric	Miscellaneous Mfg	Other	Transformers-New	Transformers-New		Per Industry	Existing	35,956	32	$27,327	37%	100%	$0.07	11
Electric	Miscellaneous Mfg	Other	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	131,549	10	$13,073	9.4%	100%	$0.01	10
Electric	Miscellaneous Mfg	Process Aircomp	Air Compressor Demand Reduction	Air Compressor Demand Reduction		Per Industry	Existing	1,409,478	10	$13,463	26%	100%	$0.02	313
Electric	Miscellaneous Mfg	Process Aircomp	Motors: Rewind 101-200 HP	Motors: Rewind 101-200 HP		Per Industry	Existing	35,236	10	$8,104	17%	100%	$0.03	4
Electric	Miscellaneous Mfg	Process Aircomp	Motors: Rewind 20-50 HP	Motors: Rewind 20-50 HP		Per Industry	Existing	63,426	10	$22,833	11%	100%	$0.05	5
Electric	Miscellaneous Mfg	Process Aircomp	Motors: Rewind 51-100 HP	Motors: Rewind 51-100 HP		Per Industry	Existing	35,236	10	$10,923	0.2%	100%	$0.04	0.05
Electric	Miscellaneous Mfg	Process Aircomp	Plant Energy Management	Plant Energy Management		Per Industry	Existing	845,687	10	$17,700	27%	100%	$0.01	185
Electric	Miscellaneous Mfg	Process Aircomp	Synchronous Belts	Synchronous Belts		Per Industry	Existing	140,947	10	$30,153	21%	100%	$0.03	23
Electric	Miscellaneous Mfg	Process Aircomp	Transformers-New	Transformers-New		Per Industry	Existing	28,894	32	$21,959	37%	100%	$0.07	8
Electric	Miscellaneous Mfg	Process Aircomp	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	105,710	10	$10,505	9.4%	100%	$0.01	7
Electric	Miscellaneous Mfg	Process Heat	Transformers-New	Transformers-New		Per Industry	Existing	62,558	32	$47,544	37%	100%	$0.07	19
Electric	Miscellaneous Mfg	Process Heat	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	228,872	10	$22,744	9.4%	100%	$0.01	18
Electric	Miscellaneous Mfg	Process Other	Motors: Rewind 101-200 HP	Motors: Rewind 101-200 HP		Per Industry	Existing	6,441	10	$1,481	17%	100%	$0.03	0.92
Electric	Miscellaneous Mfg	Process Other	Motors: Rewind 20-50 HP	Motors: Rewind 20-50 HP		Per Industry	Existing	11,594	10	$4,174	11%	100%	$0.05	1
Electric	Miscellaneous Mfg	Process Other	Motors: Rewind 51-100 HP	Motors: Rewind 51-100 HP		Per Industry	Existing	6,441	10	$1,996	0.2%	100%	$0.04	0.01
Electric	Miscellaneous Mfg	Process Other	Plant Energy Management	Plant Energy Management		Per Industry	Existing	154,599	10	$3,235	27%	100%	$0.01	35
Electric	Miscellaneous Mfg	Process Other	Synchronous Belts	Synchronous Belts		Per Industry	Existing	25,766	10	$5,512	21%	100%	$0.03	4
Electric	Miscellaneous Mfg	Process Other	Transformers-New	Transformers-New		Per Industry	Existing	5,282	32	$4,014	37%	100%	$0.07	1
Electric	Miscellaneous Mfg	Process Other	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	19,324	10	$1,920	9.4%	100%	$0.01	1
Electric	Miscellaneous Mfg	Pumps	Motors: Rewind 101-200 HP	Motors: Rewind 101-200 HP		Per Industry	Existing	21,437	10	$4,930	17%	100%	$0.03	2
Electric	Miscellaneous Mfg	Pumps	Motors: Rewind 20-50 HP	Motors: Rewind 20-50 HP		Per Industry	Existing	38,588	10	$13,891	11%	100%	$0.05	3
Electric	Miscellaneous Mfg	Pumps	Motors: Rewind 51-100 HP	Motors: Rewind 51-100 HP		Per Industry	Existing	21,437	10	$6,645	0.2%	100%	$0.04	0.03
Electric	Miscellaneous Mfg	Pumps	Plant Energy Management	Plant Energy Management		Per Industry	Existing	514,508	10	$10,768	27%	100%	$0.01	119
Electric	Miscellaneous Mfg	Pumps	Pump Energy Management	Pump Energy Management		Per Industry	Existing	321,568	10	$0.00	31%	100%	$0.01	82
Electric	Miscellaneous Mfg	Pumps	Pump Equipment Upgrade	Pump Equipment Upgrade		Per Industry	Existing	857,514	10	$7,189	34%	100%	$0.03	213
Electric	Miscellaneous Mfg	Pumps	Pump System Optimization	Pump System Optimization		Per Industry	Existing	2,143,787	12	$44,521	15%	100%	$0.06	266
Electric	Miscellaneous Mfg	Pumps	Synchronous Belts	Synchronous Belts		Per Industry	Existing	85,751	10	$18,344	21%	100%	$0.03	14
Electric	Miscellaneous Mfg	Pumps	Transformers-New	Transformers-New		Per Industry	Existing	17,579	32	$13,360	37%	100%	$0.07	5
Electric	Miscellaneous Mfg	Pumps	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	64,313	10	$6,391	9.4%	100%	$0.01	4

Table B-2.3. Industrial Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Nonmetallic Mineral Products	Fans	Fan Energy Mangement	Fan Energy Mangement		Per Industry	Existing	255,967	10	$0.00	27%	100%	$0.01	59
Electric	Nonmetallic Mineral Products	Fans	Fan Equipment Upgrade	Fan Equipment Upgrade		Per Industry	Existing	895,885	10	$76,790	23%	100%	$0.03	141
Electric	Nonmetallic Mineral Products	Fans	Fan System Optimization	Fan System Optimization		Per Industry	Existing	1,279,836	10	$53,580	30%	100%	$0.03	303
Electric	Nonmetallic Mineral Products	Fans	Motors: Rewind 101-200 HP	Motors: Rewind 101-200 HP		Per Industry	Existing	12,798	10	$2,943	17%	100%	$0.03	1
Electric	Nonmetallic Mineral Products	Fans	Motors: Rewind 20-50 HP	Motors: Rewind 20-50 HP		Per Industry	Existing	23,037	10	$8,293	11%	100%	$0.05	1
Electric	Nonmetallic Mineral Products	Fans	Motors: Rewind 51-100 HP	Motors: Rewind 51-100 HP		Per Industry	Existing	12,798	10	$3,967	0.2%	100%	$0.04	0.01
Electric	Nonmetallic Mineral Products	Fans	Plant Energy Management	Plant Energy Management		Per Industry	Existing	307,160	10	$6,428	27%	100%	$0.01	69
Electric	Nonmetallic Mineral Products	Fans	Synchronous Belts	Synchronous Belts		Per Industry	Existing	51,193	10	$10,951	21%	100%	$0.03	8
Electric	Nonmetallic Mineral Products	Fans	Transformers-New	Transformers-New		Per Industry	Existing	10,494	32	$7,975	37%	100%	$0.07	3
Electric	Nonmetallic Mineral Products	Fans	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	38,395	10	$3,815	9.4%	100%	$0.01	2
Electric	Nonmetallic Mineral Products	Hvac	Transformers-New	Transformers-New		Per Industry	Existing	8,681	32	$6,597	37%	100%	$0.07	2
Electric	Nonmetallic Mineral Products	Hvac	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	31,761	10	$3,156	9.4%	100%	$0.01	2
Electric	Nonmetallic Mineral Products	Lighting	Efficient Lighting 3 Shift	Efficient Lighting 3 Shift		Per Industry	Existing	1,213,357	10	$30,644	13%	100%	$-0.00	131
Electric	Nonmetallic Mineral Products	Lighting	HighBay Lighting 3 Shift	HighBay Lighting 3 Shift		Per Industry	Existing	884,017	10	$69,864	19%	100%	$0.01	131
Electric	Nonmetallic Mineral Products	Lighting	Lighting Controls	Lighting Controls		Per Industry	Existing	488,902	10	$4,136	15%	100%	$0.03	53
Electric	Nonmetallic Mineral Products	Lighting	Transformers-New	Transformers-New		Per Industry	Existing	7,106	32	$5,401	37%	100%	$0.07	1
Electric	Nonmetallic Mineral Products	Lighting	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	26,000	10	$2,583	9.4%	100%	$0.01	1
Electric	Nonmetallic Mineral Products	Motors Other	Motors: Rewind 101-200 HP	Motors: Rewind 101-200 HP		Per Industry	Existing	36,433	10	$8,379	17%	100%	$0.03	5
Electric	Nonmetallic Mineral Products	Motors Other	Motors: Rewind 20-50 HP	Motors: Rewind 20-50 HP		Per Industry	Existing	65,579	10	$23,608	11%	100%	$0.05	5
Electric	Nonmetallic Mineral Products	Motors Other	Motors: Rewind 51-100 HP	Motors: Rewind 51-100 HP		Per Industry	Existing	36,433	10	$11,294	0.2%	100%	$0.04	0.05
Electric	Nonmetallic Mineral Products	Motors Other	Plant Energy Management	Plant Energy Management		Per Industry	Existing	874,399	10	$18,301	27%	100%	$0.01	202

Table B-2.3. Industrial Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Nonmetallic Mineral Products	Motors Other	Synchronous Belts	Synchronous Belts		Per Industry	Existing	145,733	10	$31,176	21%	100%	$0.03	24
Electric	Nonmetallic Mineral Products	Motors Other	Transformers-New	Transformers-New		Per Industry	Existing	29,875	32	$22,705	37%	100%	$0.07	8
Electric	Nonmetallic Mineral Products	Motors Other	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	109,299	10	$10,861	9.4%	100%	$0.01	8
Electric	Nonmetallic Mineral Products	Process Aircomp	Air Compressor Demand Reduction	Air Compressor Demand Reduction		Per Industry	Existing	590,406	10	$47,527	26%	100%	$0.02	131
Electric	Nonmetallic Mineral Products	Process Aircomp	Motors: Rewind 101-200 HP	Motors: Rewind 101-200 HP		Per Industry	Existing	14,760	10	$3,394	17%	100%	$0.03	2
Electric	Nonmetallic Mineral Products	Process Aircomp	Motors: Rewind 20-50 HP	Motors: Rewind 20-50 HP		Per Industry	Existing	26,568	10	$9,564	11%	100%	$0.05	2
Electric	Nonmetallic Mineral Products	Process Aircomp	Motors: Rewind 51-100 HP	Motors: Rewind 51-100 HP		Per Industry	Existing	14,760	10	$4,575	0.2%	100%	$0.04	0.02
Electric	Nonmetallic Mineral Products	Process Aircomp	Plant Energy Management	Plant Energy Management		Per Industry	Existing	354,243	10	$7,414	27%	100%	$0.01	77
Electric	Nonmetallic Mineral Products	Process Aircomp	Synchronous Belts	Synchronous Belts		Per Industry	Existing	59,040	10	$12,630	21%	100%	$0.03	9
Electric	Nonmetallic Mineral Products	Process Aircomp	Transformers-New	Transformers-New		Per Industry	Existing	12,103	32	$9,198	37%	100%	$0.07	3
Electric	Nonmetallic Mineral Products	Process Aircomp	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	44,280	10	$4,400	9.4%	100%	$0.01	3
Electric	Nonmetallic Mineral Products	Process Other	Motors: Rewind 101-200 HP	Motors: Rewind 101-200 HP		Per Industry	Existing	5,332	10	$1,226	17%	100%	$0.03	0.76
Electric	Nonmetallic Mineral Products	Process Other	Motors: Rewind 20-50 HP	Motors: Rewind 20-50 HP		Per Industry	Existing	9,598	10	$3,455	11%	100%	$0.05	0.90
Electric	Nonmetallic Mineral Products	Process Other	Motors: Rewind 51-100 HP	Motors: Rewind 51-100 HP		Per Industry	Existing	5,332	10	$1,652	0.2%	100%	$0.04	0.00
Electric	Nonmetallic Mineral Products	Process Other	Plant Energy Management	Plant Energy Management		Per Industry	Existing	127,974	10	$2,678	27%	100%	$0.01	29
Electric	Nonmetallic Mineral Products	Process Other	Synchronous Belts	Synchronous Belts		Per Industry	Existing	21,329	10	$4,562	21%	100%	$0.03	3
Electric	Nonmetallic Mineral Products	Process Other	Transformers-New	Transformers-New		Per Industry	Existing	4,372	32	$3,323	37%	100%	$0.07	1
Electric	Nonmetallic Mineral Products	Process Other	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	15,996	10	$1,589	9.4%	100%	$0.01	1
Electric	Nonmetallic Mineral Products	Pumps	Motors: Rewind 101-200 HP	Motors: Rewind 101-200 HP		Per Industry	Existing	23,167	10	$5,328	17%	100%	$0.03	3
Electric	Nonmetallic Mineral Products	Pumps	Motors: Rewind 20-50 HP	Motors: Rewind 20-50 HP		Per Industry	Existing	41,702	10	$15,012	11%	100%	$0.05	3
Electric	Nonmetallic Mineral Products	Pumps	Motors: Rewind 51-100 HP	Motors: Rewind 51-100 HP		Per Industry	Existing	23,167	10	$7,182	0.2%	100%	$0.04	0.03

Table B-2.3. Industrial Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Nonmetallic Mineral Products	Pumps	Plant Energy Management	Plant Energy Management		Per Industry	Existing	556,028	10	$11,637	27%	100%	$0.01	128
Electric	Nonmetallic Mineral Products	Pumps	Pump Energy Management	Pump Energy Management		Per Industry	Existing	347,517	10	$0.00	31%	100%	$0.01	89
Electric	Nonmetallic Mineral Products	Pumps	Pump Equipment Upgrade	Pump Equipment Upgrade		Per Industry	Existing	926,713	10	$15,839	34%	100%	$0.03	249
Electric	Nonmetallic Mineral Products	Pumps	Synchronous Belts	Synchronous Belts		Per Industry	Existing	92,671	10	$19,825	21%	100%	$0.03	15
Electric	Nonmetallic Mineral Products	Pumps	Transformers-New	Transformers-New		Per Industry	Existing	18,997	32	$14,438	37%	100%	$0.07	5
Electric	Nonmetallic Mineral Products	Pumps	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	69,503	10	$6,907	9.4%	100%	$0.01	5
Electric	Paper Mfg	Fans	Energy Project Management	Energy Project Management		Per Industry	Existing	405,035	11	$49,855	27%	100%	$0.03	93
Electric	Paper Mfg	Fans	Fan Energy Mangement	Fan Energy Mangement		Per Industry	Existing	139,667	10	$0.00	27%	100%	$0.01	30
Electric	Paper Mfg	Fans	Fan Equipment Upgrade	Fan Equipment Upgrade		Per Industry	Existing	488,835	10	$41,900	23%	100%	$0.03	87
Electric	Paper Mfg	Fans	Fan System Optimization	Fan System Optimization		Per Industry	Existing	698,336	10	$83,800	30%	100%	$0.03	146
Electric	Paper Mfg	Fans	Integrated Plant Energy Management	Integrated Plant Energy Management		Per Industry	Existing	698,336	11	$37,664	22%	100%	$0.05	92
Electric	Paper Mfg	Fans	Motors: Rewind 101-200 HP	Motors: Rewind 101-200 HP		Per Industry	Existing	6,983	10	$1,606	9.1%	100%	$0.03	0.33
Electric	Paper Mfg	Fans	Motors: Rewind 20-50 HP	Motors: Rewind 20-50 HP		Per Industry	Existing	12,570	10	$4,525	6.3%	100%	$0.05	0.42
Electric	Paper Mfg	Fans	Motors: Rewind 201-500 HP	Motors: Rewind 201-500 HP		Per Industry	Existing	6,983	10	$1,047	13%	100%	$0.02	0.76
Electric	Paper Mfg	Fans	Motors: Rewind 501-5000 HP	Motors: Rewind 501-5000 HP		Per Industry	Existing	6,983	10	$768	23%	100%	$0.01	1
Electric	Paper Mfg	Fans	Motors: Rewind 51-100 HP	Motors: Rewind 51-100 HP		Per Industry	Existing	6,983	10	$2,164	10%	100%	$0.04	0.37
Electric	Paper Mfg	Fans	Paper: Premium Fan	Paper: Premium Fan		Per Industry	Existing	279,334	10	$50,788	25%	100%	$0.02	59
Electric	Paper Mfg	Fans	Plant Energy Management	Plant Energy Management		Per Industry	Existing	167,600	10	$3,507	27%	100%	$0.01	22
Electric	Paper Mfg	Fans	Synchronous Belts	Synchronous Belts		Per Industry	Existing	27,933	10	$5,975	21%	100%	$0.03	2
Electric	Paper Mfg	Fans	Transformers-New	Transformers-New		Per Industry	Existing	5,726	32	$4,352	37%	100%	$0.07	1
Electric	Paper Mfg	Fans	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	20,950	10	$2,081	9.4%	100%	$0.01	0.92
Electric	Paper Mfg	Hvac	Transformers-New	Transformers-New		Per Industry	Existing	1,829	32	$1,390	37%	100%	$0.07	0.58
Electric	Paper Mfg	Hvac	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	6,694	10	$665	9.4%	100%	$0.01	0.53
Electric	Paper Mfg	Lighting	Efficient Lighting 3 Shift	Efficient Lighting 3 Shift		Per Industry	Existing	282,424	10	$7,132	20%	100%	$-0.00	47
Electric	Paper Mfg	Lighting	HighBay Lighting 3 Shift	HighBay Lighting 3 Shift		Per Industry	Existing	205,766	10	$16,261	29%	100%	$0.01	44
Electric	Paper Mfg	Lighting	Lighting Controls	Lighting Controls		Per Industry	Existing	113,798	10	$24,239	15%	100%	$0.03	10
Electric	Paper Mfg	Lighting	Transformers-New	Transformers-New		Per Industry	Existing	1,654	32	$1,257	37%	100%	$0.07	0.36
Electric	Paper Mfg	Lighting	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	6,051	10	$601	9.4%	100%	$0.01	0.34
Electric	Paper Mfg	Motors Other	Efficient Centrifugal Fan	Efficient Centrifugal Fan		Per Industry	Existing	553,025	10	$550	11%	100%	$0.02	49
Electric	Paper Mfg	Motors Other	Energy Project Management	Energy Project Management		Per Industry	Existing	801,887	11	$98,703	27%	100%	$0.03	181
Electric	Paper Mfg	Motors Other	Integrated Plant Energy Management	Integrated Plant Energy Management		Per Industry	Existing	1,382,564	11	$72,547	22%	100%	$0.05	200
Electric	Paper Mfg	Motors Other	Material Handling VFD2	Material Handling VFD2		Per Industry	Existing	517,834	10	$55,350	53%	100%	$0.04	96

Table B-2.3. Industrial Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Paper Mfg	Motors Other	Material Handling2	Material Handling2		Per Industry	Existing	138,520	10	$64,729	53%	100%	$0.07	23
Electric	Paper Mfg	Motors Other	Motors: Rewind 101-200 HP	Motors: Rewind 101-200 HP		Per Industry	Existing	13,825	10	$3,179	9.1%	100%	$0.03	0.57
Electric	Paper Mfg	Motors Other	Motors: Rewind 20-50 HP	Motors: Rewind 20-50 HP		Per Industry	Existing	24,886	10	$8,959	6.3%	100%	$0.05	0.72
Electric	Paper Mfg	Motors Other	Motors: Rewind 201-500 HP	Motors: Rewind 201-500 HP		Per Industry	Existing	13,825	10	$2,073	13%	100%	$0.02	1
Electric	Paper Mfg	Motors Other	Motors: Rewind 501-5000 HP	Motors: Rewind 501-5000 HP		Per Industry	Existing	13,825	10	$1,520	23%	100%	$0.01	2
Electric	Paper Mfg	Motors Other	Motors: Rewind 51-100 HP	Motors: Rewind 51-100 HP		Per Industry	Existing	13,825	10	$4,285	10%	100%	$0.04	0.63
Electric	Paper Mfg	Motors Other	Paper: Efficient Pulp Screen	Paper: Efficient Pulp Screen		Per Industry	Existing	414,769	10	$75,053	14%	100%	$0.02	50
Electric	Paper Mfg	Motors Other	Paper: Large Material Handling	Paper: Large Material Handling		Per Industry	Existing	269,274	10	$7,133	25%	100%	$0.11	29
Electric	Paper Mfg	Motors Other	Paper: Material Handling	Paper: Material Handling		Per Industry	Existing	362,484	10	$33,025	25%	100%	$0.09	38
Electric	Paper Mfg	Motors Other	Paper: Premium Control Large Material	Paper: Premium Control Large Material		Per Industry	Existing	517,834	10	$27,847	25%	100%	$0.06	53
Electric	Paper Mfg	Motors Other	Plant Energy Management	Plant Energy Management		Per Industry	Existing	331,815	10	$6,944	27%	100%	$0.01	35
Electric	Paper Mfg	Motors Other	Synchronous Belts	Synchronous Belts		Per Industry	Existing	55,302	10	$11,830	21%	100%	$0.03	4
Electric	Paper Mfg	Motors Other	Transformers-New	Transformers-New		Per Industry	Existing	11,337	32	$8,616	37%	100%	$0.07	1
Electric	Paper Mfg	Motors Other	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	41,476	10	$4,121	9.4%	100%	$0.01	1
Electric	Paper Mfg	Other	Transformers-New	Transformers-New		Per Industry	Existing	871	32	$662	37%	100%	$0.07	0.27
Electric	Paper Mfg	Other	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	3,189	10	$316	9.4%	100%	$0.01	0.25
Electric	Paper Mfg	Process Aircomp	Air Compressor Demand Reduction	Air Compressor Demand Reduction		Per Industry	Existing	64,895	10	$5,224	26%	100%	$0.02	14
Electric	Paper Mfg	Process Aircomp	Air Compressor Equipment2	Air Compressor Equipment2		Per Industry	Existing	113,567	10	$7,268	17%	100%	$0.02	15
Electric	Paper Mfg	Process Aircomp	Air Compressor Optimization	Air Compressor Optimization		Per Industry	Existing	162,239	10	$32,480	36%	100%	$0.04	44
Electric	Paper Mfg	Process Aircomp	Energy Project Management	Energy Project Management		Per Industry	Existing	94,099	11	$11,582	27%	100%	$0.03	15
Electric	Paper Mfg	Process Aircomp	Integrated Plant Energy Management	Integrated Plant Energy Management		Per Industry	Existing	162,239	11	$31,982	22%	100%	$0.05	20
Electric	Paper Mfg	Process Aircomp	Motors: Rewind 101-200 HP	Motors: Rewind 101-200 HP		Per Industry	Existing	1,622	10	$373	9.1%	100%	$0.03	0.07
Electric	Paper Mfg	Process Aircomp	Motors: Rewind 20-50 HP	Motors: Rewind 20-50 HP		Per Industry	Existing	2,920	10	$1,051	6.3%	100%	$0.05	0.09
Electric	Paper Mfg	Process Aircomp	Motors: Rewind 201-500 HP	Motors: Rewind 201-500 HP		Per Industry	Existing	1,622	10	$243	13%	100%	$0.02	0.17
Electric	Paper Mfg	Process Aircomp	Motors: Rewind 501-5000 HP	Motors: Rewind 501-5000 HP		Per Industry	Existing	1,622	10	$178	23%	100%	$0.01	0.32
Electric	Paper Mfg	Process Aircomp	Motors: Rewind 51-100 HP	Motors: Rewind 51-100 HP		Per Industry	Existing	1,622	10	$502	10%	100%	$0.04	0.08
Electric	Paper Mfg	Process Aircomp	Plant Energy Management	Plant Energy Management		Per Industry	Existing	38,937	10	$814	27%	100%	$0.01	5
Electric	Paper Mfg	Process Aircomp	Synchronous Belts	Synchronous Belts		Per Industry	Existing	6,489	10	$1,388	21%	100%	$0.03	0.67
Electric	Paper Mfg	Process Aircomp	Transformers-New	Transformers-New		Per Industry	Existing	1,330	32	$1,011	37%	100%	$0.07	0.24
Electric	Paper Mfg	Process Aircomp	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	4,867	10	$483	9.4%	100%	$0.01	0.22
Electric	Paper Mfg	Process Heat	Transformers-New	Transformers-New		Per Industry	Existing	1,312	32	$997	37%	100%	$0.07	0.41
Electric	Paper Mfg	Process Heat	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	4,800	10	$477	9.4%	100%	$0.01	0.38

Table B-2.3. Industrial Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Paper Mfg	Process Other	Energy Project Management	Energy Project Management		Per Industry	Existing	30,643	11	$3,771	27%	100%	$0.03	7
Electric	Paper Mfg	Process Other	Integrated Plant Energy Management	Integrated Plant Energy Management		Per Industry	Existing	52,834	11	$10,415	22%	100%	$0.05	9
Electric	Paper Mfg	Process Other	Motors: Rewind 101-200 HP	Motors: Rewind 101-200 HP		Per Industry	Existing	528	10	$121	9.1%	100%	$0.03	0.03
Electric	Paper Mfg	Process Other	Motors: Rewind 20-50 HP	Motors: Rewind 20-50 HP		Per Industry	Existing	951	10	$342	6.3%	100%	$0.05	0.04
Electric	Paper Mfg	Process Other	Motors: Rewind 201-500 HP	Motors: Rewind 201-500 HP		Per Industry	Existing	528	10	$79	13%	100%	$0.02	0.05
Electric	Paper Mfg	Process Other	Motors: Rewind 501-5000 HP	Motors: Rewind 501-5000 HP		Per Industry	Existing	528	10	$58	23%	100%	$0.01	0.10
Electric	Paper Mfg	Process Other	Motors: Rewind 51-100 HP	Motors: Rewind 51-100 HP		Per Industry	Existing	528	10	$163	10%	100%	$0.04	0.03
Electric	Paper Mfg	Process Other	Plant Energy Management	Plant Energy Management		Per Industry	Existing	12,680	10	$265	27%	100%	$0.01	2
Electric	Paper Mfg	Process Other	Synchronous Belts	Synchronous Belts		Per Industry	Existing	2,113	10	$452	21%	100%	$0.03	0.30
Electric	Paper Mfg	Process Other	Transformers-New	Transformers-New		Per Industry	Existing	433	32	$329	37%	100%	$0.07	0.10
Electric	Paper Mfg	Process Other	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	1,585	10	$157	9.4%	100%	$0.01	0.10
Electric	Paper Mfg	Pumps	Energy Project Management	Energy Project Management		Per Industry	Existing	642,328	11	$79,063	27%	100%	$0.03	148
Electric	Paper Mfg	Pumps	Integrated Plant Energy Management	Integrated Plant Energy Management		Per Industry	Existing	1,107,462	11	$18,316	22%	100%	$0.05	192
Electric	Paper Mfg	Pumps	Motors: Rewind 101-200 HP	Motors: Rewind 101-200 HP		Per Industry	Existing	11,074	10	$2,547	9.1%	100%	$0.03	0.70
Electric	Paper Mfg	Pumps	Motors: Rewind 20-50 HP	Motors: Rewind 20-50 HP		Per Industry	Existing	19,934	10	$7,176	6.3%	100%	$0.05	0.88
Electric	Paper Mfg	Pumps	Motors: Rewind 201-500 HP	Motors: Rewind 201-500 HP		Per Industry	Existing	11,074	10	$1,661	13%	100%	$0.02	1
Electric	Paper Mfg	Pumps	Motors: Rewind 501-5000 HP	Motors: Rewind 501-5000 HP		Per Industry	Existing	11,074	10	$1,218	23%	100%	$0.01	2
Electric	Paper Mfg	Pumps	Motors: Rewind 51-100 HP	Motors: Rewind 51-100 HP		Per Industry	Existing	11,074	10	$3,433	10%	100%	$0.04	0.77
Electric	Paper Mfg	Pumps	Plant Energy Management	Plant Energy Management		Per Industry	Existing	265,791	10	$5,563	27%	100%	$0.01	50
Electric	Paper Mfg	Pumps	Pump Energy Management	Pump Energy Management		Per Industry	Existing	166,119	10	$0.00	31%	100%	$0.01	34
Electric	Paper Mfg	Pumps	Pump Equipment Upgrade	Pump Equipment Upgrade		Per Industry	Existing	442,985	10	$55,373	34%	100%	$0.03	98
Electric	Paper Mfg	Pumps	Pump System Optimization	Pump System Optimization		Per Industry	Existing	1,107,462	12	$81,295	15%	100%	$0.06	105
Electric	Paper Mfg	Pumps	Synchronous Belts	Synchronous Belts		Per Industry	Existing	44,298	10	$9,476	21%	100%	$0.03	5
Electric	Paper Mfg	Pumps	Transformers-New	Transformers-New		Per Industry	Existing	9,081	32	$6,901	37%	100%	$0.07	1
Electric	Paper Mfg	Pumps	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	33,223	10	$3,301	9.4%	100%	$0.01	1
Electric	Petroleum Coal Products	Fans	Energy Project Management	Energy Project Management		Per Industry	Existing	150,740	11	$18,554	27%	100%	$0.03	34
Electric	Petroleum Coal Products	Fans	Fan Energy Mangement	Fan Energy Mangement		Per Industry	Existing	51,979	10	$0.00	27%	100%	$0.01	11
Electric	Petroleum Coal Products	Fans	Fan Equipment Upgrade	Fan Equipment Upgrade		Per Industry	Existing	181,927	10	$15,593	23%	100%	$0.03	23
Electric	Petroleum Coal Products	Fans	Fan System Optimization	Fan System Optimization		Per Industry	Existing	259,896	10	$31,187	30%	100%	$0.03	50
Electric	Petroleum Coal Products	Fans	Integrated Plant Energy Management	Integrated Plant Energy Management		Per Industry	Existing	259,896	11	$51,233	22%	100%	$0.05	43

Table B-2.3. Industrial Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Petroleum Coal Products	Fans	Motors: Rewind 101-200 HP	Motors: Rewind 101-200 HP		Per Industry	Existing	2,598	10	$597	12%	100%	$0.03	0.20
Electric	Petroleum Coal Products	Fans	Motors: Rewind 20-50 HP	Motors: Rewind 20-50 HP		Per Industry	Existing	4,678	10	$1,684	8.4%	100%	$0.05	0.26
Electric	Petroleum Coal Products	Fans	Motors: Rewind 201-500 HP	Motors: Rewind 201-500 HP		Per Industry	Existing	2,598	10	$389	12%	100%	$0.02	0.27
Electric	Petroleum Coal Products	Fans	Motors: Rewind 501-5000 HP	Motors: Rewind 501-5000 HP		Per Industry	Existing	2,598	10	$285	7.7%	100%	$0.01	0.17
Electric	Petroleum Coal Products	Fans	Motors: Rewind 51-100 HP	Motors: Rewind 51-100 HP		Per Industry	Existing	2,598	10	$805	9.9%	100%	$0.04	0.17
Electric	Petroleum Coal Products	Fans	Plant Energy Management	Plant Energy Management		Per Industry	Existing	62,375	10	$1,305	27%	100%	$0.01	11
Electric	Petroleum Coal Products	Fans	Synchronous Belts	Synchronous Belts		Per Industry	Existing	10,395	10	$2,223	21%	100%	$0.03	1
Electric	Petroleum Coal Products	Fans	Transformers-New	Transformers-New		Per Industry	Existing	2,131	32	$1,619	37%	100%	$0.07	0.52
Electric	Petroleum Coal Products	Fans	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	7,796	10	$774	9.4%	100%	$0.01	0.48
Electric	Petroleum Coal Products	Hvac	Transformers-New	Transformers-New		Per Industry	Existing	594	32	$451	37%	100%	$0.07	0.18
Electric	Petroleum Coal Products	Hvac	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	2,173	10	$216	9.4%	100%	$0.01	0.17
Electric	Petroleum Coal Products	Lighting	Efficient Lighting 3 Shift	Efficient Lighting 3 Shift		Per Industry	Existing	74,031	10	$1,869	20%	100%	$-0.00	12
Electric	Petroleum Coal Products	Lighting	HighBay Lighting 3 Shift	HighBay Lighting 3 Shift		Per Industry	Existing	53,937	10	$4,262	29%	100%	$0.01	11
Electric	Petroleum Coal Products	Lighting	Lighting Controls	Lighting Controls		Per Industry	Existing	29,829	10	$6,353	15%	100%	$0.03	2
Electric	Petroleum Coal Products	Lighting	Transformers-New	Transformers-New		Per Industry	Existing	433	32	$329	37%	100%	$0.07	0.09
Electric	Petroleum Coal Products	Lighting	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	1,586	10	$157	9.4%	100%	$0.01	0.08
Electric	Petroleum Coal Products	Motors Other	Energy Project Management	Energy Project Management		Per Industry	Existing	429,114	11	$52,819	27%	100%	$0.03	99
Electric	Petroleum Coal Products	Motors Other	Integrated Plant Energy Management	Integrated Plant Energy Management		Per Industry	Existing	739,852	11	$45,848	22%	100%	$0.05	118
Electric	Petroleum Coal Products	Motors Other	Motors: Rewind 101-200 HP	Motors: Rewind 101-200 HP		Per Industry	Existing	7,398	10	$1,701	12%	100%	$0.03	0.49
Electric	Petroleum Coal Products	Motors Other	Motors: Rewind 20-50 HP	Motors: Rewind 20-50 HP		Per Industry	Existing	13,317	10	$4,794	8.4%	100%	$0.05	0.64
Electric	Petroleum Coal Products	Motors Other	Motors: Rewind 201-500 HP	Motors: Rewind 201-500 HP		Per Industry	Existing	7,398	10	$1,109	12%	100%	$0.02	0.77

Table B-2.3. Industrial Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Petroleum Coal Products	Motors Other	Motors: Rewind 501-5000 HP	Motors: Rewind 501-5000 HP		Per Industry	Existing	7,398	10	$813	7.7%	100%	$0.01	0.48
Electric	Petroleum Coal Products	Motors Other	Motors: Rewind 51-100 HP	Motors: Rewind 51-100 HP		Per Industry	Existing	7,398	10	$2,293	9.9%	100%	$0.04	0.41
Electric	Petroleum Coal Products	Motors Other	Plant Energy Management	Plant Energy Management		Per Industry	Existing	177,564	10	$3,716	27%	100%	$0.01	27
Electric	Petroleum Coal Products	Motors Other	Synchronous Belts	Synchronous Belts		Per Industry	Existing	29,594	10	$6,331	21%	100%	$0.03	3
Electric	Petroleum Coal Products	Motors Other	Transformers-New	Transformers-New		Per Industry	Existing	6,066	32	$4,610	37%	100%	$0.07	1
Electric	Petroleum Coal Products	Motors Other	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	22,195	10	$2,205	9.4%	100%	$0.01	1
Electric	Petroleum Coal Products	Other	Transformers-New	Transformers-New		Per Industry	Existing	150	32	$114	37%	100%	$0.07	0.04
Electric	Petroleum Coal Products	Other	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	550	10	$54	9.4%	100%	$0.01	0.04
Electric	Petroleum Coal Products	Process Aircomp	Air Compressor Demand Reduction	Air Compressor Demand Reduction		Per Industry	Existing	119,893	10	$9,651	26%	100%	$0.02	26
Electric	Petroleum Coal Products	Process Aircomp	Air Compressor Equipment2	Air Compressor Equipment2		Per Industry	Existing	209,814	10	$13,428	17%	100%	$0.02	29
Electric	Petroleum Coal Products	Process Aircomp	Air Compressor Optimization	Air Compressor Optimization		Per Industry	Existing	299,734	10	$60,006	36%	100%	$0.04	81
Electric	Petroleum Coal Products	Process Aircomp	Energy Project Management	Energy Project Management		Per Industry	Existing	173,846	11	$21,398	27%	100%	$0.03	29
Electric	Petroleum Coal Products	Process Aircomp	Integrated Plant Energy Management	Integrated Plant Energy Management		Per Industry	Existing	299,734	11	$59,087	22%	100%	$0.05	38
Electric	Petroleum Coal Products	Process Aircomp	Motors: Rewind 101-200 HP	Motors: Rewind 101-200 HP		Per Industry	Existing	2,997	10	$689	12%	100%	$0.03	0.17
Electric	Petroleum Coal Products	Process Aircomp	Motors: Rewind 20-50 HP	Motors: Rewind 20-50 HP		Per Industry	Existing	5,395	10	$1,942	8.4%	100%	$0.05	0.23
Electric	Petroleum Coal Products	Process Aircomp	Motors: Rewind 201-500 HP	Motors: Rewind 201-500 HP		Per Industry	Existing	2,997	10	$449	12%	100%	$0.02	0.31
Electric	Petroleum Coal Products	Process Aircomp	Motors: Rewind 501-5000 HP	Motors: Rewind 501-5000 HP		Per Industry	Existing	2,997	10	$329	7.7%	100%	$0.01	0.19
Electric	Petroleum Coal Products	Process Aircomp	Motors: Rewind 51-100 HP	Motors: Rewind 51-100 HP		Per Industry	Existing	2,997	10	$929	9.9%	100%	$0.04	0.15
Electric	Petroleum Coal Products	Process Aircomp	Plant Energy Management	Plant Energy Management		Per Industry	Existing	71,936	10	$1,505	27%	100%	$0.01	9
Electric	Petroleum Coal Products	Process Aircomp	Synchronous Belts	Synchronous Belts		Per Industry	Existing	11,989	10	$2,564	21%	100%	$0.03	1
Electric	Petroleum Coal Products	Process Aircomp	Transformers-New	Transformers-New		Per Industry	Existing	2,457	32	$1,867	37%	100%	$0.07	0.45

Table B-2.3. Industrial Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Petroleum Coal Products	Process Aircomp	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	8,992	10	$893	9.4%	100%	$0.01	0.41
Electric	Petroleum Coal Products	Pumps	Energy Project Management	Energy Project Management		Per Industry	Existing	272,872	11	$33,587	27%	100%	$0.03	63
Electric	Petroleum Coal Products	Pumps	Integrated Plant Energy Management	Integrated Plant Energy Management		Per Industry	Existing	470,470	11	$92,744	22%	100%	$0.05	81
Electric	Petroleum Coal Products	Pumps	Motors: Rewind 101-200 HP	Motors: Rewind 101-200 HP		Per Industry	Existing	4,704	10	$1,082	12%	100%	$0.03	0.38
Electric	Petroleum Coal Products	Pumps	Motors: Rewind 20-50 HP	Motors: Rewind 20-50 HP		Per Industry	Existing	8,468	10	$3,048	8.4%	100%	$0.05	0.50
Electric	Petroleum Coal Products	Pumps	Motors: Rewind 201-500 HP	Motors: Rewind 201-500 HP		Per Industry	Existing	4,704	10	$705	12%	100%	$0.02	0.49
Electric	Petroleum Coal Products	Pumps	Motors: Rewind 501-5000 HP	Motors: Rewind 501-5000 HP		Per Industry	Existing	4,704	10	$517	7.7%	100%	$0.01	0.30
Electric	Petroleum Coal Products	Pumps	Motors: Rewind 51-100 HP	Motors: Rewind 51-100 HP		Per Industry	Existing	4,704	10	$1,458	9.9%	100%	$0.04	0.32
Electric	Petroleum Coal Products	Pumps	Plant Energy Management	Plant Energy Management		Per Industry	Existing	112,912	10	$2,363	27%	100%	$0.01	21
Electric	Petroleum Coal Products	Pumps	Pump Energy Management	Pump Energy Management		Per Industry	Existing	70,570	10	$0.00	31%	100%	$0.01	14
Electric	Petroleum Coal Products	Pumps	Pump Equipment Upgrade	Pump Equipment Upgrade		Per Industry	Existing	188,188	10	$23,523	34%	100%	$0.03	38
Electric	Petroleum Coal Products	Pumps	Pump System Optimization	Pump System Optimization		Per Industry	Existing	470,470	12	$19,499	15%	100%	$0.06	47
Electric	Petroleum Coal Products	Pumps	Synchronous Belts	Synchronous Belts		Per Industry	Existing	18,818	10	$4,025	21%	100%	$0.03	2
Electric	Petroleum Coal Products	Pumps	Transformers-New	Transformers-New		Per Industry	Existing	3,857	32	$2,931	37%	100%	$0.07	0.94
Electric	Petroleum Coal Products	Pumps	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	14,114	10	$1,402	9.4%	100%	$0.01	0.87
Electric	Plastics Rubber Products	Fans	Fan Energy Mangement	Fan Energy Mangement		Per Industry	Existing	170,330	10	$0.00	27%	100%	$0.01	39
Electric	Plastics Rubber Products	Fans	Fan Equipment Upgrade	Fan Equipment Upgrade		Per Industry	Existing	596,156	10	$51,099	23%	100%	$0.03	94
Electric	Plastics Rubber Products	Fans	Fan System Optimization	Fan System Optimization		Per Industry	Existing	851,652	10	$2,198	30%	100%	$0.03	202
Electric	Plastics Rubber Products	Fans	Motors: Rewind 101-200 HP	Motors: Rewind 101-200 HP		Per Industry	Existing	8,516	10	$1,958	17%	100%	$0.03	1
Electric	Plastics Rubber Products	Fans	Motors: Rewind 20-50 HP	Motors: Rewind 20-50 HP		Per Industry	Existing	15,329	10	$5,518	11%	100%	$0.05	1
Electric	Plastics Rubber Products	Fans	Motors: Rewind 51-100 HP	Motors: Rewind 51-100 HP		Per Industry	Existing	8,516	10	$2,640	0.2%	100%	$0.04	0.01

Table B-2.3. Industrial Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Plastics Rubber Products	Fans	Plant Energy Management	Plant Energy Management		Per Industry	Existing	204,396	10	$4,278	27%	100%	$0.01	46
Electric	Plastics Rubber Products	Fans	Synchronous Belts	Synchronous Belts		Per Industry	Existing	34,066	10	$7,287	21%	100%	$0.03	5
Electric	Plastics Rubber Products	Fans	Transformers-New	Transformers-New		Per Industry	Existing	6,983	32	$5,307	37%	100%	$0.07	2
Electric	Plastics Rubber Products	Fans	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	25,549	10	$2,539	9.4%	100%	$0.01	1
Electric	Plastics Rubber Products	Hvac	Transformers-New	Transformers-New		Per Industry	Existing	10,881	32	$8,270	37%	100%	$0.07	3
Electric	Plastics Rubber Products	Hvac	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	39,811	10	$3,956	9.4%	100%	$0.01	3
Electric	Plastics Rubber Products	Lighting	Efficient Lighting 3 Shift	Efficient Lighting 3 Shift		Per Industry	Existing	1,482,938	10	$37,452	13%	100%	$-0.00	160
Electric	Plastics Rubber Products	Lighting	HighBay Lighting 3 Shift	HighBay Lighting 3 Shift		Per Industry	Existing	1,080,426	10	$85,386	19%	100%	$0.01	160
Electric	Plastics Rubber Products	Lighting	Lighting Controls	Lighting Controls		Per Industry	Existing	597,525	10	$27,273	15%	100%	$0.03	64
Electric	Plastics Rubber Products	Lighting	Transformers-New	Transformers-New		Per Industry	Existing	8,685	32	$6,601	37%	100%	$0.07	2
Electric	Plastics Rubber Products	Lighting	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	31,777	10	$3,157	9.4%	100%	$0.01	2
Electric	Plastics Rubber Products	Other	Transformers-New	Transformers-New		Per Industry	Existing	3,812	32	$2,897	37%	100%	$0.07	1
Electric	Plastics Rubber Products	Other	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	13,949	10	$1,386	9.4%	100%	$0.01	1
Electric	Plastics Rubber Products	Process Aircomp	Air Compressor Demand Reduction	Air Compressor Demand Reduction		Per Industry	Existing	392,879	10	$31,626	26%	100%	$0.02	87
Electric	Plastics Rubber Products	Process Aircomp	Motors: Rewind 101-200 HP	Motors: Rewind 101-200 HP		Per Industry	Existing	9,821	10	$2,259	17%	100%	$0.03	1
Electric	Plastics Rubber Products	Process Aircomp	Motors: Rewind 20-50 HP	Motors: Rewind 20-50 HP		Per Industry	Existing	17,679	10	$6,364	11%	100%	$0.05	1
Electric	Plastics Rubber Products	Process Aircomp	Motors: Rewind 51-100 HP	Motors: Rewind 51-100 HP		Per Industry	Existing	9,821	10	$3,044	0.2%	100%	$0.04	0.01
Electric	Plastics Rubber Products	Process Aircomp	Plant Energy Management	Plant Energy Management		Per Industry	Existing	235,727	10	$4,933	27%	100%	$0.01	51
Electric	Plastics Rubber Products	Process Aircomp	Synchronous Belts	Synchronous Belts		Per Industry	Existing	39,287	10	$8,404	21%	100%	$0.03	6
Electric	Plastics Rubber Products	Process Aircomp	Transformers-New	Transformers-New		Per Industry	Existing	8,054	32	$6,121	37%	100%	$0.07	2
Electric	Plastics Rubber Products	Process Aircomp	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	29,465	10	$2,928	9.4%	100%	$0.01	2

Table B-2.3. Industrial Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Plastics Rubber Products	Process Heat	Transformers-New	Transformers-New		Per Industry	Existing	15,524	32	$11,798	37%	100%	$0.07	4
Electric	Plastics Rubber Products	Process Heat	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	56,798	10	$5,644	9.4%	100%	$0.01	4
Electric	Plastics Rubber Products	Pumps	Motors: Rewind 101-200 HP	Motors: Rewind 101-200 HP		Per Industry	Existing	15,416	10	$3,545	17%	100%	$0.03	2
Electric	Plastics Rubber Products	Pumps	Motors: Rewind 20-50 HP	Motors: Rewind 20-50 HP		Per Industry	Existing	27,750	10	$9,990	11%	100%	$0.05	2
Electric	Plastics Rubber Products	Pumps	Motors: Rewind 51-100 HP	Motors: Rewind 51-100 HP		Per Industry	Existing	15,416	10	$4,779	0.2%	100%	$0.04	0.02
Electric	Plastics Rubber Products	Pumps	Plant Energy Management	Plant Energy Management		Per Industry	Existing	370,002	10	$7,744	27%	100%	$0.01	85
Electric	Plastics Rubber Products	Pumps	Pump Energy Management	Pump Energy Management		Per Industry	Existing	231,251	10	$0.00	31%	100%	$0.01	59
Electric	Plastics Rubber Products	Pumps	Pump Equipment Upgrade	Pump Equipment Upgrade		Per Industry	Existing	616,671	10	$77,083	34%	100%	$0.03	166
Electric	Plastics Rubber Products	Pumps	Synchronous Belts	Synchronous Belts		Per Industry	Existing	61,667	10	$13,192	21%	100%	$0.03	10
Electric	Plastics Rubber Products	Pumps	Transformers-New	Transformers-New		Per Industry	Existing	12,641	32	$9,607	37%	100%	$0.07	3
Electric	Plastics Rubber Products	Pumps	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	46,250	10	$4,596	9.4%	100%	$0.01	3
Electric	Primary Metal Mfg	Fans	Fan Energy Mangement	Fan Energy Mangement		Per Industry	Existing	39,775	10	$0.00	100%	N/A	$0.01	9
Electric	Primary Metal Mfg	Fans	Motors: Rewind 101-200 HP	Motors: Rewind 101-200 HP		Per Industry	Existing	1,988	10	$457	100%	N/A	$0.03	0.13
Electric	Primary Metal Mfg	Fans	Motors: Rewind 20-50 HP	Motors: Rewind 20-50 HP		Per Industry	Existing	3,579	10	$1,288	100%	N/A	$0.05	0.18
Electric	Primary Metal Mfg	Fans	Motors: Rewind 201-500 HP	Motors: Rewind 201-500 HP		Per Industry	Existing	1,988	10	$298	100%	N/A	$0.02	0.19
Electric	Primary Metal Mfg	Fans	Motors: Rewind 501-5000 HP	Motors: Rewind 501-5000 HP		Per Industry	Existing	1,988	10	$218	100%	N/A	$0.01	0.35
Electric	Primary Metal Mfg	Fans	Motors: Rewind 51-100 HP	Motors: Rewind 51-100 HP		Per Industry	Existing	1,988	10	$616	100%	N/A	$0.04	0.10
Electric	Primary Metal Mfg	Fans	Plant Energy Management	Plant Energy Management		Per Industry	Existing	47,731	10	$999	100%	N/A	$0.01	10
Electric	Primary Metal Mfg	Fans	Synchronous Belts	Synchronous Belts		Per Industry	Existing	7,955	10	$1,701	100%	N/A	$0.03	1
Electric	Primary Metal Mfg	Fans	Transformers-New	Transformers-New		Per Industry	Existing	1,630	32	$1,239	100%	N/A	$0.07	0.48
Electric	Primary Metal Mfg	Fans	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	5,966	10	$592	100%	N/A	$0.01	0.44
Electric	Primary Metal Mfg	Hvac	Transformers-New	Transformers-New		Per Industry	Existing	1,241	32	$943	100%	N/A	$0.07	0.39
Electric	Primary Metal Mfg	Hvac	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	4,543	10	$451	100%	N/A	$0.01	0.36
Electric	Primary Metal Mfg	Lighting	Efficient Lighting 3 Shift	Efficient Lighting 3 Shift		Per Industry	Existing	207,422	10	$5,238	100%	N/A	$-0.00	34
Electric	Primary Metal Mfg	Lighting	HighBay Lighting 3 Shift	HighBay Lighting 3 Shift		Per Industry	Existing	151,121	10	$11,943	100%	N/A	$0.01	32
Electric	Primary Metal Mfg	Lighting	Lighting Controls	Lighting Controls		Per Industry	Existing	83,577	10	$17,801	100%	N/A	$0.03	8

Table B-2.3. Industrial Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Primary Metal Mfg	Lighting	Transformers-New	Transformers-New		Per Industry	Existing	1,214	32	$923	100%	N/A	$0.07	0.27
Electric	Primary Metal Mfg	Lighting	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	4,444	10	$441	100%	N/A	$0.01	0.25
Electric	Primary Metal Mfg	Motors Other	Motors: Rewind 101-200 HP	Motors: Rewind 101-200 HP		Per Industry	Existing	8,007	10	$1,841	100%	N/A	$0.03	0.54
Electric	Primary Metal Mfg	Motors Other	Motors: Rewind 20-50 HP	Motors: Rewind 20-50 HP		Per Industry	Existing	14,412	10	$5,188	100%	N/A	$0.05	0.76
Electric	Primary Metal Mfg	Motors Other	Motors: Rewind 201-500 HP	Motors: Rewind 201-500 HP		Per Industry	Existing	8,007	10	$1,201	100%	N/A	$0.02	0.78
Electric	Primary Metal Mfg	Motors Other	Motors: Rewind 501-5000 HP	Motors: Rewind 501-5000 HP		Per Industry	Existing	8,007	10	$880	100%	N/A	$0.01	1
Electric	Primary Metal Mfg	Motors Other	Motors: Rewind 51-100 HP	Motors: Rewind 51-100 HP		Per Industry	Existing	8,007	10	$2,482	100%	N/A	$0.04	0.43
Electric	Primary Metal Mfg	Motors Other	Plant Energy Management	Plant Energy Management		Per Industry	Existing	192,172	10	$4,022	100%	N/A	$0.01	44
Electric	Primary Metal Mfg	Motors Other	Synchronous Belts	Synchronous Belts		Per Industry	Existing	32,028	10	$6,851	100%	N/A	$0.03	5
Electric	Primary Metal Mfg	Motors Other	Transformers-New	Transformers-New		Per Industry	Existing	6,565	32	$4,990	100%	N/A	$0.07	1
Electric	Primary Metal Mfg	Motors Other	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	24,021	10	$2,387	100%	N/A	$0.01	1
Electric	Primary Metal Mfg	Other	Transformers-New	Transformers-New		Per Industry	Existing	442	32	$336	100%	N/A	$0.07	0.14
Electric	Primary Metal Mfg	Other	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	1,620	10	$160	100%	N/A	$0.01	0.13
Electric	Primary Metal Mfg	Process Aircomp	Air Compressor Demand Reduction	Air Compressor Demand Reduction		Per Industry	Existing	74,352	10	$5,985	100%	N/A	$0.02	16
Electric	Primary Metal Mfg	Process Aircomp	Air Compressor Equipment2	Air Compressor Equipment2		Per Industry	Existing	130,116	10	$8,327	100%	N/A	$0.02	18
Electric	Primary Metal Mfg	Process Aircomp	Air Compressor Optimization	Air Compressor Optimization		Per Industry	Existing	185,881	10	$37,213	100%	N/A	$0.04	50
Electric	Primary Metal Mfg	Process Aircomp	Motors: Rewind 101-200 HP	Motors: Rewind 101-200 HP		Per Industry	Existing	1,858	10	$427	100%	N/A	$0.03	0.09
Electric	Primary Metal Mfg	Process Aircomp	Motors: Rewind 20-50 HP	Motors: Rewind 20-50 HP		Per Industry	Existing	3,345	10	$1,204	100%	N/A	$0.05	0.12
Electric	Primary Metal Mfg	Process Aircomp	Motors: Rewind 201-500 HP	Motors: Rewind 201-500 HP		Per Industry	Existing	1,858	10	$278	100%	N/A	$0.02	0.18
Electric	Primary Metal Mfg	Process Aircomp	Motors: Rewind 501-5000 HP	Motors: Rewind 501-5000 HP		Per Industry	Existing	1,858	10	$204	100%	N/A	$0.01	0.32
Electric	Primary Metal Mfg	Process Aircomp	Motors: Rewind 51-100 HP	Motors: Rewind 51-100 HP		Per Industry	Existing	1,858	10	$576	100%	N/A	$0.04	0.07
Electric	Primary Metal Mfg	Process Aircomp	Plant Energy Management	Plant Energy Management		Per Industry	Existing	44,611	10	$933	100%	N/A	$0.01	7
Electric	Primary Metal Mfg	Process Aircomp	Synchronous Belts	Synchronous Belts		Per Industry	Existing	7,435	10	$1,590	100%	N/A	$0.03	0.94
Electric	Primary Metal Mfg	Process Aircomp	Transformers-New	Transformers-New		Per Industry	Existing	1,524	32	$1,158	100%	N/A	$0.07	0.34
Electric	Primary Metal Mfg	Process Aircomp	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	5,576	10	$554	100%	N/A	$0.01	0.31
Electric	Primary Metal Mfg	Process Electro Chemical	Metal: New Arc Furnace	Metal: New Arc Furnace		Per Industry	Existing	1,271,945	10	$17,435	100%	N/A	$0.01	109
Electric	Primary Metal Mfg	Process Electro Chemical	Transformers-New	Transformers-New		Per Industry	Existing	11,588	32	$8,807	100%	N/A	$0.07	3
Electric	Primary Metal Mfg	Process Electro Chemical	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	42,398	10	$4,213	100%	N/A	$0.01	3
Electric	Primary Metal Mfg	Process Heat	Transformers-New	Transformers-New		Per Industry	Existing	10,606	32	$8,060	100%	N/A	$0.07	3
Electric	Primary Metal Mfg	Process Heat	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	38,804	10	$3,856	100%	N/A	$0.01	3

Table B-2.3. Industrial Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Primary Metal Mfg	Process Other	Motors: Rewind 101-200 HP	Motors: Rewind 101-200 HP		Per Industry	Existing	361	10	$83	100%	N/A	$0.03	0.02
Electric	Primary Metal Mfg	Process Other	Motors: Rewind 20-50 HP	Motors: Rewind 20-50 HP		Per Industry	Existing	650	10	$234	100%	N/A	$0.05	0.03
Electric	Primary Metal Mfg	Process Other	Motors: Rewind 201-500 HP	Motors: Rewind 201-500 HP		Per Industry	Existing	361	10	$54	100%	N/A	$0.02	0.03
Electric	Primary Metal Mfg	Process Other	Motors: Rewind 501-5000 HP	Motors: Rewind 501-5000 HP		Per Industry	Existing	361	10	$39	100%	N/A	$0.01	0.06
Electric	Primary Metal Mfg	Process Other	Motors: Rewind 51-100 HP	Motors: Rewind 51-100 HP		Per Industry	Existing	361	10	$111	100%	N/A	$0.04	0.01
Electric	Primary Metal Mfg	Process Other	Plant Energy Management	Plant Energy Management		Per Industry	Existing	8,666	10	$181	100%	N/A	$0.01	2
Electric	Primary Metal Mfg	Process Other	Synchronous Belts	Synchronous Belts		Per Industry	Existing	1,444	10	$309	100%	N/A	$0.03	0.25
Electric	Primary Metal Mfg	Process Other	Transformers-New	Transformers-New		Per Industry	Existing	296	32	$225	100%	N/A	$0.07	0.09
Electric	Primary Metal Mfg	Process Other	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	1,083	10	$107	100%	N/A	$0.01	0.08
Electric	Primary Metal Mfg	Pumps	Motors: Rewind 101-200 HP	Motors: Rewind 101-200 HP		Per Industry	Existing	1,130	10	$260	100%	N/A	$0.03	0.07
Electric	Primary Metal Mfg	Pumps	Motors: Rewind 20-50 HP	Motors: Rewind 20-50 HP		Per Industry	Existing	2,035	10	$732	100%	N/A	$0.05	0.10
Electric	Primary Metal Mfg	Pumps	Motors: Rewind 201-500 HP	Motors: Rewind 201-500 HP		Per Industry	Existing	1,130	10	$169	100%	N/A	$0.02	0.11
Electric	Primary Metal Mfg	Pumps	Motors: Rewind 501-5000 HP	Motors: Rewind 501-5000 HP		Per Industry	Existing	1,130	10	$124	100%	N/A	$0.01	0.19
Electric	Primary Metal Mfg	Pumps	Motors: Rewind 51-100 HP	Motors: Rewind 51-100 HP		Per Industry	Existing	1,130	10	$350	100%	N/A	$0.04	0.06
Electric	Primary Metal Mfg	Pumps	Plant Energy Management	Plant Energy Management		Per Industry	Existing	27,141	10	$568	100%	N/A	$0.01	6
Electric	Primary Metal Mfg	Pumps	Pump Energy Management	Pump Energy Management		Per Industry	Existing	16,963	10	$0.00	100%	N/A	$0.01	4
Electric	Primary Metal Mfg	Pumps	Synchronous Belts	Synchronous Belts		Per Industry	Existing	4,523	10	$967	100%	N/A	$0.03	0.76
Electric	Primary Metal Mfg	Pumps	Transformers-New	Transformers-New		Per Industry	Existing	927	32	$704	100%	N/A	$0.07	0.27
Electric	Primary Metal Mfg	Pumps	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	3,392	10	$337	100%	N/A	$0.01	0.25
Electric	Printing Related Support	Fans	Fan Energy Mangement	Fan Energy Mangement		Per Industry	Existing	366,519	10	$0.00	27%	100%	$0.01	85
Electric	Printing Related Support	Fans	Fan Equipment Upgrade	Fan Equipment Upgrade		Per Industry	Existing	1,282,819	10	$9,955	23%	100%	$0.03	202
Electric	Printing Related Support	Fans	Fan System Optimization	Fan System Optimization		Per Industry	Existing	1,832,598	10	$19,911	30%	100%	$0.03	434
Electric	Printing Related Support	Fans	Motors: Rewind 101-200 HP	Motors: Rewind 101-200 HP		Per Industry	Existing	18,325	10	$4,214	17%	100%	$0.03	2
Electric	Printing Related Support	Fans	Motors: Rewind 20-50 HP	Motors: Rewind 20-50 HP		Per Industry	Existing	32,986	10	$11,875	11%	100%	$0.05	2
Electric	Printing Related Support	Fans	Motors: Rewind 51-100 HP	Motors: Rewind 51-100 HP		Per Industry	Existing	18,325	10	$5,681	0.2%	100%	$0.04	0.02
Electric	Printing Related Support	Fans	Plant Energy Management	Plant Energy Management		Per Industry	Existing	439,823	10	$9,205	27%	100%	$0.01	99
Electric	Printing Related Support	Fans	Synchronous Belts	Synchronous Belts		Per Industry	Existing	73,303	10	$15,681	21%	100%	$0.03	12

Table B-2.3. Industrial Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Printing Related Support	Fans	Transformers-New	Transformers-New		Per Industry	Existing	15,027	32	$11,420	37%	100%	$0.07	4
Electric	Printing Related Support	Fans	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	54,977	10	$5,463	9.4%	100%	$0.01	4
Electric	Printing Related Support	Hvac	Transformers-New	Transformers-New		Per Industry	Existing	39,597	32	$30,094	37%	100%	$0.07	12
Electric	Printing Related Support	Hvac	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	144,870	10	$14,396	9.4%	100%	$0.01	11
Electric	Printing Related Support	Lighting	Efficient Lighting 3 Shift	Efficient Lighting 3 Shift		Per Industry	Existing	4,360,615	10	$10,129	13%	100%	$-0.00	472
Electric	Printing Related Support	Lighting	HighBay Lighting 3 Shift	HighBay Lighting 3 Shift		Per Industry	Existing	3,177,019	10	$51,081	19%	100%	$0.01	470
Electric	Printing Related Support	Lighting	Lighting Controls	Lighting Controls		Per Industry	Existing	1,757,038	10	$74,249	15%	100%	$0.03	190
Electric	Printing Related Support	Lighting	Transformers-New	Transformers-New		Per Industry	Existing	25,540	32	$19,410	37%	100%	$0.07	6
Electric	Printing Related Support	Lighting	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	93,441	10	$9,286	9.4%	100%	$0.01	5
Electric	Printing Related Support	Other	Transformers-New	Transformers-New		Per Industry	Existing	13,340	32	$10,138	37%	100%	$0.07	4
Electric	Printing Related Support	Other	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	48,806	10	$4,850	9.4%	100%	$0.01	3
Electric	Printing Related Support	Process Aircomp	Air Compressor Demand Reduction	Air Compressor Demand Reduction		Per Industry	Existing	845,403	10	$68,054	26%	100%	$0.02	188
Electric	Printing Related Support	Process Aircomp	Motors: Rewind 101-200 HP	Motors: Rewind 101-200 HP		Per Industry	Existing	21,135	10	$4,861	17%	100%	$0.03	2
Electric	Printing Related Support	Process Aircomp	Motors: Rewind 20-50 HP	Motors: Rewind 20-50 HP		Per Industry	Existing	38,043	10	$13,695	11%	100%	$0.05	3
Electric	Printing Related Support	Process Aircomp	Motors: Rewind 51-100 HP	Motors: Rewind 51-100 HP		Per Industry	Existing	21,135	10	$6,551	0.2%	100%	$0.04	0.03
Electric	Printing Related Support	Process Aircomp	Plant Energy Management	Plant Energy Management		Per Industry	Existing	507,241	10	$10,616	27%	100%	$0.01	111
Electric	Printing Related Support	Process Aircomp	Synchronous Belts	Synchronous Belts		Per Industry	Existing	84,540	10	$18,085	21%	100%	$0.03	13
Electric	Printing Related Support	Process Aircomp	Transformers-New	Transformers-New		Per Industry	Existing	17,330	32	$13,171	37%	100%	$0.07	5
Electric	Printing Related Support	Process Aircomp	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	63,405	10	$6,301	9.4%	100%	$0.01	4
Electric	Printing Related Support	Process Heat	Transformers-New	Transformers-New		Per Industry	Existing	6,091	32	$4,629	37%	100%	$0.07	1
Electric	Printing Related Support	Process Heat	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	22,287	10	$2,214	9.4%	100%	$0.01	1

Table B-2.3. Industrial Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Printing Related Support	Process Other	Motors: Rewind 101-200 HP	Motors: Rewind 101-200 HP		Per Industry	Existing	973	10	$223	17%	100%	$0.03	0.13
Electric	Printing Related Support	Process Other	Motors: Rewind 20-50 HP	Motors: Rewind 20-50 HP		Per Industry	Existing	1,752	10	$630	11%	100%	$0.05	0.16
Electric	Printing Related Support	Process Other	Motors: Rewind 51-100 HP	Motors: Rewind 51-100 HP		Per Industry	Existing	973	10	$301	0.2%	100%	$0.04	0.00
Electric	Printing Related Support	Process Other	Plant Energy Management	Plant Energy Management		Per Industry	Existing	23,360	10	$488	27%	100%	$0.01	5
Electric	Printing Related Support	Process Other	Synchronous Belts	Synchronous Belts		Per Industry	Existing	3,893	10	$832	21%	100%	$0.03	0.67
Electric	Printing Related Support	Process Other	Transformers-New	Transformers-New		Per Industry	Existing	798	32	$606	37%	100%	$0.07	0.24
Electric	Printing Related Support	Process Other	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	2,920	10	$290	9.4%	100%	$0.01	0.22
Electric	Printing Related Support	Pumps	Motors: Rewind 101-200 HP	Motors: Rewind 101-200 HP		Per Industry	Existing	33,174	10	$7,630	17%	100%	$0.03	4
Electric	Printing Related Support	Pumps	Motors: Rewind 20-50 HP	Motors: Rewind 20-50 HP		Per Industry	Existing	59,713	10	$21,496	11%	100%	$0.05	5
Electric	Printing Related Support	Pumps	Motors: Rewind 51-100 HP	Motors: Rewind 51-100 HP		Per Industry	Existing	33,174	10	$10,283	0.2%	100%	$0.04	0.05
Electric	Printing Related Support	Pumps	Plant Energy Management	Plant Energy Management		Per Industry	Existing	796,177	10	$16,663	27%	100%	$0.01	184
Electric	Printing Related Support	Pumps	Pump Energy Management	Pump Energy Management		Per Industry	Existing	497,610	10	$0.00	31%	100%	$0.01	128
Electric	Printing Related Support	Pumps	Pump Equipment Upgrade	Pump Equipment Upgrade		Per Industry	Existing	1,326,961	10	$65,870	34%	100%	$0.03	357
Electric	Printing Related Support	Pumps	Synchronous Belts	Synchronous Belts		Per Industry	Existing	132,696	10	$28,387	21%	100%	$0.03	22
Electric	Printing Related Support	Pumps	Transformers-New	Transformers-New		Per Industry	Existing	27,202	32	$20,674	37%	100%	$0.07	8
Electric	Printing Related Support	Pumps	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	99,522	10	$9,890	9.4%	100%	$0.01	7
Electric	Transportation Equipment Mfg	Fans	Fan Energy Mangement	Fan Energy Mangement		Per Industry	Existing	261,218	10	$0.00	27%	100%	$0.01	51
Electric	Transportation Equipment Mfg	Fans	Fan Equipment Upgrade	Fan Equipment Upgrade		Per Industry	Existing	914,264	10	$78,365	23%	100%	$0.03	150
Electric	Transportation Equipment Mfg	Fans	Fan System Optimization	Fan System Optimization		Per Industry	Existing	1,306,091	10	$56,731	30%	100%	$0.03	331
Electric	Transportation Equipment Mfg	Fans	Motors: Rewind 20-50 HP	Motors: Rewind 20-50 HP		Per Industry	Existing	23,509	10	$8,463	13%	100%	$0.05	1
Electric	Transportation Equipment Mfg	Fans	Plant Energy Management	Plant Energy Management		Per Industry	Existing	313,462	10	$6,560	27%	100%	$0.01	55

Table B-2.3. Industrial Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Transportation Equipment Mfg	Fans	Synchronous Belts	Synchronous Belts		Per Industry	Existing	52,243	10	$11,176	21%	100%	$0.03	6
Electric	Transportation Equipment Mfg	Fans	Transformers-New	Transformers-New		Per Industry	Existing	10,709	32	$8,139	37%	100%	$0.07	2
Electric	Transportation Equipment Mfg	Fans	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	39,182	10	$29,778	9.4%	100%	$0.11	2
Electric	Transportation Equipment Mfg	Hvac	Transformers-New	Transformers-New		Per Industry	Existing	46,561	32	$35,387	37%	100%	$0.07	14
Electric	Transportation Equipment Mfg	Hvac	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	170,348	10	$29,464	9.4%	100%	$0.11	13
Electric	Transportation Equipment Mfg	Lighting	Efficient Lighting 1 Shift	Efficient Lighting 1 Shift		Per Industry	Existing	6,056,389	10	$68,499	1.3%	100%	$0.01	66
Electric	Transportation Equipment Mfg	Lighting	HighBay Lighting 1 Shift	HighBay Lighting 1 Shift		Per Industry	Existing	4,412,512	10	$68,117	1.9%	100%	$0.03	72
Electric	Transportation Equipment Mfg	Lighting	Lighting Controls	Lighting Controls		Per Industry	Existing	2,440,323	10	$19,788	15%	100%	$0.03	315
Electric	Transportation Equipment Mfg	Lighting	Transformers-New	Transformers-New		Per Industry	Existing	35,473	32	$26,959	37%	100%	$0.07	10
Electric	Transportation Equipment Mfg	Lighting	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	129,779	10	$98,632	9.4%	100%	$0.11	9
Electric	Transportation Equipment Mfg	Motors Other	Motors: Rewind 20-50 HP	Motors: Rewind 20-50 HP		Per Industry	Existing	52,748	10	$18,989	13%	100%	$0.05	5
Electric	Transportation Equipment Mfg	Motors Other	Plant Energy Management	Plant Energy Management		Per Industry	Existing	703,313	10	$14,720	27%	100%	$0.01	162
Electric	Transportation Equipment Mfg	Motors Other	Synchronous Belts	Synchronous Belts		Per Industry	Existing	117,218	10	$25,076	21%	100%	$0.03	19
Electric	Transportation Equipment Mfg	Motors Other	Transformers-New	Transformers-New		Per Industry	Existing	24,029	32	$18,262	37%	100%	$0.07	6
Electric	Transportation Equipment Mfg	Motors Other	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	87,914	10	$66,814	9.4%	100%	$0.11	6
Electric	Transportation Equipment Mfg	Other	Transformers-New	Transformers-New		Per Industry	Existing	13,099	32	$9,955	37%	100%	$0.07	4
Electric	Transportation Equipment Mfg	Other	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	47,923	10	$36,422	9.4%	100%	$0.11	3
Electric	Transportation Equipment Mfg	Process Aircomp	Air Compressor Demand Reduction	Air Compressor Demand Reduction		Per Industry	Existing	1,216,092	10	$97,895	26%	100%	$0.02	270
Electric	Transportation Equipment Mfg	Process Aircomp	Air Compressor Equipment2	Air Compressor Equipment2		Per Industry	Existing	2,128,161	10	$36,202	17%	100%	$0.02	312
Electric	Transportation Equipment Mfg	Process Aircomp	Air Compressor Optimization	Air Compressor Optimization		Per Industry	Existing	3,040,230	10	$8,654	36%	100%	$0.04	928
Electric	Transportation Equipment Mfg	Process Aircomp	Motors: Rewind 20-50 HP	Motors: Rewind 20-50 HP		Per Industry	Existing	54,724	10	$19,700	13%	100%	$0.05	4

Table B-2.3. Industrial Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Transportation Equipment Mfg	Process Aircomp	Plant Energy Management	Plant Energy Management		Per Industry	Existing	729,655	10	$15,271	27%	100%	$0.01	119
Electric	Transportation Equipment Mfg	Process Aircomp	Synchronous Belts	Synchronous Belts		Per Industry	Existing	121,609	10	$26,015	21%	100%	$0.03	15
Electric	Transportation Equipment Mfg	Process Aircomp	Transformers-New	Transformers-New		Per Industry	Existing	24,929	32	$18,946	37%	100%	$0.07	5
Electric	Transportation Equipment Mfg	Process Aircomp	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	91,206	10	$69,317	9.4%	100%	$0.11	5
Electric	Transportation Equipment Mfg	Process Heat	Transformers-New	Transformers-New		Per Industry	Existing	32,865	32	$24,977	37%	100%	$0.07	10
Electric	Transportation Equipment Mfg	Process Heat	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	120,238	10	$91,381	9.4%	100%	$0.11	9
Electric	Transportation Equipment Mfg	Process Other	Motors: Rewind 20-50 HP	Motors: Rewind 20-50 HP		Per Industry	Existing	13,444	10	$4,840	13%	100%	$0.05	1
Electric	Transportation Equipment Mfg	Process Other	Plant Energy Management	Plant Energy Management		Per Industry	Existing	179,265	10	$3,752	27%	100%	$0.01	41
Electric	Transportation Equipment Mfg	Process Other	Synchronous Belts	Synchronous Belts		Per Industry	Existing	29,877	10	$6,391	21%	100%	$0.03	5
Electric	Transportation Equipment Mfg	Process Other	Transformers-New	Transformers-New		Per Industry	Existing	6,124	32	$4,654	37%	100%	$0.07	1
Electric	Transportation Equipment Mfg	Process Other	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	22,408	10	$17,030	9.4%	100%	$0.11	1
Electric	Wastewater	Lighting	Efficient Lighting 1 Shift	Efficient Lighting 1 Shift		Per Industry	Existing	1,207,008	10	$93,369	1.0%	100%	$0.01	10
Electric	Wastewater	Lighting	HighBay Lighting 1 Shift	HighBay Lighting 1 Shift		Per Industry	Existing	879,391	10	$12,870	2.0%	100%	$0.03	15
Electric	Wastewater	Lighting	Lighting Controls	Lighting Controls		Per Industry	Existing	486,344	10	$3,591	15%	100%	$0.03	62
Electric	Wastewater	Lighting	Transformers-New	Transformers-New		Per Industry	Existing	7,069	32	$5,372	37%	100%	$0.07	2
Electric	Wastewater	Lighting	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	25,864	10	$19,656	9.4%	100%	$0.11	1
Electric	Wastewater	Other	Transformers-New	Transformers-New		Per Industry	Existing	49,487	32	$37,610	37%	100%	$0.07	15
Electric	Wastewater	Other	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	181,051	10	$37,598	9.4%	100%	$0.11	14
Electric	Wastewater	Process Aircomp	Air Compressor Demand Reduction	Air Compressor Demand Reduction		Per Industry	Existing	11,414,848	10	$18,895	26%	100%	$0.02	2,540
Electric	Wastewater	Process Aircomp	Air Compressor Equipment2	Air Compressor Equipment2		Per Industry	Existing	19,975,985	10	$78,463	17%	100%	$0.02	2,778
Electric	Wastewater	Process Aircomp	Air Compressor Optimization	Air Compressor Optimization		Per Industry	Existing	28,537,121	10	$13,131	36%	100%	$0.04	7,765
Electric	Wastewater	Process Aircomp	Energy Project Management	Energy Project Management		Per Industry	Existing	16,551,530	11	$37,304	27%	100%	$0.03	2,809
Electric	Wastewater	Process Aircomp	Integrated Plant Energy Management	Integrated Plant Energy Management		Per Industry	Existing	28,537,121	11	$25,579	22%	100%	$0.05	3,637
Electric	Wastewater	Process Aircomp	Motors: Rewind 20-50 HP	Motors: Rewind 20-50 HP		Per Industry	Existing	513,668	10	$84,920	11%	100%	$0.05	29
Electric	Wastewater	Process Aircomp	Plant Energy Management	Plant Energy Management		Per Industry	Existing	6,848,909	10	$43,347	27%	100%	$0.01	952
Electric	Wastewater	Process Aircomp	Synchronous Belts	Synchronous Belts		Per Industry	Existing	1,141,484	10	$44,198	21%	100%	$0.03	119
Electric	Wastewater	Process Aircomp	Transformers-New	Transformers-New		Per Industry	Existing	234,004	32	$77,843	37%	100%	$0.07	43
Electric	Wastewater	Process Aircomp	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	856,113	10	$50,646	9.4%	100%	$0.11	39

Table B-2.3. Industrial Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Wastewater	Pumps	Energy Project Management	Energy Project Management		Per Industry	Existing	4,400,406	11	$41,639	27%	100%	$0.03	823
Electric	Wastewater	Pumps	Integrated Plant Energy Management	Integrated Plant Energy Management		Per Industry	Existing	7,586,908	11	$95,622	22%	100%	$0.05	1,066
Electric	Wastewater	Pumps	Motors: Rewind 20-50 HP	Motors: Rewind 20-50 HP		Per Industry	Existing	136,564	10	$49,163	11%	100%	$0.05	12
Electric	Wastewater	Pumps	Plant Energy Management	Plant Energy Management		Per Industry	Existing	1,820,858	10	$38,110	27%	100%	$0.01	352
Electric	Wastewater	Pumps	Pump Energy Management	Pump Energy Management		Per Industry	Existing	1,138,036	10	$0.00	31%	100%	$0.01	302
Electric	Wastewater	Pumps	Pump Equipment Upgrade	Pump Equipment Upgrade		Per Industry	Existing	3,034,763	10	$79,345	34%	100%	$0.03	852
Electric	Wastewater	Pumps	Pump System Optimization	Pump System Optimization		Per Industry	Existing	7,586,908	12	$27,074	15%	100%	$0.06	914
Electric	Wastewater	Pumps	Synchronous Belts	Synchronous Belts		Per Industry	Existing	303,476	10	$64,922	21%	100%	$0.03	45
Electric	Wastewater	Pumps	Transformers-New	Transformers-New		Per Industry	Existing	62,212	32	$47,281	37%	100%	$0.07	16
Electric	Wastewater	Pumps	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	227,607	10	$72,981	9.4%	100%	$0.11	12
Electric	Water	Fans	Energy Project Management	Energy Project Management		Per Industry	Existing	14,622,538	11	$99,867	27%	100%	$0.03	2,579
Electric	Water	Fans	Fan Energy Mangement	Fan Energy Mangement		Per Industry	Existing	5,042,254	10	$0.00	27%	100%	$0.01	1,176
Electric	Water	Fans	Fan Equipment Upgrade	Fan Equipment Upgrade		Per Industry	Existing	17,647,891	10	$12,676	23%	100%	$0.03	3,416
Electric	Water	Fans	Fan System Optimization	Fan System Optimization		Per Industry	Existing	25,211,273	10	$25,352	30%	100%	$0.03	5,721
Electric	Water	Fans	Integrated Plant Energy Management	Integrated Plant Energy Management		Per Industry	Existing	25,211,273	11	$69,948	22%	100%	$0.05	3,339
Electric	Water	Fans	Motors: Rewind 20-50 HP	Motors: Rewind 20-50 HP		Per Industry	Existing	453,802	10	$63,369	11%	100%	$0.05	26
Electric	Water	Fans	Plant Energy Management	Plant Energy Management		Per Industry	Existing	6,050,705	10	$26,641	27%	100%	$0.01	874
Electric	Water	Fans	Synchronous Belts	Synchronous Belts		Per Industry	Existing	1,008,450	10	$15,738	21%	100%	$0.03	109
Electric	Water	Fans	Transformers-New	Transformers-New		Per Industry	Existing	206,732	32	$57,116	37%	100%	$0.07	39
Electric	Water	Fans	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	756,338	10	$74,817	9.4%	100%	$0.11	36
Electric	Water	Lighting	Efficient Lighting 1 Shift	Efficient Lighting 1 Shift		Per Industry	Existing	7,130,461	10	$51,585	1.0%	100%	$0.01	60
Electric	Water	Lighting	HighBay Lighting 1 Shift	HighBay Lighting 1 Shift		Per Industry	Existing	5,195,050	10	$57,543	2.0%	100%	$0.03	89
Electric	Water	Lighting	Lighting Controls	Lighting Controls		Per Industry	Existing	2,873,102	10	$11,970	15%	100%	$0.03	372
Electric	Water	Lighting	Transformers-New	Transformers-New		Per Industry	Existing	41,764	32	$31,740	37%	100%	$0.07	12
Electric	Water	Lighting	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	152,795	10	$16,124	9.4%	100%	$0.11	11
Electric	Water	Motors Other	Energy Project Management	Energy Project Management		Per Industry	Existing	14,622,538	11	$99,867	27%	100%	$0.03	3,386
Electric	Water	Motors Other	Integrated Plant Energy Management	Integrated Plant Energy Management		Per Industry	Existing	25,211,273	11	$69,948	22%	100%	$0.05	4,385
Electric	Water	Motors Other	Motors: Rewind 20-50 HP	Motors: Rewind 20-50 HP		Per Industry	Existing	453,802	10	$63,369	11%	100%	$0.05	35
Electric	Water	Motors Other	Plant Energy Management	Plant Energy Management		Per Industry	Existing	6,050,705	10	$26,641	27%	100%	$0.01	1,148
Electric	Water	Motors Other	Synchronous Belts	Synchronous Belts		Per Industry	Existing	1,008,450	10	$15,738	21%	100%	$0.03	144
Electric	Water	Motors Other	Transformers-New	Transformers-New		Per Industry	Existing	206,732	32	$57,116	37%	100%	$0.07	52
Electric	Water	Motors Other	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	756,338	10	$74,817	9.4%	100%	$0.11	47
Electric	Water	Other	Transformers-New	Transformers-New		Per Industry	Existing	292,348	32	$22,185	37%	100%	$0.07	93
Electric	Water	Other	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	1,069,569	10	$12,872	9.4%	100%	$0.11	85
Electric	Water	Pumps	Energy Project Management	Energy Project Management		Per Industry	Existing	94,529,543	11	$35,506	27%	100%	$0.03	17,694

Table B-2.3. Industrial Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Water	Pumps	Integrated Plant Energy Management	Integrated Plant Energy Management		Per Industry	Existing	62,981,971	11	$28,961	22%	100%	$0.05	22,911
Electric	Water	Pumps	Motors: Rewind 20-50 HP	Motors: Rewind 20-50 HP		Per Industry	Existing	2,933,675	10	$56,123	11%	100%	$0.05	276
Electric	Water	Pumps	Plant Energy Management	Plant Energy Management		Per Industry	Existing	39,115,673	10	$18,691	27%	100%	$0.01	7,566
Electric	Water	Pumps	Pump Energy Management	Pump Energy Management		Per Industry	Existing	24,447,295	10	$0.00	31%	100%	$0.01	6,496
Electric	Water	Pumps	Pump Equipment Upgrade	Pump Equipment Upgrade		Per Industry	Existing	65,192,788	10	$49,098	34%	100%	$0.03	18,312
Electric	Water	Pumps	Pump System Optimization	Pump System Optimization		Per Industry	Existing	62,981,971	12	$97,420	15%	100%	$0.06	19,640
Electric	Water	Pumps	Synchronous Belts	Synchronous Belts		Per Industry	Existing	6,519,278	10	$94,671	21%	100%	$0.03	985
Electric	Water	Pumps	Transformers-New	Transformers-New		Per Industry	Existing	1,336,452	32	$15,703	37%	100%	$0.07	357
Electric	Water	Pumps	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	4,889,459	10	$15,988	9.4%	100%	$0.11	260
Electric	Wood Product Mfg	Fans	Fan Energy Mangement	Fan Energy Mangement		Per Industry	Existing	463,951	10	$0.00	27%	100%	$0.01	108
Electric	Wood Product Mfg	Fans	Fan Equipment Upgrade	Fan Equipment Upgrade		Per Industry	Existing	1,623,830	10	$39,185	23%	100%	$0.03	314
Electric	Wood Product Mfg	Fans	Fan System Optimization	Fan System Optimization		Per Industry	Existing	2,319,757	10	$78,370	30%	100%	$0.03	526
Electric	Wood Product Mfg	Fans	Motors: Rewind 101-200 HP	Motors: Rewind 101-200 HP		Per Industry	Existing	23,197	10	$5,335	29%	100%	$0.03	4
Electric	Wood Product Mfg	Fans	Motors: Rewind 20-50 HP	Motors: Rewind 20-50 HP		Per Industry	Existing	41,755	10	$15,032	9.5%	100%	$0.05	2
Electric	Wood Product Mfg	Fans	Motors: Rewind 201-500 HP	Motors: Rewind 201-500 HP		Per Industry	Existing	23,197	10	$3,479	8.4%	100%	$0.02	1
Electric	Wood Product Mfg	Fans	Motors: Rewind 51-100 HP	Motors: Rewind 51-100 HP		Per Industry	Existing	23,197	10	$7,191	12%	100%	$0.04	1
Electric	Wood Product Mfg	Fans	Plant Energy Management	Plant Energy Management		Per Industry	Existing	556,741	10	$11,652	27%	100%	$0.01	97
Electric	Wood Product Mfg	Fans	Synchronous Belts	Synchronous Belts		Per Industry	Existing	92,790	10	$19,850	21%	100%	$0.03	12
Electric	Wood Product Mfg	Fans	Transformers-New	Transformers-New		Per Industry	Existing	19,022	32	$14,456	37%	100%	$0.07	4
Electric	Wood Product Mfg	Fans	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	69,592	10	$6,915	9.4%	100%	$0.01	4
Electric	Wood Product Mfg	Hvac	Transformers-New	Transformers-New		Per Industry	Existing	9,068	32	$6,892	37%	100%	$0.07	2
Electric	Wood Product Mfg	Hvac	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	33,178	10	$3,297	9.4%	100%	$0.01	2
Electric	Wood Product Mfg	Lighting	Efficient Lighting 1 Shift	Efficient Lighting 1 Shift		Per Industry	Existing	2,162,383	10	$67,273	4.4%	100%	$0.01	82
Electric	Wood Product Mfg	Lighting	Efficient Lighting 2 Shift	Efficient Lighting 2 Shift		Per Industry	Existing	2,162,383	10	$97,873	4.9%	100%	$0.00	88
Electric	Wood Product Mfg	Lighting	Efficient Lighting 3 Shift	Efficient Lighting 3 Shift		Per Industry	Existing	2,162,383	10	$54,612	10%	100%	$-0.00	189
Electric	Wood Product Mfg	Lighting	HighBay Lighting 1 Shift	HighBay Lighting 1 Shift		Per Industry	Existing	1,575,450	10	$81,362	6.7%	100%	$0.03	77
Electric	Wood Product Mfg	Lighting	HighBay Lighting 2 Shift	HighBay Lighting 2 Shift		Per Industry	Existing	1,575,450	10	$23,137	7.4%	100%	$0.02	83
Electric	Wood Product Mfg	Lighting	HighBay Lighting 3 Shift	HighBay Lighting 3 Shift		Per Industry	Existing	1,575,450	10	$24,508	15%	100%	$0.01	166
Electric	Wood Product Mfg	Lighting	Lighting Controls	Lighting Controls		Per Industry	Existing	871,297	10	$85,586	15%	100%	$0.03	84
Electric	Wood Product Mfg	Lighting	Transformers-New	Transformers-New		Per Industry	Existing	12,665	32	$9,625	37%	100%	$0.07	2
Electric	Wood Product Mfg	Lighting	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	46,336	10	$4,604	9.4%	100%	$0.01	2
Electric	Wood Product Mfg	Motors Other	Efficient Centrifugal Fan	Efficient Centrifugal Fan		Per Industry	Existing	2,641,475	10	$80,268	11%	100%	$0.02	237

Table B-2.3. Industrial Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Wood Product Mfg	Motors Other	Material Handling VFD2	Material Handling VFD2		Per Industry	Existing	2,473,389	10	$42,016	53%	100%	$0.04	1,110
Electric	Wood Product Mfg	Motors Other	Material Handling2	Material Handling2		Per Industry	Existing	661,631	10	$9,173	53%	100%	$0.07	267
Electric	Wood Product Mfg	Motors Other	Motors: Rewind 101-200 HP	Motors: Rewind 101-200 HP		Per Industry	Existing	66,036	10	$15,188	29%	100%	$0.03	13
Electric	Wood Product Mfg	Motors Other	Motors: Rewind 20-50 HP	Motors: Rewind 20-50 HP		Per Industry	Existing	118,866	10	$42,791	9.5%	100%	$0.05	8
Electric	Wood Product Mfg	Motors Other	Motors: Rewind 201-500 HP	Motors: Rewind 201-500 HP		Per Industry	Existing	66,036	10	$9,905	8.4%	100%	$0.02	4
Electric	Wood Product Mfg	Motors Other	Motors: Rewind 51-100 HP	Motors: Rewind 51-100 HP		Per Industry	Existing	66,036	10	$20,471	12%	100%	$0.04	5
Electric	Wood Product Mfg	Motors Other	Plant Energy Management	Plant Energy Management		Per Industry	Existing	1,584,885	10	$33,171	27%	100%	$0.01	311
Electric	Wood Product Mfg	Motors Other	Synchronous Belts	Synchronous Belts		Per Industry	Existing	264,147	10	$56,509	21%	100%	$0.03	36
Electric	Wood Product Mfg	Motors Other	Transformers-New	Transformers-New		Per Industry	Existing	54,150	32	$41,154	37%	100%	$0.07	10
Electric	Wood Product Mfg	Motors Other	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	198,110	10	$19,687	9.4%	100%	$0.01	9
Electric	Wood Product Mfg	Motors Other	Wood: Replace Pneumatic Conveyor	Wood: Replace Pneumatic Conveyor		Per Industry	Existing	3,830,139	10	$55,537	50%	100%	$-0.00	1,642
Electric	Wood Product Mfg	Other	Transformers-New	Transformers-New		Per Industry	Existing	7,432	32	$5,648	37%	100%	$0.07	2
Electric	Wood Product Mfg	Other	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	27,193	10	$2,702	9.4%	100%	$0.01	2
Electric	Wood Product Mfg	Process Aircomp	Air Compressor Demand Reduction	Air Compressor Demand Reduction		Per Industry	Existing	1,070,136	10	$86,145	26%	100%	$0.02	238
Electric	Wood Product Mfg	Process Aircomp	Air Compressor Equipment2	Air Compressor Equipment2		Per Industry	Existing	1,872,738	10	$19,855	17%	100%	$0.02	260
Electric	Wood Product Mfg	Process Aircomp	Air Compressor Optimization	Air Compressor Optimization		Per Industry	Existing	2,675,340	10	$35,603	36%	100%	$0.04	727
Electric	Wood Product Mfg	Process Aircomp	Motors: Rewind 101-200 HP	Motors: Rewind 101-200 HP		Per Industry	Existing	26,753	10	$6,153	29%	100%	$0.03	4
Electric	Wood Product Mfg	Process Aircomp	Motors: Rewind 20-50 HP	Motors: Rewind 20-50 HP		Per Industry	Existing	48,156	10	$17,336	9.5%	100%	$0.05	2
Electric	Wood Product Mfg	Process Aircomp	Motors: Rewind 201-500 HP	Motors: Rewind 201-500 HP		Per Industry	Existing	26,753	10	$4,013	8.4%	100%	$0.02	1
Electric	Wood Product Mfg	Process Aircomp	Motors: Rewind 51-100 HP	Motors: Rewind 51-100 HP		Per Industry	Existing	26,753	10	$8,293	12%	100%	$0.04	2
Electric	Wood Product Mfg	Process Aircomp	Plant Energy Management	Plant Energy Management		Per Industry	Existing	642,081	10	$13,438	27%	100%	$0.01	108
Electric	Wood Product Mfg	Process Aircomp	Synchronous Belts	Synchronous Belts		Per Industry	Existing	107,013	10	$22,893	21%	100%	$0.03	13
Electric	Wood Product Mfg	Process Aircomp	Transformers-New	Transformers-New		Per Industry	Existing	21,937	32	$16,672	37%	100%	$0.07	4
Electric	Wood Product Mfg	Process Aircomp	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	80,260	10	$7,976	9.4%	100%	$0.01	4
Electric	Wood Product Mfg	Process Heat	Transformers-New	Transformers-New		Per Industry	Existing	13,596	32	$10,333	37%	100%	$0.07	4
Electric	Wood Product Mfg	Process Heat	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	49,742	10	$4,943	9.4%	100%	$0.01	4
Electric	Wood Product Mfg	Process Other	Motors: Rewind 101-200 HP	Motors: Rewind 101-200 HP		Per Industry	Existing	937	10	$215	29%	100%	$0.03	0.23
Electric	Wood Product Mfg	Process Other	Motors: Rewind 20-50 HP	Motors: Rewind 20-50 HP		Per Industry	Existing	1,687	10	$607	9.5%	100%	$0.05	0.13
Electric	Wood Product Mfg	Process Other	Motors: Rewind 201-500 HP	Motors: Rewind 201-500 HP		Per Industry	Existing	937	10	$140	8.4%	100%	$0.02	0.06
Electric	Wood Product Mfg	Process Other	Motors: Rewind 51-100 HP	Motors: Rewind 51-100 HP		Per Industry	Existing	937	10	$290	12%	100%	$0.04	0.09
Electric	Wood Product Mfg	Process Other	Plant Energy Management	Plant Energy Management		Per Industry	Existing	22,497	10	$470	27%	100%	$0.01	5

Table B-2.3. Industrial Electric Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (kWh)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per kWh)	2033 Cumulative Achievable Technical Potential (kWh)
Electric	Wood Product Mfg	Process Other	Synchronous Belts	Synchronous Belts		Per Industry	Existing	3,749	10	$802	21%	100%	$0.03	0.65
Electric	Wood Product Mfg	Process Other	Transformers-New	Transformers-New		Per Industry	Existing	768	32	$584	37%	100%	$0.07	0.23
Electric	Wood Product Mfg	Process Other	Transformers-Retrofit	Transformers-Retrofit		Per Industry	Existing	2,812	10	$279	9.4%	100%	$0.01	0.21

Table B-2.1. Residential Gas Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (Therms)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per Therms)	2033 Cumulative Achievable Technical Potential (Therms)
Gas	Manufactured	Heat Central Boiler	Air-to-Air Heat Exchangers	Air-to-Air Heat Exchangers	No Air to Air Heat Exchangers	Per Home	Existing	28	5	$576	25%	95%	$5.18	97
Gas	Manufactured	Heat Central Boiler	Canned Lighting Air Tight Sealing	Canned Lighting Air Tight Sealing	No Air tight Sealing	Per Fixture	Existing	1	30	$127	95%	50%	$0.68	11
Gas	Manufactured	Heat Central Boiler	Ceiling Insulation	R-49 (WA Code - Single Family and Manufactured Homes Only)	R-0 (Zero Insulation - Single Family and Manufactured Homes Only)	Per Home	Existing	154	25	$1,598	75%	1%	$1.09	16
Gas	Manufactured	Heat Central Boiler	Ceiling Insulation	R-49 (WA Code - Single Family and Manufactured Homes Only)	R-10 (Existing Insulation - Single Family and Manufactured Homes Only)	Per Home	Existing	122	25	$1,598	75%	35%	$1.38	450
Gas	Manufactured	Heat Central Boiler	Ceiling Insulation	R-60 (Above WA Code - Single Family and Manufactured Homes Only)	R-49 (WA Code - Single Family and Manufactured Homes Only)	Per Home	Existing	2	25	$1,976	40%	95%	$71.90	13
Gas	Manufactured	Heat Central Boiler	Doors	R-10 (Doors with foam core) (Above WA Code - Single Family and Manufactured Homes Only)	R-5 (Composite Doors with foam core) (WA Code Single Family and Manufactured Homes Only)	Per Door	Existing	3	20	$326	25%	95%	$6.81	11
Gas	Manufactured	Heat Central Boiler	Doors	R-5 (Composite Doors with foam core) (WA Code - Single Family and Manufactured Homes Only)	R-2.5 (Standard non-thermal wood door) (Below WA Code - Single Family and Manufactured Homes Only)	Per Door	Existing	7	20	$126	85%	75%	$0.47	59
Gas	Manufactured	Heat Central Boiler	Doors - Weatherization	Weatherstripping And Adding Door Sweeps	Existing Non-Efficient door	Per Door	Existing	1	6	$25	95%	50%	$0.37	10
Gas	Manufactured	Heat Central Boiler	Floor Insulation	R-30 (WA Code)	R-0 (Zero Insulation)	Per Home	Existing	189	25	$1,610	20%	25%	$0.90	114
Gas	Manufactured	Heat Central Boiler	Floor Insulation	R-30 (WA Code)	R-15 (Existing Insulation)	Per Home	Existing	18	25	$1,610	25%	50%	$9.35	26
Gas	Manufactured	Heat Central Boiler	Floor Insulation	R-38 (Above WA Code)	R-30 (WA Code)	Per Home	Existing	4	25	$429	25%	85%	$7.98	11
Gas	Manufactured	Heat Central Boiler	Infiltration Control (Caulk, Weather Strip, etc.) Blower-Door test	Install Caulking And Weatherstripping	Existing Infiltration Conditions	Per Home	Existing	11	11	$450	75%	50%	$5.42	49
Gas	Manufactured	Heat Central Boiler	Leak Proof Duct Fittings	Quick connect fittings that do not require mastic or drawbands (5 per unit)	standard ducts with 13 SEER HVAC	Per Home	Existing	59	30	$1,114	5.0%	95%	$1.81	32
Gas	Manufactured	Heat Central Boiler	Thermostat - Multi-Zone	Individual Room Temperature Control for Major Occupied Rooms	Programmable Thermostat - Central Control Only	Per Home	Existing	19	11	$890	10%	95%	$6.78	26
Gas	Manufactured	Heat Central Boiler	Wall Insulation 2x4	R-13 (Below WA Code - Maximum Insulation Feasible)	R-0 (Zero Insulation)	Per Home	Existing	90	25	$1,694	60%	15%	$2.00	91
Gas	Manufactured	Heat Central Boiler	Windows	U-value = 0.22 (Above WA Code)	U-value = 0.32 (WA Code)	Per Home	Existing	17	25	$3,187	55%	85%	$19.44	83
Gas	Manufactured	Heat Central Boiler	Windows	U-value = 0.32 (WA Code)	Double Pane (Existing Window)	Per Home	Existing	87	25	$3,761	55%	15%	$4.76	76
Gas	Manufactured	Heat Central Boiler	Windows	U-value = 0.32 (WA Code)	Single Pane (Existing Window)	Per Home	Existing	106	25	$3,761	55%	5%	$3.89	30

Table B-2.1. Residential Gas Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (Therms)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per Therms)	2033 Cumulative Achievable Technical Potential (Therms)
Gas	Manufactured	Heat Central Furnace	Air-to-Air Heat Exchangers	Air-to-Air Heat Exchangers	No Air to Air Heat Exchangers	Per Home	Existing	28	5	$576	25%	95%	$5.06	4,207
Gas	Manufactured	Heat Central Furnace	Canned Lighting Air Tight Sealing	Canned Lighting Air Tight Sealing	No Air tight Sealing	Per Fixture	Existing	1	30	$127	95%	50%	$0.72	444
Gas	Manufactured	Heat Central Furnace	Ceiling Insulation	R-49 (WA Code - Single Family and Manufactured Homes Only)	R-0 (Zero Insulation - Single Family and Manufactured Homes Only)	Per Home	Existing	158	25	$1,598	75%	1%	$1.07	702
Gas	Manufactured	Heat Central Furnace	Ceiling Insulation	R-49 (WA Code - Single Family and Manufactured Homes Only)	R-10 (Existing Insulation - Single Family and Manufactured Homes Only)	Per Home	Existing	125	25	$1,598	75%	35%	$1.35	19,357
Gas	Manufactured	Heat Central Furnace	Ceiling Insulation	R-60 (Above WA Code - Single Family and Manufactured Homes Only)	R-49 (WA Code - Single Family and Manufactured Homes Only)	Per Home	Existing	3	25	$1,976	40%	95%	$70.35	598
Gas	Manufactured	Heat Central Furnace	Doors	R-10 (Doors with foam core) (Above WA Code - Single Family and Manufactured Homes Only)	R-5 (Composite Doors with foam core) (WA Code Single Family and Manufactured Homes Only)	Per Door	Existing	3	20	$326	25%	95%	$6.70	487
Gas	Manufactured	Heat Central Furnace	Doors	R-5 (Composite Doors with foam core) (WA Code - Single Family and Manufactured Homes Only)	R-2.5 (Standard non-thermal wood door) (Below WA Code - Single Family and Manufactured Homes Only)	Per Door	Existing	7	20	$126	85%	75%	$0.46	2,538
Gas	Manufactured	Heat Central Furnace	Doors - Weatherization	Weatherstripping And Adding Door Sweeps	Existing Non-Efficient door	Per Door	Existing	1	6	$25	95%	50%	$0.39	424
Gas	Manufactured	Heat Central Furnace	Duct Insulation Upgrade	R-8 (WA Code)	R-4 (Existing Insulation)	Per Home	Existing	14	20	$534	75%	75%	$3.53	4,061
Gas	Manufactured	Heat Central Furnace	Duct Sealing - Aerosol-Based	Spray-in ductwork sealant to minimize duct leaks	No Duct Sealing	Per Home	Existing	15	18	$827	50%	60%	$5.69	2,309
Gas	Manufactured	Heat Central Furnace	Floor Insulation	R-30 (WA Code)	R-0 (Zero Insulation)	Per Home	Existing	201	25	$1,610	20%	25%	$0.85	4,900
Gas	Manufactured	Heat Central Furnace	Floor Insulation	R-30 (WA Code)	R-15 (Existing Insulation)	Per Home	Existing	20	25	$1,610	25%	50%	$8.35	1,199
Gas	Manufactured	Heat Central Furnace	Floor Insulation	R-38 (Above WA Code)	R-30 (WA Code)	Per Home	Existing	5	25	$429	25%	85%	$7.08	513
Gas	Manufactured	Heat Central Furnace	Infiltration Control (Caulk, Weather Strip, etc.) Blower-Door test	Install Caulking And Weatherstripping	Existing Infiltration Conditions	Per Home	Existing	10	11	$450	75%	50%	$5.87	1,838
Gas	Manufactured	Heat Central Furnace	Leak Proof Duct Fittings	Quick connect fittings that do not require mastic or drawbands (5 per unit)	standard ducts with 13 SEER HVAC	Per Home	Existing	60	30	$1,114	5.0%	95%	$1.77	1,321
Gas	Manufactured	Heat Central Furnace	Thermostat - Multi-Zone	Individual Room Temperature Control for Major Occupied Rooms	Programmable Thermostat - Central Control Only	Per Home	Existing	19	11	$890	10%	95%	$6.63	1,117
Gas	Manufactured	Heat Central Furnace	Wall Insulation 2x4	R-13 (Below WA Code - Maximum Insulation Feasible)	R-0 (Zero Insulation)	Per Home	Existing	91	25	$1,694	60%	15%	$1.96	3,746
Gas	Manufactured	Heat Central Furnace	Windows	U-value = 0.22 (Above WA Code)	U-value = 0.32 (WA Code)	Per Home	Existing	18	25	$3,187	55%	85%	$19.13	3,415

Table B-2.1. Residential Gas Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (Therms)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per Therms)	2033 Cumulative Achievable Technical Potential (Therms)
Gas	Manufactured	Heat Central Furnace	Windows	U-value = 0.32 (WA Code)	Double Pane (Existing Window)	Per Home	Existing	88	25	$3,761	55%	15%	$4.66	3,139
Gas	Manufactured	Heat Central Furnace	Windows	U-value = 0.32 (WA Code)	Single Pane (Existing Window)	Per Home	Existing	108	25	$3,761	55%	5%	$3.81	1,247
Gas	Manufactured	Water Heat GT 55 Gal	Clothes Washer	Cold Water Only Clothes Washer - Gas Dryer	MEF = 1.66 - Gas DHW & Gas Dryer	Per Unit Each	Existing	10	14	$80	99%	95%	$1.04	97
Gas	Manufactured	Water Heat GT 55 Gal	Clothes Washer	ENERGY STAR - Tier 3 (MEF 2.46 or higher) Top 10% of ENERGY STAR Model - Gas DHW & Gas Dryer	MEF = 1.66 - Gas DHW & Gas Dryer	Per Home	Existing	0.01	14	$209	100%	95%	$-1508.28	0.25
Gas	Manufactured	Water Heat GT 55 Gal	Dishwasher	RTF ENERGY STAR Dishwasher - 277 kWh/yr and 4.25 gal/cycle	RTF Market Standard 2014 Dishwasher - 289 kWh/yr and 5.0 gal/cycle	Per Home	Existing	0.84	12	$36	95%	50%	$4.68	0.28
Gas	Manufactured	Water Heat GT 55 Gal	Drain Water Heat Recovery (GFX)	Gravity Film Heat Exchanger	No Heat Exchanger	Per Home	Existing	20	40	$540	29%	90%	$2.76	76
Gas	Manufactured	Water Heat GT 55 Gal	Faucet Aerators	1.5 GPM	2.2 GPM	Per Home	Existing	3	9	$3	95%	65%	$0.16	12
Gas	Manufactured	Water Heat GT 55 Gal	Faucet Aerators	2.2 GPM	Existing Faucet Aerator (3.0 GPM)	Per Home	Existing	4	9	$2	95%	25%	$0.11	11
Gas	Manufactured	Water Heat GT 55 Gal	Faucet Aerators - Bathroom Only	0.5 GPM	2.2 GPM	Per Home	Existing	4	9	$2	50%	95%	$0.08	24
Gas	Manufactured	Water Heat GT 55 Gal	Faucet Aerators - Bathroom Only	1.0 GPM	2.2 GPM	Per Home	Existing	3	9	$1	50%	80%	$-2.44	14
Gas	Manufactured	Water Heat GT 55 Gal	Hot Water Pipe Insulation	R-4 Wrap	No insulation	Per Home	Existing	2	5	$23	95%	75%	$2.08	22
Gas	Manufactured	Water Heat GT 55 Gal	Low-Flow Showerheads	1.5 GPM	2.5 GPM	Per Home	Existing	16	10	$53	95%	85%	$-0.43	100
Gas	Manufactured	Water Heat GT 55 Gal	Low-Flow Showerheads	2.5 GPM	Existing Showerhead (3.0 GPM)	Per Home	Existing	9	10	$0.00	95%	5%	$-0.65	3
Gas	Manufactured	Water Heat LE 55 Gal	Clothes Washer	Cold Water Only Clothes Washer - Gas Dryer	MEF = 1.66 - Gas DHW & Gas Dryer	Per Unit Each	Existing	10	14	$80	99%	95%	$1.04	1,140
Gas	Manufactured	Water Heat LE 55 Gal	Clothes Washer	ENERGY STAR - Tier 3 (MEF 2.46 or higher) Top 10% of ENERGY STAR Model - Gas DHW & Gas Dryer	MEF = 1.66 - Gas DHW & Gas Dryer	Per Home	Existing	0.01	14	$209	100%	95%	$-1508.28	2
Gas	Manufactured	Water Heat LE 55 Gal	Dishwasher	RTF ENERGY STAR Dishwasher - 277 kWh/yr and 4.25 gal/cycle	RTF Market Standard 2014 Dishwasher - 289 kWh/yr and 5.0 gal/cycle	Per Home	Existing	0.84	12	$36	71%	50%	$4.68	2
Gas	Manufactured	Water Heat LE 55 Gal	Drain Water Heat Recovery (GFX)	Gravity Film Heat Exchanger	No Heat Exchanger	Per Home	Existing	20	40	$540	29%	90%	$2.76	819
Gas	Manufactured	Water Heat LE 55 Gal	Faucet Aerators	1.5 GPM	2.2 GPM	Per Home	Existing	3	9	$3	95%	65%	$0.16	146
Gas	Manufactured	Water Heat LE 55 Gal	Faucet Aerators	2.2 GPM	Existing Faucet Aerator (3.0 GPM)	Per Home	Existing	4	9	$2	95%	25%	$0.11	135
Gas	Manufactured	Water Heat LE 55 Gal	Faucet Aerators - Bathroom Only	0.5 GPM	2.2 GPM	Per Home	Existing	4	9	$2	50%	95%	$0.08	288
Gas	Manufactured	Water Heat LE 55 Gal	Faucet Aerators - Bathroom Only	1.0 GPM	2.2 GPM	Per Home	Existing	3	9	$1	50%	80%	$-2.44	171
Gas	Manufactured	Water Heat LE 55 Gal	Hot Water Pipe Insulation	R-4 Wrap	No insulation	Per Home	Existing	2	5	$23	95%	75%	$2.27	239

Table B-2.1. Residential Gas Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (Therms)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per Therms)	2033 Cumulative Achievable Technical Potential (Therms)
Gas	Manufactured	Water Heat LE 55 Gal	Low-Flow Showerheads	1.5 GPM	2.5 GPM	Per Home	Existing	16	10	$53	95%	85%	$-0.43	1,180
Gas	Manufactured	Water Heat LE 55 Gal	Low-Flow Showerheads	2.5 GPM	Existing Showerhead (3.0 GPM)	Per Home	Existing	9	10	$0.00	95%	5%	$-0.65	40
Gas	Multifamily	Heat Central Boiler	Canned Lighting Air Tight Sealing	Canned Lighting Air Tight Sealing	No Air tight Sealing	Per Fixture	Existing	1	30	$50	95%	50%	$-5.62	240
Gas	Multifamily	Heat Central Boiler	Ceiling Insulation	R-38 (WA Code - Multi Family Only)	R-0 (Zero Insulation - Multi Family Only)	Per Home	Existing	51	25	$456	50%	50%	$0.79	5,353
Gas	Multifamily	Heat Central Boiler	Ceiling Insulation	R-38 (WA Code - Multi Family Only)	R-10 (Existing Insulation - Multi Family Only)	Per Home	Existing	19	25	$456	50%	50%	$2.02	1,966
Gas	Multifamily	Heat Central Boiler	Ceiling Insulation	R-49 (Above WA Code - Multi Family Only)	R-38 (WA Code - Multi Family Only)	Per Home	Existing	1	25	$73	15%	95%	$-2.72	65
Gas	Multifamily	Heat Central Boiler	Doors - Weatherization	Weatherstripping And Adding Door Sweeps	Existing Non-Efficient door	Per Door	Existing	1	6	$25	95%	50%	$0.47	318
Gas	Multifamily	Heat Central Boiler	Floor Insulation	R-30 (WA Code)	R-0 (Zero Insulation)	Per Home	Existing	74	25	$579	20%	25%	$0.72	1,438
Gas	Multifamily	Heat Central Boiler	Floor Insulation	R-30 (WA Code)	R-15 (Existing Insulation)	Per Home	Existing	7	25	$579	25%	50%	$7.24	353
Gas	Multifamily	Heat Central Boiler	Floor Insulation	R-38 (Above WA Code)	R-30 (WA Code)	Per Home	Existing	8	25	$154	25%	85%	$0.66	720
Gas	Multifamily	Heat Central Boiler	Infiltration Control (Caulk, Weather Strip, etc.) Blower-Door test	Install Caulking And Weatherstripping	Existing Infiltration Conditions	Per Home	Existing	15	11	$358	75%	50%	$3.16	2,131
Gas	Multifamily	Heat Central Boiler	Wall Insulation 2x4	R-13 (Below WA Code - Maximum Insulation Feasible)	R-0 (Zero Insulation)	Per Home	Existing	76	25	$1,011	60%	15%	$1.35	2,498
Gas	Multifamily	Heat Central Boiler	Windows	U-value = 0.22 (Above WA Code)	U-value = 0.32 (WA Code)	Per Home	Existing	22	25	$2,272	45%	85%	$11.01	2,016
Gas	Multifamily	Heat Central Boiler	Windows	U-value = 0.32 (WA Code)	Double Pane (Existing Window)	Per Home	Existing	89	25	$2,682	45%	15%	$3.27	2,080
Gas	Multifamily	Heat Central Boiler	Windows	U-value = 0.32 (WA Code)	Single Pane (Existing Window)	Per Home	Existing	107	25	$2,682	45%	5%	$2.71	815
Gas	Multifamily	Heat Central Furnace	Canned Lighting Air Tight Sealing	Canned Lighting Air Tight Sealing	No Air tight Sealing	Per Fixture	Existing	1	30	$50	95%	50%	$-6.41	8,050
Gas	Multifamily	Heat Central Furnace	Ceiling Insulation	R-38 (WA Code - Multi Family Only)	R-0 (Zero Insulation - Multi Family Only)	Per Home	Existing	33	25	$456	50%	50%	$1.20	133,599
Gas	Multifamily	Heat Central Furnace	Ceiling Insulation	R-38 (WA Code - Multi Family Only)	R-10 (Existing Insulation - Multi Family Only)	Per Home	Existing	12	25	$456	50%	50%	$3.12	49,528
Gas	Multifamily	Heat Central Furnace	Ceiling Insulation	R-49 (Above WA Code - Multi Family Only)	R-38 (WA Code - Multi Family Only)	Per Home	Existing	0.76	25	$73	15%	95%	$-4.22	1,667
Gas	Multifamily	Heat Central Furnace	Doors - Weatherization	Weatherstripping And Adding Door Sweeps	Existing Non-Efficient door	Per Door	Existing	1	6	$25	95%	50%	$0.54	10,965
Gas	Multifamily	Heat Central Furnace	Floor Insulation	R-30 (WA Code)	R-0 (Zero Insulation)	Per Home	Existing	95	25	$579	20%	25%	$0.56	72,508
Gas	Multifamily	Heat Central Furnace	Floor Insulation	R-30 (WA Code)	R-15 (Existing Insulation)	Per Home	Existing	9	25	$579	25%	50%	$5.61	17,891

Table B-2.1. Residential Gas Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (Therms)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per Therms)	2033 Cumulative Achievable Technical Potential (Therms)
Gas	Multifamily	Heat Central Furnace	Floor Insulation	R-38 (Above WA Code)	R-30 (WA Code)	Per Home	Existing	11	25	$154	25%	85%	$0.51	36,409
Gas	Multifamily	Heat Central Furnace	Infiltration Control (Caulk, Weather Strip, etc.) Blower-Door test	Install Caulking And Weatherstripping	Existing Infiltration Conditions	Per Home	Existing	13	11	$358	75%	50%	$3.61	72,766
Gas	Multifamily	Heat Central Furnace	Wall Insulation 2x4	R-13 (Below WA Code - Maximum Insulation Feasible)	R-0 (Zero Insulation)	Per Home	Existing	75	25	$1,011	60%	15%	$1.36	97,267
Gas	Multifamily	Heat Central Furnace	Windows	U-value = 0.22 (Above WA Code)	U-value = 0.32 (WA Code)	Per Home	Existing	22	25	$2,272	45%	85%	$11.02	79,004
Gas	Multifamily	Heat Central Furnace	Windows	U-value = 0.32 (WA Code)	Double Pane (Existing Window)	Per Home	Existing	89	25	$2,682	45%	15%	$3.26	81,847
Gas	Multifamily	Heat Central Furnace	Windows	U-value = 0.32 (WA Code)	Single Pane (Existing Window)	Per Home	Existing	108	25	$2,682	45%	5%	$2.71	32,068
Gas	Multifamily	Water Heat GT 55 Gal	Clothes Washer	Cold Water Only Clothes Washer - Gas Dryer	MEF = 1.66 - Gas DHW & Gas Dryer	Per Unit Each	Existing	10	14	$80	15%	95%	$1.04	507
Gas	Multifamily	Water Heat GT 55 Gal	Clothes Washer	ENERGY STAR - Tier 1 (MEF 2.0 - 2.19) - Gas DHW & Gas Dryer	MEF = 1.66 - Gas DHW & Gas Dryer	Per Home	Existing	0.00	14	$35	15%	87%	$-3064.33	90
Gas	Multifamily	Water Heat GT 55 Gal	Clothes Washer	ENERGY STAR - Tier 2 (MEF 2.2 - 2.45) - Gas DHW & Gas Dryer	MEF = 1.66 - Gas DHW & Gas Dryer	Per Home	Existing	0.00	14	$102	15%	95%	$-2477.42	147
Gas	Multifamily	Water Heat GT 55 Gal	Clothes Washer	ENERGY STAR - Tier 3 (MEF 2.46 or higher) Top 10% of ENERGY STAR Model - Gas DHW & Dryer	RTF Market Standard 2018 Clothes Washer - MEF 2.36 and WF 4.1 (Gas DHW & Dryer)	Per Unit Each	Existing	0.77	14	$75	15%	95%	$-7.89	32
Gas	Multifamily	Water Heat GT 55 Gal	Clothes Washer	ENERGY STAR - Tier 3 (MEF 2.46 or higher) Top 10% of ENERGY STAR Model - Gas DHW & Gas Dryer	MEF = 1.66 - Gas DHW & Gas Dryer	Per Home	Existing	0.01	14	$209	15%	99%	$-1796.85	200
Gas	Multifamily	Water Heat GT 55 Gal	Dishwasher	RTF ENERGY STAR Dishwasher - 277 kWh/yr and 4.25 gal/cycle	RTF Market Standard 2014 Dishwasher - 289 kWh/yr and 5.0 gal/cycle	Per Home	Existing	0.84	12	$36	95%	50%	$4.68	13
Gas	Multifamily	Water Heat GT 55 Gal	Faucet Aerators	1.5 GPM	2.2 GPM	Per Home	Existing	4	9	$3	95%	65%	$0.13	517
Gas	Multifamily	Water Heat GT 55 Gal	Faucet Aerators	2.2 GPM	Existing Faucet Aerator (3.0 GPM)	Per Home	Existing	5	9	$2	95%	25%	$0.09	480
Gas	Multifamily	Water Heat GT 55 Gal	Faucet Aerators - Bathroom Only	0.5 GPM	2.2 GPM	Per Home	Existing	5	9	$2	50%	95%	$0.06	1,020
Gas	Multifamily	Water Heat GT 55 Gal	Faucet Aerators - Bathroom Only	1.0 GPM	2.2 GPM	Per Home	Existing	4	9	$1	50%	80%	$-2.00	606
Gas	Multifamily	Water Heat GT 55 Gal	Hot Water Pipe Insulation	R-4 Wrap	No insulation	Per Home	Existing	2	5	$23	95%	75%	$2.16	722
Gas	Multifamily	Water Heat GT 55 Gal	Low-Flow Showerheads	1.5 GPM	2.5 GPM	Per Home	Existing	16	10	$45	95%	85%	$-0.69	3,566
Gas	Multifamily	Water Heat GT 55 Gal	Low-Flow Showerheads	2.5 GPM	Existing Showerhead (3.0 GPM)	Per Home	Existing	9	10	$0.00	95%	5%	$-0.62	122
Gas	Multifamily	Water Heat LE 55 Gal	Clothes Washer	Cold Water Only Clothes Washer - Gas Dryer	MEF = 1.66 - Gas DHW & Gas Dryer	Per Unit Each	Existing	10	14	$80	15%	95%	$1.04	5,934

Table B-2.1. Residential Gas Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (Therms)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per Therms)	2033 Cumulative Achievable Technical Potential (Therms)
Gas	Multifamily	Water Heat LE 55 Gal	Clothes Washer	ENERGY STAR - Tier 1 (MEF 2.0 - 2.19) - Gas DHW & Gas Dryer	MEF = 1.66 - Gas DHW & Gas Dryer	Per Home	Existing	0.00	14	$35	15%	87%	$-3064.33	1,058
Gas	Multifamily	Water Heat LE 55 Gal	Clothes Washer	ENERGY STAR - Tier 2 (MEF 2.2 - 2.45) - Gas DHW & Gas Dryer	MEF = 1.66 - Gas DHW & Gas Dryer	Per Home	Existing	0.00	14	$102	15%	95%	$-2477.42	1,727
Gas	Multifamily	Water Heat LE 55 Gal	Clothes Washer	ENERGY STAR - Tier 3 (MEF 2.46 or higher) Top 10% of ENERGY STAR Model - Gas DHW & Dryer	RTF Market Standard 2018 Clothes Washer - MEF 2.36 and WF 4.1 (Gas DHW & Dryer)	Per Unit Each	Existing	0.77	14	$75	15%	95%	$-7.89	378
Gas	Multifamily	Water Heat LE 55 Gal	Clothes Washer	ENERGY STAR - Tier 3 (MEF 2.46 or higher) Top 10% of ENERGY STAR Model - Gas DHW & Gas Dryer	MEF = 1.66 - Gas DHW & Gas Dryer	Per Home	Existing	0.01	14	$209	15%	99%	$-1796.85	2,355
Gas	Multifamily	Water Heat LE 55 Gal	Dishwasher	RTF ENERGY STAR Dishwasher - 277 kWh/yr and 4.25 gal/cycle	RTF Market Standard 2014 Dishwasher - 289 kWh/yr and 5.0 gal/cycle	Per Home	Existing	0.84	12	$36	58%	50%	$4.68	92
Gas	Multifamily	Water Heat LE 55 Gal	Faucet Aerators	1.5 GPM	2.2 GPM	Per Home	Existing	4	9	$3	95%	65%	$0.13	6,069
Gas	Multifamily	Water Heat LE 55 Gal	Faucet Aerators	2.2 GPM	Existing Faucet Aerator (3.0 GPM)	Per Home	Existing	5	9	$2	95%	25%	$0.09	5,632
Gas	Multifamily	Water Heat LE 55 Gal	Faucet Aerators - Bathroom Only	0.5 GPM	2.2 GPM	Per Home	Existing	5	9	$2	50%	95%	$0.06	11,969
Gas	Multifamily	Water Heat LE 55 Gal	Faucet Aerators - Bathroom Only	1.0 GPM	2.2 GPM	Per Home	Existing	4	9	$1	50%	80%	$-2.00	7,115
Gas	Multifamily	Water Heat LE 55 Gal	Hot Water Pipe Insulation	R-4 Wrap	No insulation	Per Home	Existing	2	5	$23	95%	75%	$2.35	7,757
Gas	Multifamily	Water Heat LE 55 Gal	Low-Flow Showerheads	1.5 GPM	2.5 GPM	Per Home	Existing	16	10	$45	95%	85%	$-0.69	41,835
Gas	Multifamily	Water Heat LE 55 Gal	Low-Flow Showerheads	2.5 GPM	Existing Showerhead (3.0 GPM)	Per Home	Existing	9	10	$0.00	95%	5%	$-0.62	1,432
Gas	Single Family	Heat Central Boiler	Air-to-Air Heat Exchangers	Air-to-Air Heat Exchangers	No Air to Air Heat Exchangers	Per Home	Existing	52	5	$576	50%	95%	$2.66	373,668
Gas	Single Family	Heat Central Boiler	Canned Lighting Air Tight Sealing	Canned Lighting Air Tight Sealing	No Air tight Sealing	Per Fixture	Existing	4	30	$203	95%	50%	$-1.89	29,943
Gas	Single Family	Heat Central Boiler	Ceiling Insulation	R-49 (WA Code - Single Family and Manufactured Homes Only)	R-0 (Zero Insulation - Single Family and Manufactured Homes Only)	Per Home	Existing	109	45	$1,332	95%	1%	$0.93	14,654
Gas	Single Family	Heat Central Boiler	Ceiling Insulation	R-49 (WA Code - Single Family and Manufactured Homes Only)	R-10 (Existing Insulation - Single Family and Manufactured Homes Only)	Per Home	Existing	43	45	$1,332	75%	35%	$2.35	160,406
Gas	Single Family	Heat Central Boiler	Ceiling Insulation	R-60 (Above WA Code - Single Family and Manufactured Homes Only)	R-49 (WA Code - Single Family and Manufactured Homes Only)	Per Home	Existing	1	45	$315	75%	95%	$-0.75	12,187
Gas	Single Family	Heat Central Boiler	Doors	R-10 (Doors with foam core) (Above WA Code - Single Family and Manufactured Homes Only)	R-5 (Composite Doors with foam core) (WA Code Single Family and Manufactured Homes Only)	Per Door	Existing	4	20	$200	25%	95%	$-0.86	13,566

Table B-2.1. Residential Gas Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (Therms)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per Therms)	2033 Cumulative Achievable Technical Potential (Therms)
Gas	Single Family	Heat Central Boiler	Doors	R-5 (Composite Doors with foam core) (WA Code - Single Family and Manufactured Homes Only)	R-2.5 (Standard non-thermal wood door) (Below WA Code - Single Family and Manufactured Homes Only)	Per Door	Existing	8	20	$126	85%	75%	$-1.46	71,577
Gas	Single Family	Heat Central Boiler	Doors - Weatherization	Weatherstripping And Adding Door Sweeps	Existing Non-Efficient door	Per Door	Existing	3	6	$25	95%	50%	$-2.11	19,974
Gas	Single Family	Heat Central Boiler	Floor Insulation	R-30 (WA Code)	R-0 (Zero Insulation)	Per Home	Existing	183	45	$1,621	20%	25%	$0.71	124,080
Gas	Single Family	Heat Central Boiler	Floor Insulation	R-30 (WA Code)	R-15 (Existing Insulation)	Per Home	Existing	17	45	$1,621	25%	50%	$7.41	29,400
Gas	Single Family	Heat Central Boiler	Floor Insulation	R-38 (Above WA Code)	R-30 (WA Code)	Per Home	Existing	21	45	$426	25%	85%	$0.48	59,851
Gas	Single Family	Heat Central Boiler	Infiltration Control (Caulk, Weather Strip, etc.) Blower-Door test	Install Caulking And Weatherstripping	Existing Infiltration Conditions	Per Home	Existing	31	11	$596	75%	50%	$2.31	156,210
Gas	Single Family	Heat Central Boiler	Leak Proof Duct Fittings	Quick connect fittings that do not require mastic or drawbands (5 per unit)	standard ducts with 13 SEER HVAC	Per Home	Existing	110	30	$1,114	5.0%	95%	$0.81	67,359
Gas	Single Family	Heat Central Boiler	Thermostat - Multi-Zone	Individual Room Temperature Control for Major Occupied Rooms	Programmable Thermostat - Central Control Only	Per Home	Existing	35	11	$890	10%	95%	$3.33	48,405
Gas	Single Family	Heat Central Boiler	Wall Insulation 2x4	R-13 (Below WA Code - Maximum Insulation Feasible)	R-0 (Zero Insulation)	Per Home	Existing	209	45	$3,094	60%	15%	$1.34	239,346
Gas	Single Family	Heat Central Boiler	Windows	U-value = 0.22 (Above WA Code)	U-value = 0.32 (WA Code)	Per Home	Existing	44	45	$5,316	55%	75%	$11.26	205,893
Gas	Single Family	Heat Central Boiler	Windows	U-value = 0.32 (WA Code)	Double Pane (Existing Window)	Per Home	Existing	190	45	$6,274	55%	15%	$3.16	186,371
Gas	Single Family	Heat Central Boiler	Windows	U-value = 0.32 (WA Code)	Single Pane (Existing Window)	Per Home	Existing	231	45	$6,274	55%	5%	$2.60	73,222
Gas	Single Family	Heat Central Furnace	Air-to-Air Heat Exchangers	Air-to-Air Heat Exchangers	No Air to Air Heat Exchangers	Per Home	Existing	53	5	$576	50%	95%	$2.60	11,992,091
Gas	Single Family	Heat Central Furnace	Canned Lighting Air Tight Sealing	Canned Lighting Air Tight Sealing	No Air tight Sealing	Per Fixture	Existing	4	30	$203	95%	50%	$-2.03	873,471
Gas	Single Family	Heat Central Furnace	Ceiling Insulation	R-49 (WA Code - Single Family and Manufactured Homes Only)	R-0 (Zero Insulation - Single Family and Manufactured Homes Only)	Per Home	Existing	82	45	$1,332	95%	1%	$1.24	344,593
Gas	Single Family	Heat Central Furnace	Ceiling Insulation	R-49 (WA Code - Single Family and Manufactured Homes Only)	R-10 (Existing Insulation - Single Family and Manufactured Homes Only)	Per Home	Existing	32	45	$1,332	75%	35%	$3.15	3,746,232
Gas	Single Family	Heat Central Furnace	Ceiling Insulation	R-60 (Above WA Code - Single Family and Manufactured Homes Only)	R-49 (WA Code - Single Family and Manufactured Homes Only)	Per Home	Existing	0.92	45	$315	75%	95%	$-1.01	285,332
Gas	Single Family	Heat Central Furnace	Doors	R-10 (Doors with foam core) (Above WA Code - Single Family and Manufactured Homes Only)	R-5 (Composite Doors with foam core) (WA Code Single Family and Manufactured Homes Only)	Per Door	Existing	4	20	$200	25%	95%	$-0.85	432,871

Table B-2.1. Residential Gas Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (Therms)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per Therms)	2033 Cumulative Achievable Technical Potential (Therms)
Gas	Single Family	Heat Central Furnace	Doors	R-5 (Composite Doors with foam core) (WA Code - Single Family and Manufactured Homes Only)	R-2.5 (Standard non-thermal wood door) (Below WA Code - Single Family and Manufactured Homes Only)	Per Door	Existing	8	20	$126	85%	75%	$-1.44	2,284,523
Gas	Single Family	Heat Central Furnace	Doors - Weatherization	Weatherstripping And Adding Door Sweeps	Existing Non-Efficient door	Per Door	Existing	2	6	$25	95%	50%	$-2.27	587,117
Gas	Single Family	Heat Central Furnace	Duct Insulation Upgrade	R-8 (WA Code)	R-4 (Existing Insulation)	Per Home	Existing	39	20	$1,336	75%	75%	$3.22	9,433,248
Gas	Single Family	Heat Central Furnace	Duct Sealing - Aerosol-Based	Spray-in ductwork sealant to minimize duct leaks	No Duct Sealing	Per Home	Existing	30	18	$827	50%	60%	$2.46	3,687,025
Gas	Single Family	Heat Central Furnace	Floor Insulation	R-30 (WA Code)	R-0 (Zero Insulation)	Per Home	Existing	224	45	$1,621	20%	25%	$0.58	4,523,818
Gas	Single Family	Heat Central Furnace	Floor Insulation	R-30 (WA Code)	R-15 (Existing Insulation)	Per Home	Existing	21	45	$1,621	25%	50%	$6.03	1,074,182
Gas	Single Family	Heat Central Furnace	Floor Insulation	R-38 (Above WA Code)	R-30 (WA Code)	Per Home	Existing	26	45	$426	25%	85%	$0.39	2,185,405
Gas	Single Family	Heat Central Furnace	Infiltration Control (Caulk, Weather Strip, etc.) Blower-Door test	Install Caulking And Weatherstripping	Existing Infiltration Conditions	Per Home	Existing	29	11	$596	75%	50%	$2.49	4,299,886
Gas	Single Family	Heat Central Furnace	Leak Proof Duct Fittings	Quick connect fittings that do not require mastic or drawbands (5 per unit)	standard ducts with 13 SEER HVAC	Per Home	Existing	113	30	$1,114	5.0%	95%	$0.79	2,046,489
Gas	Single Family	Heat Central Furnace	Thermostat - Multi-Zone	Individual Room Temperature Control for Major Occupied Rooms	Programmable Thermostat - Central Control Only	Per Home	Existing	36	11	$890	10%	95%	$3.25	1,553,455
Gas	Single Family	Heat Central Furnace	Wall Insulation 2x4	R-13 (Below WA Code - Maximum Insulation Feasible)	R-0 (Zero Insulation)	Per Home	Existing	212	45	$3,094	60%	15%	$1.32	7,202,899
Gas	Single Family	Heat Central Furnace	Windows	U-value = 0.22 (Above WA Code)	U-value = 0.32 (WA Code)	Per Home	Existing	45	45	$5,316	55%	75%	$11.13	6,184,707
Gas	Single Family	Heat Central Furnace	Windows	U-value = 0.32 (WA Code)	Double Pane (Existing Window)	Per Home	Existing	193	45	$6,274	55%	15%	$3.11	5,621,639
Gas	Single Family	Heat Central Furnace	Windows	U-value = 0.32 (WA Code)	Single Pane (Existing Window)	Per Home	Existing	235	45	$6,274	55%	5%	$2.56	2,208,990
Gas	Single Family	Water Heat GT 55 Gal	Clothes Washer	Cold Water Only Clothes Washer - Gas Dryer	MEF = 1.66 - Gas DHW & Gas Dryer	Per Unit Each	Existing	10	14	$80	100%	95%	$1.04	163,618
Gas	Single Family	Water Heat GT 55 Gal	Clothes Washer	ENERGY STAR - Tier 3 (MEF 2.46 or higher) Top 10% of ENERGY STAR Model - Gas DHW & Dryer	RTF Market Standard 2018 Clothes Washer - MEF 2.36 and WF 4.1 (Gas DHW & Dryer)	Per Unit Each	Existing	0.84	14	$75	99%	95%	$-8.48	93
Gas	Single Family	Water Heat GT 55 Gal	Dishwasher	RTF ENERGY STAR Dishwasher - 277 kWh/yr and 4.25 gal/cycle	RTF Market Standard 2014 Dishwasher - 289 kWh/yr and 5.0 gal/cycle	Per Home	Existing	0.84	12	$36	95%	50%	$4.68	684
Gas	Single Family	Water Heat GT 55 Gal	Drain Water Heat Recovery (GFX)	Gravity Film Heat Exchanger	No Heat Exchanger	Per Home	Existing	20	40	$540	29%	90%	$2.76	126,369
Gas	Single Family	Water Heat GT 55 Gal	Faucet Aerators	1.5 GPM	2.2 GPM	Per Home	Existing	5	9	$5	95%	65%	$0.17	18,612
Gas	Single Family	Water Heat GT 55 Gal	Faucet Aerators	2.2 GPM	Existing Faucet Aerator (3.0 GPM)	Per Home	Existing	6	9	$4	95%	25%	$0.11	27,431

Table B-2.1. Residential Gas Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (Therms)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per Therms)	2033 Cumulative Achievable Technical Potential (Therms)
Gas	Single Family	Water Heat GT 55 Gal	Faucet Aerators - Bathroom Only	0.5 GPM	2.2 GPM	Per Home	Existing	9	9	$4	67%	95%	$0.08	103,630
Gas	Single Family	Water Heat GT 55 Gal	Faucet Aerators - Bathroom Only	1.0 GPM	2.2 GPM	Per Home	Existing	6	9	$3	67%	80%	$-1.22	61,600
Gas	Single Family	Water Heat GT 55 Gal	Hot Water Pipe Insulation	R-4 Wrap	No insulation	Per Home	Existing	2	5	$23	95%	75%	$2.07	36,774
Gas	Single Family	Water Heat GT 55 Gal	Low-Flow Showerheads	1.5 GPM	2.5 GPM	Per Home	Existing	27	10	$68	95%	85%	$-0.14	283,045
Gas	Single Family	Water Heat GT 55 Gal	Low-Flow Showerheads	2.5 GPM	Existing Showerhead (3.0 GPM)	Per Home	Existing	16	10	$0.00	95%	5%	$-0.38	9,692
Gas	Single Family	Water Heat LE 55 Gal	Clothes Washer	Cold Water Only Clothes Washer - Gas Dryer	MEF = 1.66 - Gas DHW & Gas Dryer	Per Unit Each	Existing	10	14	$80	100%	95%	$1.04	1,914,286
Gas	Single Family	Water Heat LE 55 Gal	Clothes Washer	ENERGY STAR - Tier 3 (MEF 2.46 or higher) Top 10% of ENERGY STAR Model - Gas DHW & Dryer	RTF Market Standard 2018 Clothes Washer - MEF 2.36 and WF 4.1 (Gas DHW & Dryer)	Per Unit Each	Existing	0.84	14	$75	99%	95%	$-8.48	1,094
Gas	Single Family	Water Heat LE 55 Gal	Dishwasher	RTF ENERGY STAR Dishwasher - 277 kWh/yr and 4.25 gal/cycle	RTF Market Standard 2014 Dishwasher - 289 kWh/yr and 5.0 gal/cycle	Per Home	Existing	0.84	12	$36	71%	50%	$4.68	5,636
Gas	Single Family	Water Heat LE 55 Gal	Drain Water Heat Recovery (GFX)	Gravity Film Heat Exchanger	No Heat Exchanger	Per Home	Existing	20	40	$540	29%	90%	$2.76	1,357,655
Gas	Single Family	Water Heat LE 55 Gal	Faucet Aerators	1.5 GPM	2.2 GPM	Per Home	Existing	5	9	$5	95%	65%	$0.17	218,314
Gas	Single Family	Water Heat LE 55 Gal	Faucet Aerators	2.2 GPM	Existing Faucet Aerator (3.0 GPM)	Per Home	Existing	6	9	$4	95%	25%	$0.11	321,756
Gas	Single Family	Water Heat LE 55 Gal	Faucet Aerators - Bathroom Only	0.5 GPM	2.2 GPM	Per Home	Existing	9	9	$4	67%	95%	$0.08	1,215,524
Gas	Single Family	Water Heat LE 55 Gal	Faucet Aerators - Bathroom Only	1.0 GPM	2.2 GPM	Per Home	Existing	6	9	$3	67%	80%	$-1.22	722,540
Gas	Single Family	Water Heat LE 55 Gal	Hot Water Pipe Insulation	R-4 Wrap	No insulation	Per Home	Existing	2	5	$23	95%	75%	$2.25	395,175
Gas	Single Family	Water Heat LE 55 Gal	Low-Flow Showerheads	1.5 GPM	2.5 GPM	Per Home	Existing	27	10	$68	95%	85%	$-0.14	3,319,966
Gas	Single Family	Water Heat LE 55 Gal	Low-Flow Showerheads	2.5 GPM	Existing Showerhead (3.0 GPM)	Per Home	Existing	16	10	$0.00	95%	5%	$-0.38	113,690

Table B-2.2. Commercial Gas Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (Therms)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per Therms)	2033 Cumulative Achievable Technical Potential (Therms)
Gas	Dry Goods Retail	Space Heat Boiler	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	Demand Controlled Ventilation (CO2 sensors)	Constant Ventilation	Per Building	Existing	78	15	$2,875	50%	94%	$5.14	57,845
Gas	Dry Goods Retail	Space Heat Boiler	Boiler Economizer	Economizer	No Economizer	Per Building	Existing	43	20	$671	10%	90%	$1.93	5,805
Gas	Dry Goods Retail	Space Heat Boiler	Commissioning of Existing Buildings	Existing Building Commissioning	Average Existing Conditions	Per Building	Existing	98	7	$2,267	90%	80%	$5.00	68,084
Gas	Dry Goods Retail	Space Heat Boiler	Convert Constant Volume Air System to VAV	Variable Volume Air System	Constant Volume Air System	Per Building	Existing	102	15	$34,959	15%	67%	$48.08	15,356
Gas	Dry Goods Retail	Space Heat Boiler	Direct Digital Control System-Installation	DDC Retrofit (Morning Warm-Up Control Logic Included in This Measure)	Pneumatic	Per Building	Existing	117	5	$11,057	10%	59%	$25.51	10,229
Gas	Dry Goods Retail	Space Heat Boiler	Direct Digital Control System-Wireless System	DDC Retrofit - Wireless System	Pneumatic	Per Building	Existing	117	5	$4,469	50%	80%	$10.31	54,793
Gas	Dry Goods Retail	Space Heat Boiler	Exhaust Air to Ventilation Air Heat Recovery	Exhaust Air Heat Recovery	No Heat Recovery	Per Building	Existing	117	10	$10,430	5.0%	94%	$15.16	7,661
Gas	Dry Goods Retail	Space Heat Boiler	Infiltration Reduction	Install Caulking And Weatherstripping (ACH 0.65)	Infiltration Conditions (ACH 1.0)	Per Building	Existing	76	10	$322	10%	39%	$0.72	4,066
Gas	Dry Goods Retail	Space Heat Boiler	Insulation - Ceiling	R-30 c.i. (WA State Code)	R-7 (Average Existing Conditions)	Per Building	Existing	186	25	$16,780	75%	85%	$11.11	162,392
Gas	Dry Goods Retail	Space Heat Boiler	Insulation - Ceiling	R-38 c.i.	R-30 c.i. (WA State Code)	Per Building	Existing	1	25	$16,780	75%	83%	$2,060.82	725
Gas	Dry Goods Retail	Space Heat Boiler	Insulation - Ceiling	R-49 c.i.	R-38 c.i.	Per Building	Existing	16	25	$4,734	75%	98%	$35.15	14,168
Gas	Dry Goods Retail	Space Heat Boiler	Insulation - Floor (non-slab)	R-30 (WA State Code)	R-11 (Average Existing Conditions)	Per Building	Existing	178	25	$8,846	35%	90%	$6.10	64,373
Gas	Dry Goods Retail	Space Heat Boiler	Insulation - Floor (non-slab)	R-38	R-30 (WA State Code)	Per Building	Existing	33	25	$2,729	35%	90%	$10.11	11,123
Gas	Dry Goods Retail	Space Heat Boiler	Insulation - Wall	R-16	R-3 (Average Existing Conditions)	Per Building	Existing	343	25	$10,857	10%	35%	$3.90	12,569
Gas	Dry Goods Retail	Space Heat Boiler	Pipe Insulation - Boiler	3" of Insulation, assuming R-12 (WA State Code)	No Insulation	Per Building	Existing	94	20	$1,553	75%	65%	$2.04	47,565
Gas	Dry Goods Retail	Space Heat Boiler	Programmable Thermostat - Web Enabled	Programmable Thermostat - Web Enabled	No Programmable Thermostat	Per Building	Existing	23	15	$779	95%	26%	$4.64	5,597
Gas	Dry Goods Retail	Space Heat Boiler	Windows-High Efficiency	U-0.40 (WA State Code)	U-0.68 (Average Existing Conditions)	Per Building	Existing	12	25	$60,038	10%	80%	$602.07	861
Gas	Dry Goods Retail	Space Heat Furnace	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	Demand Controlled Ventilation (CO2 sensors)	Constant Ventilation	Per Building	Existing	116	15	$2,875	50%	94%	$3.46	725,596
Gas	Dry Goods Retail	Space Heat Furnace	Commissioning of Existing Buildings	Existing Building Commissioning	Average Existing Conditions	Per Building	Existing	145	7	$2,267	90%	80%	$3.36	906,649
Gas	Dry Goods Retail	Space Heat Furnace	Convert Constant Volume Air System to VAV	Variable Volume Air System	Constant Volume Air System	Per Building	Existing	151	15	$34,959	15%	67%	$32.36	193,587
Gas	Dry Goods Retail	Space Heat Furnace	Direct Digital Control System-Installation	DDC Retrofit (Morning Warm-Up Control Logic Included in This Measure)	Pneumatic	Per Building	Existing	175	5	$11,057	10%	59%	$17.17	128,950
Gas	Dry Goods Retail	Space Heat Furnace	Direct Digital Control System-Wireless System	DDC Retrofit - Wireless System	Pneumatic	Per Building	Existing	175	5	$4,469	50%	80%	$6.94	690,724
Gas	Dry Goods Retail	Space Heat Furnace	Duct Repair And Sealing	Reduction In Duct Losses to 5%	No Repair or Sealing, 15% duct losses	Per Building	Existing	29	18	$4,599	45%	45%	$20.43	69,353

Table B-2.2. Commercial Gas Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (Therms)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per Therms)	2033 Cumulative Achievable Technical Potential (Therms)
Gas	Dry Goods Retail	Space Heat Furnace	Exhaust Air to Ventilation Air Heat Recovery	Exhaust Air Heat Recovery	No Heat Recovery	Per Building	Existing	175	10	$10,430	5.0%	94%	$10.21	96,091
Gas	Dry Goods Retail	Space Heat Furnace	Infiltration Reduction	Install Caulking And Weatherstripping (ACH 0.65)	Infiltration Conditions (ACH 1.0)	Per Building	Existing	113	10	$322	10%	39%	$0.49	51,005
Gas	Dry Goods Retail	Space Heat Furnace	Insulation - Ceiling	R-30 c.i. (WA State Code)	R-7 (Average Existing Conditions)	Per Building	Existing	276	25	$16,780	75%	85%	$7.48	2,036,755
Gas	Dry Goods Retail	Space Heat Furnace	Insulation - Ceiling	R-38 c.i.	R-30 c.i. (WA State Code)	Per Building	Existing	1	25	$16,780	75%	83%	$1,387.14	9,104
Gas	Dry Goods Retail	Space Heat Furnace	Insulation - Ceiling	R-49 c.i.	R-38 c.i.	Per Building	Existing	24	25	$4,734	75%	98%	$23.66	177,700
Gas	Dry Goods Retail	Space Heat Furnace	Insulation - Duct	R-7 (WA State Code)	No Insulation	Per Building	Existing	49	25	$2,224	10%	15%	$5.60	7,093
Gas	Dry Goods Retail	Space Heat Furnace	Insulation - Floor (non-slab)	R-30 (WA State Code)	R-11 (Average Existing Conditions)	Per Building	Existing	265	25	$8,846	35%	90%	$4.11	806,877
Gas	Dry Goods Retail	Space Heat Furnace	Insulation - Floor (non-slab)	R-38	R-30 (WA State Code)	Per Building	Existing	49	25	$2,729	35%	90%	$6.81	139,421
Gas	Dry Goods Retail	Space Heat Furnace	Insulation - Wall	R-16	R-3 (Average Existing Conditions)	Per Building	Existing	510	25	$10,857	10%	35%	$2.63	157,544
Gas	Dry Goods Retail	Space Heat Furnace	Programmable Thermostat - Web Enabled	Programmable Thermostat - Web Enabled	No Programmable Thermostat	Per Building	Existing	35	15	$779	95%	26%	$3.13	74,536
Gas	Dry Goods Retail	Space Heat Furnace	Windows-High Efficiency	U-0.40 (WA State Code)	U-0.68 (Average Existing Conditions)	Per Building	Existing	18	25	$60,038	10%	80%	$405.25	11,476
Gas	Dry Goods Retail	Water Heat GT 55 Gal	Demand Controlled Circulating Systems	Demand Controlled Circulating Systems (VFD control by demand)	Constant Circulation	Per Building	Existing	18	10	$3,194	75%	94%	$29.55	4,377
Gas	Dry Goods Retail	Water Heat GT 55 Gal	Dishwasher Residential	RTF ENERGY STAR Dishwasher - 277 kWh/yr and 4.25 gal/cycle	RTF Market Standard 2014 Dishwasher - 289 kWh/yr and 5.0 gal/cycle	Per Building	Existing	1	12	$44	24%	25%	$5.95	20
Gas	Dry Goods Retail	Water Heat GT 55 Gal	Drainwater Heat Recovery Water Heater	Install (Power-Pipe or GFX) - Heat Recovery Water Heater	No Heat Recovery System	Per Building	Existing	74	25	$1,250	5.0%	92%	$2.08	1,102
Gas	Dry Goods Retail	Water Heat GT 55 Gal	Low-Flow Faucet Aerators	0.5 GPM	2.2 GPM (Federal Code)	Per Building	Existing	14	9	$4	95%	75%	$-0.56	3,418
Gas	Dry Goods Retail	Water Heat GT 55 Gal	Low-Flow Faucet Aerators	2.2 GPM (Federal Code)	3.0 GPM	Per Building	Existing	4	9	$3	95%	25%	$-1.21	393
Gas	Dry Goods Retail	Water Heat GT 55 Gal	Pipe Insulation - Hot Water (DWH)	1.0" of Insulation, assuming R-4 (WA State Code)	No Insulation	Per Building	Existing	3	12	$25	75%	90%	$1.10	798
Gas	Dry Goods Retail	Water Heat GT 55 Gal	Ultrasonic Faucet Control	Install Ultrasonic Motion Faucet Control	No Faucet Control	Per Building	Existing	9	10	$452	75%	95%	$6.92	2,212
Gas	Dry Goods Retail	Water Heat LE 55 Gal	Demand Controlled Circulating Systems	Demand Controlled Circulating Systems (VFD control by demand)	Constant Circulation	Per Building	Existing	16	10	$3,194	75%	94%	$32.46	46,151
Gas	Dry Goods Retail	Water Heat LE 55 Gal	Dishwasher Residential	RTF ENERGY STAR Dishwasher - 277 kWh/yr and 4.25 gal/cycle	RTF Market Standard 2014 Dishwasher - 289 kWh/yr and 5.0 gal/cycle	Per Building	Existing	1	12	$44	24%	25%	$5.95	241
Gas	Dry Goods Retail	Water Heat LE 55 Gal	Drainwater Heat Recovery Water Heater	Install (Power-Pipe or GFX) - Heat Recovery Water Heater	No Heat Recovery System	Per Building	Existing	67	25	$1,250	5.0%	92%	$2.29	11,620
Gas	Dry Goods Retail	Water Heat LE 55 Gal	Low-Flow Faucet Aerators	0.5 GPM	2.2 GPM (Federal Code)	Per Building	Existing	13	9	$4	95%	75%	$-0.55	36,041
Gas	Dry Goods Retail	Water Heat LE 55 Gal	Low-Flow Faucet Aerators	2.2 GPM (Federal Code)	3.0 GPM	Per Building	Existing	4	9	$3	95%	25%	$-1.16	4,146
Gas	Dry Goods Retail	Water Heat LE 55 Gal	Pipe Insulation - Hot Water (DWH)	1.0" of Insulation, assuming R-4 (WA State Code)	No Insulation	Per Building	Existing	3	12	$25	75%	90%	$1.20	8,419

Table B-2.2. Commercial Gas Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (Therms)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per Therms)	2033 Cumulative Achievable Technical Potential (Therms)
Gas	Dry Goods Retail	Water Heat LE 55 Gal	Ultrasonic Faucet Control	Install Ultrasonic Motion Faucet Control	No Faucet Control	Per Building	Existing	8	10	$452	75%	95%	$7.69	23,321
Gas	Grocery	Cooking	Broiler	High-Efficiency Broiler (34% Efficient)	Standard Broiler (15% Efficient)	Per Building	Existing	115	10	$9	95%	75%	$0.01	22,673
Gas	Grocery	Cooking	Fryers - Commercial Gas Cooking	Energy Star Commercial Fryer (50% efficient)	Non-Energy Star Fryer (35% efficient)	Per Building	Existing	10	8	$54	45%	35%	$1.06	442
Gas	Grocery	Cooking	Griddle	High-Efficiency Griddle (40% Efficient)	Standard Griddle (32% Efficient)	Per Building	Existing	8	12	$166	45%	35%	$3.03	107
Gas	Grocery	Cooking	High Efficiency Convection Oven	Convection Oven	Standard Oven	Per Building	Existing	71	12	$112	85%	85%	$0.25	14,242
Gas	Grocery	Cooking	Oven - Conveyor	High-Efficiency Model (23% Efficient)	Standard Model (15% Efficient)	Per Building	Existing	647	10	$144	5.0%	85%	$0.04	7,601
Gas	Grocery	Cooking	Oven - Power Burner	Power Burner Oven - Improved Atmospheric Burner (60% Efficient)	Standard (40%-50% Efficiency)	Per Building	Existing	232	12	$269	25%	90%	$0.18	14,462
Gas	Grocery	Cooking	Steam Cooker	ENERGY STAR Steam Cooker	Non ENERGY STAR Steam Cooker	Per Building	Existing	158	12	$308	5.0%	35%	$0.31	1,459
Gas	Grocery	Space Heat Boiler	Boiler Economizer	Economizer	No Economizer	Per Building	Existing	399	20	$1,868	10%	90%	$0.58	125
Gas	Grocery	Space Heat Boiler	Commissioning of Existing Buildings	Existing Building Commissioning	Average Existing Conditions	Per Building	Existing	908	7	$6,308	90%	80%	$1.50	1,761
Gas	Grocery	Space Heat Boiler	Direct Digital Control System-Installation	DDC Retrofit (Morning Warm-Up Control Logic Included in This Measure)	Pneumatic	Per Building	Existing	1,090	5	$30,771	10%	61%	$7.68	230
Gas	Grocery	Space Heat Boiler	Direct Digital Control System-Wireless System	DDC Retrofit - Wireless System	Pneumatic	Per Building	Existing	1,090	5	$12,433	50%	80%	$3.10	1,199
Gas	Grocery	Space Heat Boiler	Exhaust Air to Ventilation Air Heat Recovery	Exhaust Air Heat Recovery	No Heat Recovery	Per Building	Existing	1,090	10	$29,025	5.0%	94%	$4.56	167
Gas	Grocery	Space Heat Boiler	Exhaust Hood Makeup Air	Provide Makeup Air Directly at Exhaust Hood Instead of Pulling Conditioned Air	Hood Pulls Conditioned Air (No Make-up Air)	Per Building	Existing	327	10	$5,448	64%	85%	$2.85	578
Gas	Grocery	Space Heat Boiler	Infiltration Reduction	Install Caulking And Weatherstripping (ACH 0.65)	Infiltration Conditions (ACH 1.0)	Per Building	Existing	554	10	$635	10%	39%	$0.20	68
Gas	Grocery	Space Heat Boiler	Insulation - Ceiling	R-30 c.i. (WA State Code)	R-7 (Average Existing Conditions)	Per Building	Existing	1,671	25	$48,345	75%	10%	$3.57	396
Gas	Grocery	Space Heat Boiler	Insulation - Ceiling	R-38 c.i.	R-30 c.i. (WA State Code)	Per Building	Existing	9	25	$48,345	75%	70%	$632.77	15
Gas	Grocery	Space Heat Boiler	Insulation - Ceiling	R-49 c.i.	R-38 c.i.	Per Building	Existing	149	25	$13,637	75%	85%	$11.28	295
Gas	Grocery	Space Heat Boiler	Insulation - Floor (non-slab)	R-30 (WA State Code)	R-11 (Average Existing Conditions)	Per Building	Existing	1,675	25	$25,490	35%	45%	$1.88	808
Gas	Grocery	Space Heat Boiler	Insulation - Floor (non-slab)	R-38	R-30 (WA State Code)	Per Building	Existing	311	25	$7,862	35%	45%	$3.11	144
Gas	Grocery	Space Heat Boiler	Insulation - Wall	R-16	R-3 (Average Existing Conditions)	Per Building	Existing	3,259	25	$27,368	10%	35%	$1.04	334
Gas	Grocery	Space Heat Boiler	Pipe Insulation - Boiler	3" of Insulation, assuming R-12 (WA State Code)	No Insulation	Per Building	Existing	876	20	$2,590	75%	65%	$0.37	1,232
Gas	Grocery	Space Heat Boiler	Programmable Thermostat - Web Enabled	Programmable Thermostat - Web Enabled	No Programmable Thermostat	Per Building	Existing	218	15	$754	95%	31%	$0.49	171
Gas	Grocery	Space Heat Boiler	Windows-High Efficiency	U-0.40 (WA State Code)	U-0.65 (Average Existing Conditions)	Per Building	Existing	54	25	$18,650	10%	85%	$268.61	11
Gas	Grocery	Space Heat Furnace	Commissioning of Existing Buildings	Existing Building Commissioning	Average Existing Conditions	Per Building	Existing	1,350	7	$6,308	90%	80%	$1.01	344,125

Table B-2.2. Commercial Gas Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (Therms)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per Therms)	2033 Cumulative Achievable Technical Potential (Therms)
Gas	Grocery	Space Heat Furnace	Direct Digital Control System-Installation	DDC Retrofit (Morning Warm-Up Control Logic Included in This Measure)	Pneumatic	Per Building	Existing	1,620	5	$30,771	10%	61%	$5.17	42,568
Gas	Grocery	Space Heat Furnace	Direct Digital Control System-Wireless System	DDC Retrofit - Wireless System	Pneumatic	Per Building	Existing	1,620	5	$12,433	50%	80%	$2.09	221,856
Gas	Grocery	Space Heat Furnace	Duct Repair And Sealing	Reduction In Duct Losses to 5%	No Repair or Sealing, 15% duct losses	Per Building	Existing	270	18	$12,799	45%	45%	$6.15	22,275
Gas	Grocery	Space Heat Furnace	Exhaust Air to Ventilation Air Heat Recovery	Exhaust Air Heat Recovery	No Heat Recovery	Per Building	Existing	1,620	10	$29,025	5.0%	94%	$3.07	30,864
Gas	Grocery	Space Heat Furnace	Exhaust Hood Makeup Air	Provide Makeup Air Directly at Exhaust Hood Instead of Pulling Conditioned Air	Hood Pulls Conditioned Air (No Make-up Air)	Per Building	Existing	486	10	$5,448	64%	85%	$1.92	106,414
Gas	Grocery	Space Heat Furnace	Infiltration Reduction	Install Caulking And Weatherstripping (ACH 0.65)	Infiltration Conditions (ACH 1.0)	Per Building	Existing	823	10	$635	10%	39%	$0.13	12,528
Gas	Grocery	Space Heat Furnace	Insulation - Ceiling	R-30 c.i. (WA State Code)	R-7 (Average Existing Conditions)	Per Building	Existing	2,483	25	$48,345	75%	10%	$2.40	72,923
Gas	Grocery	Space Heat Furnace	Insulation - Ceiling	R-38 c.i.	R-30 c.i. (WA State Code)	Per Building	Existing	14	25	$48,345	75%	70%	$425.91	2,828
Gas	Grocery	Space Heat Furnace	Insulation - Ceiling	R-49 c.i.	R-38 c.i.	Per Building	Existing	221	25	$13,637	75%	85%	$7.59	54,305
Gas	Grocery	Space Heat Furnace	Insulation - Duct	R-7 (WA State Code)	No Insulation	Per Building	Existing	453	25	$6,192	10%	15%	$1.68	2,581
Gas	Grocery	Space Heat Furnace	Insulation - Floor (non-slab)	R-30 (WA State Code)	R-11 (Average Existing Conditions)	Per Building	Existing	2,488	25	$25,490	35%	45%	$1.26	148,632
Gas	Grocery	Space Heat Furnace	Insulation - Floor (non-slab)	R-38	R-30 (WA State Code)	Per Building	Existing	463	25	$7,862	35%	45%	$2.09	26,662
Gas	Grocery	Space Heat Furnace	Insulation - Wall	R-16	R-3 (Average Existing Conditions)	Per Building	Existing	4,956	25	$27,368	10%	35%	$0.68	62,969
Gas	Grocery	Space Heat Furnace	Programmable Thermostat - Web Enabled	Programmable Thermostat - Web Enabled	No Programmable Thermostat	Per Building	Existing	324	15	$754	95%	31%	$0.33	33,553
Gas	Grocery	Space Heat Furnace	Windows-High Efficiency	U-0.40 (WA State Code)	U-0.65 (Average Existing Conditions)	Per Building	Existing	80	25	$18,650	10%	85%	$180.80	2,216
Gas	Grocery	Water Heat GT 55 Gal	Demand Controlled Circulating Systems	Demand Controlled Circulating Systems (VFD control by demand)	Constant Circulation	Per Building	Existing	233	10	$8,889	75%	94%	$6.53	2,855
Gas	Grocery	Water Heat GT 55 Gal	Dishwasher Residential	RTF ENERGY STAR Dishwasher - 277 kWh/yr and 4.25 gal/cycle	RTF Market Standard 2014 Dishwasher - 289 kWh/yr and 5.0 gal/cycle	Per Building	Existing	0.99	12	$44	24%	25%	$7.12	1
Gas	Grocery	Water Heat GT 55 Gal	Dishwashing - Commercial - Low Temp	Low-Temp Commercial Dishwasher (Includes Extra Chemical Cost) - (ENERGY STAR)	Standard High Temp Commercial Dishwasher	Per Building	Existing	37	12	$568	95%	95%	$-15.70	588
Gas	Grocery	Water Heat GT 55 Gal	Drainwater Heat Recovery Water Heater	Install (Power-Pipe or GFX) - Heat Recovery Water Heater	No Heat Recovery System	Per Building	Existing	933	25	$8,331	5.0%	92%	$1.10	713
Gas	Grocery	Water Heat GT 55 Gal	Low-Flow Faucet Aerators	0.5 GPM	2.2 GPM (Federal Code)	Per Building	Existing	180	9	$12	95%	75%	$-0.07	2,230
Gas	Grocery	Water Heat GT 55 Gal	Low-Flow Faucet Aerators	2.2 GPM (Federal Code)	3.0 GPM	Per Building	Existing	62	9	$9	95%	25%	$-0.46	256
Gas	Grocery	Water Heat GT 55 Gal	Low-Flow Pre-Rinse Spray Valves	0.6 GPM	1.6 GPM (Federal Standard)	Per Building	Existing	36	4	$247	95%	74%	$2.13	444
Gas	Grocery	Water Heat GT 55 Gal	Pipe Insulation - Hot Water (DWH)	1.0" of Insulation, assuming R-4 (WA State Code)	No Insulation	Per Building	Existing	46	12	$102	75%	90%	$0.35	514

Table B-2.2. Commercial Gas Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (Therms)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per Therms)	2033 Cumulative Achievable Technical Potential (Therms)
Gas	Grocery	Water Heat GT 55 Gal	Ultrasonic Faucet Control	Install Ultrasonic Motion Faucet Control	No Faucet Control	Per Building	Existing	116	10	$1,258	75%	95%	$1.31	1,442
Gas	Grocery	Water Heat GT 55 Gal	Water Cooled Refrigeration with Heat Recovery	Heat Recovery from refrigeration system. Applied to Water Heating Electric End use	No heat recovery	Per Building	Existing	531	10	$29,121	75%	55%	$9.38	3,474
Gas	Grocery	Water Heat LE 55 Gal	Demand Controlled Circulating Systems	Demand Controlled Circulating Systems (VFD control by demand)	Constant Circulation	Per Building	Existing	212	10	$8,889	75%	94%	$7.17	30,105
Gas	Grocery	Water Heat LE 55 Gal	Dishwasher Residential	RTF ENERGY STAR Dishwasher - 277 kWh/yr and 4.25 gal/cycle	RTF Market Standard 2014 Dishwasher - 289 kWh/yr and 5.0 gal/cycle	Per Building	Existing	0.99	12	$44	24%	25%	$7.12	12
Gas	Grocery	Water Heat LE 55 Gal	Dishwashing - Commercial - Low Temp	Low-Temp Commercial Dishwasher (Includes Extra Chemical Cost) - (ENERGY STAR)	Standard High Temp Commercial Dishwasher	Per Building	Existing	34	12	$513	95%	95%	$-17.50	6,199
Gas	Grocery	Water Heat LE 55 Gal	Drainwater Heat Recovery Water Heater	Install (Power-Pipe or GFX) - Heat Recovery Water Heater	No Heat Recovery System	Per Building	Existing	849	25	$8,331	5.0%	92%	$1.21	7,523
Gas	Grocery	Water Heat LE 55 Gal	Low-Flow Faucet Aerators	0.5 GPM	2.2 GPM (Federal Code)	Per Building	Existing	164	9	$12	95%	75%	$-0.06	23,511
Gas	Grocery	Water Heat LE 55 Gal	Low-Flow Faucet Aerators	2.2 GPM (Federal Code)	3.0 GPM	Per Building	Existing	56	9	$9	95%	25%	$-0.47	2,704
Gas	Grocery	Water Heat LE 55 Gal	Low-Flow Pre-Rinse Spray Valves	0.6 GPM	1.6 GPM (Federal Standard)	Per Building	Existing	36	4	$247	95%	74%	$2.13	5,147
Gas	Grocery	Water Heat LE 55 Gal	Pipe Insulation - Hot Water (DWH)	1.0" of Insulation, assuming R-4 (WA State Code)	No Insulation	Per Building	Existing	42	12	$102	75%	90%	$0.38	5,416
Gas	Grocery	Water Heat LE 55 Gal	Ultrasonic Faucet Control	Install Ultrasonic Motion Faucet Control	No Faucet Control	Per Building	Existing	106	10	$1,258	75%	95%	$1.50	15,213
Gas	Grocery	Water Heat LE 55 Gal	Water Cooled Refrigeration with Heat Recovery	Heat Recovery from refrigeration system. Applied to Water Heating Electric End use	No heat recovery	Per Building	Existing	484	10	$29,121	75%	55%	$10.30	36,608
Gas	Hospital	Cooking	Broiler	High-Efficiency Broiler (34% Efficient)	Standard Broiler (15% Efficient)	Per Building	Existing	11	10	$1	95%	75%	$0.02	15,617
Gas	Hospital	Cooking	Fryers - Commercial Gas Cooking	Energy Star Commercial Fryer (50% efficient)	Non-Energy Star Fryer (35% efficient)	Per Building	Existing	0.07	8	$3	45%	35%	$8.51	23
Gas	Hospital	Cooking	Griddle	High-Efficiency Griddle (40% Efficient)	Standard Griddle (32% Efficient)	Per Building	Existing	1	12	$32	45%	35%	$2.90	29
Gas	Hospital	Cooking	High Efficiency Convection Oven	Convection Oven	Standard Oven	Per Building	Existing	7	12	$23	85%	55%	$0.51	6,347
Gas	Hospital	Cooking	Oven - Conveyor	High-Efficiency Model (23% Efficient)	Standard Model (15% Efficient)	Per Building	Existing	66	10	$11	5.0%	85%	$0.03	5,236
Gas	Hospital	Cooking	Oven - Power Burner	Power Burner Oven - Improved Atmospheric Burner (60% Efficient)	Standard (40%-50% Efficiency)	Per Building	Existing	23	12	$20	25%	90%	$0.13	9,962
Gas	Hospital	Cooking	Steam Cooker	ENERGY STAR Steam Cooker	Non ENERGY STAR Steam Cooker	Per Building	Existing	32	12	$62	5.0%	35%	$0.31	1,985
Gas	Hospital	Space Heat Boiler	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	Demand Controlled Ventilation (CO2 sensors)	Constant Ventilation	Per Building	Existing	536	15	$4,249	5.0%	94%	$1.11	19,254
Gas	Hospital	Space Heat Boiler	Boiler Economizer	Economizer	No Economizer	Per Building	Existing	295	20	$992	10%	90%	$0.42	20,183

Table B-2.2. Commercial Gas Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (Therms)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per Therms)	2033 Cumulative Achievable Technical Potential (Therms)
Gas	Hospital	Space Heat Boiler	Commissioning of Existing Buildings	Existing Building Commissioning	Average Existing Conditions	Per Building	Existing	670	7	$3,352	90%	80%	$1.08	280,597
Gas	Hospital	Space Heat Boiler	Convert Constant Volume Air System to VAV	Variable Volume Air System	Constant Volume Air System	Per Building	Existing	697	15	$51,680	15%	67%	$10.41	53,182
Gas	Hospital	Space Heat Boiler	Direct Digital Control System-Installation	DDC Retrofit (Morning Warm-Up Control Logic Included in This Measure)	Pneumatic	Per Building	Existing	805	5	$16,345	20%	26%	$5.52	30,991
Gas	Hospital	Space Heat Boiler	Direct Digital Control System-Wireless System	DDC Retrofit - Wireless System	Pneumatic	Per Building	Existing	805	5	$6,606	75%	80%	$2.23	262,223
Gas	Hospital	Space Heat Boiler	Exhaust Air to Ventilation Air Heat Recovery	Exhaust Air Heat Recovery	No Heat Recovery	Per Building	Existing	805	10	$15,419	5.0%	94%	$3.28	26,161
Gas	Hospital	Space Heat Boiler	Exhaust Hood Makeup Air	Provide Makeup Air Directly at Exhaust Hood Instead of Pulling Conditioned Air	Hood Pulls Conditioned Air (No Make-up Air)	Per Building	Existing	241	10	$5,450	62%	85%	$3.87	86,734
Gas	Hospital	Space Heat Boiler	Infiltration Reduction	Install Caulking And Weatherstripping (ACH 0.65)	Infiltration Conditions (ACH 1.0)	Per Building	Existing	536	10	$440	10%	39%	$0.14	13,942
Gas	Hospital	Space Heat Boiler	Insulation - Ceiling	R-30 c.i. (WA State Code)	R-11 (Average Existing Conditions)	Per Building	Existing	918	25	$18,315	75%	13%	$2.46	59,764
Gas	Hospital	Space Heat Boiler	Insulation - Ceiling	R-38 c.i.	R-30 c.i. (WA State Code)	Per Building	Existing	10	25	$18,315	75%	70%	$209.10	3,724
Gas	Hospital	Space Heat Boiler	Insulation - Ceiling	R-49 c.i.	R-38 c.i.	Per Building	Existing	111	25	$5,166	75%	85%	$5.70	46,711
Gas	Hospital	Space Heat Boiler	Insulation - Floor (non-slab)	R-30 (WA State Code)	R-19 (Average Existing Conditions)	Per Building	Existing	486	25	$9,655	35%	35%	$2.45	38,582
Gas	Hospital	Space Heat Boiler	Insulation - Floor (non-slab)	R-38	R-30 (WA State Code)	Per Building	Existing	203	25	$2,979	35%	35%	$1.81	15,928
Gas	Hospital	Space Heat Boiler	Insulation - Wall	R-16	R-3 (Average Existing Conditions)	Per Building	Existing	3,787	25	$11,248	10%	35%	$0.37	84,445
Gas	Hospital	Space Heat Boiler	Pipe Insulation - Boiler	3" of Insulation, assuming R-12 (WA State Code)	No Insulation	Per Building	Existing	646	20	$1,888	75%	65%	$0.36	195,918
Gas	Hospital	Space Heat Boiler	Programmable Thermostat - Web Enabled	Programmable Thermostat - Web Enabled	No Programmable Thermostat	Per Building	Existing	161	15	$1,053	95%	24%	$0.92	21,202
Gas	Hospital	Space Heat Boiler	Sensible And Total Heat Recovery Devices	Install Heat Recovery Devices - rotary air-to-air enthalpy heat recovery- 70% sensible and latent recovery effectiveness	No Heat Recovery	Per Building	Existing	1,341	10	$35,871	25%	98%	$4.58	173,775
Gas	Hospital	Space Heat Boiler	Windows-High Efficiency	U-0.40 (WA State Code)	U-0.67 (Average Existing Conditions)	Per Building	Existing	69	25	$82,156	10%	60%	$145.84	2,068
Gas	Hospital	Space Heat Furnace	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	Demand Controlled Ventilation (CO2 sensors)	Constant Ventilation	Per Building	Existing	797	15	$4,249	5.0%	94%	$0.75	45,354
Gas	Hospital	Space Heat Furnace	Commissioning of Existing Buildings	Existing Building Commissioning	Average Existing Conditions	Per Building	Existing	996	7	$3,352	90%	80%	$0.73	708,122
Gas	Hospital	Space Heat Furnace	Convert Constant Volume Air System to VAV	Variable Volume Air System	Constant Volume Air System	Per Building	Existing	1,036	15	$51,680	15%	67%	$7.01	126,374
Gas	Hospital	Space Heat Furnace	Direct Digital Control System-Installation	DDC Retrofit (Morning Warm-Up Control Logic Included in This Measure)	Pneumatic	Per Building	Existing	1,196	5	$16,345	20%	26%	$3.72	73,360
Gas	Hospital	Space Heat Furnace	Direct Digital Control System-Wireless System	DDC Retrofit - Wireless System	Pneumatic	Per Building	Existing	1,196	5	$6,606	75%	80%	$1.50	620,711

Table B-2.2. Commercial Gas Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (Therms)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per Therms)	2033 Cumulative Achievable Technical Potential (Therms)
Gas	Hospital	Space Heat Furnace	Duct Repair And Sealing	Reduction In Duct Losses to 5%	No Repair or Sealing, 15% duct losses	Per Building	Existing	199	18	$6,800	45%	45%	$4.42	44,469
Gas	Hospital	Space Heat Furnace	Exhaust Air to Ventilation Air Heat Recovery	Exhaust Air Heat Recovery	No Heat Recovery	Per Building	Existing	1,196	10	$15,419	5.0%	94%	$2.21	61,613
Gas	Hospital	Space Heat Furnace	Exhaust Hood Makeup Air	Provide Makeup Air Directly at Exhaust Hood Instead of Pulling Conditioned Air	Hood Pulls Conditioned Air (No Make-up Air)	Per Building	Existing	358	10	$5,450	62%	85%	$2.60	204,269
Gas	Hospital	Space Heat Furnace	Infiltration Reduction	Install Caulking And Weatherstripping (ACH 0.65)	Infiltration Conditions (ACH 1.0)	Per Building	Existing	797	10	$440	10%	39%	$0.09	32,835
Gas	Hospital	Space Heat Furnace	Insulation - Ceiling	R-30 c.i. (WA State Code)	R-11 (Average Existing Conditions)	Per Building	Existing	1,363	25	$18,315	75%	13%	$1.66	140,751
Gas	Hospital	Space Heat Furnace	Insulation - Ceiling	R-38 c.i.	R-30 c.i. (WA State Code)	Per Building	Existing	16	25	$18,315	75%	70%	$140.74	8,772
Gas	Hospital	Space Heat Furnace	Insulation - Ceiling	R-49 c.i.	R-38 c.i.	Per Building	Existing	165	25	$5,166	75%	85%	$3.84	110,012
Gas	Hospital	Space Heat Furnace	Insulation - Duct	R-7 (WA State Code)	No Insulation	Per Building	Existing	334	25	$3,289	10%	15%	$1.21	5,154
Gas	Hospital	Space Heat Furnace	Insulation - Floor (non-slab)	R-30 (WA State Code)	R-19 (Average Existing Conditions)	Per Building	Existing	723	25	$9,655	35%	35%	$1.65	90,809
Gas	Hospital	Space Heat Furnace	Insulation - Floor (non-slab)	R-38	R-30 (WA State Code)	Per Building	Existing	301	25	$2,979	35%	35%	$1.22	37,490
Gas	Hospital	Space Heat Furnace	Insulation - Wall	R-16	R-3 (Average Existing Conditions)	Per Building	Existing	3,575	25	$11,248	10%	35%	$0.39	126,287
Gas	Hospital	Space Heat Furnace	Programmable Thermostat - Web Enabled	Programmable Thermostat - Web Enabled	No Programmable Thermostat	Per Building	Existing	239	15	$1,053	95%	24%	$0.62	53,506
Gas	Hospital	Space Heat Furnace	Windows-High Efficiency	U-0.40 (WA State Code)	U-0.67 (Average Existing Conditions)	Per Building	Existing	103	25	$82,156	10%	60%	$98.17	5,561
Gas	Hospital	Water Heat GT 55 Gal	Clothes Washer - Ozonating	Ozonating Clothes Washer	2013 Federal Standard Clothes Washer - MEF = 1.6, WF = 8.5	Per Building	Existing	1,243	10	$8,285	0.8%	95%	$0.12	669
Gas	Hospital	Water Heat GT 55 Gal	Clothes Washer Commercial	ENERGY STAR Commercial Clothes Washer - MEF = 2.43, WF = 4.0	2013 Federal Standard Clothes Washer - MEF = 1.6, WF = 8.5	Per Building	Existing	3	7	$42	95%	80%	$-8.01	220
Gas	Hospital	Water Heat GT 55 Gal	Demand Controlled Circulating Systems	Demand Controlled Circulating Systems (VFD control by demand)	Constant Circulation	Per Building	Existing	410	10	$4,722	55%	94%	$1.97	16,042
Gas	Hospital	Water Heat GT 55 Gal	Dishwasher Residential	RTF ENERGY STAR Dishwasher - 277 kWh/yr and 4.25 gal/cycle	RTF Market Standard 2014 Dishwasher - 289 kWh/yr and 5.0 gal/cycle	Per Building	Existing	1	12	$61	11%	25%	$6.00	2
Gas	Hospital	Water Heat GT 55 Gal	Dishwashing - Commercial - Low Temp	Low-Temp Commercial Dishwasher (Includes Extra Chemical Cost) - (ENERGY STAR)	Standard High Temp Commercial Dishwasher	Per Building	Existing	41	12	$627	95%	95%	$-13.97	2,830
Gas	Hospital	Water Heat GT 55 Gal	Drainwater Heat Recovery Water Heater	Install (Power-Pipe or GFX) - Heat Recovery Water Heater	No Heat Recovery System	Per Building	Existing	1,643	25	$12,082	5.0%	92%	$0.91	5,535
Gas	Hospital	Water Heat GT 55 Gal	Low-Flow Faucet Aerators	0.5 GPM	2.2 GPM (Federal Code)	Per Building	Existing	317	9	$17	95%	75%	$-0.03	17,108
Gas	Hospital	Water Heat GT 55 Gal	Low-Flow Faucet Aerators	2.2 GPM (Federal Code)	3.0 GPM	Per Building	Existing	109	9	$13	95%	25%	$-0.35	1,968
Gas	Hospital	Water Heat GT 55 Gal	Low-Flow Pre-Rinse Spray Valves	0.6 GPM	1.6 GPM (Federal Standard)	Per Building	Existing	19	4	$129	95%	83%	$2.06	1,146
Gas	Hospital	Water Heat GT 55 Gal	Low-Flow Showerheads	1.5 GPM	2.5 GPM (Federal Code)	Per Building	Existing	6	10	$62	95%	73%	$-0.94	356

Table B-2.2. Commercial Gas Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (Therms)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per Therms)	2033 Cumulative Achievable Technical Potential (Therms)
Gas	Hospital	Water Heat GT 55 Gal	Low-Flow Showerheads	2.5 GPM (Federal Code)	4.5 GPM	Per Building	Existing	13	10	$51	95%	35%	$-1.80	341
Gas	Hospital	Water Heat GT 55 Gal	Pipe Insulation - Hot Water (DWH)	1.0" of Insulation, assuming R-4 (WA State Code)	No Insulation	Per Building	Existing	82	12	$148	75%	70%	$0.28	3,111
Gas	Hospital	Water Heat GT 55 Gal	Ultrasonic Faucet Control	Install Ultrasonic Motion Faucet Control	No Faucet Control	Per Building	Existing	205	10	$1,669	75%	90%	$0.99	10,487
Gas	Hospital	Water Heat LE 55 Gal	Clothes Washer - Ozonating	Ozonating Clothes Washer	2013 Federal Standard Clothes Washer - MEF = 1.6, WF = 8.5	Per Building	Existing	1,131	10	$8,285	0.8%	95%	$0.24	7,061
Gas	Hospital	Water Heat LE 55 Gal	Clothes Washer Commercial	ENERGY STAR Commercial Clothes Washer - MEF = 2.43, WF = 4.0	2013 Federal Standard Clothes Washer - MEF = 1.6, WF = 8.5	Per Building	Existing	3	7	$42	95%	80%	$-8.01	2,554
Gas	Hospital	Water Heat LE 55 Gal	Demand Controlled Circulating Systems	Demand Controlled Circulating Systems (VFD control by demand)	Constant Circulation	Per Building	Existing	374	10	$4,722	55%	94%	$2.16	169,129
Gas	Hospital	Water Heat LE 55 Gal	Dishwasher Residential	RTF ENERGY STAR Dishwasher - 277 kWh/yr and 4.25 gal/cycle	RTF Market Standard 2014 Dishwasher - 289 kWh/yr and 5.0 gal/cycle	Per Building	Existing	1	12	$61	11%	25%	$6.00	32
Gas	Hospital	Water Heat LE 55 Gal	Dishwashing - Commercial - Low Temp	Low-Temp Commercial Dishwasher (Includes Extra Chemical Cost) - (ENERGY STAR)	Standard High Temp Commercial Dishwasher	Per Building	Existing	37	12	$570	95%	95%	$-15.58	29,845
Gas	Hospital	Water Heat LE 55 Gal	Drainwater Heat Recovery Water Heater	Install (Power-Pipe or GFX) - Heat Recovery Water Heater	No Heat Recovery System	Per Building	Existing	1,496	25	$12,082	5.0%	92%	$1.00	58,362
Gas	Hospital	Water Heat LE 55 Gal	Low-Flow Faucet Aerators	0.5 GPM	2.2 GPM (Federal Code)	Per Building	Existing	289	9	$17	95%	75%	$-0.03	180,376
Gas	Hospital	Water Heat LE 55 Gal	Low-Flow Faucet Aerators	2.2 GPM (Federal Code)	3.0 GPM	Per Building	Existing	99	9	$13	95%	25%	$-0.35	20,749
Gas	Hospital	Water Heat LE 55 Gal	Low-Flow Pre-Rinse Spray Valves	0.6 GPM	1.6 GPM (Federal Standard)	Per Building	Existing	19	4	$129	95%	83%	$2.06	13,274
Gas	Hospital	Water Heat LE 55 Gal	Low-Flow Showerheads	1.5 GPM	2.5 GPM (Federal Code)	Per Building	Existing	6	10	$62	95%	73%	$-0.94	4,128
Gas	Hospital	Water Heat LE 55 Gal	Low-Flow Showerheads	2.5 GPM (Federal Code)	4.5 GPM	Per Building	Existing	13	10	$51	95%	35%	$-1.80	3,959
Gas	Hospital	Water Heat LE 55 Gal	Pipe Insulation - Hot Water (DWH)	1.0" of Insulation, assuming R-4 (WA State Code)	No Insulation	Per Building	Existing	74	12	$148	75%	70%	$0.31	32,798
Gas	Hospital	Water Heat LE 55 Gal	Ultrasonic Faucet Control	Install Ultrasonic Motion Faucet Control	No Faucet Control	Per Building	Existing	187	10	$1,669	75%	90%	$1.12	110,571
Gas	Hotel Motel	Cooking	Broiler	High-Efficiency Broiler (34% Efficient)	Standard Broiler (15% Efficient)	Per Building	Existing	26	10	$1	95%	75%	$0.01	15,080
Gas	Hotel Motel	Cooking	Fryers - Commercial Gas Cooking	Energy Star Commercial Fryer (50% efficient)	Non-Energy Star Fryer (35% efficient)	Per Building	Existing	0.56	8	$13	35%	35%	$4.91	55
Gas	Hotel Motel	Cooking	Griddle	High-Efficiency Griddle (40% Efficient)	Standard Griddle (32% Efficient)	Per Building	Existing	2	12	$40	45%	35%	$2.99	18
Gas	Hotel Motel	Cooking	High Efficiency Convection Oven	Convection Oven	Standard Oven	Per Building	Existing	16	12	$27	85%	55%	$0.27	6,129
Gas	Hotel Motel	Cooking	Oven - Conveyor	High-Efficiency Model (23% Efficient)	Standard Model (15% Efficient)	Per Building	Existing	147	10	$34	5.0%	85%	$0.04	5,056
Gas	Hotel Motel	Cooking	Oven - Power Burner	Power Burner Oven - Improved Atmospheric Burner (60% Efficient)	Standard (40%-50% Efficiency)	Per Building	Existing	52	12	$64	15%	90%	$0.19	5,771
Gas	Hotel Motel	Cooking	Steam Cooker	ENERGY STAR Steam Cooker	Non ENERGY STAR Steam Cooker	Per Building	Existing	38	12	$75	2.5%	35%	$0.31	520

Table B-2.2. Commercial Gas Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (Therms)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per Therms)	2033 Cumulative Achievable Technical Potential (Therms)
Gas	Hotel Motel	Pool Heat	RE - Installation of Solar Pool/Spa Heating Systems	Solar Pool/Spa Heating Systems	No Solar Pool Heating System	Per Building	Existing	197	12	$9,119	30%	90%	$7.26	19,313
Gas	Hotel Motel	Pool Heat	Swimming Pool/Spa Covers	Automatic Plastic Or Foam Pool Covers (50-65% Energy Savings)	No Pool Covers	Per Building	Existing	784	10	$6,292	95%	35%	$1.37	94,393
Gas	Hotel Motel	Space Heat Boiler	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	Demand Controlled Ventilation (CO2 sensors)	Constant Ventilation	Per Building	Existing	57	15	$4,375	50%	94%	$10.73	7,908
Gas	Hotel Motel	Space Heat Boiler	Boiler Economizer	Economizer	No Economizer	Per Building	Existing	157	20	$1,022	10%	30%	$0.81	1,375
Gas	Hotel Motel	Space Heat Boiler	Commissioning of Existing Buildings	Existing Building Commissioning	Average Existing Conditions	Per Building	Existing	358	7	$3,450	90%	80%	$2.09	57,036
Gas	Hotel Motel	Space Heat Boiler	Convert Constant Volume Air System to VAV	Variable Volume Air System	Constant Volume Air System	Per Building	Existing	372	15	$53,200	15%	67%	$20.07	10,948
Gas	Hotel Motel	Space Heat Boiler	Direct Digital Control System-Installation	DDC Retrofit (Morning Warm-Up Control Logic Included in This Measure)	Pneumatic	Per Building	Existing	429	5	$16,826	10%	52%	$10.65	6,462
Gas	Hotel Motel	Space Heat Boiler	Direct Digital Control System-Wireless System	DDC Retrofit - Wireless System	Pneumatic	Per Building	Existing	429	5	$6,800	50%	80%	$4.30	39,102
Gas	Hotel Motel	Space Heat Boiler	Exhaust Air to Ventilation Air Heat Recovery	Exhaust Air Heat Recovery	No Heat Recovery	Per Building	Existing	429	10	$15,872	5.0%	94%	$6.33	5,467
Gas	Hotel Motel	Space Heat Boiler	Exhaust Hood Makeup Air	Provide Makeup Air Directly at Exhaust Hood Instead of Pulling Conditioned Air	Hood Pulls Conditioned Air (No Make-up Air)	Per Building	Existing	128	10	$5,449	58%	85%	$7.24	16,992
Gas	Hotel Motel	Space Heat Boiler	Infiltration Reduction	Install Caulking And Weatherstripping (ACH 0.65)	Infiltration Conditions (ACH 1.0)	Per Building	Existing	286	10	$933	10%	39%	$0.56	2,918
Gas	Hotel Motel	Space Heat Boiler	Insulation - Ceiling	R-30 c.i. (WA State Code)	R-11 (Average Existing Conditions)	Per Building	Existing	421	25	$11,371	75%	25%	$3.32	20,703
Gas	Hotel Motel	Space Heat Boiler	Insulation - Ceiling	R-38 c.i.	R-30 c.i. (WA State Code)	Per Building	Existing	4	25	$11,371	75%	70%	$320.78	584
Gas	Hotel Motel	Space Heat Boiler	Insulation - Ceiling	R-49 c.i.	R-38 c.i.	Per Building	Existing	51	25	$3,208	75%	85%	$7.71	8,323
Gas	Hotel Motel	Space Heat Boiler	Insulation - Floor (non-slab)	R-30 (WA State Code)	R-7 (Average Existing Conditions)	Per Building	Existing	678	25	$5,995	35%	45%	$1.09	26,858
Gas	Hotel Motel	Space Heat Boiler	Insulation - Floor (non-slab)	R-38	R-30 (WA State Code)	Per Building	Existing	86	25	$1,850	35%	45%	$2.63	3,312
Gas	Hotel Motel	Space Heat Boiler	Insulation - Wall	R-16	R-3 (Average Existing Conditions)	Per Building	Existing	1,314	25	$17,675	10%	35%	$1.66	11,084
Gas	Hotel Motel	Space Heat Boiler	Pipe Insulation - Boiler	3" of Insulation, assuming R-12 (WA State Code)	No Insulation	Per Building	Existing	345	20	$1,915	75%	65%	$0.69	39,907
Gas	Hotel Motel	Space Heat Boiler	Programmable Thermostat - Web Enabled	Programmable Thermostat - Web Enabled	No Programmable Thermostat	Per Building	Existing	85	15	$1,749	95%	31%	$2.86	5,647
Gas	Hotel Motel	Space Heat Boiler	Sensible And Total Heat Recovery Devices	Install Heat Recovery Devices - rotary air-to-air enthalpy heat recovery- 70% sensible and latent recovery effectiveness	No Heat Recovery	Per Building	Existing	716	10	$36,924	25%	98%	$8.83	35,322
Gas	Hotel Motel	Space Heat Boiler	Windows-High Efficiency	U-0.40 (WA State Code)	U-0.65 (Average Existing Conditions)	Per Building	Existing	21	25	$74,129	10%	50%	$999.87	202

Table B-2.2. Commercial Gas Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (Therms)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per Therms)	2033 Cumulative Achievable Technical Potential (Therms)
Gas	Hotel Motel	Space Heat Furnace	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	Demand Controlled Ventilation (CO2 sensors)	Constant Ventilation	Per Building	Existing	85	15	$4,375	50%	94%	$7.22	4,465
Gas	Hotel Motel	Space Heat Furnace	Commissioning of Existing Buildings	Existing Building Commissioning	Average Existing Conditions	Per Building	Existing	532	7	$3,450	90%	80%	$1.40	33,961
Gas	Hotel Motel	Space Heat Furnace	Convert Constant Volume Air System to VAV	Variable Volume Air System	Constant Volume Air System	Per Building	Existing	553	15	$53,200	15%	67%	$13.51	6,191
Gas	Hotel Motel	Space Heat Furnace	Direct Digital Control System-Installation	DDC Retrofit (Morning Warm-Up Control Logic Included in This Measure)	Pneumatic	Per Building	Existing	638	5	$16,826	10%	52%	$7.17	3,654
Gas	Hotel Motel	Space Heat Furnace	Direct Digital Control System-Wireless System	DDC Retrofit - Wireless System	Pneumatic	Per Building	Existing	638	5	$6,800	50%	80%	$2.90	22,113
Gas	Hotel Motel	Space Heat Furnace	Duct Repair And Sealing	Reduction In Duct Losses to 5%	No Repair or Sealing, 15% duct losses	Per Building	Existing	106	18	$6,999	45%	45%	$8.52	2,220
Gas	Hotel Motel	Space Heat Furnace	Exhaust Air to Ventilation Air Heat Recovery	Exhaust Air Heat Recovery	No Heat Recovery	Per Building	Existing	638	10	$15,872	5.0%	94%	$4.26	3,076
Gas	Hotel Motel	Space Heat Furnace	Exhaust Hood Makeup Air	Provide Makeup Air Directly at Exhaust Hood Instead of Pulling Conditioned Air	Hood Pulls Conditioned Air (No Make-up Air)	Per Building	Existing	191	10	$5,449	58%	85%	$4.87	9,561
Gas	Hotel Motel	Space Heat Furnace	Infiltration Reduction	Install Caulking And Weatherstripping (ACH 0.65)	Infiltration Conditions (ACH 1.0)	Per Building	Existing	425	10	$933	10%	39%	$0.38	1,641
Gas	Hotel Motel	Space Heat Furnace	Insulation - Ceiling	R-30 c.i. (WA State Code)	R-11 (Average Existing Conditions)	Per Building	Existing	626	25	$11,371	75%	25%	$2.24	11,649
Gas	Hotel Motel	Space Heat Furnace	Insulation - Ceiling	R-38 c.i.	R-30 c.i. (WA State Code)	Per Building	Existing	6	25	$11,371	75%	70%	$215.92	328
Gas	Hotel Motel	Space Heat Furnace	Insulation - Ceiling	R-49 c.i.	R-38 c.i.	Per Building	Existing	76	25	$3,208	75%	85%	$5.19	4,683
Gas	Hotel Motel	Space Heat Furnace	Insulation - Duct	R-7 (WA State Code)	No Insulation	Per Building	Existing	178	25	$3,386	10%	15%	$2.34	255
Gas	Hotel Motel	Space Heat Furnace	Insulation - Floor (non-slab)	R-30 (WA State Code)	R-7 (Average Existing Conditions)	Per Building	Existing	1,007	25	$5,995	35%	45%	$0.73	15,102
Gas	Hotel Motel	Space Heat Furnace	Insulation - Floor (non-slab)	R-38	R-30 (WA State Code)	Per Building	Existing	129	25	$1,850	35%	45%	$1.77	1,862
Gas	Hotel Motel	Space Heat Furnace	Insulation - Wall	R-16	R-3 (Average Existing Conditions)	Per Building	Existing	2,348	25	$17,675	10%	35%	$0.93	7,492
Gas	Hotel Motel	Space Heat Furnace	Programmable Thermostat - Web Enabled	Programmable Thermostat - Web Enabled	No Programmable Thermostat	Per Building	Existing	127	15	$1,749	95%	31%	$1.92	3,362
Gas	Hotel Motel	Space Heat Furnace	Windows-High Efficiency	U-0.40 (WA State Code)	U-0.65 (Average Existing Conditions)	Per Building	Existing	31	25	$74,129	10%	50%	$673.02	128
Gas	Hotel Motel	Water Heat GT 55 Gal	Clothes Washer - Ozonating	Ozonating Clothes Washer	2013 Federal Standard Clothes Washer - MEF = 1.6, WF = 8.5	Per Building	Existing	967	10	$8,285	1.8%	95%	$0.45	432
Gas	Hotel Motel	Water Heat GT 55 Gal	Clothes Washer Commercial	ENERGY STAR Commercial Clothes Washer - MEF = 2.43, WF = 4.0	2013 Federal Standard Clothes Washer - MEF = 1.6, WF = 8.5	Per Building	Existing	35	7	$401	95%	80%	$1.31	733
Gas	Hotel Motel	Water Heat GT 55 Gal	Demand Controlled Circulating Systems	Demand Controlled Circulating Systems (VFD control by demand)	Constant Circulation	Per Building	Existing	319	10	$4,861	55%	80%	$2.61	3,761
Gas	Hotel Motel	Water Heat GT 55 Gal	Dishwasher Residential	RTF ENERGY STAR Dishwasher - 277 kWh/yr and 4.25 gal/cycle	RTF Market Standard 2014 Dishwasher - 289 kWh/yr and 5.0 gal/cycle	Per Building	Existing	2	12	$101	24%	25%	$6.34	3

Table B-2.2. Commercial Gas Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (Therms)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per Therms)	2033 Cumulative Achievable Technical Potential (Therms)
Gas	Hotel Motel	Water Heat GT 55 Gal	Dishwashing - Commercial - Low Temp	Low-Temp Commercial Dishwasher (Includes Extra Chemical Cost) - (ENERGY STAR)	Standard High Temp Commercial Dishwasher	Per Building	Existing	56	12	$852	95%	95%	$-9.63	1,371
Gas	Hotel Motel	Water Heat GT 55 Gal	Drainwater Heat Recovery Water Heater	Install (Power-Pipe or GFX) - Heat Recovery Water Heater	No Heat Recovery System	Per Building	Existing	1,279	25	$11,458	5.0%	92%	$1.11	1,525
Gas	Hotel Motel	Water Heat GT 55 Gal	Low-Flow Faucet Aerators	0.5 GPM	2.2 GPM (Federal Code)	Per Building	Existing	247	9	$69	95%	75%	$0.05	4,739
Gas	Hotel Motel	Water Heat GT 55 Gal	Low-Flow Faucet Aerators	2.2 GPM (Federal Code)	3.0 GPM	Per Building	Existing	85	9	$59	95%	25%	$0.04	545
Gas	Hotel Motel	Water Heat GT 55 Gal	Low-Flow Pre-Rinse Spray Valves	0.6 GPM	1.6 GPM (Federal Standard)	Per Building	Existing	32	4	$220	95%	93%	$2.11	770
Gas	Hotel Motel	Water Heat GT 55 Gal	Low-Flow Showerheads	1.5 GPM	2.5 GPM (Federal Code)	Per Building	Existing	245	10	$1,591	95%	73%	$1.02	4,573
Gas	Hotel Motel	Water Heat GT 55 Gal	Low-Flow Showerheads	2.5 GPM (Federal Code)	4.5 GPM	Per Building	Existing	490	10	$1,324	95%	35%	$0.37	4,385
Gas	Hotel Motel	Water Heat GT 55 Gal	Pipe Insulation - Hot Water (DWH)	1.0" of Insulation, assuming R-4 (WA State Code)	No Insulation	Per Building	Existing	63	12	$139	75%	90%	$0.34	1,070
Gas	Hotel Motel	Water Heat GT 55 Gal	Ultrasonic Faucet Control	Install Ultrasonic Motion Faucet Control	No Faucet Control	Per Building	Existing	159	10	$6,877	75%	85%	$7.28	2,743
Gas	Hotel Motel	Water Heat LE 55 Gal	Clothes Washer - Ozonating	Ozonating Clothes Washer	2013 Federal Standard Clothes Washer - MEF = 1.6, WF = 8.5	Per Building	Existing	880	10	$8,285	1.8%	95%	$0.59	4,563
Gas	Hotel Motel	Water Heat LE 55 Gal	Clothes Washer Commercial	ENERGY STAR Commercial Clothes Washer - MEF = 2.43, WF = 4.0	2013 Federal Standard Clothes Washer - MEF = 1.6, WF = 8.5	Per Building	Existing	35	7	$401	95%	80%	$1.31	8,489
Gas	Hotel Motel	Water Heat LE 55 Gal	Demand Controlled Circulating Systems	Demand Controlled Circulating Systems (VFD control by demand)	Constant Circulation	Per Building	Existing	291	10	$4,861	55%	80%	$2.86	39,643
Gas	Hotel Motel	Water Heat LE 55 Gal	Dishwasher Residential	RTF ENERGY STAR Dishwasher - 277 kWh/yr and 4.25 gal/cycle	RTF Market Standard 2014 Dishwasher - 289 kWh/yr and 5.0 gal/cycle	Per Building	Existing	2	12	$101	24%	25%	$6.34	43
Gas	Hotel Motel	Water Heat LE 55 Gal	Dishwashing - Commercial - Low Temp	Low-Temp Commercial Dishwasher (Includes Extra Chemical Cost) - (ENERGY STAR)	Standard High Temp Commercial Dishwasher	Per Building	Existing	51	12	$775	95%	95%	$-10.82	14,455
Gas	Hotel Motel	Water Heat LE 55 Gal	Drainwater Heat Recovery Water Heater	Install (Power-Pipe or GFX) - Heat Recovery Water Heater	No Heat Recovery System	Per Building	Existing	1,164	25	$11,458	5.0%	92%	$1.21	16,080
Gas	Hotel Motel	Water Heat LE 55 Gal	Low-Flow Faucet Aerators	0.5 GPM	2.2 GPM (Federal Code)	Per Building	Existing	224	9	$69	95%	75%	$0.05	49,964
Gas	Hotel Motel	Water Heat LE 55 Gal	Low-Flow Faucet Aerators	2.2 GPM (Federal Code)	3.0 GPM	Per Building	Existing	77	9	$59	95%	25%	$0.06	5,747
Gas	Hotel Motel	Water Heat LE 55 Gal	Low-Flow Pre-Rinse Spray Valves	0.6 GPM	1.6 GPM (Federal Standard)	Per Building	Existing	32	4	$220	95%	93%	$2.11	8,926
Gas	Hotel Motel	Water Heat LE 55 Gal	Low-Flow Showerheads	1.5 GPM	2.5 GPM (Federal Code)	Per Building	Existing	245	10	$1,591	95%	73%	$1.02	52,958
Gas	Hotel Motel	Water Heat LE 55 Gal	Low-Flow Showerheads	2.5 GPM (Federal Code)	4.5 GPM	Per Building	Existing	490	10	$1,324	95%	35%	$0.37	50,782
Gas	Hotel Motel	Water Heat LE 55 Gal	Pipe Insulation - Hot Water (DWH)	1.0" of Insulation, assuming R-4 (WA State Code)	No Insulation	Per Building	Existing	58	12	$139	75%	90%	$0.38	11,247
Gas	Hotel Motel	Water Heat LE 55 Gal	Ultrasonic Faucet Control	Install Ultrasonic Motion Faucet Control	No Faucet Control	Per Building	Existing	145	10	$6,877	75%	85%	$8.00	28,927

Table B-2.2. Commercial Gas Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (Therms)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per Therms)	2033 Cumulative Achievable Technical Potential (Therms)
Gas	Office	Space Heat Boiler	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	Demand Controlled Ventilation (CO2 sensors)	Constant Ventilation	Per Building	Existing	328	15	$3,875	75%	94%	$1.66	1,066,807
Gas	Office	Space Heat Boiler	Boiler Economizer	Economizer	No Economizer	Per Building	Existing	180	20	$904	10%	45%	$0.62	34,811
Gas	Office	Space Heat Boiler	Commissioning of Existing Buildings	Existing Building Commissioning	Average Existing Conditions	Per Building	Existing	411	7	$3,056	90%	80%	$1.61	1,026,378
Gas	Office	Space Heat Boiler	Convert Constant Volume Air System to VAV	Variable Volume Air System	Constant Volume Air System	Per Building	Existing	427	15	$47,120	15%	67%	$15.49	184,610
Gas	Office	Space Heat Boiler	Direct Digital Control System-Installation	DDC Retrofit (Morning Warm-Up Control Logic Included in This Measure)	Pneumatic	Per Building	Existing	493	5	$14,904	20%	28%	$8.22	115,515
Gas	Office	Space Heat Boiler	Direct Digital Control System-Wireless System	DDC Retrofit - Wireless System	Pneumatic	Per Building	Existing	493	5	$6,024	75%	80%	$3.32	906,197
Gas	Office	Space Heat Boiler	Exhaust Air to Ventilation Air Heat Recovery	Exhaust Air Heat Recovery	No Heat Recovery	Per Building	Existing	493	10	$14,059	5.0%	94%	$4.89	90,409
Gas	Office	Space Heat Boiler	Infiltration Reduction	Install Caulking And Weatherstripping (ACH 0.65)	Infiltration Conditions (ACH 1.0)	Per Building	Existing	328	10	$502	10%	39%	$0.26	49,342
Gas	Office	Space Heat Boiler	Insulation - Ceiling	R-30 c.i. (WA State Code)	R-11 (Average Existing Conditions)	Per Building	Existing	366	25	$15,196	75%	4%	$5.11	42,449
Gas	Office	Space Heat Boiler	Insulation - Ceiling	R-38 c.i.	R-30 c.i. (WA State Code)	Per Building	Existing	6	25	$15,196	75%	50%	$296.57	9,112
Gas	Office	Space Heat Boiler	Insulation - Ceiling	R-49 c.i.	R-38 c.i.	Per Building	Existing	44	25	$4,286	75%	65%	$11.85	83,605
Gas	Office	Space Heat Boiler	Insulation - Floor (non-slab)	R-30 (WA State Code)	R-11 (Average Existing Conditions)	Per Building	Existing	643	25	$8,011	35%	15%	$1.53	129,001
Gas	Office	Space Heat Boiler	Insulation - Floor (non-slab)	R-38	R-30 (WA State Code)	Per Building	Existing	119	25	$2,471	35%	15%	$2.54	23,765
Gas	Office	Space Heat Boiler	Insulation - Wall	R-16	R-3 (Average Existing Conditions)	Per Building	Existing	1,445	25	$16,510	10%	35%	$1.41	190,740
Gas	Office	Space Heat Boiler	Pipe Insulation - Boiler	3" of Insulation, assuming R-12 (WA State Code)	No Insulation	Per Building	Existing	396	20	$1,802	75%	65%	$0.57	717,062
Gas	Office	Space Heat Boiler	Programmable Thermostat - Web Enabled	Programmable Thermostat - Web Enabled	No Programmable Thermostat	Per Building	Existing	98	15	$1,158	95%	26%	$1.65	84,379
Gas	Office	Space Heat Boiler	Sensible And Total Heat Recovery Devices	Install Heat Recovery Devices - rotary air-to-air enthalpy heat recovery- 70% sensible and latent recovery effectiveness	No Heat Recovery	Per Building	Existing	822	10	$32,704	25%	98%	$6.82	635,641
Gas	Office	Space Heat Furnace	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	Demand Controlled Ventilation (CO2 sensors)	Constant Ventilation	Per Building	Existing	488	15	$3,875	75%	94%	$1.11	2,142,715
Gas	Office	Space Heat Furnace	Commissioning of Existing Buildings	Existing Building Commissioning	Average Existing Conditions	Per Building	Existing	610	7	$3,056	90%	80%	$1.08	2,162,482
Gas	Office	Space Heat Furnace	Convert Constant Volume Air System to VAV	Variable Volume Air System	Constant Volume Air System	Per Building	Existing	635	15	$47,120	15%	67%	$10.43	371,716
Gas	Office	Space Heat Furnace	Direct Digital Control System-Installation	DDC Retrofit (Morning Warm-Up Control Logic Included in This Measure)	Pneumatic	Per Building	Existing	732	5	$14,904	20%	28%	$5.53	232,591

Table B-2.2. Commercial Gas Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (Therms)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per Therms)	2033 Cumulative Achievable Technical Potential (Therms)
Gas	Office	Space Heat Furnace	Direct Digital Control System-Wireless System	DDC Retrofit - Wireless System	Pneumatic	Per Building	Existing	732	5	$6,024	75%	80%	$2.24	1,824,642
Gas	Office	Space Heat Furnace	Duct Repair And Sealing	Reduction In Duct Losses to 5%	No Repair or Sealing, 15% duct losses	Per Building	Existing	122	18	$6,199	45%	45%	$6.58	130,721
Gas	Office	Space Heat Furnace	Exhaust Air to Ventilation Air Heat Recovery	Exhaust Air Heat Recovery	No Heat Recovery	Per Building	Existing	732	10	$14,059	5.0%	94%	$3.29	181,119
Gas	Office	Space Heat Furnace	Infiltration Reduction	Install Caulking And Weatherstripping (ACH 0.65)	Infiltration Conditions (ACH 1.0)	Per Building	Existing	488	10	$502	10%	39%	$0.18	98,849
Gas	Office	Space Heat Furnace	Insulation - Ceiling	R-30 c.i. (WA State Code)	R-11 (Average Existing Conditions)	Per Building	Existing	544	25	$15,196	75%	4%	$3.44	85,040
Gas	Office	Space Heat Furnace	Insulation - Ceiling	R-38 c.i.	R-30 c.i. (WA State Code)	Per Building	Existing	9	25	$15,196	75%	50%	$199.62	18,255
Gas	Office	Space Heat Furnace	Insulation - Ceiling	R-49 c.i.	R-38 c.i.	Per Building	Existing	66	25	$4,286	75%	65%	$7.97	167,488
Gas	Office	Space Heat Furnace	Insulation - Duct	R-7 (WA State Code)	No Insulation	Per Building	Existing	205	25	$2,998	10%	15%	$1.80	15,838
Gas	Office	Space Heat Furnace	Insulation - Floor (non-slab)	R-30 (WA State Code)	R-11 (Average Existing Conditions)	Per Building	Existing	956	25	$8,011	35%	15%	$1.03	258,269
Gas	Office	Space Heat Furnace	Insulation - Floor (non-slab)	R-38	R-30 (WA State Code)	Per Building	Existing	178	25	$2,471	35%	15%	$1.71	47,579
Gas	Office	Space Heat Furnace	Insulation - Wall	R-16	R-3 (Average Existing Conditions)	Per Building	Existing	3,447	25	$16,510	10%	35%	$0.59	612,927
Gas	Office	Space Heat Furnace	Programmable Thermostat - Web Enabled	Programmable Thermostat - Web Enabled	No Programmable Thermostat	Per Building	Existing	146	15	$1,158	95%	26%	$1.11	177,778
Gas	Office	Water Heat GT 55 Gal	Demand Controlled Circulating Systems	Demand Controlled Circulating Systems (VFD control by demand)	Constant Circulation	Per Building	Existing	31	10	$4,305	55%	80%	$23.08	5,568
Gas	Office	Water Heat GT 55 Gal	Dishwasher Residential	RTF ENERGY STAR Dishwasher - 277 kWh/yr and 4.25 gal/cycle	RTF Market Standard 2014 Dishwasher - 289 kWh/yr and 5.0 gal/cycle	Per Building	Existing	1	12	$66	8.1%	25%	$6.09	12
Gas	Office	Water Heat GT 55 Gal	Drainwater Heat Recovery Water Heater	Install (Power-Pipe or GFX) - Heat Recovery Water Heater	No Heat Recovery System	Per Building	Existing	127	25	$2,083	5.0%	92%	$2.01	2,277
Gas	Office	Water Heat GT 55 Gal	Low-Flow Faucet Aerators	0.5 GPM	2.2 GPM (Federal Code)	Per Building	Existing	24	9	$6	95%	75%	$-0.27	6,968
Gas	Office	Water Heat GT 55 Gal	Low-Flow Faucet Aerators	2.2 GPM (Federal Code)	3.0 GPM	Per Building	Existing	8	9	$4	95%	25%	$-0.93	801
Gas	Office	Water Heat GT 55 Gal	Low-Flow Showerheads	1.5 GPM	2.5 GPM (Federal Code)	Per Building	Existing	1	10	$13	95%	73%	$-9.03	340
Gas	Office	Water Heat GT 55 Gal	Low-Flow Showerheads	2.5 GPM (Federal Code)	4.5 GPM	Per Building	Existing	2	10	$12	95%	35%	$-10.10	326
Gas	Office	Water Heat GT 55 Gal	Pipe Insulation - Hot Water (DWH)	1.0" of Insulation, assuming R-4 (WA State Code)	No Insulation	Per Building	Existing	6	12	$24	75%	30%	$0.61	549
Gas	Office	Water Heat GT 55 Gal	Ultrasonic Faucet Control	Install Ultrasonic Motion Faucet Control	No Faucet Control	Per Building	Existing	15	10	$609	75%	85%	$5.43	4,034
Gas	Office	Water Heat LE 55 Gal	Demand Controlled Circulating Systems	Demand Controlled Circulating Systems (VFD control by demand)	Constant Circulation	Per Building	Existing	29	10	$4,305	55%	80%	$25.35	58,710
Gas	Office	Water Heat LE 55 Gal	Dishwasher Residential	RTF ENERGY STAR Dishwasher - 277 kWh/yr and 4.25 gal/cycle	RTF Market Standard 2014 Dishwasher - 289 kWh/yr and 5.0 gal/cycle	Per Building	Existing	1	12	$66	8.1%	25%	$6.09	141
Gas	Office	Water Heat LE 55 Gal	Drainwater Heat Recovery Water Heater	Install (Power-Pipe or GFX) - Heat Recovery Water Heater	No Heat Recovery System	Per Building	Existing	116	25	$2,083	5.0%	92%	$2.21	24,011

Table B-2.2. Commercial Gas Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (Therms)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per Therms)	2033 Cumulative Achievable Technical Potential (Therms)
Gas	Office	Water Heat LE 55 Gal	Low-Flow Faucet Aerators	0.5 GPM	2.2 GPM (Federal Code)	Per Building	Existing	22	9	$6	95%	75%	$-0.30	73,463
Gas	Office	Water Heat LE 55 Gal	Low-Flow Faucet Aerators	2.2 GPM (Federal Code)	3.0 GPM	Per Building	Existing	7	9	$4	95%	25%	$-0.89	8,450
Gas	Office	Water Heat LE 55 Gal	Low-Flow Showerheads	1.5 GPM	2.5 GPM (Federal Code)	Per Building	Existing	1	10	$13	95%	73%	$-9.03	3,941
Gas	Office	Water Heat LE 55 Gal	Low-Flow Showerheads	2.5 GPM (Federal Code)	4.5 GPM	Per Building	Existing	2	10	$12	95%	35%	$-10.10	3,779
Gas	Office	Water Heat LE 55 Gal	Pipe Insulation - Hot Water (DWH)	1.0" of Insulation, assuming R-4 (WA State Code)	No Insulation	Per Building	Existing	5	12	$24	75%	30%	$0.67	5,790
Gas	Office	Water Heat LE 55 Gal	Ultrasonic Faucet Control	Install Ultrasonic Motion Faucet Control	No Faucet Control	Per Building	Existing	14	10	$609	75%	85%	$6.10	42,531
Gas	Other	Cooking	Broiler	High-Efficiency Broiler (34% Efficient)	Standard Broiler (15% Efficient)	Per Building	Existing	8	10	$2	95%	75%	$0.05	55,971
Gas	Other	Cooking	Fryers - Commercial Gas Cooking	Energy Star Commercial Fryer (50% efficient)	Non-Energy Star Fryer (35% efficient)	Per Building	Existing	0.19	8	$14	20%	35%	$14.70	118
Gas	Other	Cooking	Griddle	High-Efficiency Griddle (40% Efficient)	Standard Griddle (32% Efficient)	Per Building	Existing	2	12	$39	20%	35%	$2.94	53
Gas	Other	Cooking	High Efficiency Convection Oven	Convection Oven	Standard Oven	Per Building	Existing	5	12	$27	85%	85%	$0.78	35,158
Gas	Other	Cooking	Oven - Conveyor	High-Efficiency Model (23% Efficient)	Standard Model (15% Efficient)	Per Building	Existing	50	10	$34	5.0%	85%	$0.12	18,765
Gas	Other	Cooking	Oven - Power Burner	Power Burner Oven - Improved Atmospheric Burner (60% Efficient)	Standard (40%-50% Efficiency)	Per Building	Existing	18	12	$65	5.0%	90%	$0.57	7,140
Gas	Other	Cooking	Steam Cooker	ENERGY STAR Steam Cooker	Non ENERGY STAR Steam Cooker	Per Building	Existing	23	12	$44	5.0%	35%	$0.30	6,757
Gas	Other	Pool Heat	RE - Installation of Solar Pool/Spa Heating Systems	Solar Pool/Spa Heating Systems	No Solar Pool Heating System	Per Building	Existing	197	12	$9,119	5.0%	90%	$7.26	20,653
Gas	Other	Pool Heat	Swimming Pool/Spa Covers	Automatic Plastic Or Foam Pool Covers (50-65% Energy Savings)	No Pool Covers	Per Building	Existing	784	10	$6,292	95%	35%	$1.37	605,640
Gas	Other	Space Heat Boiler	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	Demand Controlled Ventilation (CO2 sensors)	Constant Ventilation	Per Building	Existing	168	15	$3,000	50%	94%	$2.51	325,115
Gas	Other	Space Heat Boiler	Boiler Economizer	Economizer	No Economizer	Per Building	Existing	92	20	$700	10%	90%	$0.94	32,631
Gas	Other	Space Heat Boiler	Commissioning of Existing Buildings	Existing Building Commissioning	Average Existing Conditions	Per Building	Existing	210	7	$2,366	90%	80%	$2.44	446,510
Gas	Other	Space Heat Boiler	Convert Constant Volume Air System to VAV	Variable Volume Air System	Constant Volume Air System	Per Building	Existing	218	15	$36,479	15%	67%	$23.43	85,983
Gas	Other	Space Heat Boiler	Direct Digital Control System-Installation	DDC Retrofit (Morning Warm-Up Control Logic Included in This Measure)	Pneumatic	Per Building	Existing	252	5	$11,538	10%	66%	$12.43	63,622
Gas	Other	Space Heat Boiler	Direct Digital Control System-Wireless System	DDC Retrofit - Wireless System	Pneumatic	Per Building	Existing	252	5	$4,663	50%	80%	$5.03	307,680
Gas	Other	Space Heat Boiler	Exhaust Air to Ventilation Air Heat Recovery	Exhaust Air Heat Recovery	No Heat Recovery	Per Building	Existing	252	10	$10,883	5.0%	94%	$7.39	43,021
Gas	Other	Space Heat Boiler	Exhaust Hood Makeup Air	Provide Makeup Air Directly at Exhaust Hood Instead of Pulling Conditioned Air	Hood Pulls Conditioned Air (No Make-up Air)	Per Building	Existing	75	10	$5,450	5.0%	85%	$12.33	11,588

Table B-2.2. Commercial Gas Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (Therms)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per Therms)	2033 Cumulative Achievable Technical Potential (Therms)
Gas	Other	Space Heat Boiler	Infiltration Reduction	Install Caulking And Weatherstripping (ACH 0.65)	Infiltration Conditions (ACH 1.0)	Per Building	Existing	110	10	$172	10%	39%	$0.27	15,325
Gas	Other	Space Heat Boiler	Insulation - Ceiling	R-30 c.i. (WA State Code)	R-11 (Average Existing Conditions)	Per Building	Existing	236	25	$17,522	75%	30%	$9.14	190,766
Gas	Other	Space Heat Boiler	Insulation - Ceiling	R-38 c.i.	R-30 c.i. (WA State Code)	Per Building	Existing	3	25	$17,522	75%	70%	$556.89	7,072
Gas	Other	Space Heat Boiler	Insulation - Ceiling	R-49 c.i.	R-38 c.i.	Per Building	Existing	28	25	$4,943	75%	85%	$21.18	63,619
Gas	Other	Space Heat Boiler	Insulation - Floor (non-slab)	R-30 (WA State Code)	R-7 (Average Existing Conditions)	Per Building	Existing	556	25	$9,238	35%	50%	$2.05	334,164
Gas	Other	Space Heat Boiler	Insulation - Floor (non-slab)	R-38	R-30 (WA State Code)	Per Building	Existing	71	25	$2,849	35%	50%	$4.93	40,325
Gas	Other	Space Heat Boiler	Insulation - Wall	R-16	R-3 (Average Existing Conditions)	Per Building	Existing	735	25	$8,620	10%	35%	$1.45	82,494
Gas	Other	Space Heat Boiler	Pipe Insulation - Boiler	3" of Insulation, assuming R-12 (WA State Code)	No Insulation	Per Building	Existing	202	20	$1,586	75%	65%	$0.97	312,185
Gas	Other	Space Heat Boiler	Programmable Thermostat - Web Enabled	Programmable Thermostat - Web Enabled	No Programmable Thermostat	Per Building	Existing	50	15	$778	95%	28%	$2.17	40,531
Gas	Other	Space Heat Boiler	Sensible And Total Heat Recovery Devices	Install Heat Recovery Devices - rotary air-to-air enthalpy heat recovery- 70% sensible and latent recovery effectiveness	No Heat Recovery	Per Building	Existing	420	10	$25,319	25%	98%	$10.31	276,526
Gas	Other	Space Heat Boiler	Windows-High Efficiency	U-0.40 (WA State Code)	U-0.65 (Average Existing Conditions)	Per Building	Existing	12	25	$32,054	10%	70%	$313.46	2,223
Gas	Other	Space Heat Furnace	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	Demand Controlled Ventilation (CO2 sensors)	Constant Ventilation	Per Building	Existing	250	15	$3,000	50%	94%	$1.69	1,006,165
Gas	Other	Space Heat Furnace	Commissioning of Existing Buildings	Existing Building Commissioning	Average Existing Conditions	Per Building	Existing	312	7	$2,366	90%	80%	$1.64	1,459,463
Gas	Other	Space Heat Furnace	Convert Constant Volume Air System to VAV	Variable Volume Air System	Constant Volume Air System	Per Building	Existing	325	15	$36,479	15%	67%	$15.77	268,442
Gas	Other	Space Heat Furnace	Direct Digital Control System-Installation	DDC Retrofit (Morning Warm-Up Control Logic Included in This Measure)	Pneumatic	Per Building	Existing	375	5	$11,538	10%	66%	$8.37	197,868
Gas	Other	Space Heat Furnace	Direct Digital Control System-Wireless System	DDC Retrofit - Wireless System	Pneumatic	Per Building	Existing	375	5	$4,663	50%	80%	$3.38	956,894
Gas	Other	Space Heat Furnace	Duct Repair And Sealing	Reduction In Duct Losses to 5%	No Repair or Sealing, 15% duct losses	Per Building	Existing	62	18	$4,799	45%	45%	$9.95	96,078
Gas	Other	Space Heat Furnace	Exhaust Air to Ventilation Air Heat Recovery	Exhaust Air Heat Recovery	No Heat Recovery	Per Building	Existing	375	10	$10,883	5.0%	94%	$4.97	133,120
Gas	Other	Space Heat Furnace	Exhaust Hood Makeup Air	Provide Makeup Air Directly at Exhaust Hood Instead of Pulling Conditioned Air	Hood Pulls Conditioned Air (No Make-up Air)	Per Building	Existing	112	10	$5,450	5.0%	85%	$8.30	35,857
Gas	Other	Space Heat Furnace	Infiltration Reduction	Install Caulking And Weatherstripping (ACH 0.65)	Infiltration Conditions (ACH 1.0)	Per Building	Existing	163	10	$172	10%	39%	$0.18	47,422
Gas	Other	Space Heat Furnace	Insulation - Ceiling	R-30 c.i. (WA State Code)	R-11 (Average Existing Conditions)	Per Building	Existing	351	25	$17,522	75%	30%	$6.15	590,285
Gas	Other	Space Heat Furnace	Insulation - Ceiling	R-38 c.i.	R-30 c.i. (WA State Code)	Per Building	Existing	5	25	$17,522	75%	70%	$374.84	21,885
Gas	Other	Space Heat Furnace	Insulation - Ceiling	R-49 c.i.	R-38 c.i.	Per Building	Existing	42	25	$4,943	75%	85%	$14.26	196,857

Table B-2.2. Commercial Gas Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (Therms)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per Therms)	2033 Cumulative Achievable Technical Potential (Therms)
Gas	Other	Space Heat Furnace	Insulation - Duct	R-7 (WA State Code)	No Insulation	Per Building	Existing	105	25	$2,320	10%	15%	$2.73	11,249
Gas	Other	Space Heat Furnace	Insulation - Floor (non-slab)	R-30 (WA State Code)	R-7 (Average Existing Conditions)	Per Building	Existing	827	25	$9,238	35%	50%	$1.38	1,033,348
Gas	Other	Space Heat Furnace	Insulation - Floor (non-slab)	R-38	R-30 (WA State Code)	Per Building	Existing	105	25	$2,849	35%	50%	$3.32	124,700
Gas	Other	Space Heat Furnace	Insulation - Wall	R-16	R-3 (Average Existing Conditions)	Per Building	Existing	1,450	25	$8,620	10%	35%	$0.73	338,868
Gas	Other	Space Heat Furnace	Programmable Thermostat - Web Enabled	Programmable Thermostat - Web Enabled	No Programmable Thermostat	Per Building	Existing	75	15	$778	95%	28%	$1.46	132,479
Gas	Other	Space Heat Furnace	Windows-High Efficiency	U-0.40 (WA State Code)	U-0.65 (Average Existing Conditions)	Per Building	Existing	18	25	$32,054	10%	70%	$210.99	7,742
Gas	Other	Water Heat GT 55 Gal	Clothes Washer - Ozonating	Ozonating Clothes Washer	2013 Federal Standard Clothes Washer - MEF = 1.6, WF = 8.5	Per Building	Existing	66	10	$8,285	0.3%	95%	$20.28	68
Gas	Other	Water Heat GT 55 Gal	Clothes Washer Commercial	ENERGY STAR Commercial Clothes Washer - MEF = 2.43, WF = 4.0	2013 Federal Standard Clothes Washer - MEF = 1.6, WF = 8.5	Per Building	Existing	1	7	$14	95%	80%	$-10.25	422
Gas	Other	Water Heat GT 55 Gal	Demand Controlled Circulating Systems	Demand Controlled Circulating Systems (VFD control by demand)	Constant Circulation	Per Building	Existing	22	10	$3,333	75%	94%	$25.92	6,738
Gas	Other	Water Heat GT 55 Gal	Dishwasher Residential	RTF ENERGY STAR Dishwasher - 277 kWh/yr and 4.25 gal/cycle	RTF Market Standard 2014 Dishwasher - 289 kWh/yr and 5.0 gal/cycle	Per Building	Existing	1	12	$45	5.4%	25%	$6.08	6
Gas	Other	Water Heat GT 55 Gal	Dishwashing - Commercial - Low Temp	Low-Temp Commercial Dishwasher (Includes Extra Chemical Cost) - (ENERGY STAR)	Standard High Temp Commercial Dishwasher	Per Building	Existing	1	12	$19	95%	95%	$-535.99	494
Gas	Other	Water Heat GT 55 Gal	Drainwater Heat Recovery Water Heater	Install (Power-Pipe or GFX) - Heat Recovery Water Heater	No Heat Recovery System	Per Building	Existing	88	25	$2,292	5.0%	92%	$3.21	1,692
Gas	Other	Water Heat GT 55 Gal	Low-Flow Faucet Aerators	0.5 GPM	2.2 GPM (Federal Code)	Per Building	Existing	17	9	$4	95%	75%	$-0.52	5,275
Gas	Other	Water Heat GT 55 Gal	Low-Flow Faucet Aerators	2.2 GPM (Federal Code)	3.0 GPM	Per Building	Existing	5	9	$3	95%	25%	$-1.16	606
Gas	Other	Water Heat GT 55 Gal	Low-Flow Pre-Rinse Spray Valves	0.6 GPM	1.6 GPM (Federal Standard)	Per Building	Existing	19	4	$130	95%	93%	$2.09	7,323
Gas	Other	Water Heat GT 55 Gal	Low-Flow Showerheads	1.5 GPM	2.5 GPM (Federal Code)	Per Building	Existing	0.96	10	$10	95%	73%	$-12.35	289
Gas	Other	Water Heat GT 55 Gal	Low-Flow Showerheads	2.5 GPM (Federal Code)	4.5 GPM	Per Building	Existing	1	10	$9	95%	35%	$-13.00	277
Gas	Other	Water Heat GT 55 Gal	Pipe Insulation - Hot Water (DWH)	1.0" of Insulation, assuming R-4 (WA State Code)	No Insulation	Per Building	Existing	4	12	$28	75%	90%	$1.03	1,174
Gas	Other	Water Heat GT 55 Gal	Ultrasonic Faucet Control	Install Ultrasonic Motion Faucet Control	No Faucet Control	Per Building	Existing	11	10	$471	75%	95%	$5.94	3,413
Gas	Other	Water Heat GT 55 Gal	Water Cooled Refrigeration with Heat Recovery	Heat Recovery from refrigeration system. Applied to Water Heating Electric End use	No heat recovery	Per Building	Existing	0.49	10	$10,920	75%	100%	$3,797.33	142
Gas	Other	Water Heat LE 55 Gal	Clothes Washer - Ozonating	Ozonating Clothes Washer	2013 Federal Standard Clothes Washer - MEF = 1.6, WF = 8.5	Per Building	Existing	60	10	$8,285	0.3%	95%	$22.37	725

Table B-2.2. Commercial Gas Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (Therms)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per Therms)	2033 Cumulative Achievable Technical Potential (Therms)
Gas	Other	Water Heat LE 55 Gal	Clothes Washer Commercial	ENERGY STAR Commercial Clothes Washer - MEF = 2.43, WF = 4.0	2013 Federal Standard Clothes Washer - MEF = 1.6, WF = 8.5	Per Building	Existing	1	7	$14	95%	80%	$-10.25	4,896
Gas	Other	Water Heat LE 55 Gal	Demand Controlled Circulating Systems	Demand Controlled Circulating Systems (VFD control by demand)	Constant Circulation	Per Building	Existing	20	10	$3,333	75%	94%	$28.47	71,024
Gas	Other	Water Heat LE 55 Gal	Dishwasher Residential	RTF ENERGY STAR Dishwasher - 277 kWh/yr and 4.25 gal/cycle	RTF Market Standard 2014 Dishwasher - 289 kWh/yr and 5.0 gal/cycle	Per Building	Existing	1	12	$45	5.4%	25%	$6.08	69
Gas	Other	Water Heat LE 55 Gal	Dishwashing - Commercial - Low Temp	Low-Temp Commercial Dishwasher (Includes Extra Chemical Cost) - (ENERGY STAR)	Standard High Temp Commercial Dishwasher	Per Building	Existing	1	12	$17	95%	95%	$-588.83	5,215
Gas	Other	Water Heat LE 55 Gal	Drainwater Heat Recovery Water Heater	Install (Power-Pipe or GFX) - Heat Recovery Water Heater	No Heat Recovery System	Per Building	Existing	80	25	$2,292	5.0%	92%	$3.52	17,835
Gas	Other	Water Heat LE 55 Gal	Low-Flow Faucet Aerators	0.5 GPM	2.2 GPM (Federal Code)	Per Building	Existing	15	9	$4	95%	75%	$-0.48	55,621
Gas	Other	Water Heat LE 55 Gal	Low-Flow Faucet Aerators	2.2 GPM (Federal Code)	3.0 GPM	Per Building	Existing	5	9	$3	95%	25%	$-1.14	6,398
Gas	Other	Water Heat LE 55 Gal	Low-Flow Pre-Rinse Spray Valves	0.6 GPM	1.6 GPM (Federal Standard)	Per Building	Existing	19	4	$130	95%	93%	$2.09	84,796
Gas	Other	Water Heat LE 55 Gal	Low-Flow Showerheads	1.5 GPM	2.5 GPM (Federal Code)	Per Building	Existing	0.96	10	$10	95%	73%	$-12.35	3,350
Gas	Other	Water Heat LE 55 Gal	Low-Flow Showerheads	2.5 GPM (Federal Code)	4.5 GPM	Per Building	Existing	1	10	$9	95%	35%	$-13.00	3,213
Gas	Other	Water Heat LE 55 Gal	Pipe Insulation - Hot Water (DWH)	1.0" of Insulation, assuming R-4 (WA State Code)	No Insulation	Per Building	Existing	4	12	$28	75%	90%	$1.13	12,328
Gas	Other	Water Heat LE 55 Gal	Ultrasonic Faucet Control	Install Ultrasonic Motion Faucet Control	No Faucet Control	Per Building	Existing	10	10	$471	75%	95%	$6.60	35,990
Gas	Other	Water Heat LE 55 Gal	Water Cooled Refrigeration with Heat Recovery	Heat Recovery from refrigeration system. Applied to Water Heating Electric End use	No heat recovery	Per Building	Existing	0.44	10	$10,920	75%	100%	$4,170.53	1,490
Gas	Restaurant	Cooking	Broiler	High-Efficiency Broiler (34% Efficient)	Standard Broiler (15% Efficient)	Per Building	Existing	104	10	$79	95%	75%	$0.13	267,388
Gas	Restaurant	Cooking	Fryers - Commercial Gas Cooking	Energy Star Commercial Fryer (50% efficient)	Non-Energy Star Fryer (35% efficient)	Per Building	Existing	69	8	$419	65%	35%	$1.20	56,481
Gas	Restaurant	Cooking	Griddle	High-Efficiency Griddle (40% Efficient)	Standard Griddle (32% Efficient)	Per Building	Existing	30	12	$582	75%	35%	$3.00	28,791
Gas	Restaurant	Cooking	High Efficiency Convection Oven	Convection Oven	Standard Oven	Per Building	Existing	64	12	$400	85%	85%	$0.97	167,961
Gas	Restaurant	Cooking	Oven - Conveyor	High-Efficiency Model (23% Efficient)	Standard Model (15% Efficient)	Per Building	Existing	589	10	$1,069	35%	85%	$0.31	627,543
Gas	Restaurant	Cooking	Oven - Power Burner	Power Burner Oven - Improved Atmospheric Burner (60% Efficient)	Standard (40%-50% Efficiency)	Per Building	Existing	211	12	$2,022	45%	80%	$1.50	272,902
Gas	Restaurant	Cooking	Steam Cooker	ENERGY STAR Steam Cooker	Non ENERGY STAR Steam Cooker	Per Building	Existing	560	12	$1,091	20%	35%	$0.31	267,028
Gas	Restaurant	Space Heat Furnace	Commissioning of Existing Buildings	Existing Building Commissioning	Average Existing Conditions	Per Building	Existing	27	7	$690	90%	80%	$5.49	49,883
Gas	Restaurant	Space Heat Furnace	Direct Digital Control System-Installation	DDC Retrofit (Morning Warm-Up Control Logic Included in This Measure)	Pneumatic	Per Building	Existing	32	5	$3,365	10%	100%	$28.05	11,922

Table B-2.2. Commercial Gas Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (Therms)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per Therms)	2033 Cumulative Achievable Technical Potential (Therms)
Gas	Restaurant	Space Heat Furnace	Direct Digital Control System-Wireless System	DDC Retrofit - Wireless System	Pneumatic	Per Building	Existing	32	5	$1,360	50%	80%	$11.34	37,579
Gas	Restaurant	Space Heat Furnace	Duct Repair And Sealing	Reduction In Duct Losses to 5%	No Repair or Sealing, 15% duct losses	Per Building	Existing	5	18	$1,399	45%	45%	$33.37	3,773
Gas	Restaurant	Space Heat Furnace	Exhaust Air to Ventilation Air Heat Recovery	Exhaust Air Heat Recovery	No Heat Recovery	Per Building	Existing	32	10	$6,019	5.0%	94%	$31.61	5,227
Gas	Restaurant	Space Heat Furnace	Exhaust Hood Makeup Air	Provide Makeup Air Directly at Exhaust Hood Instead of Pulling Conditioned Air	Hood Pulls Conditioned Air (No Make-up Air)	Per Building	Existing	9	10	$5,449	100%	85%	$95.41	28,164
Gas	Restaurant	Space Heat Furnace	Infiltration Reduction	Install Caulking And Weatherstripping (ACH 0.65)	Infiltration Conditions (ACH 1.0)	Per Building	Existing	21	10	$142	10%	39%	$1.13	2,744
Gas	Restaurant	Space Heat Furnace	Insulation - Ceiling	R-30 c.i. (WA State Code)	R-11 (Average Existing Conditions)	Per Building	Existing	36	25	$4,929	75%	85%	$16.57	75,832
Gas	Restaurant	Space Heat Furnace	Insulation - Ceiling	R-38 c.i.	R-30 c.i. (WA State Code)	Per Building	Existing	0.49	25	$4,929	75%	83%	$1,230.50	890
Gas	Restaurant	Space Heat Furnace	Insulation - Ceiling	R-49 c.i.	R-38 c.i.	Per Building	Existing	4	25	$1,390	75%	98%	$38.42	9,482
Gas	Restaurant	Space Heat Furnace	Insulation - Duct	R-7 (WA State Code)	No Insulation	Per Building	Existing	9	25	$677	10%	15%	$9.14	390
Gas	Restaurant	Space Heat Furnace	Insulation - Floor (non-slab)	R-30 (WA State Code)	R-11 (Average Existing Conditions)	Per Building	Existing	48	25	$2,598	35%	90%	$6.55	43,822
Gas	Restaurant	Space Heat Furnace	Insulation - Floor (non-slab)	R-38	R-30 (WA State Code)	Per Building	Existing	9	25	$801	35%	90%	$10.87	7,579
Gas	Restaurant	Space Heat Furnace	Insulation - Wall	R-16	R-3 (Average Existing Conditions)	Per Building	Existing	99	25	$4,526	10%	35%	$5.59	9,110
Gas	Restaurant	Space Heat Furnace	Programmable Thermostat - Web Enabled	Programmable Thermostat - Web Enabled	No Programmable Thermostat	Per Building	Existing	6	15	$807	95%	25%	$17.38	4,052
Gas	Restaurant	Space Heat Furnace	Windows-High Efficiency	U-0.40 (WA State Code)	U-0.65 (Average Existing Conditions)	Per Building	Existing	1	25	$26,631	10%	80%	$2,014.59	302
Gas	Restaurant	Water Heat GT 55 Gal	Demand Controlled Circulating Systems	Demand Controlled Circulating Systems (VFD control by demand)	Constant Circulation	Per Building	Existing	88	10	$972	75%	94%	$1.88	7,721
Gas	Restaurant	Water Heat GT 55 Gal	Dishwasher Residential	RTF ENERGY STAR Dishwasher - 277 kWh/yr and 4.25 gal/cycle	RTF Market Standard 2014 Dishwasher - 289 kWh/yr and 5.0 gal/cycle	Per Building	Existing	1	12	$46	46%	25%	$5.80	15
Gas	Restaurant	Water Heat GT 55 Gal	Dishwashing - Commercial - Low Temp	Low-Temp Commercial Dishwasher (Includes Extra Chemical Cost) - (ENERGY STAR)	Standard High Temp Commercial Dishwasher	Per Building	Existing	173	12	$2,624	95%	95%	$-1.53	19,385
Gas	Restaurant	Water Heat GT 55 Gal	Drainwater Heat Recovery Water Heater	Install (Power-Pipe or GFX) - Heat Recovery Water Heater	No Heat Recovery System	Per Building	Existing	354	25	$1,874	5.0%	92%	$0.65	1,765
Gas	Restaurant	Water Heat GT 55 Gal	Low-Flow Faucet Aerators	0.5 GPM	2.2 GPM (Federal Code)	Per Building	Existing	68	9	$4	95%	75%	$-0.79	6,030
Gas	Restaurant	Water Heat GT 55 Gal	Low-Flow Faucet Aerators	2.2 GPM (Federal Code)	3.0 GPM	Per Building	Existing	23	9	$3	95%	25%	$-1.56	693
Gas	Restaurant	Water Heat GT 55 Gal	Low-Flow Pre-Rinse Spray Valves	0.6 GPM	1.6 GPM (Federal Standard)	Per Building	Existing	36	4	$246	95%	46%	$1.42	1,979
Gas	Restaurant	Water Heat GT 55 Gal	Pipe Insulation - Hot Water (DWH)	1.0" of Insulation, assuming R-4 (WA State Code)	No Insulation	Per Building	Existing	17	12	$25	75%	90%	$0.23	1,265
Gas	Restaurant	Water Heat GT 55 Gal	Ultrasonic Faucet Control	Install Ultrasonic Motion Faucet Control	No Faucet Control	Per Building	Existing	44	10	$392	75%	75%	$-0.19	3,080

Table B-2.2. Commercial Gas Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (Therms)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per Therms)	2033 Cumulative Achievable Technical Potential (Therms)
Gas	Restaurant	Water Heat LE 55 Gal	Demand Controlled Circulating Systems	Demand Controlled Circulating Systems (VFD control by demand)	Constant Circulation	Per Building	Existing	80	10	$972	75%	94%	$2.07	81,409
Gas	Restaurant	Water Heat LE 55 Gal	Dishwasher Residential	RTF ENERGY STAR Dishwasher - 277 kWh/yr and 4.25 gal/cycle	RTF Market Standard 2014 Dishwasher - 289 kWh/yr and 5.0 gal/cycle	Per Building	Existing	1	12	$46	46%	25%	$5.80	174
Gas	Restaurant	Water Heat LE 55 Gal	Dishwashing - Commercial - Low Temp	Low-Temp Commercial Dishwasher (Includes Extra Chemical Cost) - (ENERGY STAR)	Standard High Temp Commercial Dishwasher	Per Building	Existing	158	12	$2,390	95%	95%	$-1.91	204,378
Gas	Restaurant	Water Heat LE 55 Gal	Drainwater Heat Recovery Water Heater	Install (Power-Pipe or GFX) - Heat Recovery Water Heater	No Heat Recovery System	Per Building	Existing	322	25	$1,874	5.0%	92%	$0.72	18,618
Gas	Restaurant	Water Heat LE 55 Gal	Low-Flow Faucet Aerators	0.5 GPM	2.2 GPM (Federal Code)	Per Building	Existing	62	9	$4	95%	75%	$-0.78	63,576
Gas	Restaurant	Water Heat LE 55 Gal	Low-Flow Faucet Aerators	2.2 GPM (Federal Code)	3.0 GPM	Per Building	Existing	21	9	$3	95%	25%	$-1.56	7,313
Gas	Restaurant	Water Heat LE 55 Gal	Low-Flow Pre-Rinse Spray Valves	0.6 GPM	1.6 GPM (Federal Standard)	Per Building	Existing	36	4	$246	95%	46%	$1.42	22,916
Gas	Restaurant	Water Heat LE 55 Gal	Pipe Insulation - Hot Water (DWH)	1.0" of Insulation, assuming R-4 (WA State Code)	No Insulation	Per Building	Existing	16	12	$25	75%	90%	$0.25	13,330
Gas	Restaurant	Water Heat LE 55 Gal	Ultrasonic Faucet Control	Install Ultrasonic Motion Faucet Control	No Faucet Control	Per Building	Existing	40	10	$392	75%	75%	$-0.04	32,477
Gas	School	Cooking	Broiler	High-Efficiency Broiler (34% Efficient)	Standard Broiler (15% Efficient)	Per Building	Existing	21	10	$0.00	95%	75%	$0.00	11,562
Gas	School	Cooking	Fryers - Commercial Gas Cooking	Energy Star Commercial Fryer (50% efficient)	Non-Energy Star Fryer (35% efficient)	Per Building	Existing	0.21	8	$5	45%	35%	$4.87	25
Gas	School	Cooking	Griddle	High-Efficiency Griddle (40% Efficient)	Standard Griddle (32% Efficient)	Per Building	Existing	0.71	12	$16	65%	35%	$3.54	2
Gas	School	Cooking	High Efficiency Convection Oven	Convection Oven	Standard Oven	Per Building	Existing	13	12	$5	85%	40%	$0.06	3,417
Gas	School	Cooking	Oven - Conveyor	High-Efficiency Model (23% Efficient)	Standard Model (15% Efficient)	Per Building	Existing	122	10	$16	5.0%	85%	$0.02	3,876
Gas	School	Cooking	Oven - Power Burner	Power Burner Oven - Improved Atmospheric Burner (60% Efficient)	Standard (40%-50% Efficiency)	Per Building	Existing	43	12	$32	25%	90%	$0.12	7,375
Gas	School	Cooking	Steam Cooker	ENERGY STAR Steam Cooker	Non ENERGY STAR Steam Cooker	Per Building	Existing	13	12	$26	5.0%	35%	$0.32	325
Gas	School	Pool Heat	RE - Installation of Solar Pool/Spa Heating Systems	Solar Pool/Spa Heating Systems	No Solar Pool Heating System	Per Building	Existing	851	12	$9,118	5.0%	90%	$1.69	8,128
Gas	School	Pool Heat	Swimming Pool/Spa Covers	Automatic Plastic Or Foam Pool Covers (50-65% Energy Savings)	No Pool Covers	Per Building	Existing	3,379	10	$6,291	95%	35%	$0.32	238,353
Gas	School	Space Heat Boiler	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	Demand Controlled Ventilation (CO2 sensors)	Constant Ventilation	Per Building	Existing	598	15	$13,377	25%	94%	$3.14	153,825
Gas	School	Space Heat Boiler	Boiler Economizer	Economizer	No Economizer	Per Building	Existing	328	20	$3,121	10%	65%	$1.18	22,851
Gas	School	Space Heat Boiler	Commissioning of Existing Buildings	Existing Building Commissioning	Average Existing Conditions	Per Building	Existing	747	7	$10,545	90%	80%	$3.05	436,755
Gas	School	Space Heat Boiler	Convert Constant Volume Air System to VAV	Variable Volume Air System	Constant Volume Air System	Per Building	Existing	777	15	$62,639	15%	67%	$29.39	83,486

Table B-2.2. Commercial Gas Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (Therms)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per Therms)	2033 Cumulative Achievable Technical Potential (Therms)
Gas	School	Space Heat Boiler	Direct Digital Control System-Installation	DDC Retrofit (Morning Warm-Up Control Logic Included in This Measure)	Pneumatic	Per Building	Existing	897	5	$51,438	10%	34%	$15.60	32,348
Gas	School	Space Heat Boiler	Direct Digital Control System-Wireless System	DDC Retrofit - Wireless System	Pneumatic	Per Building	Existing	897	5	$20,795	50%	80%	$6.30	300,156
Gas	School	Space Heat Boiler	Exhaust Air to Ventilation Air Heat Recovery	Exhaust Air Heat Recovery	No Heat Recovery	Per Building	Existing	897	10	$48,525	5.0%	94%	$9.27	41,969
Gas	School	Space Heat Boiler	Exhaust Hood Makeup Air	Provide Makeup Air Directly at Exhaust Hood Instead of Pulling Conditioned Air	Hood Pulls Conditioned Air (No Make-up Air)	Per Building	Existing	269	10	$5,454	73%	85%	$3.47	164,443
Gas	School	Space Heat Boiler	Infiltration Reduction	Install Caulking And Weatherstripping (ACH 0.65)	Infiltration Conditions (ACH 1.0)	Per Building	Existing	598	10	$1,410	10%	39%	$0.40	22,268
Gas	School	Space Heat Boiler	Insulation - Ceiling	R-30 c.i. (WA State Code)	R-7 (Average Existing Conditions)	Per Building	Existing	1,355	25	$83,170	75%	15%	$7.57	145,906
Gas	School	Space Heat Boiler	Insulation - Ceiling	R-38 c.i.	R-30 c.i. (WA State Code)	Per Building	Existing	7	25	$83,170	75%	70%	$1,307.59	3,841
Gas	School	Space Heat Boiler	Insulation - Ceiling	R-49 c.i.	R-38 c.i.	Per Building	Existing	120	25	$23,466	75%	85%	$23.94	71,829
Gas	School	Space Heat Boiler	Insulation - Floor (non-slab)	R-30 (WA State Code)	R-11 (Average Existing Conditions)	Per Building	Existing	1,392	25	$43,848	35%	35%	$3.89	156,874
Gas	School	Space Heat Boiler	Insulation - Floor (non-slab)	R-38	R-30 (WA State Code)	Per Building	Existing	259	25	$13,532	35%	35%	$6.44	28,368
Gas	School	Space Heat Boiler	Insulation - Wall	R-16	R-3 (Average Existing Conditions)	Per Building	Existing	4,220	25	$20,366	10%	35%	$0.60	131,326
Gas	School	Space Heat Boiler	Pipe Insulation - Boiler	3" of Insulation, assuming R-12 (WA State Code)	No Insulation	Per Building	Existing	720	20	$3,352	75%	65%	$0.58	304,685
Gas	School	Space Heat Boiler	Programmable Thermostat - Web Enabled	Programmable Thermostat - Web Enabled	No Programmable Thermostat	Per Building	Existing	179	15	$734	95%	21%	$0.58	28,745
Gas	School	Space Heat Boiler	Sensible And Total Heat Recovery Devices	Install Heat Recovery Devices - rotary air-to-air enthalpy heat recovery- 70% sensible and latent recovery effectiveness	No Heat Recovery	Per Building	Existing	1,495	10	$12,885	25%	98%	$12.94	270,485
Gas	School	Space Heat Boiler	Windows-High Efficiency	U-0.40 (WA State Code)	U-0.67 (Average Existing Conditions)	Per Building	Existing	77	25	$63,000	10%	60%	$418.94	3,220
Gas	School	Space Heat Furnace	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	Demand Controlled Ventilation (CO2 sensors)	Constant Ventilation	Per Building	Existing	888	15	$13,377	25%	94%	$2.12	64,312
Gas	School	Space Heat Furnace	Commissioning of Existing Buildings	Existing Building Commissioning	Average Existing Conditions	Per Building	Existing	1,110	7	$10,545	90%	80%	$2.06	195,215
Gas	School	Space Heat Furnace	Convert Constant Volume Air System to VAV	Variable Volume Air System	Constant Volume Air System	Per Building	Existing	1,155	15	$62,639	15%	67%	$19.78	35,162
Gas	School	Space Heat Furnace	Direct Digital Control System-Installation	DDC Retrofit (Morning Warm-Up Control Logic Included in This Measure)	Pneumatic	Per Building	Existing	1,332	5	$51,438	10%	34%	$10.50	13,572
Gas	School	Space Heat Furnace	Direct Digital Control System-Wireless System	DDC Retrofit - Wireless System	Pneumatic	Per Building	Existing	1,332	5	$20,795	50%	80%	$4.24	125,934
Gas	School	Space Heat Furnace	Duct Repair And Sealing	Reduction In Duct Losses to 5%	No Repair or Sealing, 15% duct losses	Per Building	Existing	222	18	$21,401	45%	45%	$12.49	12,644
Gas	School	Space Heat Furnace	Exhaust Air to Ventilation Air Heat Recovery	Exhaust Air Heat Recovery	No Heat Recovery	Per Building	Existing	1,332	10	$48,525	5.0%	94%	$6.24	17,519

Table B-2.2. Commercial Gas Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (Therms)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per Therms)	2033 Cumulative Achievable Technical Potential (Therms)
Gas	School	Space Heat Furnace	Exhaust Hood Makeup Air	Provide Makeup Air Directly at Exhaust Hood Instead of Pulling Conditioned Air	Hood Pulls Conditioned Air (No Make-up Air)	Per Building	Existing	399	10	$5,454	73%	85%	$2.34	68,645
Gas	School	Space Heat Furnace	Infiltration Reduction	Install Caulking And Weatherstripping (ACH 0.65)	Infiltration Conditions (ACH 1.0)	Per Building	Existing	888	10	$1,410	10%	39%	$0.27	9,295
Gas	School	Space Heat Furnace	Insulation - Ceiling	R-30 c.i. (WA State Code)	R-7 (Average Existing Conditions)	Per Building	Existing	2,013	25	$83,170	75%	15%	$5.10	60,907
Gas	School	Space Heat Furnace	Insulation - Ceiling	R-38 c.i.	R-30 c.i. (WA State Code)	Per Building	Existing	11	25	$83,170	75%	70%	$880.16	1,603
Gas	School	Space Heat Furnace	Insulation - Ceiling	R-49 c.i.	R-38 c.i.	Per Building	Existing	179	25	$23,466	75%	85%	$16.12	29,984
Gas	School	Space Heat Furnace	Insulation - Duct	R-7 (WA State Code)	No Insulation	Per Building	Existing	373	25	$10,352	10%	15%	$3.42	1,447
Gas	School	Space Heat Furnace	Insulation - Floor (non-slab)	R-30 (WA State Code)	R-11 (Average Existing Conditions)	Per Building	Existing	2,068	25	$43,848	35%	35%	$2.62	65,444
Gas	School	Space Heat Furnace	Insulation - Floor (non-slab)	R-38	R-30 (WA State Code)	Per Building	Existing	384	25	$13,532	35%	35%	$4.34	11,834
Gas	School	Space Heat Furnace	Insulation - Wall	R-16	R-3 (Average Existing Conditions)	Per Building	Existing	4,174	25	$20,366	10%	35%	$0.60	36,471
Gas	School	Space Heat Furnace	Programmable Thermostat - Web Enabled	Programmable Thermostat - Web Enabled	No Programmable Thermostat	Per Building	Existing	266	15	$734	95%	21%	$0.39	12,848
Gas	School	Space Heat Furnace	Windows-High Efficiency	U-0.40 (WA State Code)	U-0.67 (Average Existing Conditions)	Per Building	Existing	115	25	$63,000	10%	60%	$281.99	1,533
Gas	School	Water Heat GT 55 Gal	Clothes Washer - Ozonating	Ozonating Clothes Washer	2013 Federal Standard Clothes Washer - MEF = 1.6, WF = 8.5	Per Building	Existing	548	10	$8,281	1.8%	95%	$1.57	497
Gas	School	Water Heat GT 55 Gal	Clothes Washer Commercial	ENERGY STAR Commercial Clothes Washer - MEF = 2.43, WF = 4.0	2013 Federal Standard Clothes Washer - MEF = 1.6, WF = 8.5	Per Building	Existing	9	7	$107	95%	80%	$-1.66	397
Gas	School	Water Heat GT 55 Gal	Demand Controlled Circulating Systems	Demand Controlled Circulating Systems (VFD control by demand)	Constant Circulation	Per Building	Existing	181	10	$14,862	55%	94%	$14.05	5,093
Gas	School	Water Heat GT 55 Gal	Dishwasher Residential	RTF ENERGY STAR Dishwasher - 277 kWh/yr and 4.25 gal/cycle	RTF Market Standard 2014 Dishwasher - 289 kWh/yr and 5.0 gal/cycle	Per Building	Existing	0.96	12	$42	35%	25%	$7.00	4
Gas	School	Water Heat GT 55 Gal	Dishwashing - Commercial - Low Temp	Low-Temp Commercial Dishwasher (Includes Extra Chemical Cost) - (ENERGY STAR)	Standard High Temp Commercial Dishwasher	Per Building	Existing	19	12	$300	95%	95%	$-31.95	974
Gas	School	Water Heat GT 55 Gal	Drainwater Heat Recovery Water Heater	Install (Power-Pipe or GFX) - Heat Recovery Water Heater	No Heat Recovery System	Per Building	Existing	725	25	$7,916	5.0%	92%	$1.35	1,757
Gas	School	Water Heat GT 55 Gal	Low-Flow Faucet Aerators	0.5 GPM	2.2 GPM (Federal Code)	Per Building	Existing	140	9	$21	95%	75%	$0.00	5,449
Gas	School	Water Heat GT 55 Gal	Low-Flow Faucet Aerators	2.2 GPM (Federal Code)	3.0 GPM	Per Building	Existing	48	9	$16	95%	25%	$-0.22	626
Gas	School	Water Heat GT 55 Gal	Low-Flow Pre-Rinse Spray Valves	0.6 GPM	1.6 GPM (Federal Standard)	Per Building	Existing	36	4	$246	95%	65%	$2.14	1,223
Gas	School	Water Heat GT 55 Gal	Low-Flow Showerheads	1.5 GPM	2.5 GPM (Federal Code)	Per Building	Existing	30	10	$348	95%	73%	$1.48	1,157
Gas	School	Water Heat GT 55 Gal	Low-Flow Showerheads	2.5 GPM (Federal Code)	4.5 GPM	Per Building	Existing	61	10	$289	95%	35%	$0.40	1,110
Gas	School	Water Heat GT 55 Gal	Pipe Insulation - Hot Water (DWH)	1.0" of Insulation, assuming R-4 (WA State Code)	No Insulation	Per Building	Existing	36	12	$96	75%	70%	$0.42	977

Table B-2.2. Commercial Gas Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (Therms)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per Therms)	2033 Cumulative Achievable Technical Potential (Therms)
Gas	School	Water Heat GT 55 Gal	Ultrasonic Faucet Control	Install Ultrasonic Motion Faucet Control	No Faucet Control	Per Building	Existing	90	10	$2,102	75%	75%	$3.66	2,783
Gas	School	Water Heat LE 55 Gal	Clothes Washer - Ozonating	Ozonating Clothes Washer	2013 Federal Standard Clothes Washer - MEF = 1.6, WF = 8.5	Per Building	Existing	499	10	$8,281	1.8%	95%	$1.83	5,247
Gas	School	Water Heat LE 55 Gal	Clothes Washer Commercial	ENERGY STAR Commercial Clothes Washer - MEF = 2.43, WF = 4.0	2013 Federal Standard Clothes Washer - MEF = 1.6, WF = 8.5	Per Building	Existing	9	7	$107	95%	80%	$-1.66	4,606
Gas	School	Water Heat LE 55 Gal	Demand Controlled Circulating Systems	Demand Controlled Circulating Systems (VFD control by demand)	Constant Circulation	Per Building	Existing	165	10	$14,862	55%	94%	$15.43	53,693
Gas	School	Water Heat LE 55 Gal	Dishwasher Residential	RTF ENERGY STAR Dishwasher - 277 kWh/yr and 4.25 gal/cycle	RTF Market Standard 2014 Dishwasher - 289 kWh/yr and 5.0 gal/cycle	Per Building	Existing	0.96	12	$42	35%	25%	$7.00	53
Gas	School	Water Heat LE 55 Gal	Dishwashing - Commercial - Low Temp	Low-Temp Commercial Dishwasher (Includes Extra Chemical Cost) - (ENERGY STAR)	Standard High Temp Commercial Dishwasher	Per Building	Existing	17	12	$273	95%	95%	$-35.33	10,269
Gas	School	Water Heat LE 55 Gal	Drainwater Heat Recovery Water Heater	Install (Power-Pipe or GFX) - Heat Recovery Water Heater	No Heat Recovery System	Per Building	Existing	660	25	$7,916	5.0%	92%	$1.48	18,521
Gas	School	Water Heat LE 55 Gal	Low-Flow Faucet Aerators	0.5 GPM	2.2 GPM (Federal Code)	Per Building	Existing	127	9	$21	95%	75%	$0.00	57,451
Gas	School	Water Heat LE 55 Gal	Low-Flow Faucet Aerators	2.2 GPM (Federal Code)	3.0 GPM	Per Building	Existing	44	9	$16	95%	25%	$-0.24	6,608
Gas	School	Water Heat LE 55 Gal	Low-Flow Pre-Rinse Spray Valves	0.6 GPM	1.6 GPM (Federal Standard)	Per Building	Existing	36	4	$246	95%	65%	$2.14	14,165
Gas	School	Water Heat LE 55 Gal	Low-Flow Showerheads	1.5 GPM	2.5 GPM (Federal Code)	Per Building	Existing	30	10	$348	95%	73%	$1.48	13,403
Gas	School	Water Heat LE 55 Gal	Low-Flow Showerheads	2.5 GPM (Federal Code)	4.5 GPM	Per Building	Existing	61	10	$289	95%	35%	$0.40	12,852
Gas	School	Water Heat LE 55 Gal	Pipe Insulation - Hot Water (DWH)	1.0" of Insulation, assuming R-4 (WA State Code)	No Insulation	Per Building	Existing	33	12	$96	75%	70%	$0.46	10,295
Gas	School	Water Heat LE 55 Gal	Ultrasonic Faucet Control	Install Ultrasonic Motion Faucet Control	No Faucet Control	Per Building	Existing	82	10	$2,102	75%	75%	$4.06	29,348
Gas	University	Cooking	Broiler	High-Efficiency Broiler (34% Efficient)	Standard Broiler (15% Efficient)	Per Building	Existing	51	10	$0.00	95%	75%	$0.00	16,625
Gas	University	Cooking	Fryers - Commercial Gas Cooking	Energy Star Commercial Fryer (50% efficient)	Non-Energy Star Fryer (35% efficient)	Per Building	Existing	0.97	8	$11	45%	35%	$2.28	70
Gas	University	Cooking	Griddle	High-Efficiency Griddle (40% Efficient)	Standard Griddle (32% Efficient)	Per Building	Existing	1	12	$28	65%	35%	$3.24	6
Gas	University	Cooking	High Efficiency Convection Oven	Convection Oven	Standard Oven	Per Building	Existing	31	12	$16	85%	40%	$0.08	4,914
Gas	University	Cooking	Oven - Conveyor	High-Efficiency Model (23% Efficient)	Standard Model (15% Efficient)	Per Building	Existing	286	10	$28	5.0%	85%	$0.02	5,573
Gas	University	Cooking	Oven - Power Burner	Power Burner Oven - Improved Atmospheric Burner (60% Efficient)	Standard (40%-50% Efficiency)	Per Building	Existing	103	12	$61	25%	90%	$0.09	10,604
Gas	University	Cooking	Steam Cooker	ENERGY STAR Steam Cooker	Non ENERGY STAR Steam Cooker	Per Building	Existing	24	12	$44	5.0%	35%	$0.28	380
Gas	University	Pool Heat	RE - Installation of Solar Pool/Spa Heating Systems	Solar Pool/Spa Heating Systems	No Solar Pool Heating System	Per Building	Existing	851	12	$9,123	50%	90%	$1.69	49,800

Table B-2.2. Commercial Gas Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (Therms)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per Therms)	2033 Cumulative Achievable Technical Potential (Therms)
Gas	University	Pool Heat	Swimming Pool/Spa Covers	Automatic Plastic Or Foam Pool Covers (50-65% Energy Savings)	No Pool Covers	Per Building	Existing	3,379	10	$6,295	95%	35%	$0.32	146,037
Gas	University	Space Heat Boiler	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	Demand Controlled Ventilation (CO2 sensors)	Constant Ventilation	Per Building	Existing	1,252	15	$13,996	25%	94%	$1.57	197,303
Gas	University	Space Heat Boiler	Boiler Economizer	Economizer	No Economizer	Per Building	Existing	688	20	$3,271	10%	90%	$0.59	40,583
Gas	University	Space Heat Boiler	Commissioning of Existing Buildings	Existing Building Commissioning	Average Existing Conditions	Per Building	Existing	1,565	7	$11,040	90%	80%	$1.53	571,108
Gas	University	Space Heat Boiler	Convert Constant Volume Air System to VAV	Variable Volume Air System	Constant Volume Air System	Per Building	Existing	1,627	15	$70,238	15%	67%	$14.70	106,935
Gas	University	Space Heat Boiler	Direct Digital Control System-Installation	DDC Retrofit (Morning Warm-Up Control Logic Included in This Measure)	Pneumatic	Per Building	Existing	1,878	5	$53,845	10%	34%	$7.80	41,302
Gas	University	Space Heat Boiler	Direct Digital Control System-Wireless System	DDC Retrofit - Wireless System	Pneumatic	Per Building	Existing	1,878	5	$21,765	50%	80%	$3.15	384,469
Gas	University	Space Heat Boiler	Exhaust Air to Ventilation Air Heat Recovery	Exhaust Air Heat Recovery	No Heat Recovery	Per Building	Existing	1,878	10	$50,793	5.0%	94%	$4.63	53,758
Gas	University	Space Heat Boiler	Exhaust Hood Makeup Air	Provide Makeup Air Directly at Exhaust Hood Instead of Pulling Conditioned Air	Hood Pulls Conditioned Air (No Make-up Air)	Per Building	Existing	563	10	$5,452	73%	85%	$1.66	210,634
Gas	University	Space Heat Boiler	Infiltration Reduction	Install Caulking And Weatherstripping (ACH 0.65)	Infiltration Conditions (ACH 1.0)	Per Building	Existing	1,252	10	$1,472	10%	39%	$0.20	28,523
Gas	University	Space Heat Boiler	Insulation - Ceiling	R-30 c.i. (WA State Code)	R-7 (Average Existing Conditions)	Per Building	Existing	2,956	25	$38,808	75%	13%	$1.62	168,760
Gas	University	Space Heat Boiler	Insulation - Ceiling	R-38 c.i.	R-30 c.i. (WA State Code)	Per Building	Existing	11	25	$38,808	75%	70%	$434.45	3,309
Gas	University	Space Heat Boiler	Insulation - Ceiling	R-49 c.i.	R-38 c.i.	Per Building	Existing	263	25	$10,944	75%	85%	$5.12	96,126
Gas	University	Space Heat Boiler	Insulation - Floor (non-slab)	R-30 (WA State Code)	R-11 (Average Existing Conditions)	Per Building	Existing	2,103	25	$20,461	35%	35%	$1.20	145,393
Gas	University	Space Heat Boiler	Insulation - Floor (non-slab)	R-38	R-30 (WA State Code)	Per Building	Existing	391	25	$6,306	35%	35%	$1.99	26,506
Gas	University	Space Heat Boiler	Insulation - Wall	R-16	R-3 (Average Existing Conditions)	Per Building	Existing	5,744	25	$21,315	10%	35%	$0.46	110,659
Gas	University	Space Heat Boiler	Pipe Insulation - Boiler	3" of Insulation, assuming R-12 (WA State Code)	No Insulation	Per Building	Existing	1,509	20	$3,428	75%	65%	$0.28	398,410
Gas	University	Space Heat Boiler	Programmable Thermostat - Web Enabled	Programmable Thermostat - Web Enabled	No Programmable Thermostat	Per Building	Existing	375	15	$1,641	95%	21%	$0.61	37,587
Gas	University	Space Heat Boiler	Sensible And Total Heat Recovery Devices	Install Heat Recovery Devices - rotary air-to-air enthalpy heat recovery- 70% sensible and latent recovery effectiveness	No Heat Recovery	Per Building	Existing	3,130	10	$18,163	25%	98%	$6.47	353,690
Gas	University	Space Heat Boiler	Windows-High Efficiency	U-0.40 (WA State Code)	U-0.67 (Average Existing Conditions)	Per Building	Existing	162	25	$75,287	10%	60%	$209.47	4,210
Gas	University	Space Heat Furnace	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	Demand Controlled Ventilation (CO2 sensors)	Constant Ventilation	Per Building	Existing	1,860	15	$13,996	25%	94%	$1.06	82,491

Table B-2.2. Commercial Gas Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (Therms)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per Therms)	2033 Cumulative Achievable Technical Potential (Therms)
Gas	University	Space Heat Furnace	Commissioning of Existing Buildings	Existing Building Commissioning	Average Existing Conditions	Per Building	Existing	2,325	7	$11,040	90%	80%	$1.03	253,652
Gas	University	Space Heat Furnace	Convert Constant Volume Air System to VAV	Variable Volume Air System	Constant Volume Air System	Per Building	Existing	2,418	15	$70,238	15%	67%	$9.89	45,102
Gas	University	Space Heat Furnace	Direct Digital Control System-Installation	DDC Retrofit (Morning Warm-Up Control Logic Included in This Measure)	Pneumatic	Per Building	Existing	2,790	5	$53,845	10%	34%	$5.25	17,353
Gas	University	Space Heat Furnace	Direct Digital Control System-Wireless System	DDC Retrofit - Wireless System	Pneumatic	Per Building	Existing	2,790	5	$21,765	50%	80%	$2.12	161,536
Gas	University	Space Heat Furnace	Duct Repair And Sealing	Reduction In Duct Losses to 5%	No Repair or Sealing, 15% duct losses	Per Building	Existing	465	18	$22,400	45%	45%	$6.24	16,219
Gas	University	Space Heat Furnace	Exhaust Air to Ventilation Air Heat Recovery	Exhaust Air Heat Recovery	No Heat Recovery	Per Building	Existing	2,790	10	$50,793	5.0%	94%	$3.12	22,472
Gas	University	Space Heat Furnace	Exhaust Hood Makeup Air	Provide Makeup Air Directly at Exhaust Hood Instead of Pulling Conditioned Air	Hood Pulls Conditioned Air (No Make-up Air)	Per Building	Existing	837	10	$5,452	73%	85%	$1.12	88,051
Gas	University	Space Heat Furnace	Infiltration Reduction	Install Caulking And Weatherstripping (ACH 0.65)	Infiltration Conditions (ACH 1.0)	Per Building	Existing	1,860	10	$1,472	10%	39%	$0.14	11,923
Gas	University	Space Heat Furnace	Insulation - Ceiling	R-30 c.i. (WA State Code)	R-7 (Average Existing Conditions)	Per Building	Existing	4,391	25	$38,808	75%	13%	$1.09	70,546
Gas	University	Space Heat Furnace	Insulation - Ceiling	R-38 c.i.	R-30 c.i. (WA State Code)	Per Building	Existing	16	25	$38,808	75%	70%	$292.43	1,383
Gas	University	Space Heat Furnace	Insulation - Ceiling	R-49 c.i.	R-38 c.i.	Per Building	Existing	391	25	$10,944	75%	85%	$3.45	40,183
Gas	University	Space Heat Furnace	Insulation - Duct	R-7 (WA State Code)	No Insulation	Per Building	Existing	781	25	$10,832	10%	15%	$1.71	1,860
Gas	University	Space Heat Furnace	Insulation - Floor (non-slab)	R-30 (WA State Code)	R-11 (Average Existing Conditions)	Per Building	Existing	3,125	25	$20,461	35%	35%	$0.81	60,740
Gas	University	Space Heat Furnace	Insulation - Floor (non-slab)	R-38	R-30 (WA State Code)	Per Building	Existing	581	25	$6,306	35%	35%	$1.34	11,073
Gas	University	Space Heat Furnace	Insulation - Wall	R-16	R-3 (Average Existing Conditions)	Per Building	Existing	8,178	25	$21,315	10%	35%	$0.32	44,304
Gas	University	Space Heat Furnace	Programmable Thermostat - Web Enabled	Programmable Thermostat - Web Enabled	No Programmable Thermostat	Per Building	Existing	558	15	$1,641	95%	21%	$0.41	16,694
Gas	University	Space Heat Furnace	Windows-High Efficiency	U-0.40 (WA State Code)	U-0.67 (Average Existing Conditions)	Per Building	Existing	240	25	$75,287	10%	60%	$140.99	1,992
Gas	University	Water Heat GT 55 Gal	Clothes Washer - Ozonating	Ozonating Clothes Washer	2013 Federal Standard Clothes Washer - MEF = 1.6, WF = 8.5	Per Building	Existing	973	10	$8,280	1.8%	95%	$0.44	541
Gas	University	Water Heat GT 55 Gal	Clothes Washer Commercial	ENERGY STAR Commercial Clothes Washer - MEF = 2.43, WF = 4.0	2013 Federal Standard Clothes Washer - MEF = 1.6, WF = 8.5	Per Building	Existing	10	7	$118	95%	80%	$-1.25	255
Gas	University	Water Heat GT 55 Gal	Demand Controlled Circulating Systems	Demand Controlled Circulating Systems (VFD control by demand)	Constant Circulation	Per Building	Existing	321	10	$15,559	55%	94%	$8.28	5,546
Gas	University	Water Heat GT 55 Gal	Dishwasher Residential	RTF ENERGY STAR Dishwasher - 277 kWh/yr and 4.25 gal/cycle	RTF Market Standard 2014 Dishwasher - 289 kWh/yr and 5.0 gal/cycle	Per Building	Existing	2	12	$89	35%	25%	$6.54	6

Table B-2.2. Commercial Gas Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (Therms)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per Therms)	2033 Cumulative Achievable Technical Potential (Therms)
Gas	University	Water Heat GT 55 Gal	Dishwashing - Commercial - Low Temp	Low-Temp Commercial Dishwasher (Includes Extra Chemical Cost) - (ENERGY STAR)	Standard High Temp Commercial Dishwasher	Per Building	Existing	33	12	$505	95%	95%	$-17.82	1,012
Gas	University	Water Heat GT 55 Gal	Drainwater Heat Recovery Water Heater	Install (Power-Pipe or GFX) - Heat Recovery Water Heater	No Heat Recovery System	Per Building	Existing	1,287	25	$8,330	5.0%	92%	$0.80	1,913
Gas	University	Water Heat GT 55 Gal	Low-Flow Faucet Aerators	0.5 GPM	2.2 GPM (Federal Code)	Per Building	Existing	248	9	$22	95%	75%	$-0.01	5,928
Gas	University	Water Heat GT 55 Gal	Low-Flow Faucet Aerators	2.2 GPM (Federal Code)	3.0 GPM	Per Building	Existing	85	9	$16	95%	25%	$-0.25	681
Gas	University	Water Heat GT 55 Gal	Low-Flow Pre-Rinse Spray Valves	0.6 GPM	1.6 GPM (Federal Standard)	Per Building	Existing	36	4	$247	95%	65%	$2.14	749
Gas	University	Water Heat GT 55 Gal	Low-Flow Showerheads	1.5 GPM	2.5 GPM (Federal Code)	Per Building	Existing	32	10	$365	95%	73%	$1.48	742
Gas	University	Water Heat GT 55 Gal	Low-Flow Showerheads	2.5 GPM (Federal Code)	4.5 GPM	Per Building	Existing	64	10	$303	95%	35%	$0.40	711
Gas	University	Water Heat GT 55 Gal	Pipe Insulation - Hot Water (DWH)	1.0" of Insulation, assuming R-4 (WA State Code)	No Insulation	Per Building	Existing	64	12	$101	75%	70%	$0.25	1,070
Gas	University	Water Heat GT 55 Gal	Ultrasonic Faucet Control	Install Ultrasonic Motion Faucet Control	No Faucet Control	Per Building	Existing	160	10	$2,203	75%	75%	$2.04	3,028
Gas	University	Water Heat LE 55 Gal	Clothes Washer - Ozonating	Ozonating Clothes Washer	2013 Federal Standard Clothes Washer - MEF = 1.6, WF = 8.5	Per Building	Existing	886	10	$8,280	1.8%	95%	$0.58	5,709
Gas	University	Water Heat LE 55 Gal	Clothes Washer Commercial	ENERGY STAR Commercial Clothes Washer - MEF = 2.43, WF = 4.0	2013 Federal Standard Clothes Washer - MEF = 1.6, WF = 8.5	Per Building	Existing	10	7	$118	95%	80%	$-1.25	2,954
Gas	University	Water Heat LE 55 Gal	Demand Controlled Circulating Systems	Demand Controlled Circulating Systems (VFD control by demand)	Constant Circulation	Per Building	Existing	293	10	$15,559	55%	94%	$9.10	58,470
Gas	University	Water Heat LE 55 Gal	Dishwasher Residential	RTF ENERGY STAR Dishwasher - 277 kWh/yr and 4.25 gal/cycle	RTF Market Standard 2014 Dishwasher - 289 kWh/yr and 5.0 gal/cycle	Per Building	Existing	2	12	$89	35%	25%	$6.54	73
Gas	University	Water Heat LE 55 Gal	Dishwashing - Commercial - Low Temp	Low-Temp Commercial Dishwasher (Includes Extra Chemical Cost) - (ENERGY STAR)	Standard High Temp Commercial Dishwasher	Per Building	Existing	30	12	$460	95%	95%	$-19.81	10,674
Gas	University	Water Heat LE 55 Gal	Drainwater Heat Recovery Water Heater	Install (Power-Pipe or GFX) - Heat Recovery Water Heater	No Heat Recovery System	Per Building	Existing	1,172	25	$8,330	5.0%	92%	$0.88	20,173
Gas	University	Water Heat LE 55 Gal	Low-Flow Faucet Aerators	0.5 GPM	2.2 GPM (Federal Code)	Per Building	Existing	226	9	$22	95%	75%	$-0.01	62,505
Gas	University	Water Heat LE 55 Gal	Low-Flow Faucet Aerators	2.2 GPM (Federal Code)	3.0 GPM	Per Building	Existing	78	9	$16	95%	25%	$-0.23	7,190
Gas	University	Water Heat LE 55 Gal	Low-Flow Pre-Rinse Spray Valves	0.6 GPM	1.6 GPM (Federal Standard)	Per Building	Existing	36	4	$247	95%	65%	$2.14	8,679
Gas	University	Water Heat LE 55 Gal	Low-Flow Showerheads	1.5 GPM	2.5 GPM (Federal Code)	Per Building	Existing	32	10	$365	95%	73%	$1.48	8,596
Gas	University	Water Heat LE 55 Gal	Low-Flow Showerheads	2.5 GPM (Federal Code)	4.5 GPM	Per Building	Existing	64	10	$303	95%	35%	$0.40	8,242
Gas	University	Water Heat LE 55 Gal	Pipe Insulation - Hot Water (DWH)	1.0" of Insulation, assuming R-4 (WA State Code)	No Insulation	Per Building	Existing	58	12	$101	75%	70%	$0.27	11,279
Gas	University	Water Heat LE 55 Gal	Ultrasonic Faucet Control	Install Ultrasonic Motion Faucet Control	No Faucet Control	Per Building	Existing	146	10	$2,203	75%	75%	$2.27	31,929

Table B-2.2. Commercial Gas Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (Therms)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per Therms)	2033 Cumulative Achievable Technical Potential (Therms)
Gas	Warehouse	Space Heat Boiler	Boiler Economizer	Economizer	No Economizer	Per Building	Existing	275	20	$3,533	10%	90%	$1.60	857
Gas	Warehouse	Space Heat Boiler	Commissioning of Existing Buildings	Existing Building Commissioning	Average Existing Conditions	Per Building	Existing	625	7	$11,924	90%	80%	$4.13	11,635
Gas	Warehouse	Space Heat Boiler	Direct Digital Control System-Installation	DDC Retrofit (Morning Warm-Up Control Logic Included in This Measure)	Pneumatic	Per Building	Existing	750	5	$58,171	20%	93%	$21.08	4,819
Gas	Warehouse	Space Heat Boiler	Direct Digital Control System-Wireless System	DDC Retrofit - Wireless System	Pneumatic	Per Building	Existing	750	5	$23,516	75%	98%	$8.52	13,543
Gas	Warehouse	Space Heat Boiler	Exhaust Air to Ventilation Air Heat Recovery	Exhaust Air Heat Recovery	No Heat Recovery	Per Building	Existing	750	10	$54,874	5.0%	94%	$12.53	1,085
Gas	Warehouse	Space Heat Boiler	Infiltration Reduction	Install Caulking And Weatherstripping (ACH 0.65)	Infiltration Conditions (ACH 1.0)	Per Building	Existing	156	10	$429	10%	39%	$0.47	184
Gas	Warehouse	Space Heat Boiler	Insulation - Ceiling	R-30 c.i. (WA State Code)	R-8 (Average Existing Conditions)	Per Building	Existing	792	25	$94,937	75%	10%	$14.77	1,813
Gas	Warehouse	Space Heat Boiler	Insulation - Ceiling	R-38 c.i.	R-30 c.i. (WA State Code)	Per Building	Existing	7	25	$94,937	75%	70%	$1,504.69	123
Gas	Warehouse	Space Heat Boiler	Insulation - Ceiling	R-49 c.i.	R-38 c.i.	Per Building	Existing	70	25	$26,789	75%	85%	$46.73	1,357
Gas	Warehouse	Space Heat Boiler	Insulation - Floor (non-slab)	R-30 (WA State Code)	R-8 (Average Existing Conditions)	Per Building	Existing	1,698	25	$50,058	35%	45%	$3.64	7,983
Gas	Warehouse	Space Heat Boiler	Insulation - Floor (non-slab)	R-38	R-30 (WA State Code)	Per Building	Existing	217	25	$15,445	35%	45%	$8.76	967
Gas	Warehouse	Space Heat Boiler	Insulation - Wall	R-16	R-3 (Average Existing Conditions)	Per Building	Existing	2,200	25	$44,782	10%	35%	$2.51	2,161
Gas	Warehouse	Space Heat Boiler	Pipe Insulation - Boiler	3" of Insulation, assuming R-12 (WA State Code)	No Insulation	Per Building	Existing	603	20	$3,563	75%	65%	$0.74	8,124
Gas	Warehouse	Space Heat Boiler	Programmable Thermostat - Web Enabled	Programmable Thermostat - Web Enabled	No Programmable Thermostat	Per Building	Existing	150	15	$726	95%	24%	$0.68	879
Gas	Warehouse	Space Heat Boiler	Sensible And Total Heat Recovery Devices	Install Heat Recovery Devices - rotary air-to-air enthalpy heat recovery- 70% sensible and latent recovery effectiveness	No Heat Recovery	Per Building	Existing	1,251	10	$27,656	25%	98%	$17.48	7,206
Gas	Warehouse	Space Heat Boiler	Windows-High Efficiency	U-0.40 (WA State Code)	U-0.65 (Average Existing Conditions)	Per Building	Existing	37	25	$79,510	10%	98%	$261.44	81
Gas	Warehouse	Space Heat Furnace	Commissioning of Existing Buildings	Existing Building Commissioning	Average Existing Conditions	Per Building	Existing	929	7	$11,924	90%	80%	$2.78	970,945
Gas	Warehouse	Space Heat Furnace	Direct Digital Control System-Installation	DDC Retrofit (Morning Warm-Up Control Logic Included in This Measure)	Pneumatic	Per Building	Existing	1,115	5	$58,171	20%	93%	$14.19	377,949
Gas	Warehouse	Space Heat Furnace	Direct Digital Control System-Wireless System	DDC Retrofit - Wireless System	Pneumatic	Per Building	Existing	1,115	5	$23,516	75%	80%	$5.74	867,019
Gas	Warehouse	Space Heat Furnace	Duct Repair And Sealing	Reduction In Duct Losses to 5%	No Repair or Sealing, 15% duct losses	Per Building	Existing	185	18	$24,200	45%	45%	$16.88	62,115
Gas	Warehouse	Space Heat Furnace	Exhaust Air to Ventilation Air Heat Recovery	Exhaust Air Heat Recovery	No Heat Recovery	Per Building	Existing	1,115	10	$54,874	5.0%	94%	$8.43	86,062
Gas	Warehouse	Space Heat Furnace	Infiltration Reduction	Install Caulking And Weatherstripping (ACH 0.65)	Infiltration Conditions (ACH 1.0)	Per Building	Existing	232	10	$429	10%	39%	$0.32	14,665
Gas	Warehouse	Space Heat Furnace	Insulation - Ceiling	R-30 c.i. (WA State Code)	R-8 (Average Existing Conditions)	Per Building	Existing	1,177	25	$94,937	75%	10%	$9.95	143,792
Gas	Warehouse	Space Heat Furnace	Insulation - Ceiling	R-38 c.i.	R-30 c.i. (WA State Code)	Per Building	Existing	11	25	$94,937	75%	70%	$1,012.82	9,766

Table B-2.2. Commercial Gas Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (Therms)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per Therms)	2033 Cumulative Achievable Technical Potential (Therms)
Gas	Warehouse	Space Heat Furnace	Insulation - Ceiling	R-49 c.i.	R-38 c.i.	Per Building	Existing	105	25	$26,789	75%	85%	$31.46	107,652
Gas	Warehouse	Space Heat Furnace	Insulation - Duct	R-7 (WA State Code)	No Insulation	Per Building	Existing	312	25	$11,700	10%	15%	$4.62	7,462
Gas	Warehouse	Space Heat Furnace	Insulation - Floor (non-slab)	R-30 (WA State Code)	R-8 (Average Existing Conditions)	Per Building	Existing	2,522	25	$50,058	35%	45%	$2.45	632,562
Gas	Warehouse	Space Heat Furnace	Insulation - Floor (non-slab)	R-38	R-30 (WA State Code)	Per Building	Existing	323	25	$15,445	35%	45%	$5.90	76,697
Gas	Warehouse	Space Heat Furnace	Insulation - Wall	R-16	R-3 (Average Existing Conditions)	Per Building	Existing	5,101	25	$44,782	10%	35%	$1.08	267,208
Gas	Warehouse	Space Heat Furnace	Programmable Thermostat - Web Enabled	Programmable Thermostat - Web Enabled	No Programmable Thermostat	Per Building	Existing	223	15	$726	95%	24%	$0.46	73,364
Gas	Warehouse	Space Heat Furnace	Windows-High Efficiency	U-0.40 (WA State Code)	U-0.65 (Average Existing Conditions)	Per Building	Existing	55	25	$79,510	10%	98%	$175.98	7,210
Gas	Warehouse	Water Heat GT 55 Gal	Demand Controlled Circulating Systems	Demand Controlled Circulating Systems (VFD control by demand)	Constant Circulation	Per Building	Existing	69	10	$16,807	55%	94%	$41.67	1,009
Gas	Warehouse	Water Heat GT 55 Gal	Dishwasher Residential	RTF ENERGY STAR Dishwasher - 277 kWh/yr and 4.25 gal/cycle	RTF Market Standard 2014 Dishwasher - 289 kWh/yr and 5.0 gal/cycle	Per Building	Existing	0.95	12	$42	2.7%	25%	$6.97	0.18
Gas	Warehouse	Water Heat GT 55 Gal	Drainwater Heat Recovery Water Heater	Install (Power-Pipe or GFX) - Heat Recovery Water Heater	No Heat Recovery System	Per Building	Existing	276	25	$1,458	5.0%	92%	$0.65	349
Gas	Warehouse	Water Heat GT 55 Gal	Low-Flow Faucet Aerators	0.5 GPM	2.2 GPM (Federal Code)	Per Building	Existing	53	9	$6	95%	75%	$-0.55	1,074
Gas	Warehouse	Water Heat GT 55 Gal	Low-Flow Faucet Aerators	2.2 GPM (Federal Code)	3.0 GPM	Per Building	Existing	18	9	$6	95%	25%	$-1.17	123
Gas	Warehouse	Water Heat GT 55 Gal	Pipe Insulation - Hot Water (DWH)	1.0" of Insulation, assuming R-4 (WA State Code)	No Insulation	Per Building	Existing	13	12	$24	75%	90%	$0.28	253
Gas	Warehouse	Water Heat GT 55 Gal	Ultrasonic Faucet Control	Install Ultrasonic Motion Faucet Control	No Faucet Control	Per Building	Existing	34	10	$471	75%	95%	$0.92	695
Gas	Warehouse	Water Heat LE 55 Gal	Demand Controlled Circulating Systems	Demand Controlled Circulating Systems (VFD control by demand)	Constant Circulation	Per Building	Existing	62	10	$16,807	55%	94%	$45.76	10,640
Gas	Warehouse	Water Heat LE 55 Gal	Dishwasher Residential	RTF ENERGY STAR Dishwasher - 277 kWh/yr and 4.25 gal/cycle	RTF Market Standard 2014 Dishwasher - 289 kWh/yr and 5.0 gal/cycle	Per Building	Existing	0.95	12	$42	2.7%	25%	$6.97	2
Gas	Warehouse	Water Heat LE 55 Gal	Drainwater Heat Recovery Water Heater	Install (Power-Pipe or GFX) - Heat Recovery Water Heater	No Heat Recovery System	Per Building	Existing	251	25	$1,458	5.0%	92%	$0.71	3,689
Gas	Warehouse	Water Heat LE 55 Gal	Low-Flow Faucet Aerators	0.5 GPM	2.2 GPM (Federal Code)	Per Building	Existing	48	9	$6	95%	75%	$-0.52	11,331
Gas	Warehouse	Water Heat LE 55 Gal	Low-Flow Faucet Aerators	2.2 GPM (Federal Code)	3.0 GPM	Per Building	Existing	16	9	$6	95%	25%	$-1.29	1,303
Gas	Warehouse	Water Heat LE 55 Gal	Pipe Insulation - Hot Water (DWH)	1.0" of Insulation, assuming R-4 (WA State Code)	No Insulation	Per Building	Existing	12	12	$24	75%	90%	$0.30	2,672
Gas	Warehouse	Water Heat LE 55 Gal	Ultrasonic Faucet Control	Install Ultrasonic Motion Faucet Control	No Faucet Control	Per Building	Existing	31	10	$471	75%	95%	$1.14	7,332

Table B-2.3. Industrial Gas Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (Therms)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per Therms)	2033 Cumulative Achievable Technical Potential (Therms)
Gas	Chemical Mfg	Hvac	HVAC Improvements			Per Industry	Existing	3,797	15	$3,573	100%	100%	$0.13	2,509
Gas	Chemical Mfg	Indirect Boiler	Boiler Improvements			Per Industry	Existing	15,085	15	$3,910	10%	100%	$0.04	996
Gas	Chemical Mfg	Indirect Boiler	Boiler O&M			Per Industry	Existing	22,018	2	$3,622	10%	100%	$0.10	1,454
Gas	Chemical Mfg	Process Heat	Boiler Improvements			Per Industry	Existing	65,684	15	$4,249	10%	100%	$0.01	4,339
Gas	Chemical Mfg	Process Heat	Heat Improvements			Per Industry	Existing	33,191	15	$12,015	100%	100%	$0.05	21,929
Gas	Chemical Mfg	Process Heat	Heat O&M			Per Industry	Existing	1,818	2	$971	100%	100%	$0.31	1,201
Gas	Chemical Mfg	Process Heat	Steam Distribution			Per Industry	Existing	45,459	15	$2,486	100%	100%	$0.01	30,035
Gas	Chemical Mfg	Process Other	Other O&M			Per Industry	Existing	9,737	2	$2,705	100%	100%	$0.16	6,433
Gas	Computer Electronic Mfg	Hvac	HVAC Improvements			Per Industry	Existing	89,110	15	$66,217	100%	100%	$0.10	58,876
Gas	Computer Electronic Mfg	Indirect Boiler	Boiler Improvements			Per Industry	Existing	111,856	15	$31,286	10%	100%	$0.16	7,390
Gas	Computer Electronic Mfg	Indirect Boiler	Boiler O&M			Per Industry	Existing	85,220	2	$11,479	10%	100%	$0.08	5,630
Gas	Computer Electronic Mfg	Process Heat	Boiler Improvements			Per Industry	Existing	6,675	15	$11,301	10%	100%	$0.24	441
Gas	Computer Electronic Mfg	Process Heat	Heat Improvements			Per Industry	Existing	36,125	15	$13,236	100%	100%	$0.05	23,868
Gas	Computer Electronic Mfg	Process Heat	Heat O&M			Per Industry	Existing	6,445	2	$3,759	100%	100%	$0.34	4,258
Gas	Computer Electronic Mfg	Process Heat	Steam Distribution			Per Industry	Existing	14,722	15	$7,253	100%	100%	$0.07	9,727
Gas	Electrical Equipment Mfg	Hvac	HVAC Improvements			Per Industry	Existing	18,061	15	$10,885	100%	100%	$0.08	11,933
Gas	Electrical Equipment Mfg	Indirect Boiler	Boiler Improvements			Per Industry	Existing	18,262	15	$20,671	10%	100%	$0.16	1,206
Gas	Electrical Equipment Mfg	Indirect Boiler	Boiler O&M			Per Industry	Existing	19,606	2	$4,456	10%	100%	$0.13	1,295
Gas	Electrical Equipment Mfg	Process Heat	Boiler Improvements			Per Industry	Existing	35,028	15	$18,547	10%	100%	$0.07	2,314
Gas	Electrical Equipment Mfg	Process Heat	Heat Improvements			Per Industry	Existing	82,015	15	$46,125	100%	100%	$0.08	54,189
Gas	Electrical Equipment Mfg	Process Heat	Heat O&M			Per Industry	Existing	12,031	2	$5,171	100%	100%	$0.25	7,949
Gas	Electrical Equipment Mfg	Process Heat	Steam Distribution			Per Industry	Existing	30,008	15	$10,151	100%	100%	$0.05	19,827
Gas	Fabricated Metal Products	Hvac	HVAC Improvements			Per Industry	Existing	81,184	15	$99,126	100%	100%	$0.17	53,640
Gas	Fabricated Metal Products	Indirect Boiler	Boiler Improvements			Per Industry	Existing	102,488	15	$60,681	10%	100%	$0.22	6,771

Table B-2.3. Industrial Gas Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (Therms)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per Therms)	2033 Cumulative Achievable Technical Potential (Therms)
Gas	Fabricated Metal Products	Indirect Boiler	Boiler O&M			Per Industry	Existing	70,142	2	$7,855	10%	100%	$0.06	4,634
Gas	Fabricated Metal Products	Process Heat	Boiler Improvements			Per Industry	Existing	147,093	15	$69,692	10%	100%	$0.07	9,718
Gas	Fabricated Metal Products	Process Heat	Heat Improvements			Per Industry	Existing	168,469	15	$53,290	100%	100%	$0.13	111,310
Gas	Fabricated Metal Products	Process Heat	Heat O&M			Per Industry	Existing	86,814	2	$41,401	100%	100%	$0.28	57,359
Gas	Fabricated Metal Products	Process Heat	Steam Distribution			Per Industry	Existing	127,716	15	$83,002	100%	100%	$0.09	84,384
Gas	Fabricated Metal Products	Process Other	Other O&M			Per Industry	Existing	2,047	2	$1,004	100%	100%	$0.28	1,352
Gas	Food Mfg	Hvac	HVAC Improvements			Per Industry	Existing	37,476	15	$21,912	100%	100%	$0.08	24,761
Gas	Food Mfg	Indirect Boiler	Boiler Improvements			Per Industry	Existing	129,755	15	$6,101	10%	100%	$0.11	8,573
Gas	Food Mfg	Indirect Boiler	Boiler O&M			Per Industry	Existing	89,780	2	$32,195	10%	100%	$0.21	5,931
Gas	Food Mfg	Process Heat	Boiler Improvements			Per Industry	Existing	91,138	15	$28,936	10%	100%	$0.04	6,021
Gas	Food Mfg	Process Heat	Heat Improvements			Per Industry	Existing	165,822	15	$83,690	100%	100%	$0.07	109,561
Gas	Food Mfg	Process Heat	Heat O&M			Per Industry	Existing	45,395	2	$15,806	100%	100%	$0.20	29,993
Gas	Food Mfg	Process Heat	Steam Distribution			Per Industry	Existing	66,880	15	$30,778	100%	100%	$0.06	44,189
Gas	Food Mfg	Process Other	Other O&M			Per Industry	Existing	39,071	2	$5,399	100%	100%	$0.08	25,815
Gas	Industrial Machinery	Hvac	HVAC Improvements			Per Industry	Existing	201,880	15	$65,723	100%	100%	$0.12	133,385
Gas	Industrial Machinery	Indirect Boiler	Boiler Improvements			Per Industry	Existing	176,604	15	$82,255	10%	100%	$0.15	11,668
Gas	Industrial Machinery	Indirect Boiler	Boiler O&M			Per Industry	Existing	141,433	2	$24,383	10%	100%	$0.10	9,344
Gas	Industrial Machinery	Process Heat	Boiler Improvements			Per Industry	Existing	23,420	15	$25,589	10%	100%	$0.15	1,547
Gas	Industrial Machinery	Process Heat	Heat Improvements			Per Industry	Existing	148,898	15	$75,581	100%	100%	$0.07	98,380
Gas	Industrial Machinery	Process Heat	Heat O&M			Per Industry	Existing	109,181	2	$62,287	100%	100%	$0.33	72,137
Gas	Industrial Machinery	Process Heat	Steam Distribution			Per Industry	Existing	69,880	15	$25,422	100%	100%	$0.05	46,170
Gas	Miscellaneous Mfg	Hvac	HVAC Improvements			Per Industry	Existing	710,833	15	$97,086	100%	100%	$0.10	469,659
Gas	Miscellaneous Mfg	Indirect Boiler	Boiler Improvements			Per Industry	Existing	203,481	15	$20,217	10%	100%	$0.08	13,444
Gas	Miscellaneous Mfg	Indirect Boiler	Boiler O&M			Per Industry	Existing	77,690	2	$16,346	10%	100%	$0.12	5,133
Gas	Miscellaneous Mfg	Process Heat	Boiler Improvements			Per Industry	Existing	77,747	15	$81,370	10%	100%	$0.15	5,136
Gas	Miscellaneous Mfg	Process Heat	Heat Improvements			Per Industry	Existing	144,512	15	$66,504	100%	100%	$0.06	95,481
Gas	Miscellaneous Mfg	Process Heat	Heat O&M			Per Industry	Existing	63,134	2	$20,954	100%	100%	$0.19	41,713
Gas	Miscellaneous Mfg	Process Heat	Steam Distribution			Per Industry	Existing	208,964	15	$44,592	100%	100%	$0.03	138,066

Table B-2.3. Industrial Gas Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (Therms)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per Therms)	2033 Cumulative Achievable Technical Potential (Therms)
Gas	Nonmetallic Mineral Products	Hvac	HVAC Improvements			Per Industry	Existing	7,450	15	$8,633	100%	100%	$0.16	4,922
Gas	Nonmetallic Mineral Products	Indirect Boiler	Boiler O&M			Per Industry	Existing	3,870	2	$259	10%	100%	$0.04	255
Gas	Nonmetallic Mineral Products	Process Heat	Boiler Improvements			Per Industry	Existing	307,399	15	$61,541	10%	100%	$0.03	20,310
Gas	Nonmetallic Mineral Products	Process Heat	Heat Improvements			Per Industry	Existing	181,869	15	$64,101	100%	100%	$0.13	120,164
Gas	Nonmetallic Mineral Products	Process Heat	Heat O&M			Per Industry	Existing	42,841	2	$12,929	100%	100%	$0.17	28,305
Gas	Nonmetallic Mineral Products	Process Heat	Steam Distribution			Per Industry	Existing	65,405	15	$26,796	100%	100%	$0.06	43,214
Gas	Nonmetallic Mineral Products	Process Other	Other O&M			Per Industry	Existing	3,728	2	$7,270	100%	100%	$1.13	2,463
Gas	Paper Mfg	Hvac	HVAC Improvements			Per Industry	Existing	2,730	15	$1,808	100%	100%	$0.09	1,804
Gas	Paper Mfg	Indirect Boiler	Boiler Improvements			Per Industry	Existing	23,958	15	$11,387	10%	100%	$0.07	1,582
Gas	Paper Mfg	Indirect Boiler	Boiler O&M			Per Industry	Existing	12,701	2	$1,545	10%	100%	$0.07	839
Gas	Paper Mfg	Process Heat	Boiler Improvements			Per Industry	Existing	8,584	15	$4,161	10%	100%	$0.07	567
Gas	Paper Mfg	Process Heat	Heat Improvements			Per Industry	Existing	14,286	15	$9,695	100%	100%	$0.10	9,439
Gas	Paper Mfg	Process Heat	Heat O&M			Per Industry	Existing	4,258	2	$1,029	100%	100%	$0.14	2,813
Gas	Paper Mfg	Process Heat	Steam Distribution			Per Industry	Existing	5,176	15	$920	100%	100%	$0.03	3,420
Gas	Paper Mfg	Process Other	Other O&M			Per Industry	Existing	4,116	2	$2,736	100%	100%	$0.39	2,719
Gas	Petroleum Coal Products	Indirect Boiler	Boiler Improvements			Per Industry	Existing	6,391	15	$5,864	10%	100%	$0.13	422
Gas	Petroleum Coal Products	Indirect Boiler	Boiler O&M			Per Industry	Existing	4,223	2	$723	10%	100%	$0.10	279
Gas	Petroleum Coal Products	Process Heat	Boiler Improvements			Per Industry	Existing	2,509	15	$1,925	10%	100%	$0.11	165
Gas	Petroleum Coal Products	Process Heat	Heat Improvements			Per Industry	Existing	6,311	15	$4,720	100%	100%	$0.11	4,169
Gas	Petroleum Coal Products	Process Heat	Heat O&M			Per Industry	Existing	2,996	2	$574	100%	100%	$0.11	1,979
Gas	Petroleum Coal Products	Process Heat	Steam Distribution			Per Industry	Existing	3,971	15	$196	100%	100%	$0.01	2,623
Gas	Plastics Rubber Products	Hvac	HVAC Improvements			Per Industry	Existing	23,824	15	$15,040	100%	100%	$0.09	15,740
Gas	Plastics Rubber Products	Indirect Boiler	Boiler Improvements			Per Industry	Existing	74,676	15	$23,000	10%	100%	$0.04	4,933
Gas	Plastics Rubber Products	Indirect Boiler	Boiler O&M			Per Industry	Existing	38,377	2	$8,558	10%	100%	$0.13	2,535

Table B-2.3. Industrial Gas Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (Therms)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per Therms)	2033 Cumulative Achievable Technical Potential (Therms)
Gas	Plastics Rubber Products	Process Heat	Boiler Improvements			Per Industry	Existing	34,121	15	$21,489	10%	100%	$0.09	2,254
Gas	Plastics Rubber Products	Process Heat	Heat Improvements			Per Industry	Existing	43,666	15	$27,440	100%	100%	$0.09	28,851
Gas	Plastics Rubber Products	Process Heat	Heat O&M			Per Industry	Existing	28,058	2	$17,435	100%	100%	$0.36	18,539
Gas	Plastics Rubber Products	Process Heat	Steam Distribution			Per Industry	Existing	22,481	15	$3,563	100%	100%	$0.02	14,854
Gas	Plastics Rubber Products	Process Other	Other O&M			Per Industry	Existing	10,659	2	$2,039	100%	100%	$0.11	7,042
Gas	Primary Metal Mfg	Hvac	HVAC Improvements			Per Industry	Existing	3,109	15	$1,438	100%	N/A	$0.07	2,054
Gas	Primary Metal Mfg	Indirect Boiler	Boiler Improvements			Per Industry	Existing	5,985	15	$5,884	100%	N/A	$0.14	395
Gas	Primary Metal Mfg	Indirect Boiler	Boiler O&M			Per Industry	Existing	4,577	2	$666	100%	N/A	$0.08	302
Gas	Primary Metal Mfg	Process Heat	Boiler Improvements			Per Industry	Existing	20,882	15	$9,058	100%	N/A	$0.06	1,379
Gas	Primary Metal Mfg	Process Heat	Heat Improvements			Per Industry	Existing	22,433	15	$16,670	100%	N/A	$0.10	14,822
Gas	Primary Metal Mfg	Process Heat	Heat O&M			Per Industry	Existing	4,417	2	$2,153	100%	N/A	$0.28	2,918
Gas	Primary Metal Mfg	Process Heat	Steam Distribution			Per Industry	Existing	11,268	15	$4,368	100%	N/A	$0.05	7,444
Gas	Printing Related Support	Hvac	HVAC Improvements			Per Industry	Existing	74,801	15	$32,897	100%	100%	$0.06	49,422
Gas	Printing Related Support	Indirect Boiler	Boiler Improvements			Per Industry	Existing	37,835	15	$39,451	10%	100%	$0.15	2,499
Gas	Printing Related Support	Indirect Boiler	Boiler O&M			Per Industry	Existing	31,647	2	$4,098	10%	100%	$0.08	2,090
Gas	Printing Related Support	Process Heat	Boiler Improvements			Per Industry	Existing	249,072	15	$34,756	10%	100%	$0.25	16,456
Gas	Printing Related Support	Process Heat	Heat Improvements			Per Industry	Existing	71,535	15	$31,754	100%	100%	$0.06	47,264
Gas	Printing Related Support	Process Heat	Heat O&M			Per Industry	Existing	66,970	2	$40,303	100%	100%	$0.35	44,248
Gas	Printing Related Support	Process Heat	Steam Distribution			Per Industry	Existing	264,697	15	$95,820	100%	100%	$0.05	174,889
Gas	Transportation Equipment Mfg	Hvac	HVAC Improvements			Per Industry	Existing	82,262	15	$81,291	100%	100%	$0.14	54,352
Gas	Transportation Equipment Mfg	Indirect Boiler	Boiler Improvements			Per Industry	Existing	102,390	15	$1,612	10%	100%	$0.14	6,765
Gas	Transportation Equipment Mfg	Indirect Boiler	Boiler O&M			Per Industry	Existing	33,861	2	$24,048	10%	100%	$0.41	2,237
Gas	Transportation Equipment Mfg	Process Heat	Boiler Improvements			Per Industry	Existing	149,767	15	$36,812	10%	100%	$0.03	9,895
Gas	Transportation Equipment Mfg	Process Heat	Heat Improvements			Per Industry	Existing	193,985	15	$62,191	100%	100%	$0.05	128,169

Table B-2.3. Industrial Gas Measure Details

Fuel Type	Segment	End Use	Measure Name	Measure Description	Baseline Description	Unit Description	Construction Vintage	Savings per Unit (Therms)	Measure Life	Incremental Cost per Unit	Percent of Installations Technically Feasible	Percent of Installations Incomplete	Levelized Cost ($ per Therms)	2033 Cumulative Achievable Technical Potential (Therms)
Gas	Transportation Equipment Mfg	Process Heat	Heat O&M			Per Industry	Existing	33,989	2	$24,941	100%	100%	$0.43	22,457
Gas	Transportation Equipment Mfg	Process Heat	Steam Distribution			Per Industry	Existing	52,784	15	$37,046	100%	100%	$1.16	34,875
Gas	Transportation Equipment Mfg	Process Other	Other O&M			Per Industry	Existing	11,762	2	$4,940	100%	100%	$0.24	7,771
Gas	Wood Product Mfg	Hvac	HVAC Improvements			Per Industry	Existing	10,872	15	$11,892	100%	100%	$0.15	7,183
Gas	Wood Product Mfg	Indirect Boiler	Boiler Improvements			Per Industry	Existing	53,695	15	$25,645	10%	100%	$0.07	3,547
Gas	Wood Product Mfg	Indirect Boiler	Boiler O&M			Per Industry	Existing	15,940	2	$1,262	10%	100%	$0.05	1,053
Gas	Wood Product Mfg	Process Heat	Boiler Improvements			Per Industry	Existing	96,887	15	$32,951	10%	100%	$0.05	6,401
Gas	Wood Product Mfg	Process Heat	Heat Improvements			Per Industry	Existing	68,144	15	$50,400	100%	100%	$0.31	45,023
Gas	Wood Product Mfg	Process Heat	Heat O&M			Per Industry	Existing	49,292	2	$5,486	100%	100%	$0.06	32,568
Gas	Wood Product Mfg	Process Heat	Steam Distribution			Per Industry	Existing	12,473	15	$987	100%	100%	$0.01	8,241
Gas	Wood Product Mfg	Process Other	Other O&M			Per Industry	Existing	3,817	2	$597	100%	100%	$0.09	2,522

Appendix B.4: Detailed Results

The following pie charts show how achievable potential is distributed by fuel, sector, segment, and end use.

Figure B.4.1 Electric Achievable Technical Potential: Residential by Segment

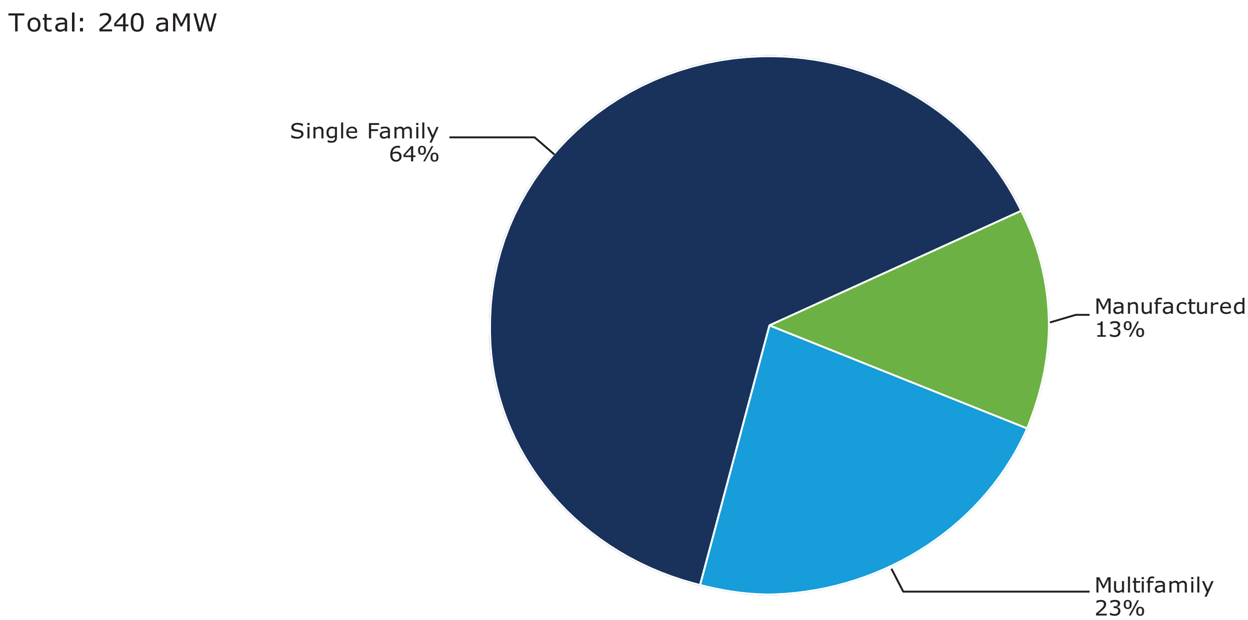


Figure B.4.2 Electric Achievable Technical Potential: Commercial by Segment

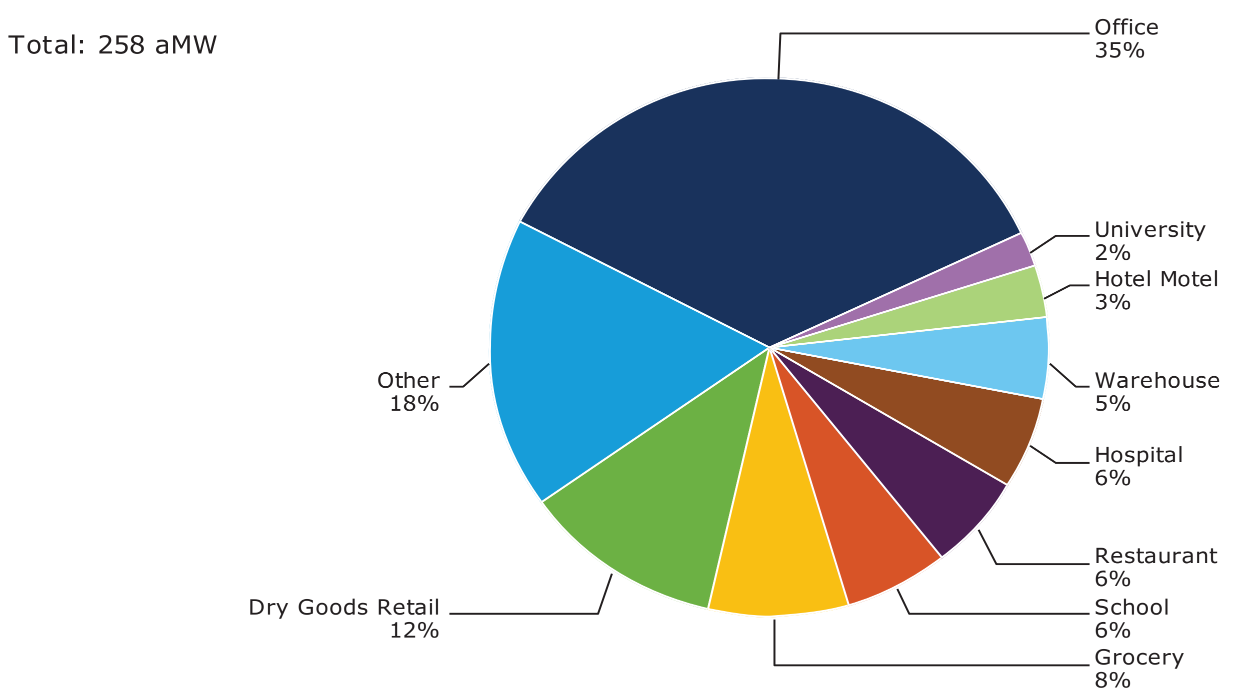
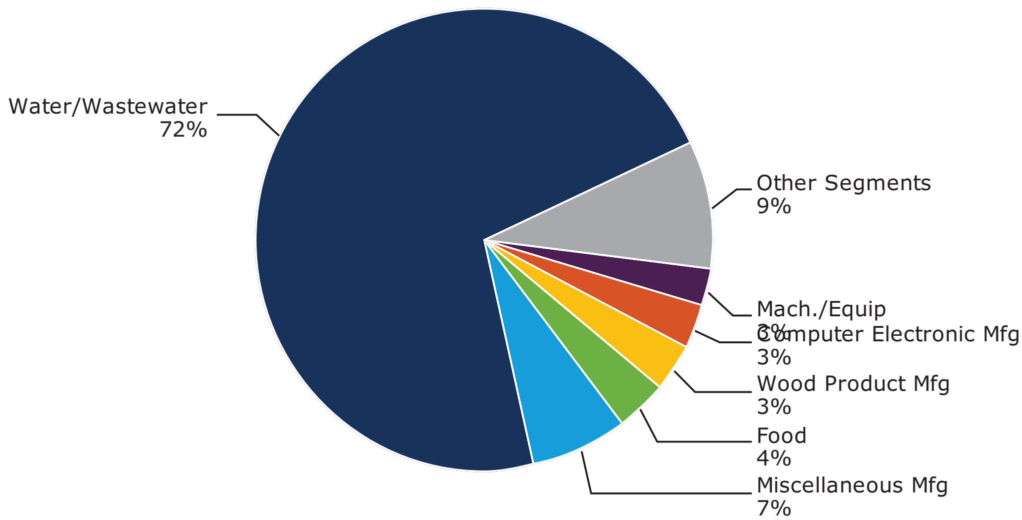


Figure B.4.3 Electric Achievable Technical Potential: Industrial by Segment

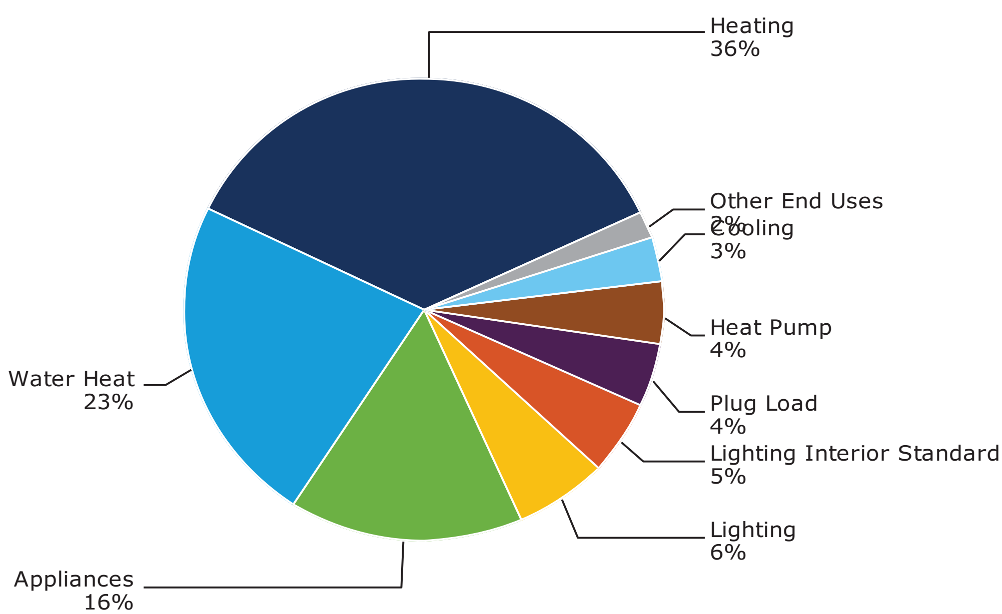
Total: 23 aMW



Note: 'Other Segments' includes:
Printing Related Support: 2%, Transportation: 1%, Fabricated Metal Products: 1%, Paper: 1%, Nonmetallic Mineral Produ: <1%, Electrical Equipment Mfg: <1%, Plastics Rubber Products: <1%, Chemicals: <1%, Petroleum Coal Products: <1%, Metals: <1%

Figure B.4.4 Electric Achievable Technical Potential: Residential by End Use

Total: 240 aMW



Note: 'Other End Uses' includes:
Cooking: <1%, Ventilation And Circulation: <1%, Pool Pump: <1%

Figure B.4.5 Electric Achievable Technical Potential: Commercial by End Use

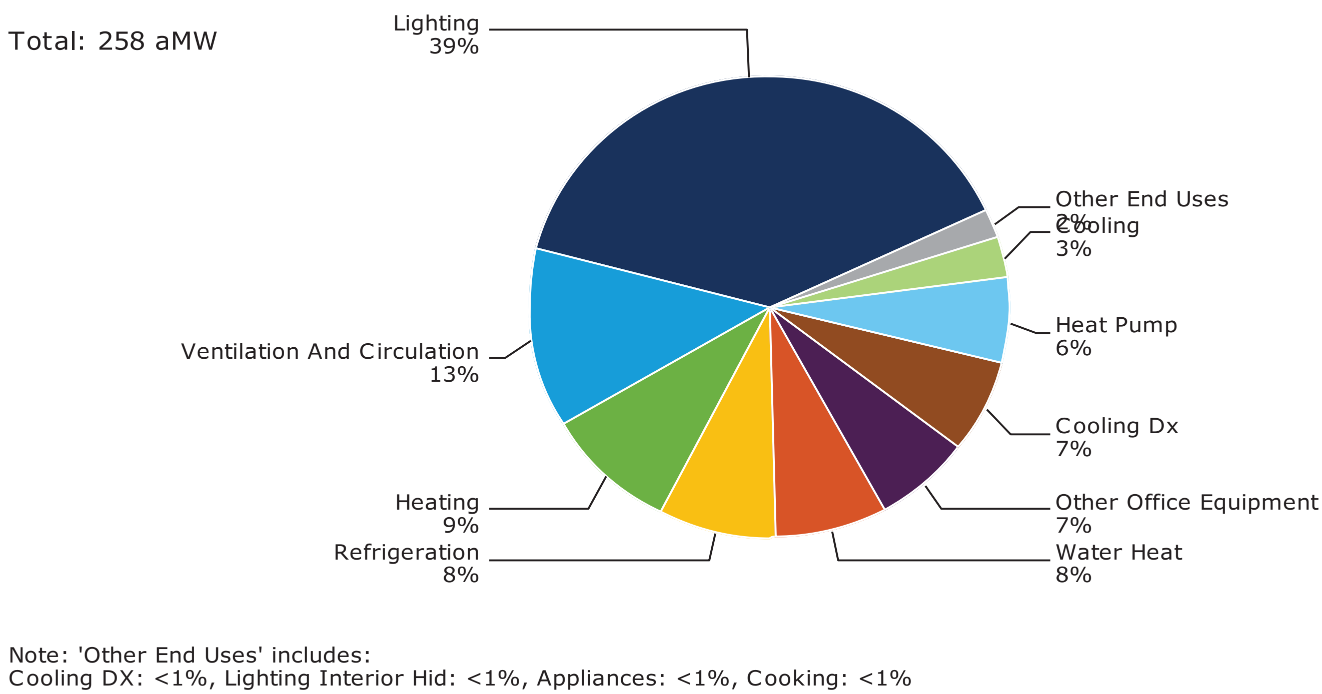


Figure B.4.6 Electric Achievable Technical Potential: Industrial by End Use

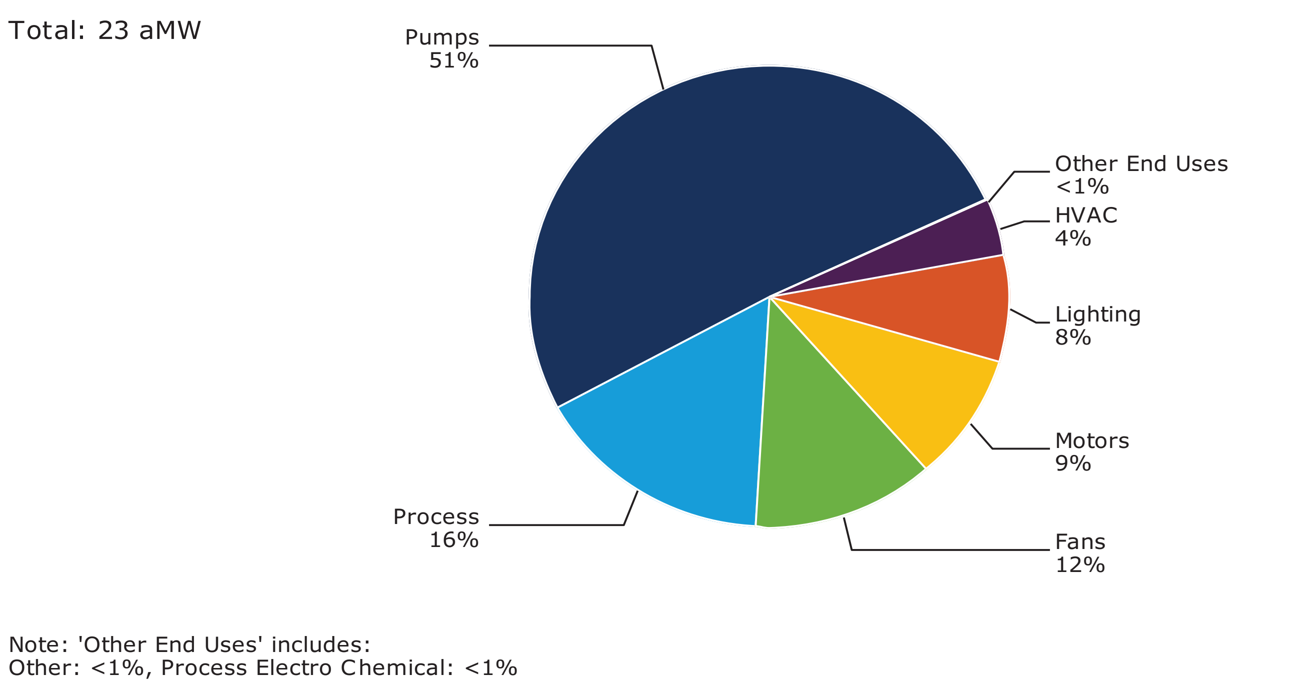


Figure B.4.7 Electric Achievable Technical Potential: Residential Single Family by End Use

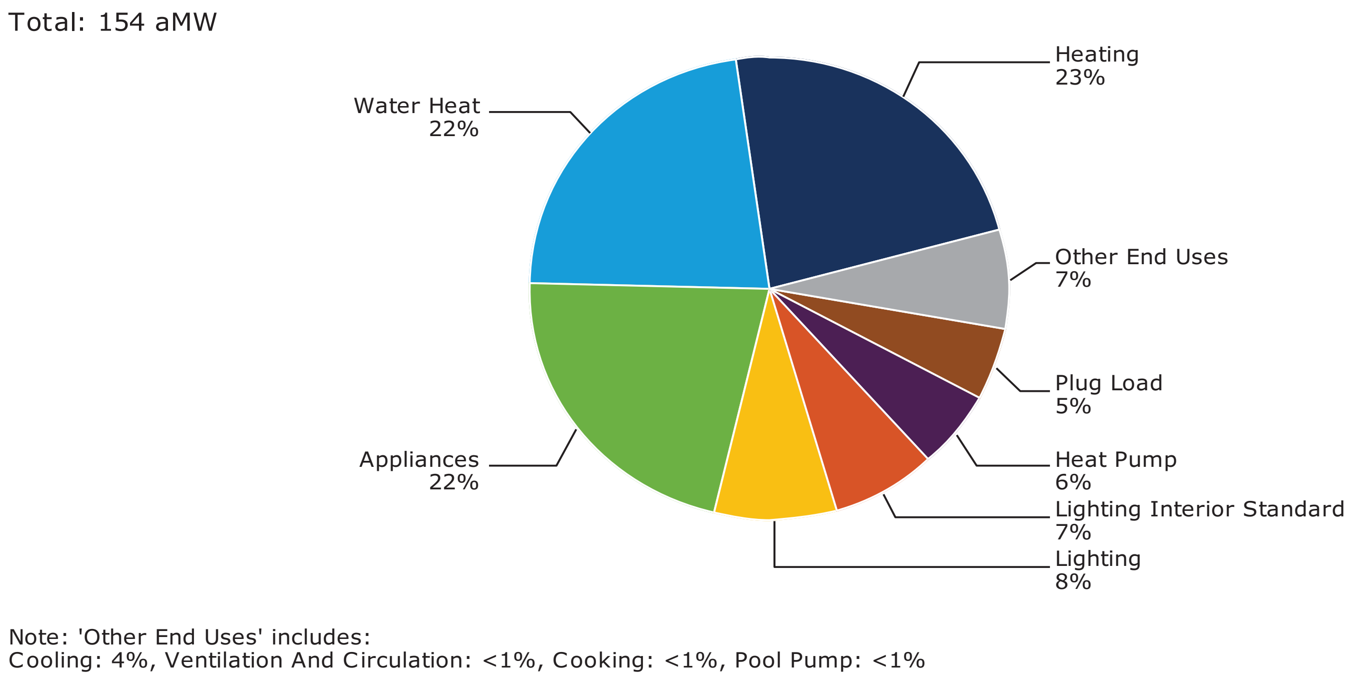


Figure B.4.8 Electric Achievable Technical Potential: Residential Multifamily by End Use

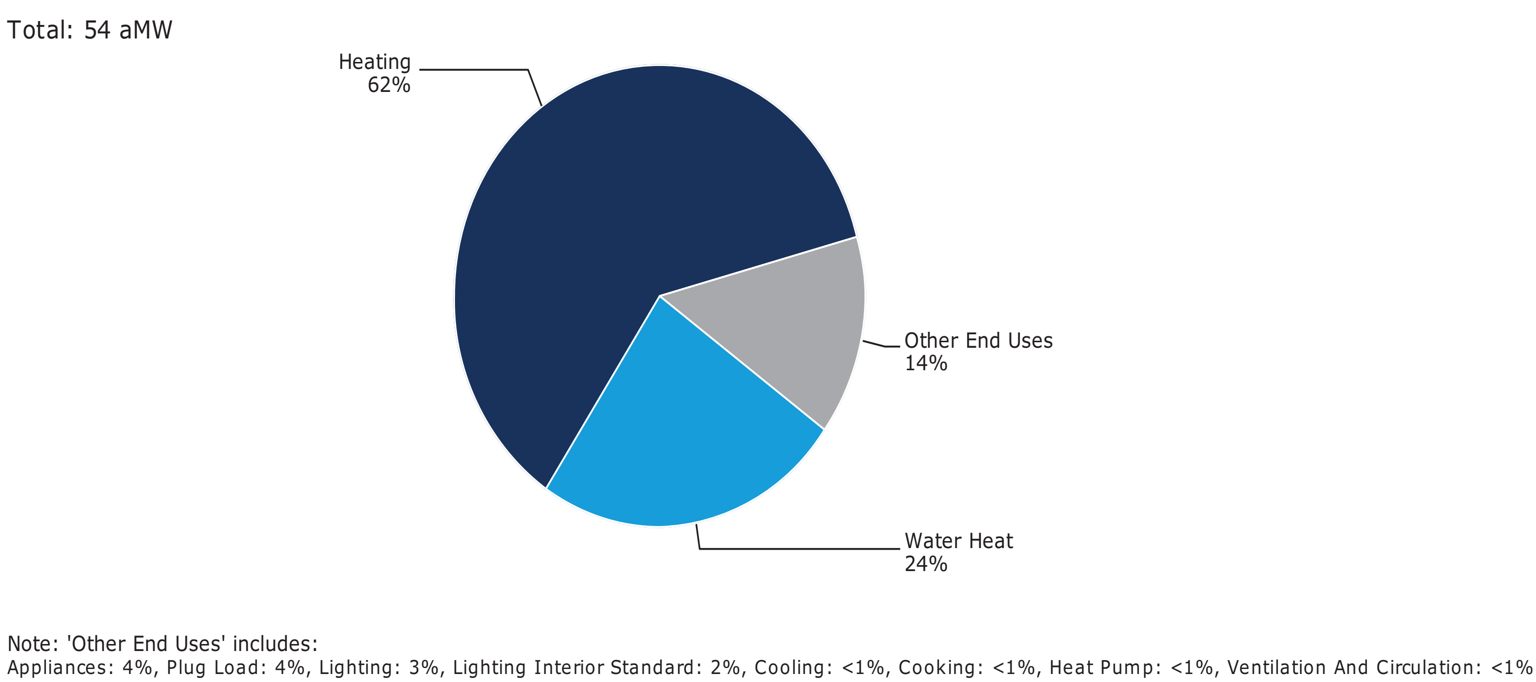
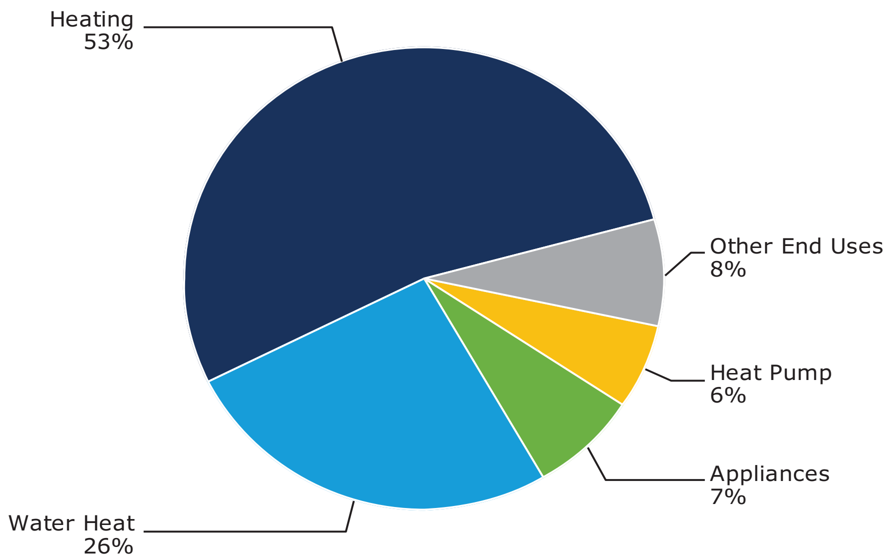


Figure B.4.9 Electric Achievable Technical Potential: Residential Manufactured by End Use

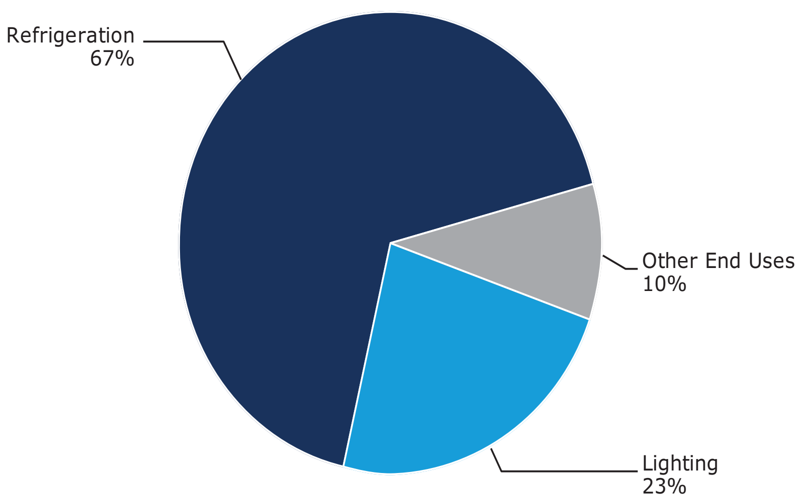
Total: 32 aMW



Note: 'Other End Uses' includes:
Plug Load: 2%, Lighting: 2%, Lighting Interior Standard: 1%, Cooling: 1%, Cooking: <1%, Ventilation And Circulation: <1%

Figure B.4.11 Electric Achievable Technical Potential: Commercial Grocery by End Use

Total: 21 aMW



Note: 'Other End Uses' includes:
Ventilation And Circulation: 3%, Cooling Dx: 3%, Heat Pump: 2%, Other Office Equipment: <1%, Water Heat: <1%, Cooling DX: <1%, Heating: <1%, Lighting Interior Hid: <1%, Cooking: <1%, Appliances: <1%

Figure B.4.12 Electric Achievable Technical Potential: Commercial Hospital by End Use

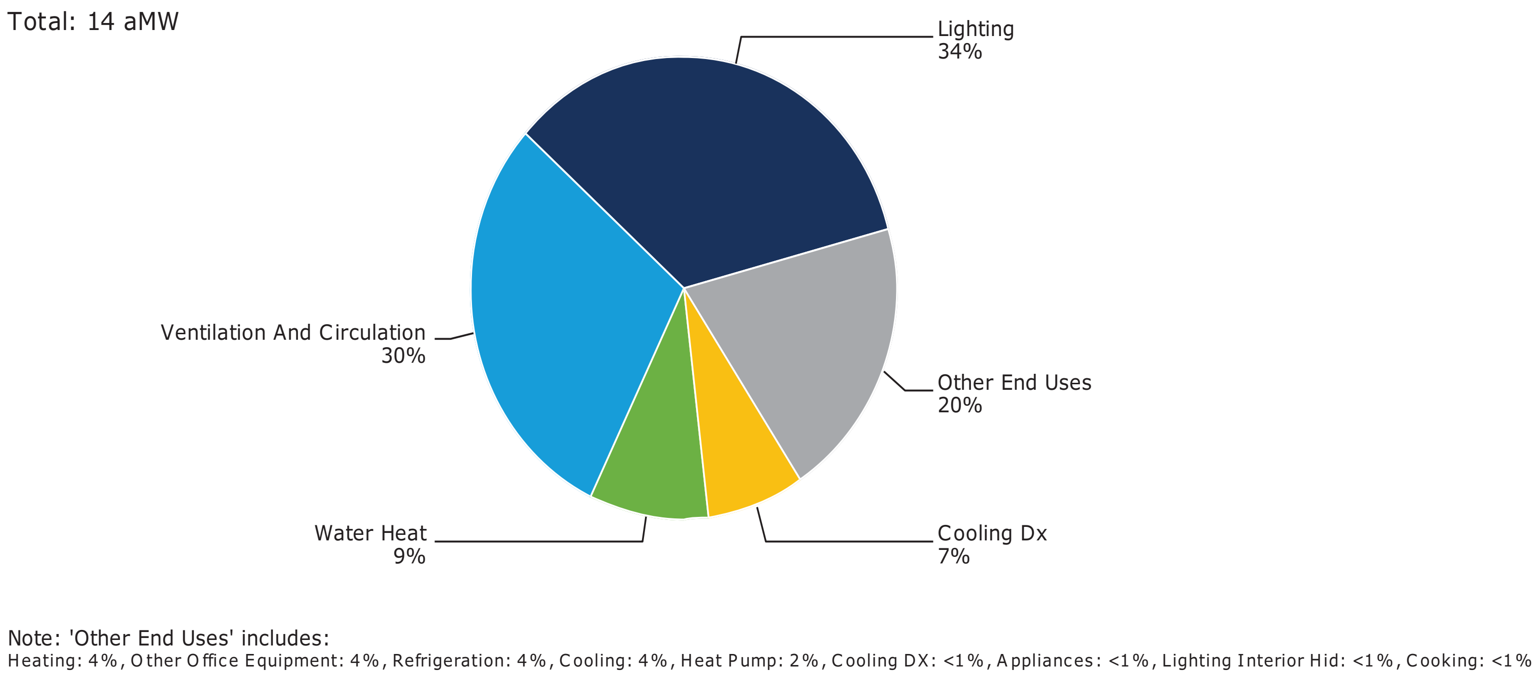


Figure B.4.15 Electric Achievable Technical Potential: Commercial Office by End Use

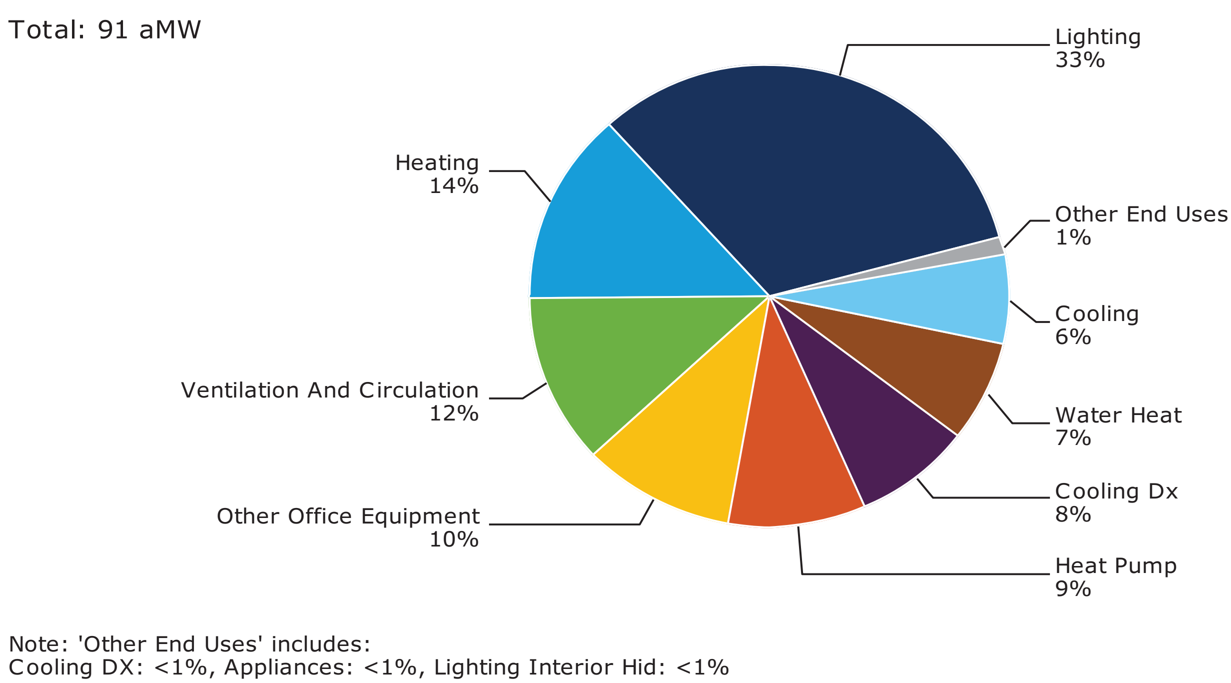


Figure B.4.16 Electric Achievable Technical Potential: Commercial Restaurant by End Use

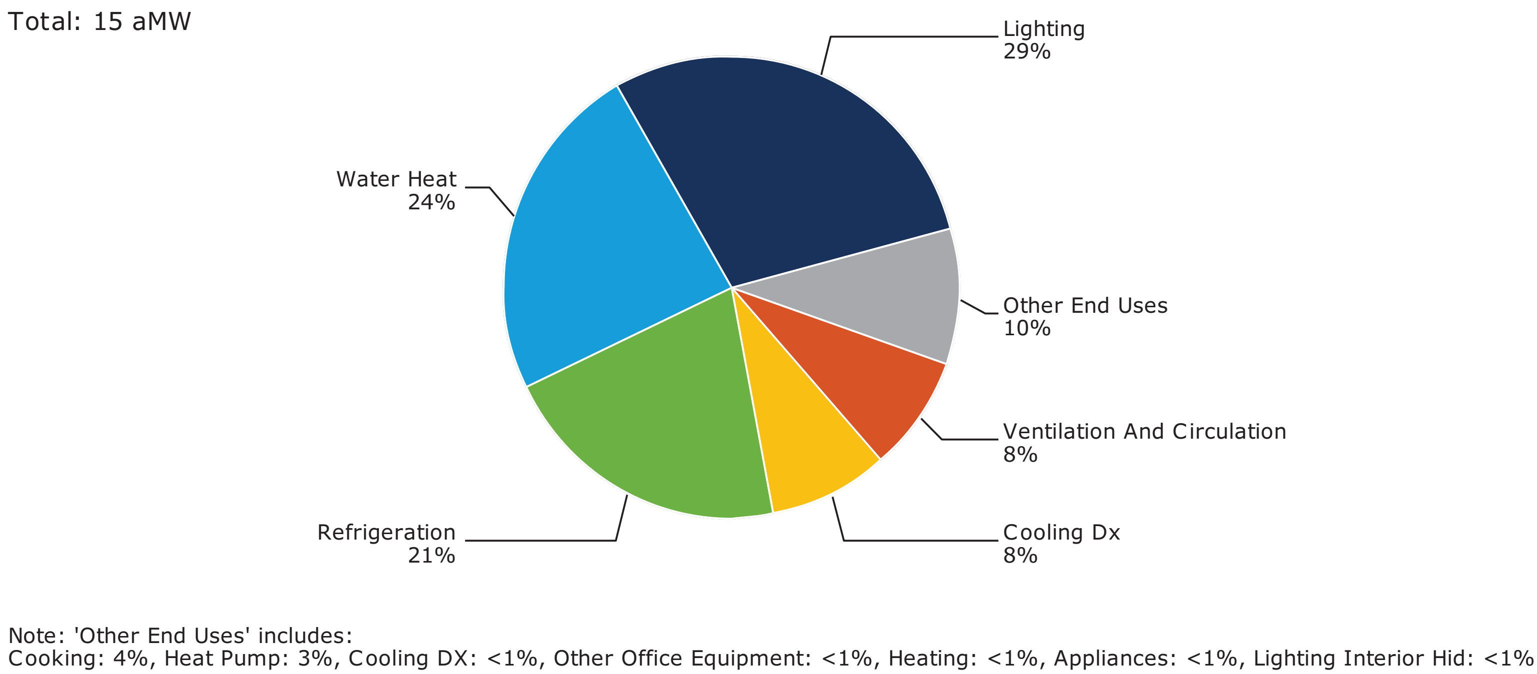


Figure B.4.18 Electric Achievable Technical Potential: Commercial Warehouse by End Use

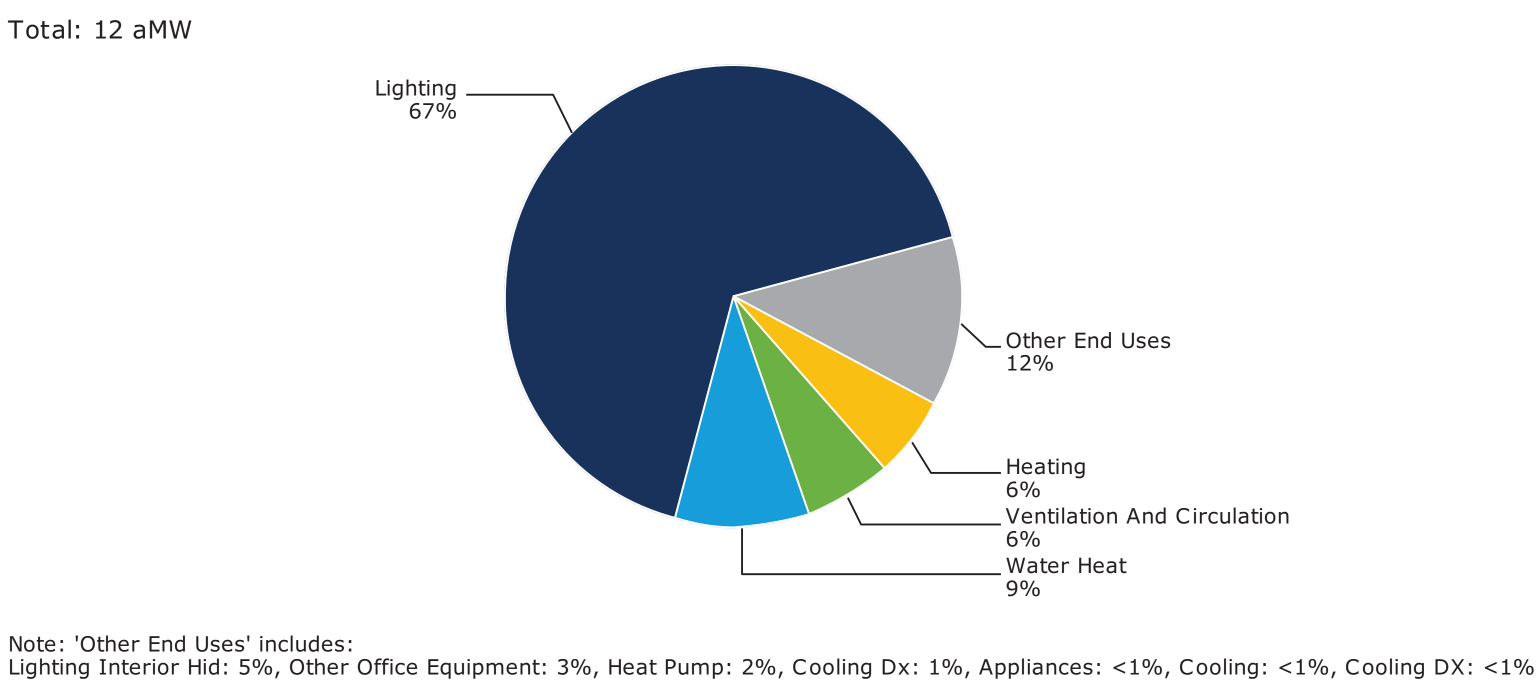


Figure B.4.19 Electric Achievable Technical Potential: Industrial Chemicals by End Use

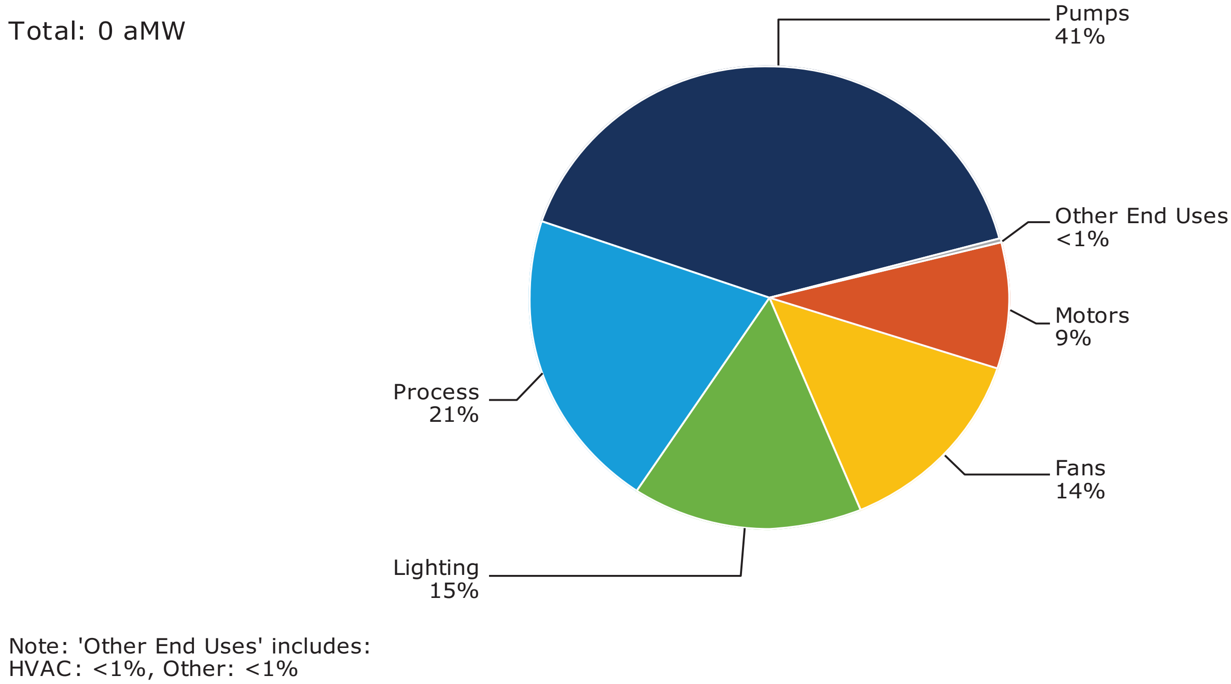


Figure B.4.22 Electric Achievable Technical Potential: Industrial Food by End Use

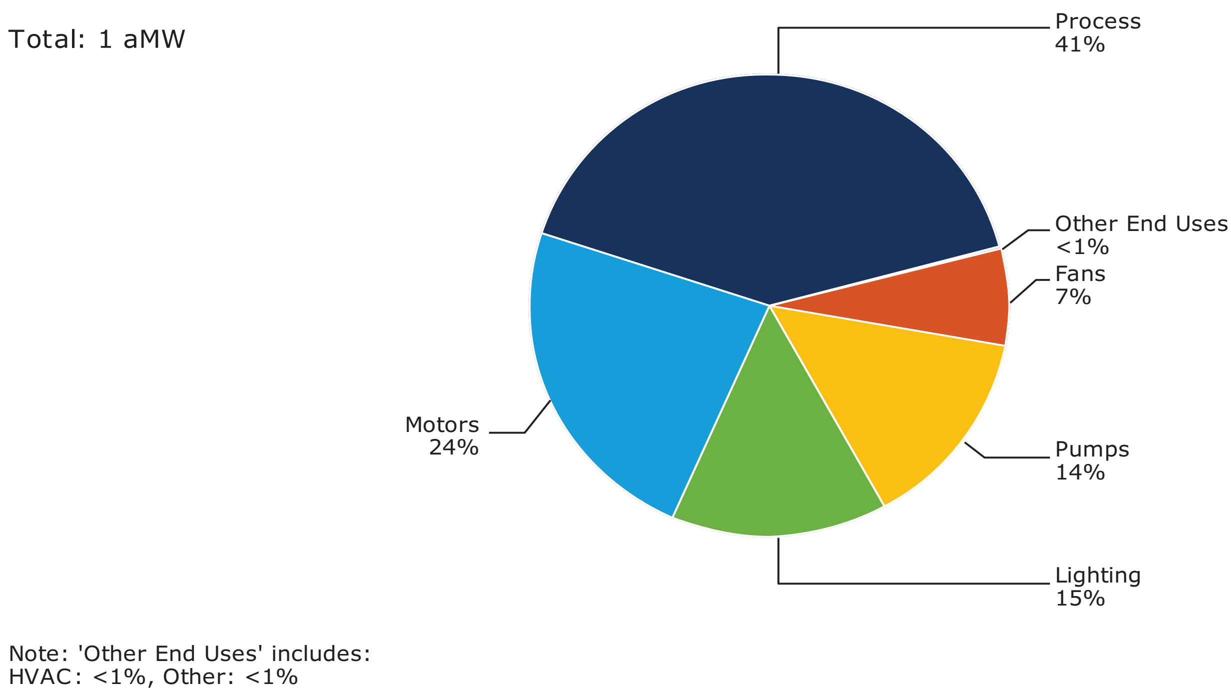


Figure B.4.24 Electric Achievable Technical Potential: Industrial Metals by End Use

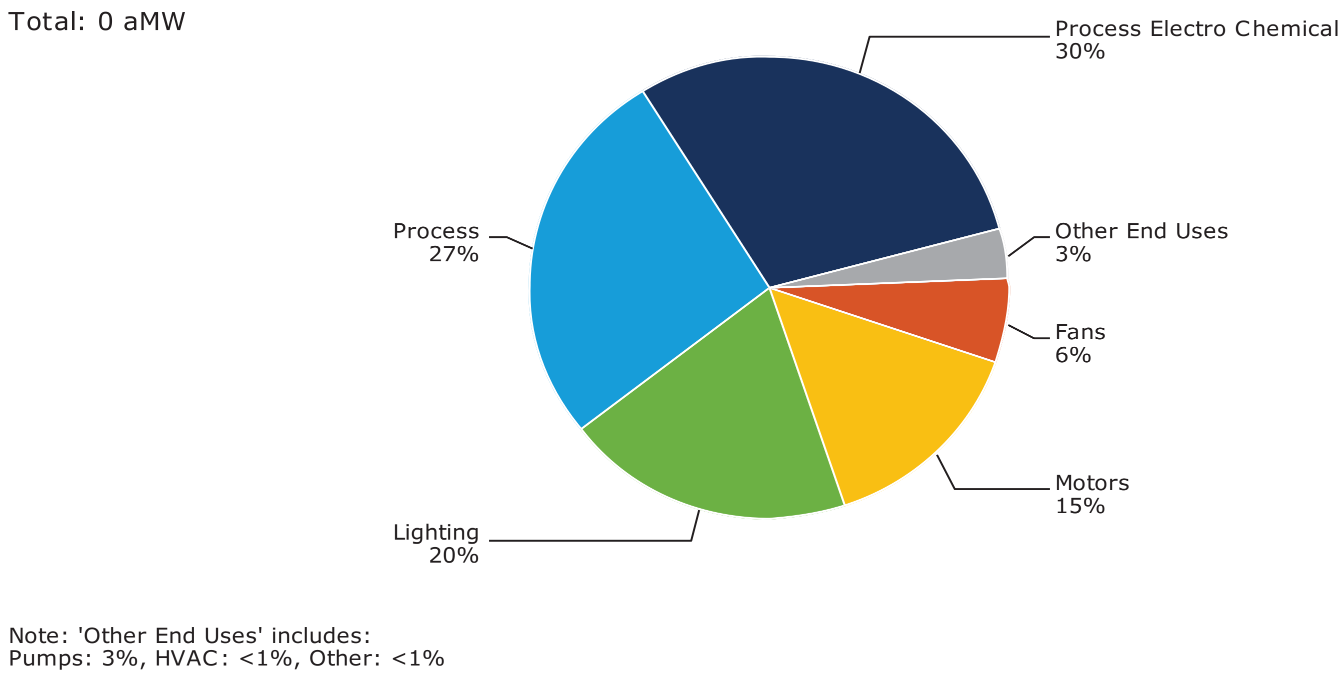


Figure B.4.30 Electric Achievable Technical Potential: Industrial Transportation by End Use

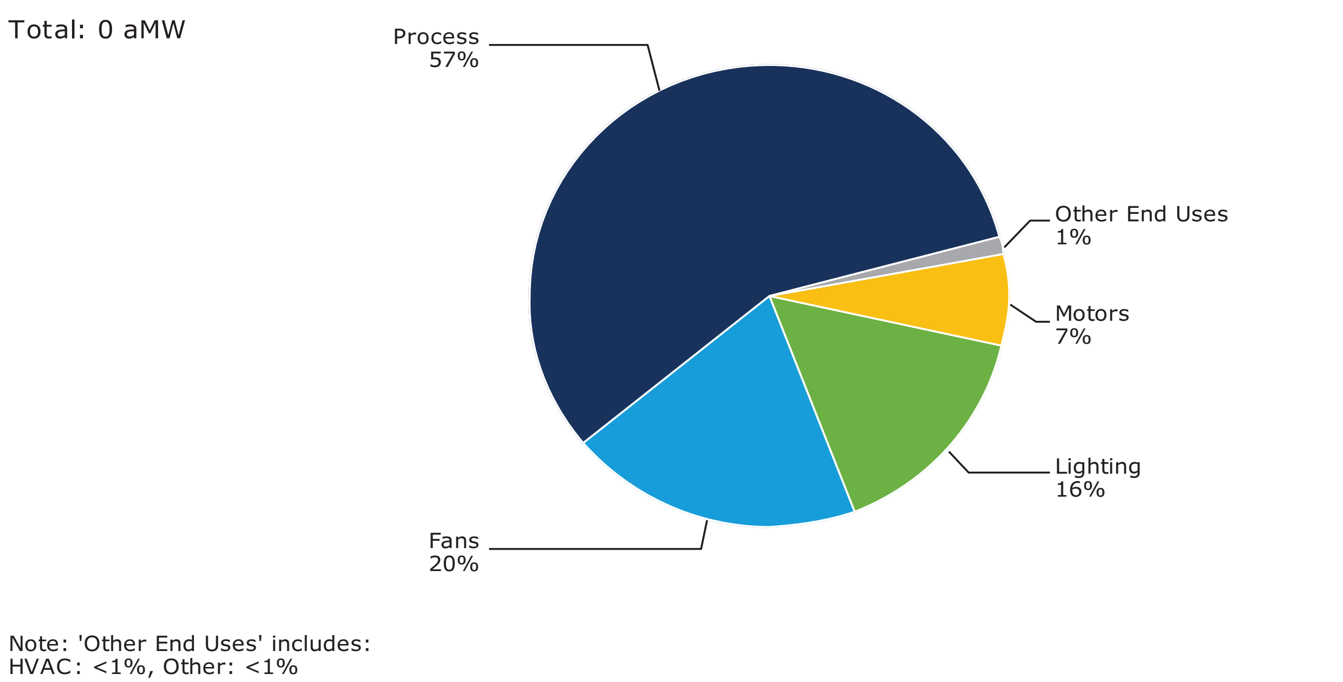


Figure B.4.32 Gas Achievable Technical Potential: Residential by Segment

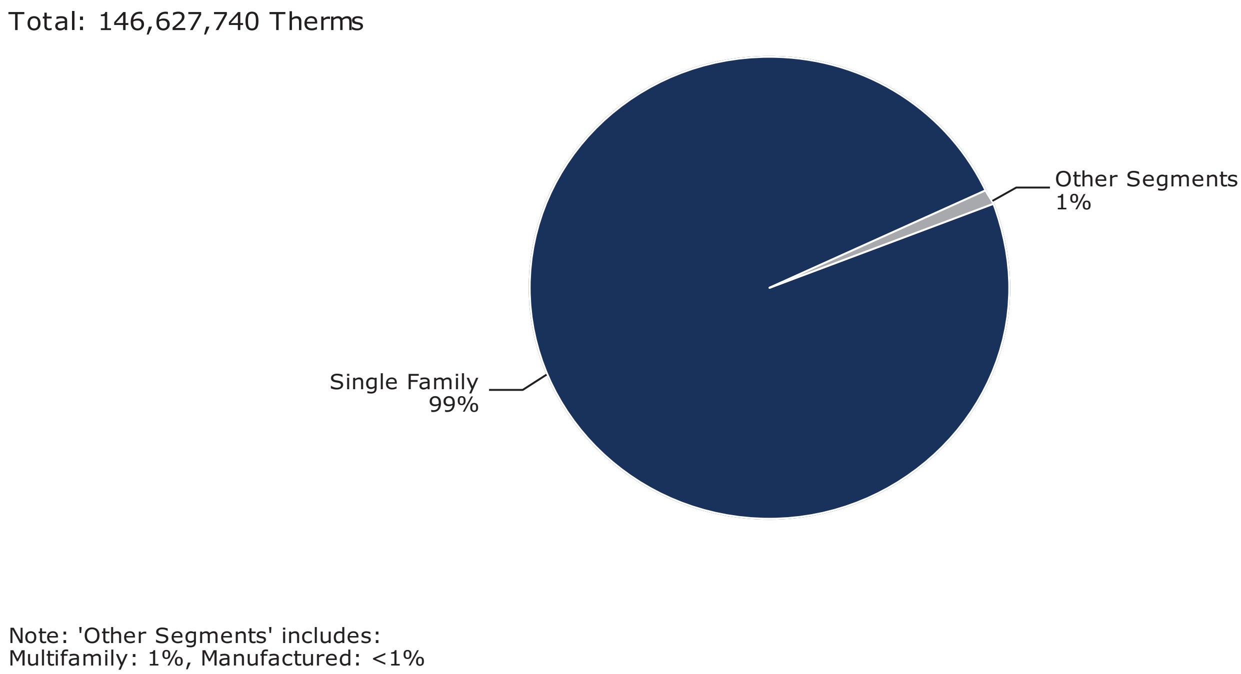


Figure B.4.33 Gas Achievable Technical Potential: Commercial by Segment

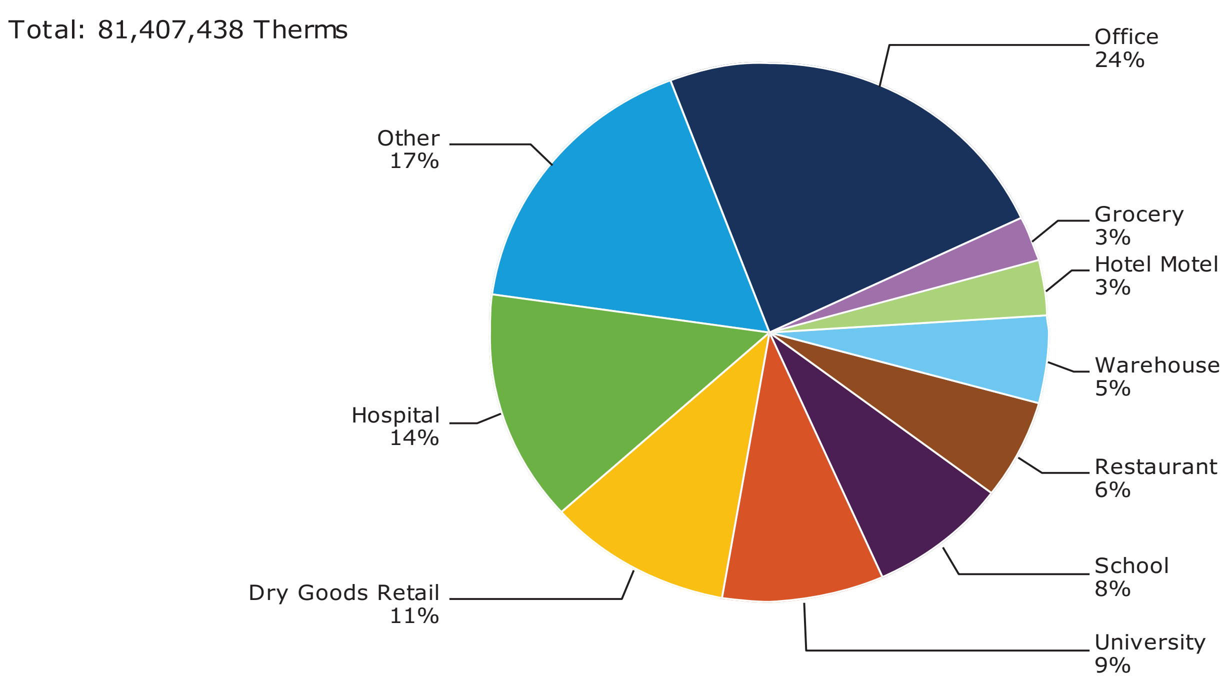


Figure B.4.34 Gas Achievable Technical Potential: Industrial by Segment

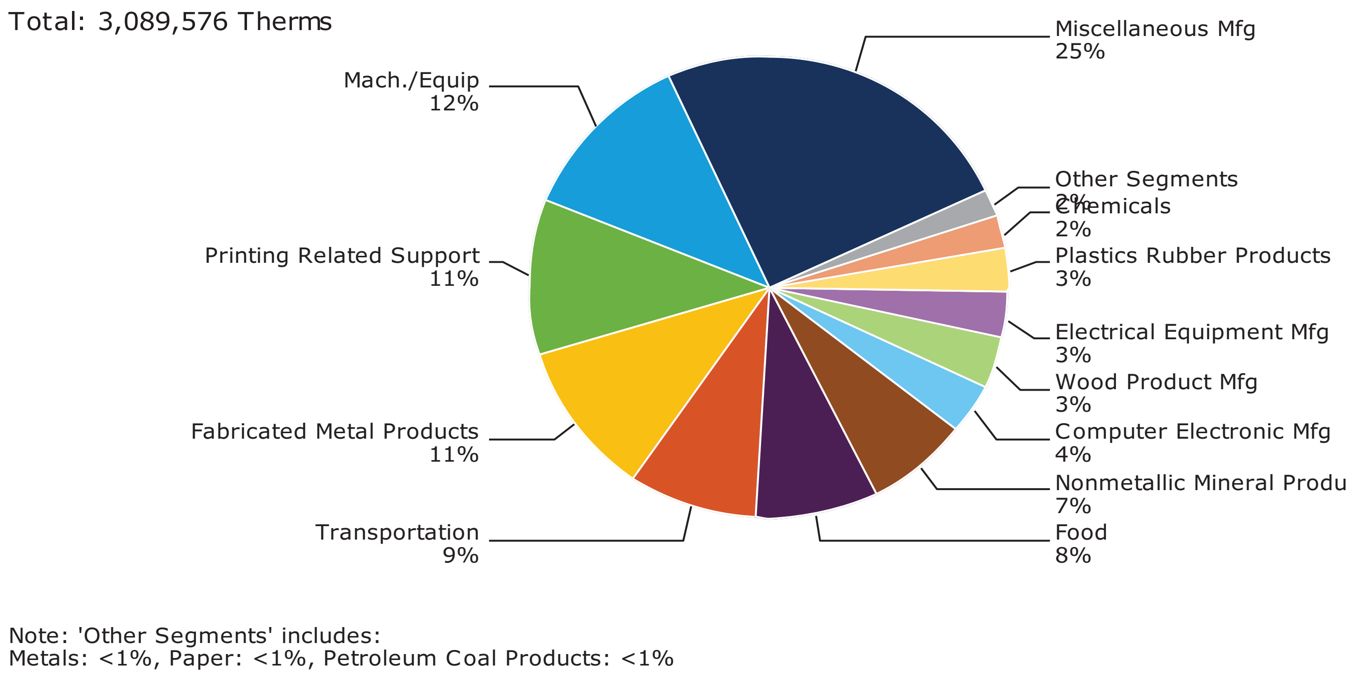


Figure B.4.35 Gas Achievable Technical Potential: Residential by End Use

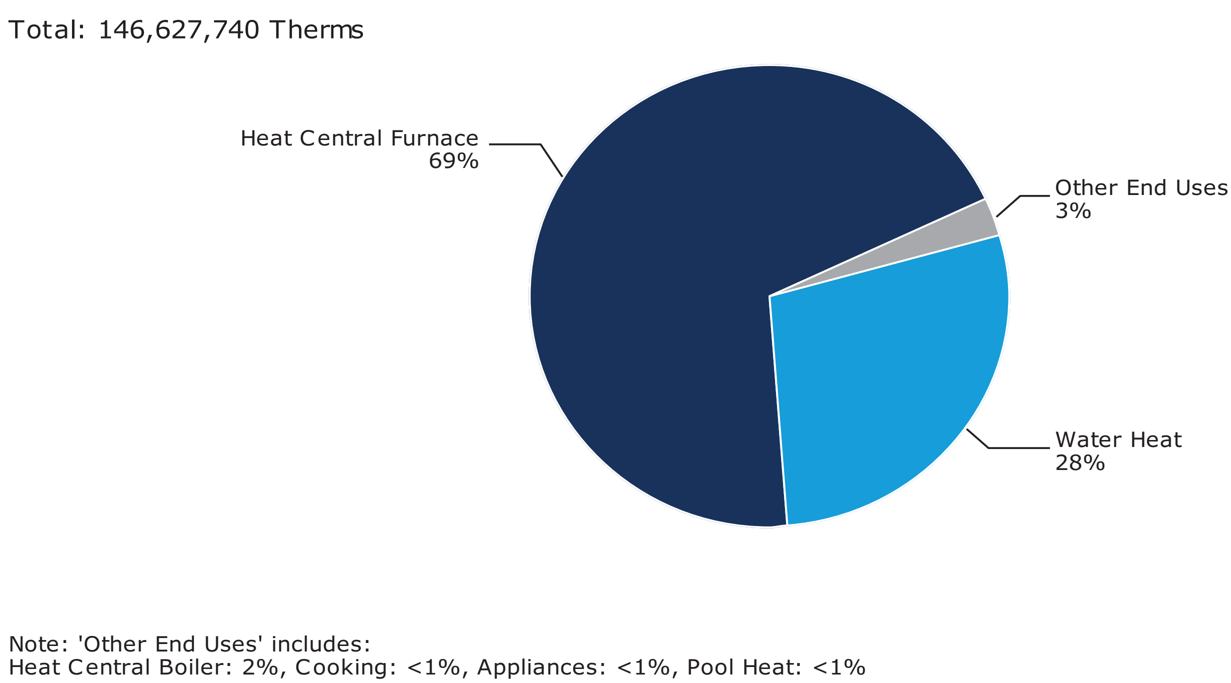


Figure B.4.36 Gas Achievable Technical Potential: Commercial by End Use

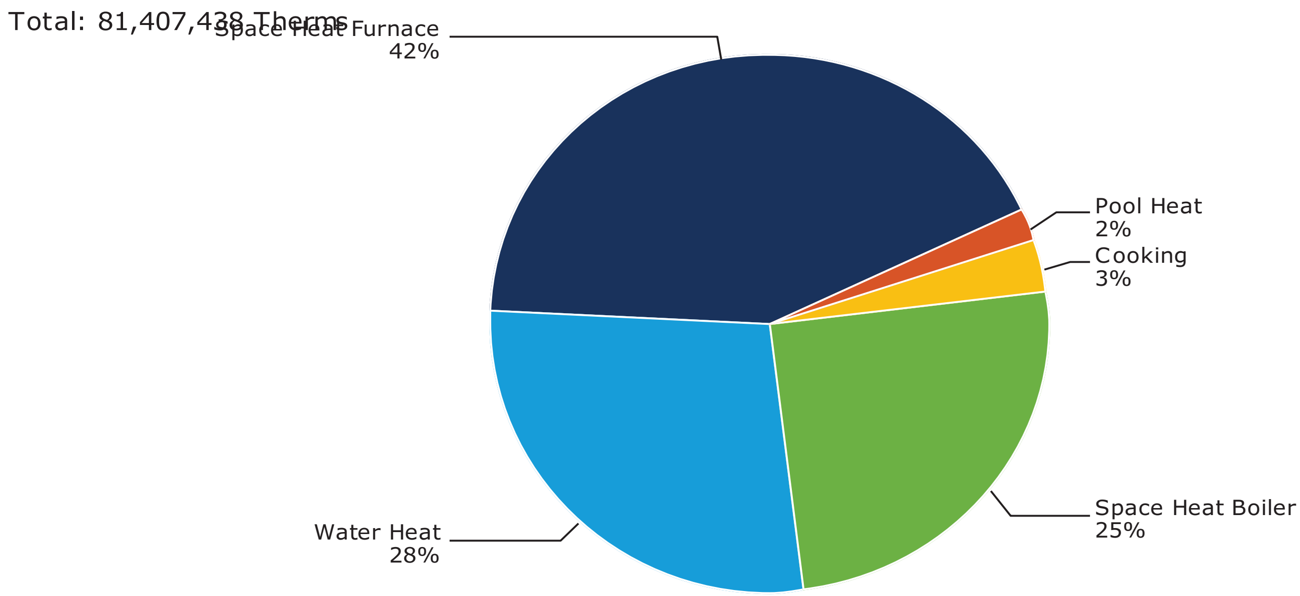


Figure B.4.37 Gas Achievable Technical Potential: Industrial by End Use

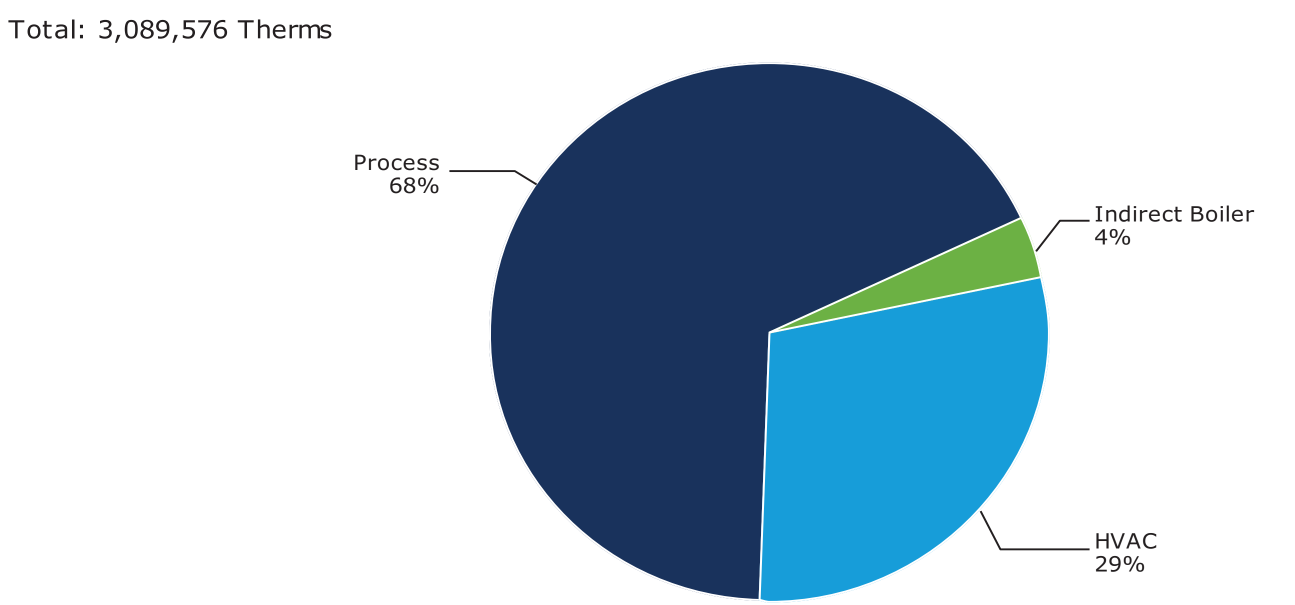


Figure B.4.38 Gas Achievable Technical Potential: Residential Single Family by End Use

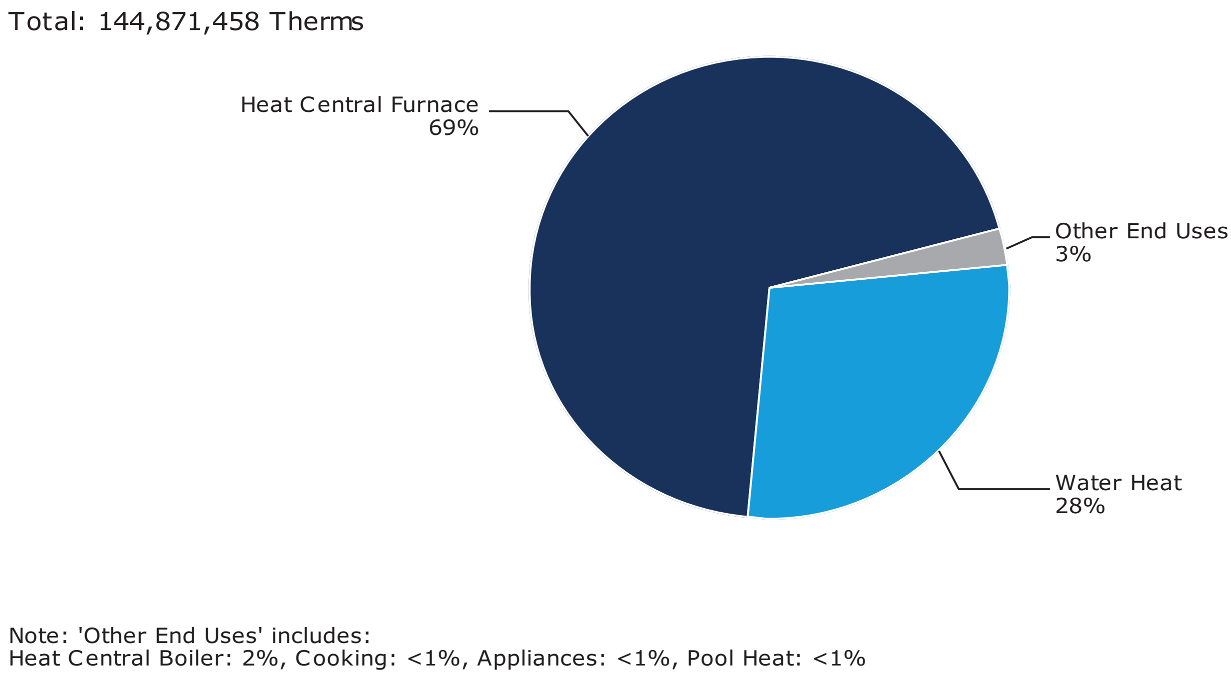


Figure B.4.39 Gas Achievable Technical Potential: Residential Multifamily by End Use

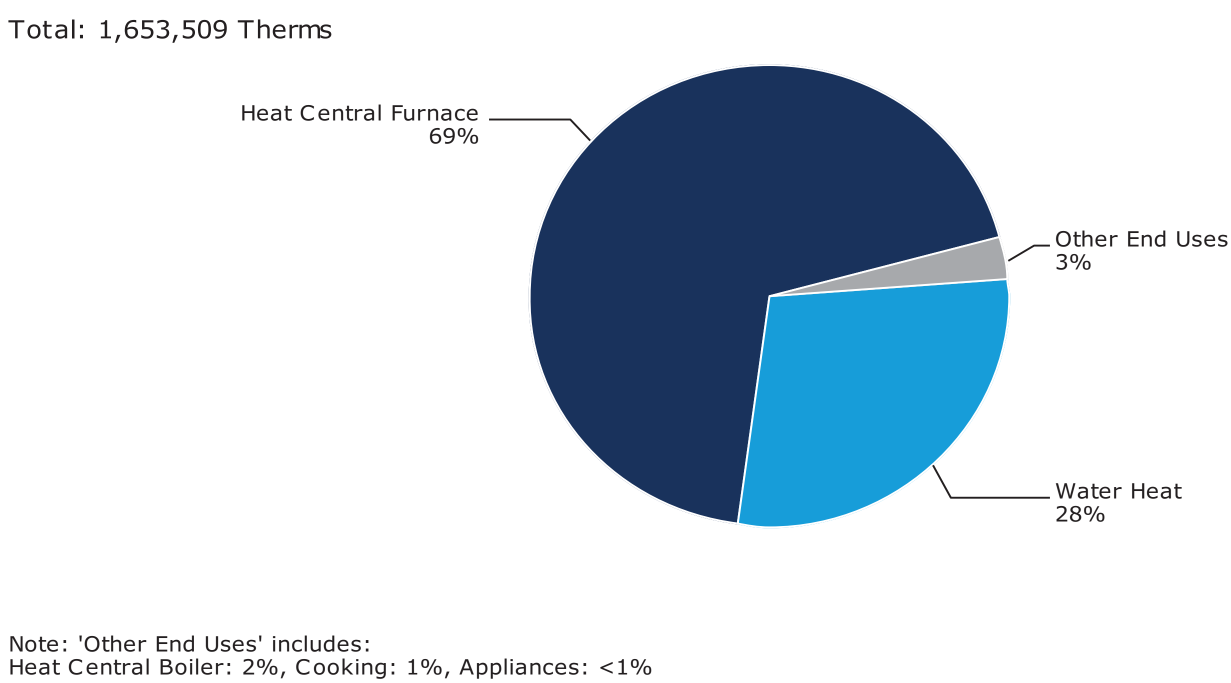


Figure B.4.40 Gas Achievable Technical Potential: Residential Manufactured by End Use

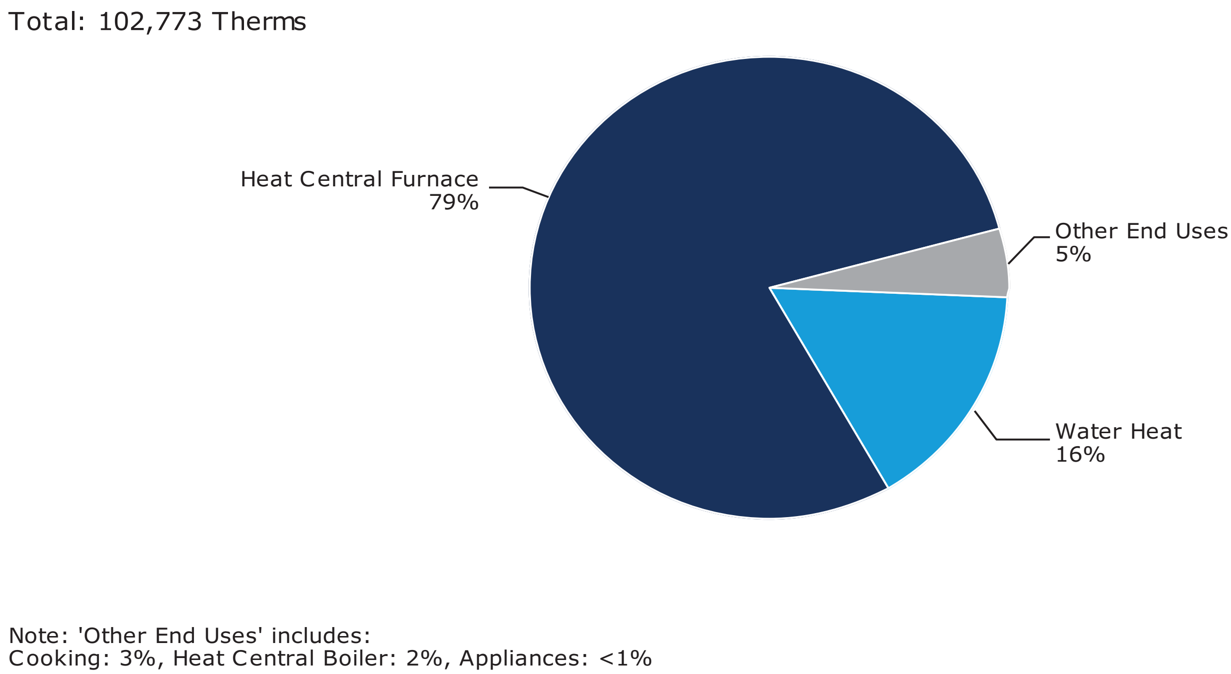


Figure B.4.42 Gas Achievable Technical Potential: Commercial Grocery by End Use

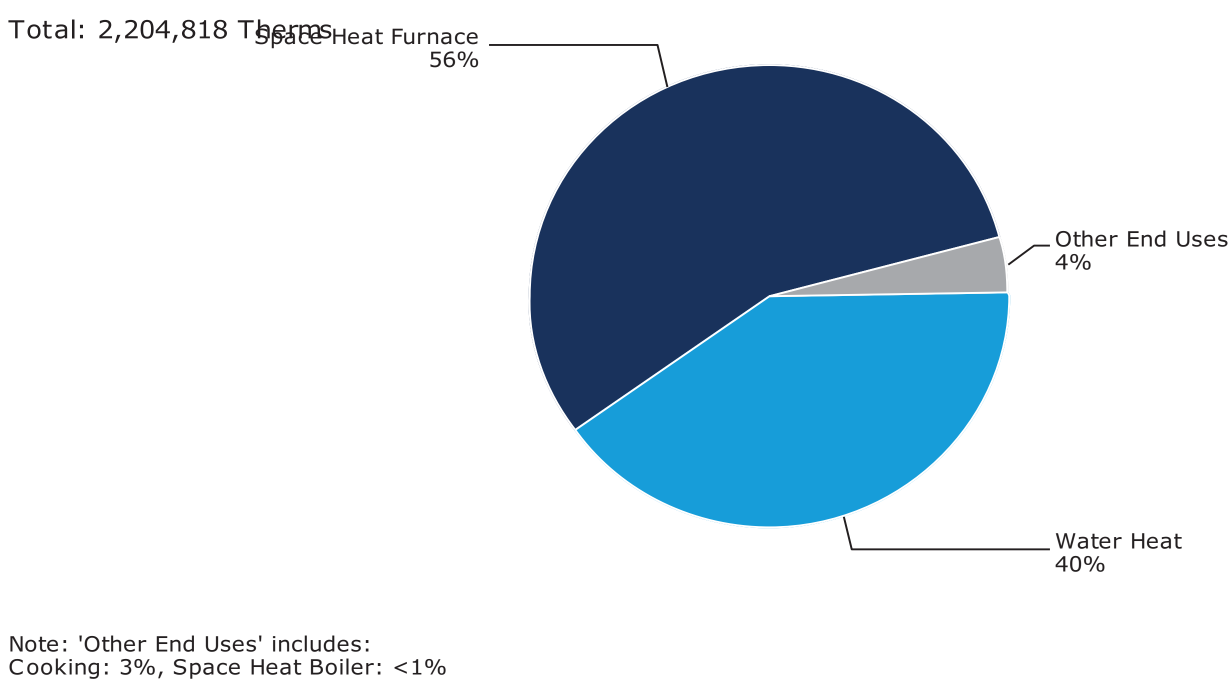


Figure B.4.43 Gas Achievable Technical Potential: Commercial Hospital by End Use

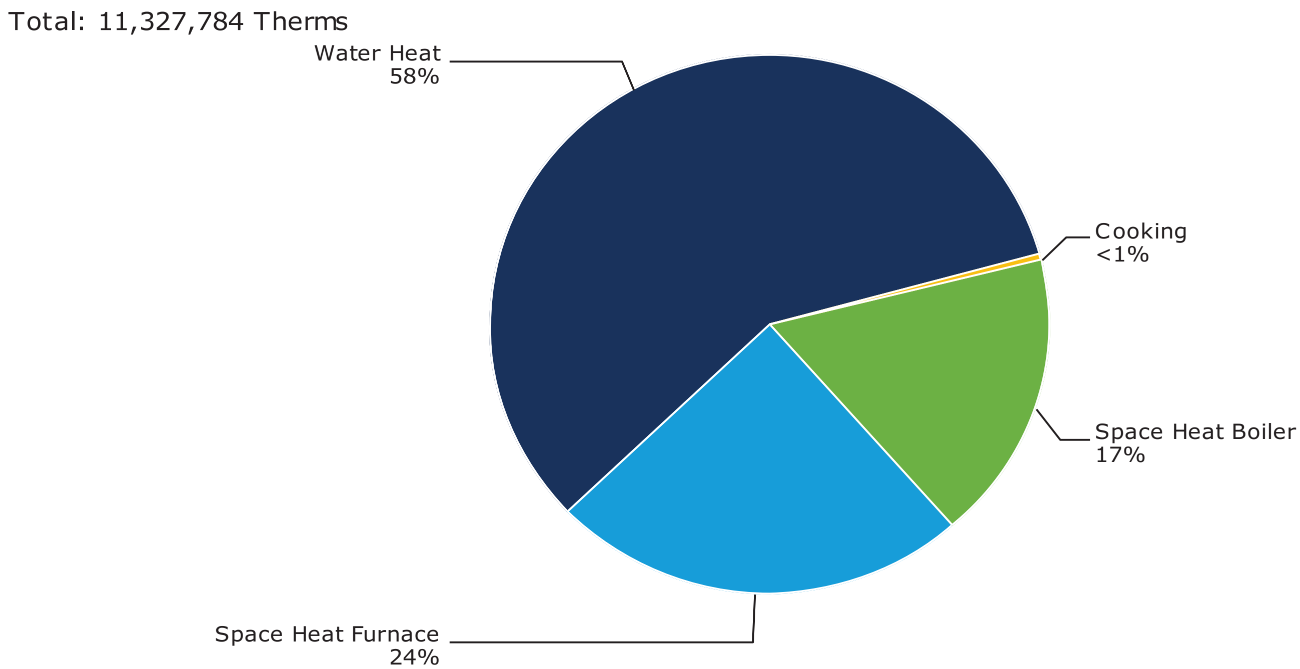


Figure B.4.46 Gas Achievable Technical Potential: Commercial Office by End Use

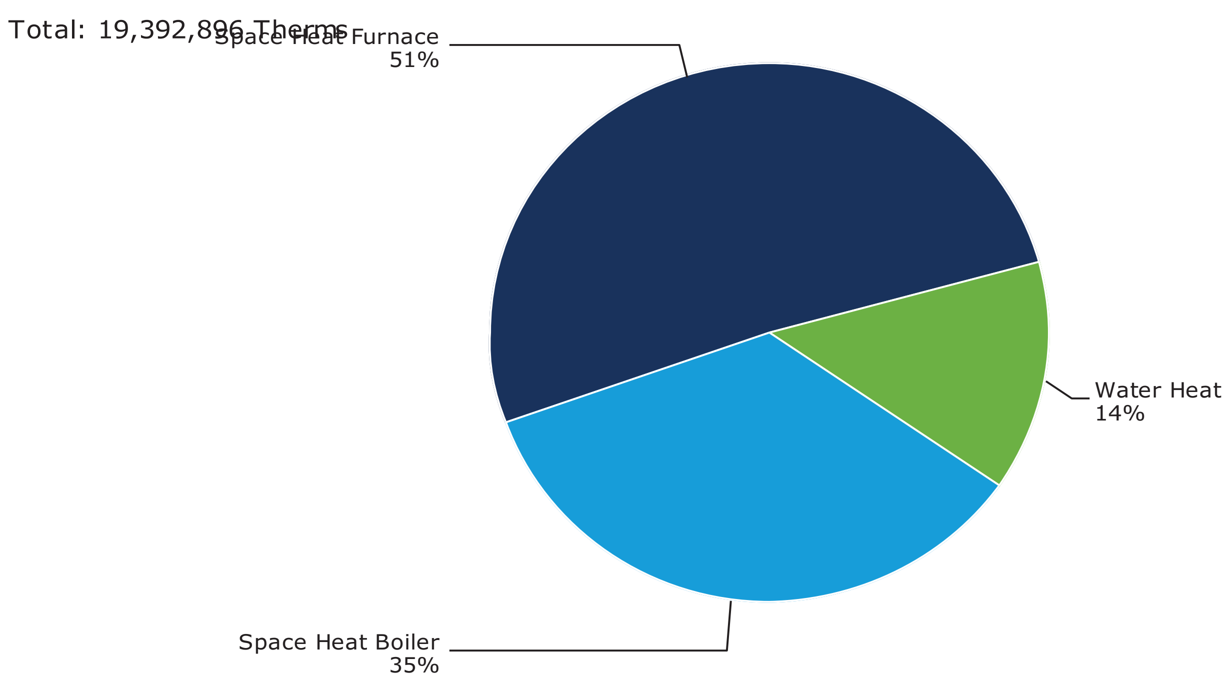


Figure B.4.47 Gas Achievable Technical Potential: Commercial Restaurant by End Use

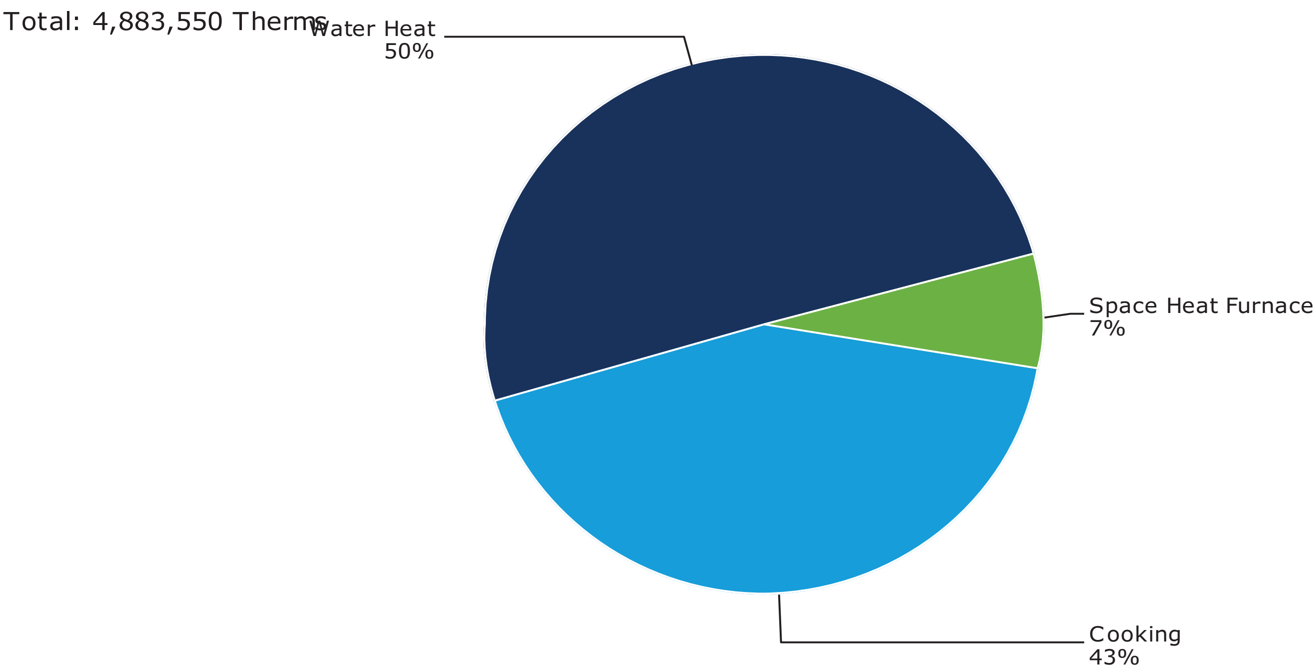


Figure B.4.49 Gas Achievable Technical Potential: Commercial Warehouse by End Use

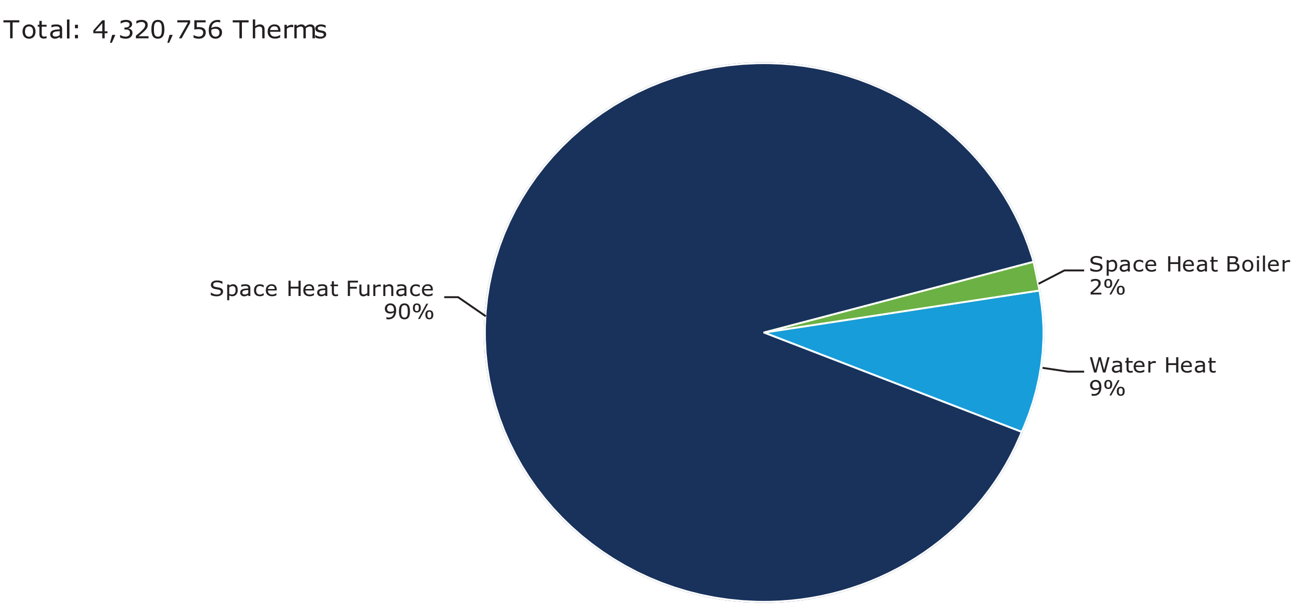


Figure B.4.50 Gas Achievable Technical Potential: Industrial Chemicals by End Use

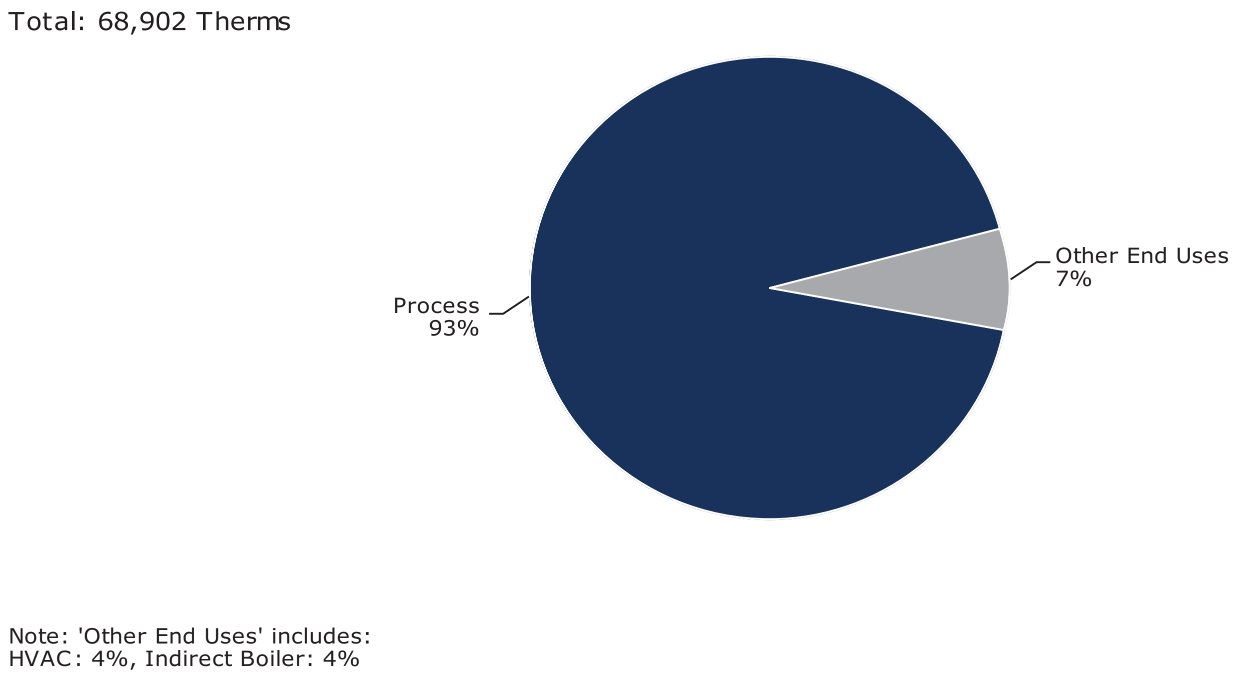


Figure B.4.53 Gas Achievable Technical Potential: Industrial Food by End Use

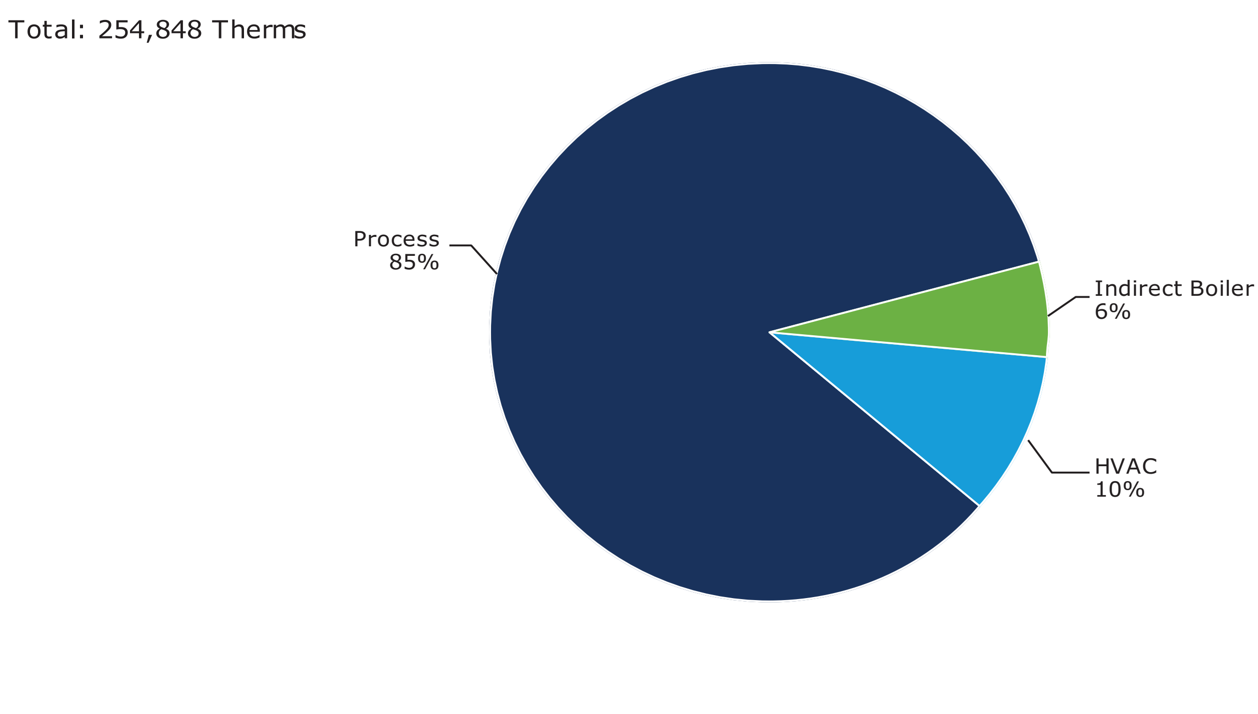


Figure B.4.55 Gas Achievable Technical Potential: Industrial Metals by End Use

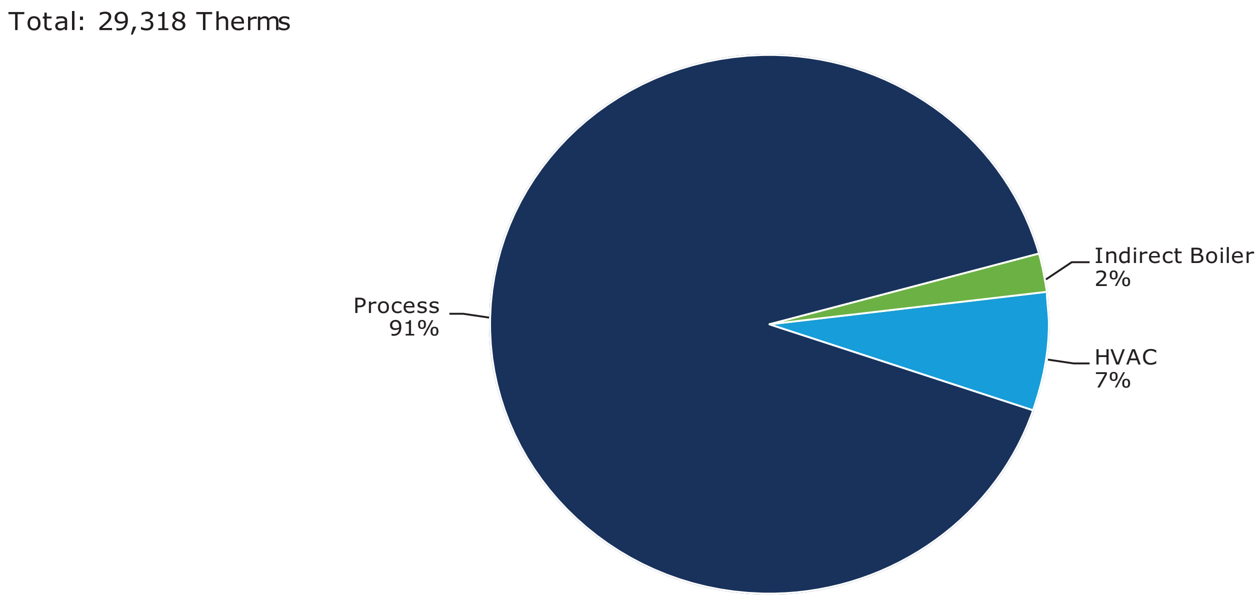
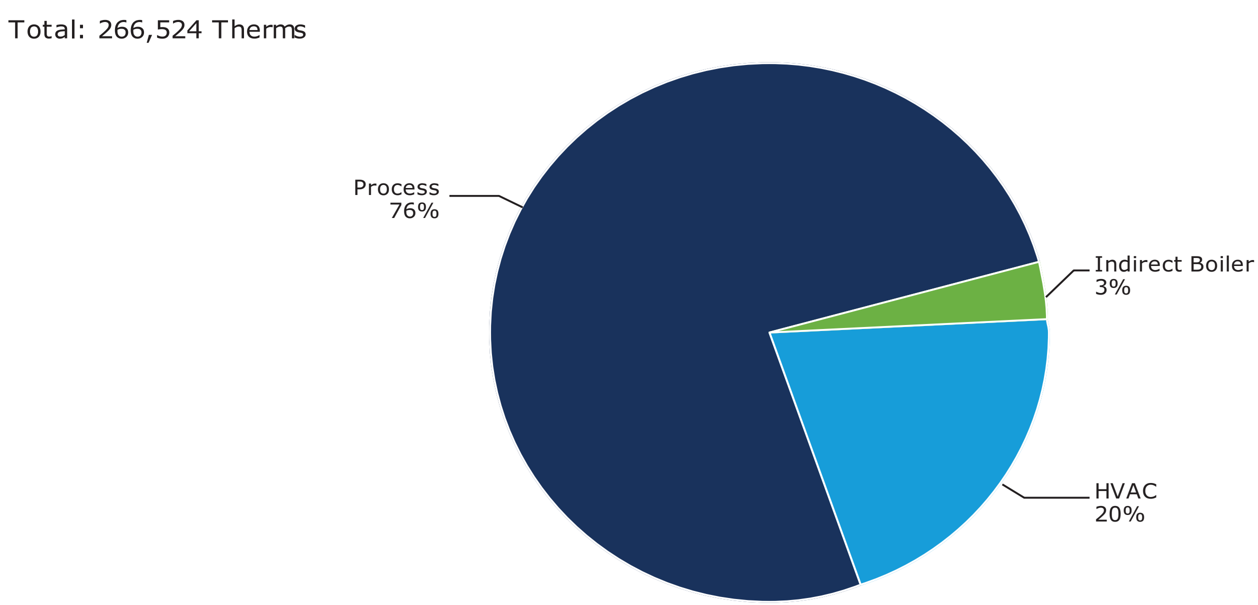


Figure B.4.61 Gas Achievable Technical Potential: Industrial Transportation by End Use



Appendix C. Technical Supplements: Fuel Conversion

This appendix contains technical details about the fuel conversion potentials.

Table C.1 Economic Assumptions

Assumption	Value
Discount Rate	8.10%
Inflation Rate	2.50%
Electric T&D Savings	0.00%
Gas T&D Savings	0.80%
Admin Adder	5.00%
Conservation Credit	10.00%
Electric: Carbon Adder	20.00%
Gas: Carbon Adder	10.00%
Main Ext - Short (ft)	50
Main Ext - Medium (ft)	300
Main Ext - Long (ft)	500
Line Cost per foot	$40
In-House Extension	$3,406
therms/kWh Conversion Factor	0.0341
Zone Heating Adoption Percentage	5%
Electric Dryer Energy Factor	2.67
Gas Dryer Energy Factor	3.01
Electric Range Energy Factor	0.068
Gas Range Energy Factor	0.112
Electric Retail Rate - Residential	$0.097
Electric Retail Rate - Commercial	$0.090
Gas Retail Rate - Residential	$0.68
Gas Retail Rate - Commercial	$0.67
Rate Escalators	Yearly
Levelized Gas Avoided Cost (Dth)	$9.53

Table C.2 Piping and Labor Costs

End Use	Costs
Space Heating: Ducted	$700
Space Heating: Baseboard	$500
Zone Heating: Baseboard	$500
Clothes Drying	$200
Cooking	$200
Water Heating	$200
Space Heating: Ducted, Water Heating	$700
Space Heating: Baseboard, Water Heating	$700
Commercial Space Heating	$700
Commercial Space Heating, Water Heating	$900

Table C.3 Total Customers in 2033

Cutstomer Type	New	Existing
Single Family	NA	978,574
Commercial	67,432	162,651
Multifamily	123,175	NA

Table C.4 Distribution of Single-Family Home Size

Home Size	% of Homes
SFam - 1800 sq ft	45%
SFam - 2100 sq ft	15%
SFam - 2400 sq ft	40%

Table C.5 Fuel Conversion Measure Assumptions for Existing Gas Customers

Sector	Segment	End Use	Construction Type	Measure Name	Measure Description	Baseline Description	Measure Life	EEM Per Unit Cost ($)	Baseline Measure Per Unit Cost ($)	Incremental Per Unit Cost ($)	Per Unit Site Savings (kWh)	Annual Incremental Gas Costs ($)
Residential	SFam - 1800 sq ft	Space Heating: Ducted	Existing	Furnace	95% Furnace	Electric Furnace	30	$2,463	$1,500	$963	12,688	$508
Residential	SFam - 1800 sq ft	Space Heating: Baseboard	Existing	Wall Heater	Wall Heater 84% eff	Electric Baseboard	30	$2,049	$653	$1,396	8,220	$373
Residential	SFam - 1800 sq ft	Space Heating: Baseboard	Existing	Gas Fireplace	Gas Fireplace	Electric Baseboard	30	$3,475	$364	$3,111	4,052	$211
Residential	SFam - 1800 sq ft	Space Heating: Ducted, Water Heating	Existing	Integrated Space & Water Heat	Integrated Space & Water Heat	Electric Furnace, Electric Water Heater, 55 gal.	30	$6,140	$2,005	$4,135	15,940	$580
Residential	SFam - 2100 sq ft	Space Heating: Ducted	Existing	Furnace	95% Furnace	Electric Furnace	30	$2,463	$1,500	$963	14,802	$593
Residential	SFam - 2100 sq ft	Space Heating: Baseboard	Existing	Wall Heater	Wall Heater 84% eff	Electric Baseboard	30	$2,049	$762	$1,287	9,590	$435
Residential	SFam - 2100 sq ft	Space Heating: Baseboard	Existing	Gas Fireplace	Gas Fireplace	Electric Baseboard	30	$3,475	$363	$3,112	4,719	$246
Residential	SFam - 2100 sq ft	Space Heating: Ducted, Water Heating	Existing	Integrated Space & Water Heat	Integrated Space & Water Heat	Electric Furnace, Electric Water Heater, 55 gal.	30	$6,140	$2,005	$4,135	18,054	$676
Residential	SFam - 2400 sq ft	Space Heating: Ducted	Existing	Furnace	95% Furnace	Electric Furnace	30	$2,463	$1,500	$963	16,917	$678
Residential	SFam - 2400 sq ft	Space Heating: Baseboard	Existing	Wall Heater	Wall Heater 84% eff	Electric Baseboard	30	$2,049	$870	$1,179	10,960	$497
Residential	SFam - 2400 sq ft	Space Heating: Baseboard	Existing	Gas Fireplace	Gas Fireplace	Electric Baseboard	30	$3,475	$363	$3,112	5,386	$281
Residential	SFam - 2400 sq ft	Space Heating: Ducted, Water Heating	Existing	Integrated Space & Water Heat	Integrated Space & Water Heat	Electric Furnace, Electric Water Heater, 55 gal.	30	$6,140	$2,005	$4,135	20,169	$773
Residential	SFam - 1800 sq ft	Zone Heating: Baseboard	Existing	Wall Heater	Wall Heater 84% eff	Electric Baseboard	30	$2,049	$653	$1,396	6,344	$288
Residential	SFam - 1800 sq ft	Clothes Drying	Existing	Dryer	Dryer - Advanced Efficiency	Dryer - Federal Standard 2015	30	$1,213	$727	$486	768	$25
Residential	SFam - 1800 sq ft	Cooking	Existing	Cooking Oven	Cooking Oven - High Efficiency	Federal Standard 2012 Cooking Oven	30	$1,413	$757	$656	159	$12
Residential	SFam - 1800 sq ft	Water Heating	Existing	Water Heater	Tankless WH	Electric Water Heater, 55 gal.	30	$1,634	$505	$1,128	3,252	$212
Residential	SFam - 1800 sq ft	Water Heating	Existing	Water Heater	WH (>67% EF)	Electric Water Heater, 55 gal.	30	$1,564	$505	$1,058	3,252	$259
Residential	SFam - 2100 sq ft	Zone Heating: Baseboard	Existing	Wall Heater	Wall Heater 84% eff	Electric Baseboard	30	$2,049	$762	$1,287	7,401	$335
Residential	SFam - 2100 sq ft	Clothes Drying	Existing	Dryer	Dryer - Advanced Efficiency	Dryer - Federal Standard 2015	30	$1,213	$727	$486	768	$25
Residential	SFam - 2100 sq ft	Cooking	Existing	Cooking Oven	Cooking Oven - High Efficiency	Federal Standard 2012 Cooking Oven	30	$1,413	$757	$656	159	$12
Residential	SFam - 2100 sq ft	Water Heating	Existing	Water Heater	Tankless WH	Electric Water Heater, 55 gal.	30	$1,634	$505	$1,128	3,252	$212
Residential	SFam - 2100 sq ft	Water Heating	Existing	Water Heater	WH (>67% EF)	Electric Water Heater, 55 gal.	30	$1,564	$505	$1,058	3,252	$259
Residential	SFam - 2400 sq ft	Zone Heating: Baseboard	Existing	Wall Heater	Wall Heater 84% eff	Electric Baseboard	30	$2,049	$870	$1,179	8,459	$383
Residential	SFam - 2400 sq ft	Clothes Drying	Existing	Dryer	Dryer - Advanced Efficiency	Dryer - Federal Standard 2015	30	$1,213	$727	$486	768	$25
Residential	SFam - 2400 sq ft	Cooking	Existing	Cooking Oven	Cooking Oven - High Efficiency	Federal Standard 2012 Cooking Oven	30	$1,413	$757	$656	159	$12
Residential	SFam - 2400 sq ft	Water Heating	Existing	Water Heater	Tankless WH	Electric Water Heater, 55 gal.	30	$1,634	$505	$1,128	3,252	$212
Residential	SFam - 2400 sq ft	Water Heating	Existing	Water Heater	WH (>67% EF)	Electric Water Heater, 55 gal.	30	$1,564	$505	$1,058	3,252	$259
Commercial	Commercial	Space Heating: Ducted	Existing	Furnace	94% Furnace	Electric Furnace	30	$3,723	$4,595	-$872	13,716	$1,025
Commercial	Commercial	Water Heating	Existing	Water Heater	Tankless WH	Electric Water Heater, 50 gal.	30	$3,216	$1,195	$2,021	9,736	$639
Commercial	Commercial	Water Heating	Existing	Water Heater	WH (>67% EF)	Electric Water Heater, 50 gal.	30	$2,142	$1,195	$946	9,736	$782

Table C.6 Fuel Conversion Measure Assumptions for On-Main Gas Customers

Sector	Segment	End Use	Construction Type	Measure Name	Measure Description	Baseline Description	Measure Life	EEM Per Unit Cost ($)	Baseline Measure Per Unit Cost ($)	Incremental Per Unit Cost ($)	Per Unit Site Savings (kWh)	Annual Incremental Gas Costs ($)
Residential	SFam - 1800 sq ft	Space Heating: Ducted	Existing	Furnace	95% Furnace	Electric Furnace	30	$5,869	$1,500	$4,369	12,688	$508
Residential	SFam - 1800 sq ft	Space Heating: Baseboard	Existing	Wall Heater	Wall Heater 84% eff	Electric Baseboard	30	$2,049	$653	$1,396	8,220	$373
Residential	SFam - 1800 sq ft	Space Heating: Baseboard	Existing	Gas Fireplace	Gas Fireplace	Electric Baseboard	30	$3,475	$364	$3,111	4,052	$211
Residential	SFam - 1800 sq ft	Space Heating: Ducted, Water Heating	Existing	Integrated Space & Water Heat	Integrated Space & Water Heat	Electric Furnace, Electric Water Heater, 55 gal.	30	$9,546	$2,005	$7,541	15,940	$580
Residential	SFam - 2100 sq ft	Space Heating: Ducted	Existing	Furnace	95% Furnace	Electric Furnace	30	$5,869	$1,500	$4,369	14,802	$593
Residential	SFam - 2100 sq ft	Space Heating: Baseboard	Existing	Wall Heater	Wall Heater 84% eff	Electric Baseboard	30	$2,049	$762	$1,287	9,590	$435
Residential	SFam - 2100 sq ft	Space Heating: Baseboard	Existing	Gas Fireplace	Gas Fireplace	Electric Baseboard	30	$3,475	$363	$3,112	4,719	$246
Residential	SFam - 2100 sq ft	Space Heating: Ducted, Water Heating	Existing	Integrated Space & Water Heat	Integrated Space & Water Heat	Electric Furnace, Electric Water Heater, 55 gal.	30	$9,546	$2,005	$7,541	18,054	$676
Residential	SFam - 2400 sq ft	Space Heating: Ducted	Existing	Furnace	95% Furnace	Electric Furnace	30	$5,869	$1,500	$4,369	16,917	$678
Residential	SFam - 2400 sq ft	Space Heating: Baseboard	Existing	Wall Heater	Wall Heater 84% eff	Electric Baseboard	30	$2,049	$870	$1,179	10,960	$497
Residential	SFam - 2400 sq ft	Space Heating: Baseboard	Existing	Gas Fireplace	Gas Fireplace	Electric Baseboard	30	$3,475	$363	$3,112	5,386	$281
Residential	SFam - 2400 sq ft	Space Heating: Ducted, Water Heating	Existing	Integrated Space & Water Heat	Integrated Space & Water Heat	Electric Furnace, Electric Water Heater, 55 gal.	30	$9,546	$2,005	$7,541	20,169	$773
Residential	SFam - 1800 sq ft	Zone Heating: Baseboard	Existing	Wall Heater	Wall Heater 84% eff	Electric Baseboard	30	$2,049	$653	$1,396	6,344	$288
Residential	SFam - 1800 sq ft	Clothes Drying	Existing	Dryer	Dryer - Advanced Efficiency	Dryer - Federal Standard 2015	30	$1,213	$727	$486	768	$25
Residential	SFam - 1800 sq ft	Cooking	Existing	Cooking Oven	Cooking Oven - High Efficiency	Federal Standard 2012 Cooking Oven	30	$1,413	$757	$656	159	$12
Residential	SFam - 1800 sq ft	Water Heating	Existing	Water Heater	Tankless WH	Electric Water Heater, 55 gal.	30	$3,882	$505	$3,376	3,252	$212
Residential	SFam - 1800 sq ft	Water Heating	Existing	Water Heater	WH (>67% EF)	Electric Water Heater, 55 gal.	30	$3,812	$505	$3,306	3,252	$259
Residential	SFam - 2100 sq ft	Zone Heating: Baseboard	Existing	Wall Heater	Wall Heater 84% eff	Electric Baseboard	30	$2,049	$762	$1,287	7,401	$335
Residential	SFam - 2100 sq ft	Clothes Drying	Existing	Dryer	Dryer - Advanced Efficiency	Dryer - Federal Standard 2015	30	$1,213	$727	$486	768	$25
Residential	SFam - 2100 sq ft	Cooking	Existing	Cooking Oven	Cooking Oven - High Efficiency	Federal Standard 2012 Cooking Oven	30	$1,413	$757	$656	159	$12
Residential	SFam - 2100 sq ft	Water Heating	Existing	Water Heater	Tankless WH	Electric Water Heater, 55 gal.	30	$3,882	$505	$3,376	3,252	$212
Residential	SFam - 2100 sq ft	Water Heating	Existing	Water Heater	WH (>67% EF)	Electric Water Heater, 55 gal.	30	$3,812	$505	$3,306	3,252	$259
Residential	SFam - 2400 sq ft	Zone Heating: Baseboard	Existing	Wall Heater	Wall Heater 84% eff	Electric Baseboard	30	$2,049	$870	$1,179	8,459	$383
Residential	SFam - 2400 sq ft	Clothes Drying	Existing	Dryer	Dryer - Advanced Efficiency	Dryer - Federal Standard 2015	30	$1,213	$727	$486	768	$25
Residential	SFam - 2400 sq ft	Cooking	Existing	Cooking Oven	Cooking Oven - High Efficiency	Federal Standard 2012 Cooking Oven	30	$1,413	$757	$656	159	$12
Residential	SFam - 2400 sq ft	Water Heating	Existing	Water Heater	Tankless WH	Electric Water Heater, 55 gal.	30	$3,882	$505	$3,376	3,252	$212
Residential	SFam - 2400 sq ft	Water Heating	Existing	Water Heater	WH (>67% EF)	Electric Water Heater, 55 gal.	30	$3,812	$505	$3,306	3,252	$259
Commercial	Commercial	Space Heating: Ducted	Existing	Furnace	94% Furnace	Electric Furnace	30	$7,129	$4,595	$2,534	13,716	$1,025
Commercial	Commercial	Water Heating	Existing	Water Heater	Tankless WH	Electric Water Heater, 50 gal.	30	$6,486	$1,195	$5,290	9,736	$639
Commercial	Commercial	Water Heating	Existing	Water Heater	WH (>67% EF)	Electric Water Heater, 50 gal.	30	$5,411	$1,195	$4,216	9,736	$782
Commercial	Commercial	Water Heating	New	Water Heater	Tankless WH	Electric Water Heater, 50 gal.	30	$5,975	$1,195	$4,779	9,945	$674
Commercial	Commercial	Water Heating	New	Water Heater	WH (>67% EF)	Electric Water Heater, 50 gal.	30	$4,901	$1,195	$3,705	9,945	$825
Commercial	Commercial	Space Heating	New	Warm-Up Heat	Gas warm up heat	Electric Furnace	30	$15,601	$4,595	$11,006	2,851	$971
Commercial	Commercial	Space Heating	New	Furnace	94% Furnace	Electric Furnace	30	$5,599	$4,595	$1,004	2,851	$516
Commercial	Commercial	Space Heating, Water Heating	New	Boiler	Boiler	Packaged Rooftop Unit, Electric Water Heater, 50 gal.	30	$8,219	$1,998	$6,221	12,546	$668
Commercial	Commercial	Space Heating, Water Heating	New	Boiler	Boiler	Packaged Rooftop VAV w/ Electrical Resistance Reheat & Electric Water Heater, 50	30	$8,219	$2,383	$5,836	12,546	$668
Commercial	Commercial	Space Heating	New	Gas PACs	Gas PACs	Packaged Rooftop Unit	30	$9,891	$3,585	$6,305	3,601	$248
Residential	MFam Mid Rise: Renter	Space Heating: Ducted	New	Furnace	95% Furnace	Electric Furnace	30	$5,869	$1,431	$4,438	2,303	$106
Residential	MFam Mid Rise: Renter	Space Heating: Baseboard	New	Furnace	95% Furnace	Baseboard Heating	30	$5,669	$119	$5,550	1,771	$106
Residential	MFam Mid Rise: Renter	Clothes Drying	New	Dryer	Dryer - Advanced Efficiency	Dryer - Federal Standard 2015	30	$1,213	$481	$732	868	$23
Residential	MFam Mid Rise: Renter	Cooking	New	Cooking Oven	Cooking Oven - High Efficiency	Cooking Oven - Standard	30	$1,413	$757	$656	159	$12
Residential	MFam Mid Rise: Renter	Water Heating	New	Water Heater	Tankless WH	Electric Water Heater, 55 gal.	30	$1,475	$505	$969	1,647	$104
Residential	MFam Mid Rise: Renter	Water Heating	New	Water Heater	WH (>67% EF)	Electric Water Heater, 55 gal.	30	$1,564	$505	$1,058	1,647	$127
Residential	MFam Mid Rise: Renter	Space Heating: Ducted, Water Heating	New	Integrated Space & Water Heat	Integrated Space & Water Heat	Electric Furnace, Electric Water Heater, 55 gal.	30	$9,546	$1,936	$7,610	3,950	$165
Residential	MFam Mid Rise: Renter	Space Heating: Baseboard, Water Heating	New	Boiler	Boiler	Baseboard Heating, Electric Water Heater, 55 gal.	30	$9,346	$625	$8,721	3,418	$165
Residential	MFam Low Rise: Renter	Space Heating: Ducted	New	Furnace	95% Furnace	Electric Furnace	30	$5,869	$1,431	$4,438	2,303	$106
Residential	MFam Low Rise: Renter	Space Heating: Baseboard	New	Furnace	95% Furnace	Baseboard Heating	30	$5,669	$119	$5,550	1,771	$106
Residential	MFam Low Rise: Renter	Clothes Drying	New	Dryer	Dryer - Advanced Efficiency	Dryer - Federal Standard 2015	30	$1,213	$481	$732	868	$23
Residential	MFam Low Rise: Renter	Cooking	New	Cooking Oven	Cooking Oven - High Efficiency	Cooking Oven - Standard	30	$1,413	$757	$656	159	$12
Residential	MFam Low Rise: Renter	Water Heating	New	Water Heater	Tankless WH	Electric Water Heater, 55 gal.	30	$1,475	$505	$969	1,647	$104
Residential	MFam Low Rise: Renter	Water Heating	New	Water Heater	WH (>67% EF)	Electric Water Heater, 55 gal.	30	$1,564	$505	$1,058	1,647	$127
Residential	MFam Low Rise: Renter	Space Heating: Ducted, Water Heating	New	Integrated Space & Water Heat	Integrated Space & Water Heat	Electric Furnace, Electric Water Heater, 55 gal.	30	$9,546	$1,936	$7,610	3,950	$165
Residential	MFam Low Rise: Renter	Space Heating: Baseboard, Water Heating	New	Boiler	Boiler	Baseboard Heating, Electric Water Heater, 55 gal.	30	$9,346	$625	$8,721	3,418	$165
Residential	MFam Mid Rise: Owner	Space Heating: Ducted	New	Furnace	95% Furnace	Electric Furnace	30	$5,869	$1,431	$4,438	2,303	$106
Residential	MFam Mid Rise: Owner	Space Heating: Baseboard	New	Furnace	95% Furnace	Baseboard Heating	30	$5,669	$137	$5,532	1,771	$106
Residential	MFam Mid Rise: Owner	Clothes Drying	New	Dryer	Dryer - Advanced Efficiency	Dryer - Federal Standard 2015	30	$1,213	$481	$732	868	$23
Residential	MFam Mid Rise: Owner	Cooking	New	Cooking Oven	Cooking Oven - High Efficiency	Cooking Oven - Standard	30	$1,413	$757	$656	159	$12
Residential	MFam Mid Rise: Owner	Water Heating	New	Water Heater	Tankless WH	Electric Water Heater, 55 gal.	30	$1,475	$505	$969	1,647	$104
Residential	MFam Mid Rise: Owner	Water Heating	New	Water Heater	WH (>67% EF)	Electric Water Heater, 55 gal.	30	$1,564	$505	$1,058	1,647	$127
Residential	MFam Mid Rise: Owner	Space Heating: Ducted, Water Heating	New	Integrated Space & Water Heat	Integrated Space & Water Heat	Electric Furnace, Electric Water Heater, 55 gal.	30	$9,546	$1,936	$7,610	3,950	$165
Residential	MFam Mid Rise: Owner	Space Heating: Baseboard, Water Heating	New	Boiler	Boiler	Baseboard Heating, Electric Water Heater, 55 gal.	30	$9,346	$625	$8,721	3,418	$165
Residential	MFam Low Rise: Owner	Space Heating: Ducted	New	Furnace	95% Furnace	Electric Furnace	30	$5,869	$1,431	$4,438	2,303	$106
Residential	MFam Low Rise: Owner	Space Heating: Baseboard	New	Furnace	95% Furnace	Baseboard Heating	30	$5,669	$119	$5,550	1,771	$106
Residential	MFam Low Rise: Owner	Clothes Drying	New	Dryer	Dryer - Advanced Efficiency	Dryer - Federal Standard 2015	30	$1,213	$481	$732	868	$23
Residential	MFam Low Rise: Owner	Cooking	New	Cooking Oven	Cooking Oven - High Efficiency	Cooking Oven - Standard	30	$1,413	$757	$656	159	$12
Residential	MFam Low Rise: Owner	Water Heating	New	Water Heater	Tankless WH	Electric Water Heater, 55 gal.	30	$1,475	$505	$969	1,647	$104
Residential	MFam Low Rise: Owner	Water Heating	New	Water Heater	WH (>67% EF)	Electric Water Heater, 55 gal.	30	$1,564	$505	$1,058	1,647	$127
Residential	MFam Low Rise: Owner	Space Heating: Ducted, Water Heating	New	Integrated Space & Water Heat	Integrated Space & Water Heat	Electric Furnace, Electric Water Heater, 55 gal.	30	$9,546	$1,936	$7,610	3,950	$165
Residential	MFam Low Rise: Owner	Space Heating: Baseboard, Water Heating	New	Boiler	Boiler	Baseboard Heating, Electric Water Heater, 55 gal.	30	$9,346	$625	$8,721	3,418	$165

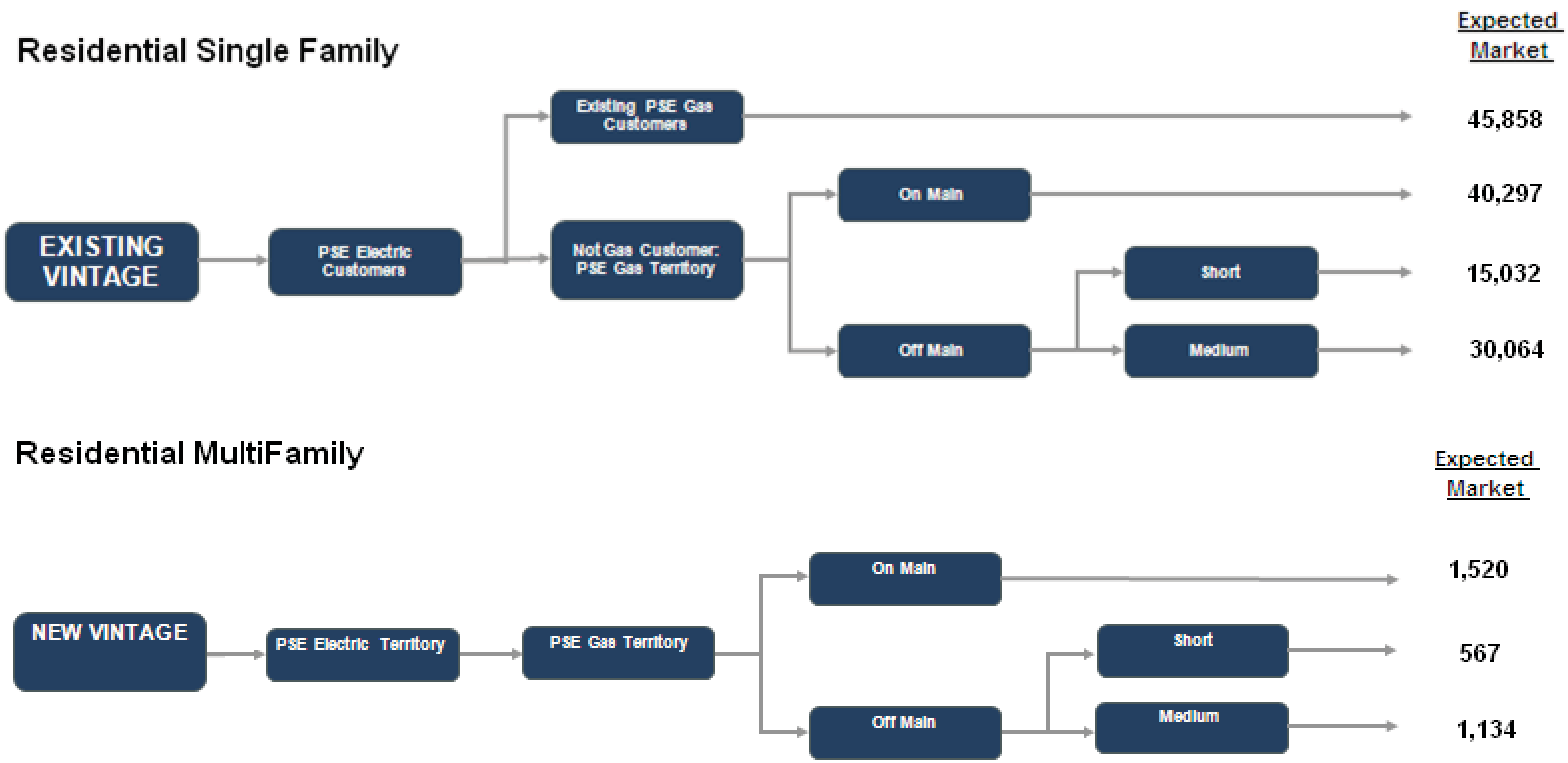
Table C.7 Fuel Conversion Measure Assumptions for Short Main Extension Gas Customers

Sector	Segment	End Use	Construction Type	Measure Name	Measure Description	Baseline Description	Measure Life	EEM Per Unit Cost ($)	Baseline Measure Per Unit Cost ($)	Incremental Per Unit Cost ($)	Per Unit Site Savings (kWh)	Annual Incremental Gas Costs ($)
Residential	SFam - 1800 sq ft	Space Heating: Ducted	Existing	Furnace	95% Furnace	Electric Furnace	30	$7,869	$1,500	$6,369	12,688	$508
Residential	SFam - 1800 sq ft	Space Heating: Baseboard	Existing	Wall Heater	Wall Heater 84% eff	Electric Baseboard	30	$2,049	$653	$1,396	8,220	$373
Residential	SFam - 1800 sq ft	Space Heating: Baseboard	Existing	Gas Fireplace	Gas Fireplace	Electric Baseboard	30	$3,475	$364	$3,111	4,052	$211
Residential	SFam - 1800 sq ft	Space Heating: Ducted, Water Heating	Existing	Integrated Space & Water Heat	Integrated Space & Water Heat	Electric Furnace, Electric Water Heater, 55 gal.	30	$11,546	$2,005	$9,541	15,940	$580
Residential	SFam - 2100 sq ft	Space Heating: Ducted	Existing	Furnace	95% Furnace	Electric Furnace	30	$7,869	$1,500	$6,369	14,802	$593
Residential	SFam - 2100 sq ft	Space Heating: Baseboard	Existing	Wall Heater	Wall Heater 84% eff	Electric Baseboard	30	$2,049	$762	$1,287	9,590	$435
Residential	SFam - 2100 sq ft	Space Heating: Baseboard	Existing	Gas Fireplace	Gas Fireplace	Electric Baseboard	30	$3,475	$363	$3,112	4,719	$246
Residential	SFam - 2100 sq ft	Space Heating: Ducted, Water Heating	Existing	Integrated Space & Water Heat	Integrated Space & Water Heat	Electric Furnace, Electric Water Heater, 55 gal.	30	$11,546	$2,005	$9,541	18,054	$676
Residential	SFam - 2400 sq ft	Space Heating: Ducted	Existing	Furnace	95% Furnace	Electric Furnace	30	$7,869	$1,500	$6,369	16,917	$678
Residential	SFam - 2400 sq ft	Space Heating: Baseboard	Existing	Wall Heater	Wall Heater 84% eff	Electric Baseboard	30	$2,049	$870	$1,179	10,960	$497
Residential	SFam - 2400 sq ft	Space Heating: Baseboard	Existing	Gas Fireplace	Gas Fireplace	Electric Baseboard	30	$3,475	$363	$3,112	5,386	$281
Residential	SFam - 2400 sq ft	Space Heating: Ducted, Water Heating	Existing	Integrated Space & Water Heat	Integrated Space & Water Heat	Electric Furnace, Electric Water Heater, 55 gal.	30	$11,546	$2,005	$9,541	20,169	$773
Residential	SFam - 1800 sq ft	Zone Heating: Baseboard	Existing	Wall Heater	Wall Heater 84% eff	Electric Baseboard	30	$2,049	$653	$1,396	6,344	$288
Residential	SFam - 1800 sq ft	Clothes Drying	Existing	Dryer	Dryer - Advanced Efficiency	Dryer - Federal Standard 2015	30	$1,213	$727	$486	768	$25
Residential	SFam - 1800 sq ft	Cooking	Existing	Cooking Oven	Cooking Oven - High Efficiency	Federal Standard 2012 Cooking Oven	30	$1,413	$757	$656	159	$12
Residential	SFam - 1800 sq ft	Water Heating	Existing	Water Heater	Tankless WH	Electric Water Heater, 55 gal.	30	$5,202	$505	$4,696	3,252	$212
Residential	SFam - 1800 sq ft	Water Heating	Existing	Water Heater	WH (>67% EF)	Electric Water Heater, 55 gal.	30	$5,132	$505	$4,626	3,252	$259
Residential	SFam - 2100 sq ft	Zone Heating: Baseboard	Existing	Wall Heater	Wall Heater 84% eff	Electric Baseboard	30	$2,049	$762	$1,287	7,401	$335
Residential	SFam - 2100 sq ft	Clothes Drying	Existing	Dryer	Dryer - Advanced Efficiency	Dryer - Federal Standard 2015	30	$1,213	$727	$486	768	$25
Residential	SFam - 2100 sq ft	Cooking	Existing	Cooking Oven	Cooking Oven - High Efficiency	Federal Standard 2012 Cooking Oven	30	$1,413	$757	$656	159	$12
Residential	SFam - 2100 sq ft	Water Heating	Existing	Water Heater	Tankless WH	Electric Water Heater, 55 gal.	30	$5,202	$505	$4,696	3,252	$212
Residential	SFam - 2100 sq ft	Water Heating	Existing	Water Heater	WH (>67% EF)	Electric Water Heater, 55 gal.	30	$5,132	$505	$4,626	3,252	$259
Residential	SFam - 2400 sq ft	Zone Heating: Baseboard	Existing	Wall Heater	Wall Heater 84% eff	Electric Baseboard	30	$2,049	$870	$1,179	8,459	$383
Residential	SFam - 2400 sq ft	Clothes Drying	Existing	Dryer	Dryer - Advanced Efficiency	Dryer - Federal Standard 2015	30	$1,213	$727	$486	768	$25
Residential	SFam - 2400 sq ft	Cooking	Existing	Cooking Oven	Cooking Oven - High Efficiency	Federal Standard 2012 Cooking Oven	30	$1,413	$757	$656	159	$12
Residential	SFam - 2400 sq ft	Water Heating	Existing	Water Heater	Tankless WH	Electric Water Heater, 55 gal.	30	$5,202	$505	$4,696	3,252	$212
Residential	SFam - 2400 sq ft	Water Heating	Existing	Water Heater	WH (>67% EF)	Electric Water Heater, 55 gal.	30	$5,132	$505	$4,626	3,252	$259
Commercial	Commercial	Space Heating: Ducted	Existing	Furnace	94% Furnace	Electric Furnace	30	$9,129	$4,595	$4,534	13,716	$1,025
Commercial	Commercial	Water Heating	Existing	Water Heater	Tankless WH	Electric Water Heater, 50 gal.	30	$8,406	$1,195	$7,210	9,736	$639
Commercial	Commercial	Water Heating	Existing	Water Heater	WH (>67% EF)	Electric Water Heater, 50 gal.	30	$7,331	$1,195	$6,136	9,736	$782
Commercial	Commercial	Water Heating	New	Water Heater	Tankless WH	Electric Water Heater, 50 gal.	30	$7,595	$1,195	$6,399	9,945	$674
Commercial	Commercial	Water Heating	New	Water Heater	WH (>67% EF)	Electric Water Heater, 50 gal.	30	$6,521	$1,195	$5,325	9,945	$825
Commercial	Commercial	Space Heating	New	Warm-Up Heat	Gas warm up heat	Electric Furnace	30	$17,601	$4,595	$13,006	2,851	$971
Commercial	Commercial	Space Heating	New	Furnace	94% Furnace	Electric Furnace	30	$7,599	$4,595	$3,004	2,851	$516
Commercial	Commercial	Space Heating, Water Heating	New	Boiler	Boiler	Packaged Rooftop Unit, Electric Water Heater, 50 gal.	30	$10,219	$1,998	$8,221	12,546	$668
Commercial	Commercial	Space Heating, Water Heating	New	Boiler	Boiler	Packaged Rooftop VAV w/ Electrical Resistance Reheat & Electric Water Heater, 50	30	$10,219	$2,383	$7,836	12,546	$668
Commercial	Commercial	Space Heating	New	Gas PACs	Gas PACs	Packaged Rooftop Unit	30	$11,891	$3,585	$8,305	3,601	$248
Residential	MFam Mid Rise: Renter	Space Heating: Ducted	New	Furnace	95% Furnace	Electric Furnace	30	$7,869	$1,431	$6,438	2,303	$106
Residential	MFam Mid Rise: Renter	Space Heating: Baseboard	New	Furnace	95% Furnace	Baseboard Heating	30	$7,669	$119	$7,550	1,771	$106
Residential	MFam Mid Rise: Renter	Clothes Drying	New	Dryer	Dryer - Advanced Efficiency	Dryer - Federal Standard 2015	30	$1,213	$481	$732	868	$23
Residential	MFam Mid Rise: Renter	Cooking	New	Cooking Oven	Cooking Oven - High Efficiency	Cooking Oven - Standard	30	$1,413	$757	$656	159	$12
Residential	MFam Mid Rise: Renter	Water Heating	New	Water Heater	Tankless WH	Electric Water Heater, 55 gal.	30	$1,475	$505	$969	1,647	$104
Residential	MFam Mid Rise: Renter	Water Heating	New	Water Heater	WH (>67% EF)	Electric Water Heater, 55 gal.	30	$1,564	$505	$1,058	1,647	$127
Residential	MFam Mid Rise: Renter	Space Heating: Ducted, Water Heating	New	Integrated Space & Water Heat	Integrated Space & Water Heat	Electric Furnace, Electric Water Heater, 55 gal.	30	$11,546	$1,936	$9,610	3,950	$165
Residential	MFam Mid Rise: Renter	Space Heating: Baseboard, Water Heating	New	Boiler	Boiler	Baseboard Heating, Electric Water Heater, 55 gal.	30	$11,346	$625	$10,721	3,418	$165
Residential	MFam Low Rise: Renter	Space Heating: Ducted	New	Furnace	95% Furnace	Electric Furnace	30	$7,869	$1,431	$6,438	2,303	$106
Residential	MFam Low Rise: Renter	Space Heating: Baseboard	New	Furnace	95% Furnace	Baseboard Heating	30	$7,669	$119	$7,550	1,771	$106
Residential	MFam Low Rise: Renter	Clothes Drying	New	Dryer	Dryer - Advanced Efficiency	Dryer - Federal Standard 2015	30	$1,213	$481	$732	868	$23
Residential	MFam Low Rise: Renter	Cooking	New	Cooking Oven	Cooking Oven - High Efficiency	Cooking Oven - Standard	30	$1,413	$757	$656	159	$12
Residential	MFam Low Rise: Renter	Water Heating	New	Water Heater	Tankless WH	Electric Water Heater, 55 gal.	30	$1,475	$505	$969	1,647	$104
Residential	MFam Low Rise: Renter	Water Heating	New	Water Heater	WH (>67% EF)	Electric Water Heater, 55 gal.	30	$1,564	$505	$1,058	1,647	$127
Residential	MFam Low Rise: Renter	Space Heating: Ducted, Water Heating	New	Integrated Space & Water Heat	Integrated Space & Water Heat	Electric Furnace, Electric Water Heater, 55 gal.	30	$11,546	$1,936	$9,610	3,950	$165
Residential	MFam Low Rise: Renter	Space Heating: Baseboard, Water Heating	New	Boiler	Boiler	Baseboard Heating, Electric Water Heater, 55 gal.	30	$11,346	$625	$10,721	3,418	$165
Residential	MFam Mid Rise: Owner	Space Heating: Ducted	New	Furnace	95% Furnace	Electric Furnace	30	$7,869	$1,431	$6,438	2,303	$106
Residential	MFam Mid Rise: Owner	Space Heating: Baseboard	New	Furnace	95% Furnace	Baseboard Heating	30	$7,669	$137	$7,532	1,771	$106
Residential	MFam Mid Rise: Owner	Clothes Drying	New	Dryer	Dryer - Advanced Efficiency	Dryer - Federal Standard 2015	30	$1,213	$481	$732	868	$23
Residential	MFam Mid Rise: Owner	Cooking	New	Cooking Oven	Cooking Oven - High Efficiency	Cooking Oven - Standard	30	$1,413	$757	$656	159	$12
Residential	MFam Mid Rise: Owner	Water Heating	New	Water Heater	Tankless WH	Electric Water Heater, 55 gal.	30	$1,475	$505	$969	1,647	$104
Residential	MFam Mid Rise: Owner	Water Heating	New	Water Heater	WH (>67% EF)	Electric Water Heater, 55 gal.	30	$1,564	$505	$1,058	1,647	$127
Residential	MFam Mid Rise: Owner	Space Heating: Ducted, Water Heating	New	Integrated Space & Water Heat	Integrated Space & Water Heat	Electric Furnace, Electric Water Heater, 55 gal.	30	$11,546	$1,936	$9,610	3,950	$165
Residential	MFam Mid Rise: Owner	Space Heating: Baseboard, Water Heating	New	Boiler	Boiler	Baseboard Heating, Electric Water Heater, 55 gal.	30	$11,346	$625	$10,721	3,418	$165
Residential	MFam Low Rise: Owner	Space Heating: Ducted	New	Furnace	95% Furnace	Electric Furnace	30	$7,869	$1,431	$6,438	2,303	$106
Residential	MFam Low Rise: Owner	Space Heating: Baseboard	New	Furnace	95% Furnace	Baseboard Heating	30	$7,669	$119	$7,550	1,771	$106
Residential	MFam Low Rise: Owner	Clothes Drying	New	Dryer	Dryer - Advanced Efficiency	Dryer - Federal Standard 2015	30	$1,213	$481	$732	868	$23
Residential	MFam Low Rise: Owner	Cooking	New	Cooking Oven	Cooking Oven - High Efficiency	Cooking Oven - Standard	30	$1,413	$757	$656	159	$12
Residential	MFam Low Rise: Owner	Water Heating	New	Water Heater	Tankless WH	Electric Water Heater, 55 gal.	30	$1,475	$505	$969	1,647	$104
Residential	MFam Low Rise: Owner	Water Heating	New	Water Heater	WH (>67% EF)	Electric Water Heater, 55 gal.	30	$1,564	$505	$1,058	1,647	$127
Residential	MFam Low Rise: Owner	Space Heating: Ducted, Water Heating	New	Integrated Space & Water Heat	Integrated Space & Water Heat	Electric Furnace, Electric Water Heater, 55 gal.	30	$11,546	$1,936	$9,610	3,950	$165
Residential	MFam Low Rise: Owner	Space Heating: Baseboard, Water Heating	New	Boiler	Boiler	Baseboard Heating, Electric Water Heater, 55 gal.	30	$11,346	$625	$10,721	3,418	$165

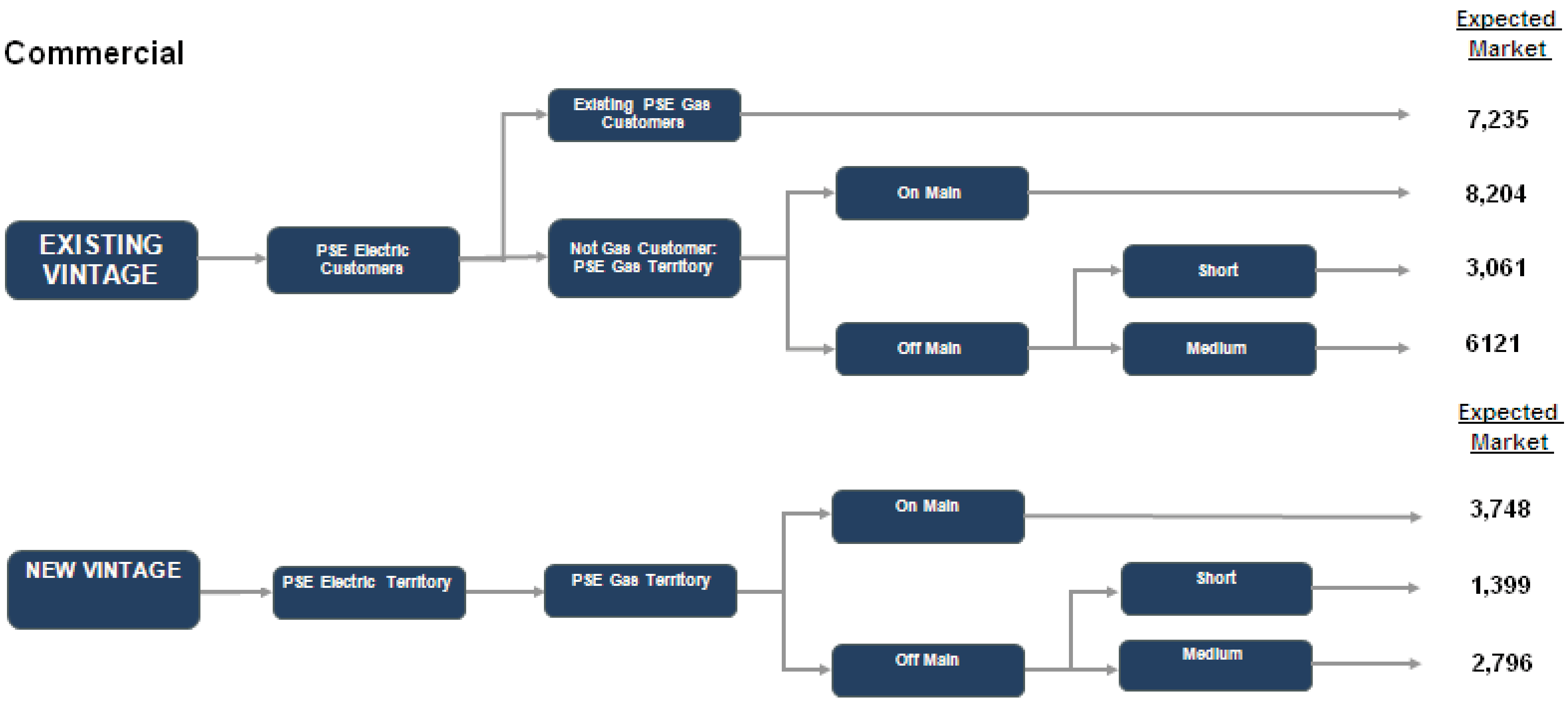
Table C.8 Fuel Conversion Measure Assumptions for Medium Main Extension Gas Customers

Sector	Segment	End Use	Construction Type	Measure Name	Measure Description	Baseline Description	Measure Life	EEM Per Unit Cost ($)	Baseline Measure Per Unit Cost ($)	Incremental Per Unit Cost ($)	Per Unit Site Savings (kWh)	Annual Incremental Gas Costs ($)
Residential	SFam - 1800 sq ft	Space Heating: Ducted	Existing	Furnace	95% Furnace	Electric Furnace	30	$17,869	$1,500	$16,369	12,688	$508
Residential	SFam - 1800 sq ft	Space Heating: Baseboard	Existing	Wall Heater	Wall Heater 84% eff	Electric Baseboard	30	$2,049	$653	$1,396	8,220	$373
Residential	SFam - 1800 sq ft	Space Heating: Baseboard	Existing	Gas Fireplace	Gas Fireplace	Electric Baseboard	30	$3,475	$364	$3,111	4,052	$211
Residential	SFam - 1800 sq ft	Space Heating: Ducted, Water Heating	Existing	Integrated Space & Water Heat	Integrated Space & Water Heat	Electric Furnace, Electric Water Heater, 55 gal.	30	$21,546	$2,005	$19,541	15,940	$580
Residential	SFam - 2100 sq ft	Space Heating: Ducted	Existing	Furnace	95% Furnace	Electric Furnace	30	$17,869	$1,500	$16,369	14,802	$593
Residential	SFam - 2100 sq ft	Space Heating: Baseboard	Existing	Wall Heater	Wall Heater 84% eff	Electric Baseboard	30	$2,049	$762	$1,287	9,590	$435
Residential	SFam - 2100 sq ft	Space Heating: Baseboard	Existing	Gas Fireplace	Gas Fireplace	Electric Baseboard	30	$3,475	$363	$3,112	4,719	$246
Residential	SFam - 2100 sq ft	Space Heating: Ducted, Water Heating	Existing	Integrated Space & Water Heat	Integrated Space & Water Heat	Electric Furnace, Electric Water Heater, 55 gal.	30	$21,546	$2,005	$19,541	18,054	$676
Residential	SFam - 2400 sq ft	Space Heating: Ducted	Existing	Furnace	95% Furnace	Electric Furnace	30	$17,869	$1,500	$16,369	16,917	$678
Residential	SFam - 2400 sq ft	Space Heating: Baseboard	Existing	Wall Heater	Wall Heater 84% eff	Electric Baseboard	30	$2,049	$870	$1,179	10,960	$497
Residential	SFam - 2400 sq ft	Space Heating: Baseboard	Existing	Gas Fireplace	Gas Fireplace	Electric Baseboard	30	$3,475	$363	$3,112	5,386	$281
Residential	SFam - 2400 sq ft	Space Heating: Ducted, Water Heating	Existing	Integrated Space & Water Heat	Integrated Space & Water Heat	Electric Furnace, Electric Water Heater, 55 gal.	30	$21,546	$2,005	$19,541	20,169	$773
Residential	SFam - 1800 sq ft	Zone Heating: Baseboard	Existing	Wall Heater	Wall Heater 84% eff	Electric Baseboard	30	$2,049	$653	$1,396	6,344	$288
Residential	SFam - 1800 sq ft	Clothes Drying	Existing	Dryer	Dryer - Advanced Efficiency	Dryer - Federal Standard 2015	30	$1,213	$727	$486	768	$25
Residential	SFam - 1800 sq ft	Cooking	Existing	Cooking Oven	Cooking Oven - High Efficiency	Federal Standard 2012 Cooking Oven	30	$1,413	$757	$656	159	$12
Residential	SFam - 1800 sq ft	Water Heating	Existing	Water Heater	Tankless WH	Electric Water Heater, 55 gal.	30	$11,802	$505	$11,296	3,252	$212
Residential	SFam - 1800 sq ft	Water Heating	Existing	Water Heater	WH (>67% EF)	Electric Water Heater, 55 gal.	30	$11,732	$505	$11,226	3,252	$259
Residential	SFam - 2100 sq ft	Zone Heating: Baseboard	Existing	Wall Heater	Wall Heater 84% eff	Electric Baseboard	30	$2,049	$762	$1,287	7,401	$335
Residential	SFam - 2100 sq ft	Clothes Drying	Existing	Dryer	Dryer - Advanced Efficiency	Dryer - Federal Standard 2015	30	$1,213	$727	$486	768	$25
Residential	SFam - 2100 sq ft	Cooking	Existing	Cooking Oven	Cooking Oven - High Efficiency	Federal Standard 2012 Cooking Oven	30	$1,413	$757	$656	159	$12
Residential	SFam - 2100 sq ft	Water Heating	Existing	Water Heater	Tankless WH	Electric Water Heater, 55 gal.	30	$11,802	$505	$11,296	3,252	$212
Residential	SFam - 2100 sq ft	Water Heating	Existing	Water Heater	WH (>67% EF)	Electric Water Heater, 55 gal.	30	$11,732	$505	$11,226	3,252	$259
Residential	SFam - 2400 sq ft	Zone Heating: Baseboard	Existing	Wall Heater	Wall Heater 84% eff	Electric Baseboard	30	$2,049	$870	$1,179	8,459	$383
Residential	SFam - 2400 sq ft	Clothes Drying	Existing	Dryer	Dryer - Advanced Efficiency	Dryer - Federal Standard 2015	30	$1,213	$727	$486	768	$25
Residential	SFam - 2400 sq ft	Cooking	Existing	Cooking Oven	Cooking Oven - High Efficiency	Federal Standard 2012 Cooking Oven	30	$1,413	$757	$656	159	$12
Residential	SFam - 2400 sq ft	Water Heating	Existing	Water Heater	Tankless WH	Electric Water Heater, 55 gal.	30	$11,802	$505	$11,296	3,252	$212
Residential	SFam - 2400 sq ft	Water Heating	Existing	Water Heater	WH (>67% EF)	Electric Water Heater, 55 gal.	30	$11,732	$505	$11,226	3,252	$259
Commercial	Commercial	Space Heating: Ducted	Existing	Furnace	94% Furnace	Electric Furnace	30	$19,129	$4,595	$14,534	13,716	$1,025
Commercial	Commercial	Water Heating	Existing	Water Heater	Tankless WH	Electric Water Heater, 50 gal.	30	$18,006	$1,195	$16,810	9,736	$639
Commercial	Commercial	Water Heating	Existing	Water Heater	WH (>67% EF)	Electric Water Heater, 50 gal.	30	$16,931	$1,195	$15,736	9,736	$782
Commercial	Commercial	Water Heating	New	Water Heater	Tankless WH	Electric Water Heater, 50 gal.	30	$15,695	$1,195	$14,499	9,945	$674
Commercial	Commercial	Water Heating	New	Water Heater	WH (>67% EF)	Electric Water Heater, 50 gal.	30	$14,621	$1,195	$13,425	9,945	$825
Commercial	Commercial	Space Heating	New	Warm-Up Heat	Gas warm up heat	Electric Furnace	30	$27,601	$4,595	$23,006	2,851	$971
Commercial	Commercial	Space Heating	New	Furnace	94% Furnace	Electric Furnace	30	$17,599	$4,595	$13,004	2,851	$516
Commercial	Commercial	Space Heating, Water Heating	New	Boiler	Boiler	Packaged Rooftop Unit, Electric Water Heater, 50 gal.	30	$20,219	$1,998	$18,221	12,546	$668
Commercial	Commercial	Space Heating, Water Heating	New	Boiler	Boiler	Packaged Rooftop VAV w/ Electrical Resistance Reheat & Electric Water Heater, 50	30	$20,219	$2,383	$17,836	12,546	$668
Commercial	Commercial	Space Heating	New	Gas PACs	Gas PACs	Packaged Rooftop Unit	30	$21,891	$3,585	$18,305	3,601	$248
Residential	MFam Mid Rise: Renter	Space Heating: Ducted	New	Furnace	95% Furnace	Electric Furnace	30	$17,869	$1,431	$16,438	2,303	$106
Residential	MFam Mid Rise: Renter	Space Heating: Baseboard	New	Furnace	95% Furnace	Baseboard Heating	30	$17,669	$119	$17,550	1,771	$106
Residential	MFam Mid Rise: Renter	Clothes Drying	New	Dryer	Dryer - Advanced Efficiency	Dryer - Federal Standard 2015	30	$1,213	$481	$732	868	$23
Residential	MFam Mid Rise: Renter	Cooking	New	Cooking Oven	Cooking Oven - High Efficiency	Cooking Oven - Standard	30	$1,413	$757	$656	159	$12
Residential	MFam Mid Rise: Renter	Water Heating	New	Water Heater	Tankless WH	Electric Water Heater, 55 gal.	30	$1,475	$505	$969	1,647	$104
Residential	MFam Mid Rise: Renter	Water Heating	New	Water Heater	WH (>67% EF)	Electric Water Heater, 55 gal.	30	$1,564	$505	$1,058	1,647	$127
Residential	MFam Mid Rise: Renter	Space Heating: Ducted, Water Heating	New	Integrated Space & Water Heat	Integrated Space & Water Heat	Electric Furnace, Electric Water Heater, 55 gal.	30	$21,546	$1,936	$19,610	3,950	$165
Residential	MFam Mid Rise: Renter	Space Heating: Baseboard, Water Heating	New	Boiler	Boiler	Baseboard Heating, Electric Water Heater, 55 gal.	30	$21,346	$625	$20,721	3,418	$165
Residential	MFam Low Rise: Renter	Space Heating: Ducted	New	Furnace	95% Furnace	Electric Furnace	30	$17,869	$1,431	$16,438	2,303	$106
Residential	MFam Low Rise: Renter	Space Heating: Baseboard	New	Furnace	95% Furnace	Baseboard Heating	30	$17,669	$119	$17,550	1,771	$106
Residential	MFam Low Rise: Renter	Clothes Drying	New	Dryer	Dryer - Advanced Efficiency	Dryer - Federal Standard 2015	30	$1,213	$481	$732	868	$23
Residential	MFam Low Rise: Renter	Cooking	New	Cooking Oven	Cooking Oven - High Efficiency	Cooking Oven - Standard	30	$1,413	$757	$656	159	$12
Residential	MFam Low Rise: Renter	Water Heating	New	Water Heater	Tankless WH	Electric Water Heater, 55 gal.	30	$1,475	$505	$969	1,647	$104
Residential	MFam Low Rise: Renter	Water Heating	New	Water Heater	WH (>67% EF)	Electric Water Heater, 55 gal.	30	$1,564	$505	$1,058	1,647	$127
Residential	MFam Low Rise: Renter	Space Heating: Ducted, Water Heating	New	Integrated Space & Water Heat	Integrated Space & Water Heat	Electric Furnace, Electric Water Heater, 55 gal.	30	$21,546	$1,936	$19,610	3,950	$165
Residential	MFam Low Rise: Renter	Space Heating: Baseboard, Water Heating	New	Boiler	Boiler	Baseboard Heating, Electric Water Heater, 55 gal.	30	$21,346	$625	$20,721	3,418	$165
Residential	MFam Mid Rise: Owner	Space Heating: Ducted	New	Furnace	95% Furnace	Electric Furnace	30	$17,869	$1,431	$16,438	2,303	$106
Residential	MFam Mid Rise: Owner	Space Heating: Baseboard	New	Furnace	95% Furnace	Baseboard Heating	30	$17,669	$137	$17,532	1,771	$106
Residential	MFam Mid Rise: Owner	Clothes Drying	New	Dryer	Dryer - Advanced Efficiency	Dryer - Federal Standard 2015	30	$1,213	$481	$732	868	$23
Residential	MFam Mid Rise: Owner	Cooking	New	Cooking Oven	Cooking Oven - High Efficiency	Cooking Oven - Standard	30	$1,413	$757	$656	159	$12
Residential	MFam Mid Rise: Owner	Water Heating	New	Water Heater	Tankless WH	Electric Water Heater, 55 gal.	30	$1,475	$505	$969	1,647	$104
Residential	MFam Mid Rise: Owner	Water Heating	New	Water Heater	WH (>67% EF)	Electric Water Heater, 55 gal.	30	$1,564	$505	$1,058	1,647	$127
Residential	MFam Mid Rise: Owner	Space Heating: Ducted, Water Heating	New	Integrated Space & Water Heat	Integrated Space & Water Heat	Electric Furnace, Electric Water Heater, 55 gal.	30	$21,546	$1,936	$19,610	3,950	$165
Residential	MFam Mid Rise: Owner	Space Heating: Baseboard, Water Heating	New	Boiler	Boiler	Baseboard Heating, Electric Water Heater, 55 gal.	30	$21,346	$625	$20,721	3,418	$165
Residential	MFam Low Rise: Owner	Space Heating: Ducted	New	Furnace	95% Furnace	Electric Furnace	30	$17,869	$1,431	$16,438	2,303	$106
Residential	MFam Low Rise: Owner	Space Heating: Baseboard	New	Furnace	95% Furnace	Baseboard Heating	30	$17,669	$119	$17,550	1,771	$106
Residential	MFam Low Rise: Owner	Clothes Drying	New	Dryer	Dryer - Advanced Efficiency	Dryer - Federal Standard 2015	30	$1,213	$481	$732	868	$23
Residential	MFam Low Rise: Owner	Cooking	New	Cooking Oven	Cooking Oven - High Efficiency	Cooking Oven - Standard	30	$1,413	$757	$656	159	$12
Residential	MFam Low Rise: Owner	Water Heating	New	Water Heater	Tankless WH	Electric Water Heater, 55 gal.	30	$1,475	$505	$969	1,647	$104
Residential	MFam Low Rise: Owner	Water Heating	New	Water Heater	WH (>67% EF)	Electric Water Heater, 55 gal.	30	$1,564	$505	$1,058	1,647	$127
Residential	MFam Low Rise: Owner	Space Heating: Ducted, Water Heating	New	Integrated Space & Water Heat	Integrated Space & Water Heat	Electric Furnace, Electric Water Heater, 55 gal.	30	$21,546	$1,936	$19,610	3,950	$165
Residential	MFam Low Rise: Owner	Space Heating: Baseboard, Water Heating	New	Boiler	Boiler	Baseboard Heating, Electric Water Heater, 55 gal.	30	$21,346	$625	$20,721	3,418	$165

Figure C.1 Customers Available for Fuel Conversion*



Commercial



* Expected Market represents customers with electric central heating or electric water heating.

Appendix D: Conditional Demand Modeling

A Residential Energy Study (RES) was conducted for PSE in 2010 of 5,850 residential customers. The 5,850 customers were distributed by electric & gas service types as follows: 3,000 gas customers (Gas Only, and Combination Customers), 4,327 electric customers (Electric Only, and Combination Customers).

For the conditional demand analysis (CDA) – we received from PSE electric & gas monthly usage data for 2009 for all the 5,850 RES customers. The monthly usage was allocated to calendar months to remove the variability due to varying read cycles.

Data Preparation

The monthly usage data was merged with all the RES survey responses. Each RES ZIP code was mapped to the nearest station. Daily 2009 temperature data were obtained for all the weather stations associated with the RES ZIP codes. The 11 weather stations used in the CDA estimation were: Bellingham, Everett, Olympia, Port Angeles, Renton, SEATAC, Seattle, Tacoma (McCord AFB), Toledo, Wenatchee, and Yakima.

Heating degree days with base 65 and cooling degree days with base 65 were calculated from the average daily temperature data. NOAA TMY3 (1991-2005) series base 65 normal heating and cooling degree days were also matched in for each zipcode.

RES & Usage Data Validation

Comparing the usage data and the RES customer responses is ideal for fixing inconsistencies in self-reported survey responses that could lead to unreliable conditional demand model results. For example, for about 19% of sites the heating system fuel could not be determined, and for 8% water heating fuel was not specified. By examining the usage patterns it is possible to determine the space heating fuel and water heating fuel. Based on the summer usages it is also possible to determine the water heating fuel and presence of air conditioners. In order to improve CDA model accuracy – monthly 2009 billing data for all the 5,850 sites with data were examined along with some key RES variables which were potentially important in the conditional demand modeling.

Variables Used

The following variables were examined for each customer:

Usage related

- 2009 Monthly Usage
- Total number of billing days by year
- kWh per square foot for electric or therms per square foot for gas

End Use Presence

- Gas/Electric Heating
- Secondary Gas/Electric Heating

- Gas/Electric Water Heating
- Gas/Electrically Heated Spa
- Gas/Electric Heated Pool
- Electric/Gas Dryer (Only if home did not have gas heating/water heating)
- Electric/Gas Cooking (Only if home did not have gas heating/water heating)
- Gas Fireplace (Only if home did not have gas heating/water heating)
- Electric AC

Home characteristics & occupant related fields

- Square footage of home
- Number of heated rooms
- Number of bathrooms
- Number of occupants

Data Validation and Cleansing

The 2009 monthly usages were plotted for each customer and compared to the associated RES responses. For the electric validation only the large end uses could be tested: space heating presence, water heating presence, air conditioning presence, pool presence, and spa presence. If the monthly usage was inconsistent with the RES response, the source of error was noted. Many of the accounts were consistent or there was insufficient evidence that the usage was inconsistent with the RES response. The problems and inconsistencies that were flagged include:

Billing Data

- Insufficient number of days in a year
- Extreme usage outliers from bad meter data
- Vacancies and Seasonal Usage

Survey Responses (Gas customers)

- Usage indicates gas space heating but survey response was gas space heating was not primary or no response
- Usage does not indicate gas heating although respondent said primary heating system was gas. It is possible that the respondent was using gas as backup, or using fireplaces.
- Usage indicates gas water heating but survey response was no gas water heating or no response
- Usage does not indicate gas water heating although respondent said primary water heating system was gas.
- Usage indicated no gas heated pool but survey response was pool was heated with gas

Survey Responses (Electric customers)

- Usage indicates electric space heating but survey response was electric space heating was not primary or no response

- Usage does not indicate electric space heating although respondent said primary heating system was electric. It is possible that the respondent was using electric heat as backup instead, or using gas fireplaces.
- Usage indicates electric water heating but survey response was no electric water heating or no response
- Usage does not indicate electric water heating although respondent said primary water heating system was electric.
- Usage indicates electric AC but survey response was no electric AC or no response

Accounts with bad/incomplete data were dropped. Each customer had to have at least 300 days of billing data to be included in the CDA analysis. Sites with extended vacancy periods were dropped. Sites with incorrect square footage estimates were dropped from the gas analysis – because it was not possible to obtain or estimate the actual square footage of the home, and the square footage was necessary to determine the water heating usage. For the electric analysis, the water heating flag was interacted with the number of occupants. The number of occupants was seldom missing, and in these instances, the number of occupants was assigned to the most common response – two occupants. For the sites with inconsistent survey responses – the survey responses were changed to the more correct responses after usage data review.

PRISM Usage Estimation

In addition to reviewing survey and billing data, Princeton ScoreKeeping models (PRISM) were also estimated for each RES response.

The second step in the conditional demand screening process was to estimate PRISM models for each customer from the billing data. The PRISM models were only used for screening out unreliable responses in a systematic way. These models obtain weather normalized annual consumption (NAC) and also separate the total usage into the weather sensitive heating/cooling usages and the base load usage. The drawback of the models is that they do not necessarily disaggregate the individual end-uses correctly. In general the PRISM models estimate higher end-use UECs and when they are weighted by their associated saturations, the overall usage per customer is overstated due to the double counting.

For each electric customer we estimated three PRISM models: a heating and cooling, heating only, and cooling only model to weather-normalize raw billing data.

PRISM Model Specification

The heating and cooling PRISM model specification used was:

$$ADC_{it} = \alpha_i + \beta_1 AVGHDD_{it} + \beta_2 AVGCDD_{it} + \varepsilon_{it}$$

Where for each customer ‘i’ and calendar month ‘t’:

ADC_{it}	=	the average daily kWh consumption
α_i	=	the participant intercept; represents the average daily kWh base load
β_1	=	the model space heating slope (used only in the heating only, heating + cooling model)

$AVGHDD_{it}$ = the base 65 average daily HDDs for the specific location (used only in the heating only, heating + cooling model)

β_2 = the model space cooling slope (used only in the cooling only, heating + cooling model)

$AVGCDD_{it}$ = the base 65 average daily CDDs for the specific location (used only in the cooling only, heating + cooling model)

ε_{it} = the error term

From the model above, we computed the weather-normalized annual consumption (NAC) as follows:

$$NAC_i = \alpha_i * 365 + \beta_1 LRHDD_i + \beta_2 LRCDD_i + \varepsilon_i$$

Where for each customer 'i':

NAC_i = the normalized annual kWh consumption

α_i = the intercept that is the average daily or base load for each participant; represents the average daily base load from the model

$\alpha_i * 365$ = the annual base load kWh usage (non-weather sensitive)

β_1 = the heating slope; in effect, this is the usage per heating degree from the model above

$LRHDD_i$ = the annual, long-term base 65 HDDs of a typical month year (TMY3) in the 1991-2005 series from NOAA, based on home location

$\beta_1 * LRHDD_i$ = the weather-normalized annual weather sensitive (heating) usage, also known as HEATNAC

β_2 = the cooling slope; in effect, this is the usage per cooling degree from the model above

$LRCDD_i$ = the annual, long-term base 65 CDDs of a typical month year (TMY3) in the 1991-2005 series from NOAA, based on home location

$\beta_2 * LRCDD_i$ = the weather-normalized annual weather sensitive (cooling) usage, also known as COOLNAC

ε_i = the error term

For the gas customers we estimated only one model, a heating only model, to weather-normalize raw billing data for each customer. This model type is a special case of the electric PRISM models above where COOLNAC is 0.

PRISM-Based Data Screening

Based on the PRISM model runs additional screens were placed on the data to remove and re-classify inconsistent responses from the conditional demand model.

Electric Customers

- If the customer indicated the presence of electric space heating but the total HEATNAC was less than 1,000 kWh then the customer was dropped
- If the customer indicated that they had electric water heating but the total PRISM base load usage was less than 1,000 kWh then the customer was dropped
- If the customer indicated that they had an air conditioner but the COOLNAC was less than 100 kWh per year then the customer was dropped
- If a customer indicated that they did not heat with electricity but showed a HEATNAC over 2,000 kWh and heating usage over 30% of total usage, then the customer was assigned to an electric heating category

Gas Customers

- If the customer said they had gas space heating but the total HEATNAC was less than 100 therms then the customer was dropped
- If the customer said they had gas water heating but the total PRISM base load usage was less than 100 therms then the customer was dropped

Data Validation Results

After all the screening and re-assignments, 14% of the gas accounts and 19% of the electric accounts were removed due to the various data quality and data consistency screening above. The final CDA models only included the customers with good data.

The following summaries show the attrition of the customers for the 2009 data.

Gas

- **All gas data in 2009: n=3,000**
- Bad or incomplete usage data: 198 of 3,000 (7%)
- Inconsistent Survey response: 187 of 3,000 (6%)
- Bad Square footage: 15 of 3,000 (1%)
- Vacancies: 7 of 3,000 (2%)
- **Good data: 2,593 of 3,000 (86%)**[1]

Electric

- **All electric data in 2009: n=4,327**
- Bad or incomplete usage data: 281 of 4,327 (6%)
- Inconsistent Survey response: 485 of 4,327 (11%)
- Vacancies: 45 of 4,327 (1%)
- **Good data: 3,516 of 4,327 (81%)**[2]

[1] The final gas sample includes 2,368 single family, 209 multifamily/condo, and 16 manufactured homes.

[2] The final electric sample includes 2,708 single family, 553 multifamily/condo, and 255 manufactured homes.

Gas Conditional Demand Modeling Results

Single Family

The single family gas conditional demand specification was[3]:

For customer i and calendar month t in 2009,

$$ADC\_THERMS_{it} = \beta_1\, GASFURNACE_i * HDD65_{it} + \beta_2\, GASBOILER_i * HDD65_{it} + \beta_3\, GASOTHER_i * HDD65_{it} + \beta_4\, GASFIREPLACE_i * HDD65_{it} + \beta_5\, GASWATERHEAT_i * SQFT_i + \beta_6\, GASSPA_i + \beta_7\, GASPOOL_i + \beta_8\, GASAUNA_i + \beta_9 GASCOOK\_DRY_i + \varepsilon_{it}$$

where

ADC_THERMS_{it} = Average daily therms for customer i in month t

$SQFT_i$= Heated square footage of home for customer i

$HDD65_{it}$ = Average daily heating degree days (base 65) for customer i in month t

$GASFURNACE_i$= 1 if customer i has a gas furnace for space heating, 0 otherwise

$GASBOILER_i$= 1 if customer i has a gas boiler for space heating, 0 otherwise

$GASOTHER_i$= 1 if customer i uses non-furnace/boiler gas space heating, 0 otherwise

$GASFIREPLACE_i$ = 1 if customer i has a gas fireplace, 0 otherwise

$GASWATERHEAT_i$= 1 if customer i has gas water heating, 0 otherwise

$GASSPA_i$ = 1 if customer i has a gas heated spa, 0 otherwise

$GASPOOL_i$ = 1 if customer i has a gas heated pool, 0 otherwise

$GASSAUNA_i$ = 1 if customer i has a gas heated sauna, 0 otherwise

$GASCOOK\_DRY_i$ = 1 if customer i has a gas dryer or gas cooking[4], 0 otherwise

ε_{it} = Error term for customer i and month t.

The single family model results are shown in Table 1[5]:

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[3] The extreme outliers of usage in a day were 19 therms.

[4] It was not possible to disaggregate the UECs for cooking and drying separately; this is the average UEC for both cooking and drying. The sample sizes are very small for the manufactured home group, and 70% of the cooking/drying customers also had water heating so likely there is high collinearity between cooking, drying, and water heating and hence the individual UECs are likely biased.

[5] This model has an r-square of 0.81, but this is not a reliable indicator of model fit since this model does not have an intercept.

Table 1. Single Family Gas CDA Model

Variable	Parameter Estimate	T-value
FURNACE * HDD65	0.14186	189.64
BOILER * HDD65	0.19867	50.47
OTHER * HDD65	0.1988	27.54
FIREPLACE * HDD65	0.11728	41.49
WATERHEAT * SQFT	0.000298	45.58
SPA	0.55419	9.16
POOL	1.9149	20.76
SAUNA	2.38184	5.61
COOKING_DRYING	0.16685	9.61

Multifamily

Due to smaller sample sizes for the individual end-uses a simpler model was used to disaggregate the UECs for multifamily. The CDA specification was generally similar to the single family specification[6]:

For each customer i and calendar month t in 2009,

$$ADC\_THERMS_{it} = \beta_1 GASFURNACE_i * HDD65_{it} + \beta_2 GASBOILER_i * HDD65_{it} + \beta_3 GASOTHER_i * HDD65_{it} + \beta_4 GASFIREPLACE_i * HDD65_{it} + \beta_5 GASWATERHEAT_i * SQFT_i + \beta_9 GASCOOK\_DRY_i + \varepsilon_{it}$$

where

ADC_THERMS_{it} = Average daily therms for customer i in month t

$SQFT_i$= Heated square footage of home for customer i

$HDD65_{it}$ = Average daily heating degree days (base 65) for customer i in month t

$GASFURNACE_i$= 1 if customer i has a gas furnace for space heating, 0 otherwise

$GASBOILER_i$= 1 if customer i has a gas boiler for space heating, 0 otherwise

$GASOTHER_i$= 1 if customer i uses non-furnace/boiler gas space heating, 0 otherwise

$GASFIREPLACE_i$ = 1 if customer i has a gas fireplace, 0 otherwise

$GASWATERHEAT_i$= 1 if customer i has gas water heating, 0 otherwise

$GASCOOK\_DRY_i$ = 1 if customer i has a gas dryer or gas cooking[7], 0 otherwise

ε_{it} = Error term for customer i and month t.

[6] The extreme outliers of usage in a day were 8 therms. The final multifamily model removes customers with pools, spas, or saunas.

[7] It was not possible to disaggregate the UECs for cooking and drying separately; this is the average UEC for both cooking and drying. The sample sizes are very small for the manufactured home group, and 70% of the cooking/drying customers also had water heating so likely there is high collinearity between cooking, drying, and water heating and hence the individual UECs are likely biased.

The multifamily model results are shown in Table 2.[8]

Table 2. Multifamily Gas CDA Model

Variable	Parameter Estimate	T-value
FURNACE * HDD65	0.07589	41.86
BOILER * HDD65	0.14799	20.28
OTHER * HDD65	0.09377	10.47
FIREPLACE * HDD65	0.04258	11.28
WATERHEAT * SQFT	0.00041	18.23
COOKING_DRYING	0.20172	5.7

Manufactured Home

Due to smaller sample sizes for the individual end-uses a simpler model was used to disaggregate the UECs for manufactured homes. The CDA specification was generally similar to the single family specification[9]:

For each customer i and calendar month t in 2009,

$$ADC\_THERMS_{it} = \beta_1 \, GASFURNACE_i * HDD65_{it} + \beta_4 \, GASFIREPLACE_i * HDD65_{it} + \beta_5 \, GASWATERHEAT_i * SQFT_i + \beta_9 GASCOOK\_DRY_i + \varepsilon_{it}$$

where

ADC_THERMS_{it} = Average daily therms for customer i in month t

$SQFT_i$= Heated square footage of home for customer i

$HDD65_{it}$ = Average daily heating degree days (base 65) for customer i in month t

$GASFURNACE_i$= 1 if customer i has a gas furnace for space heating, 0 otherwise

$GASFIREPLACE_i$ = 1 if customer i has a gas fireplace, 0 otherwise

$GASWATERHEAT_i$= 1 if customer i has gas water heating, 0 otherwise

$GASCOOK\_DRY_i$ = 1 if customer i has a gas dryer or gas cooking[10], 0 otherwise

ε_{it} = Error term for customer i and month t.

The manufactured home model results are shown in Table 3.[11]

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[8] This model has an r-square of 0.75, but this is not a reliable indicator of model fit since this model does not have an intercept.

[9] The extreme outliers of usage in a day were 8 therms. The final manufactured home model removes customers with pools, spas, or saunas. There are no boiler and other gas system customers.

[10] It was not possible to disaggregate the UECs for cooking and drying separately. This UEC is the average UEC for both cooking and drying. In this case the UEC for cooking and drying is unusually high. The sample sizes are very small for the manufactured home group, and 70% of the cooking/drying customers also had water heating so likely there is high collinearity between cooking, drying, and water heating and hence the individual UECs are likely biased.

[11] This model has an r-square of 0.71, but this is not a reliable indicator of model fit since this model does not have an intercept.

Table 3. Manufactured Home Gas CDA Model

Variable	Parameter Estimate	T-value
FURNACE * HDD65	0.0812	8.66
FIREPLACE * HDD65	0.0687	3.97
WATERHEAT * SQFT	0.000384	3.27
COOKING_DRYING	0.90908	5.26

For all three models all variables are statistically significant, and have the correct signs.

UEC and Average Use Per Customer Results

Once the conditional demand models were estimated – the average use per customer is derived by multiplying the coefficients by their averages. In the case of the HDD space heat interaction variables – TMY3 normal base 65 heating and cooling degree days were used in place of the actual 2009 averages.

The detailed average use per customer calculations for each end-use was calculated as follows:

$$ADC\_THERMS_{it} = \beta_1 \, GASFURNACE_i * HDD65_{it} + \beta_2 \, GASBOILER_i * HDD65_{it} + \beta_3 \, GASOTHER_i * HDD65_{it} + \beta_4 \, GASFIREPLACE_i * HDD65_{it} + \beta_5 \, GASWATERHEAT_i * SQFT_i + \beta_6 \, GASSPA_i + \beta_7 \, GASPOOL_i + \beta_8 \, GASAUNA_i + \beta_9 GASCOOK\_DRY_i + \varepsilon_{it}$$

$AverageUsePerCustomer\_Furnace = \beta_1 * FURNACE * TMY3HDD65\_AVG$

$AverageUsePerCustomer\_Boiler = \beta_2 * BOILER * TMY3HDD65\_AVG$

$AverageUsePerCustomer\_Other = \beta_3 * OTHER * TMY3HDD65\_AVG$

$AverageUsePerCustomer\_FIREPLACE = \beta_4 * FIREPLACE * TMY3HDD65\_AVG$

$AverageUsePerCustomer\_WATERHEAT = \beta_5 * GASWATERHEAT * TOTSQFT * 365$

$AverageUsePerCustomer\_SPA = \beta_6 * GASSPA\_AVG * 365$

$AverageUsePerCustomer\_POOL = \beta_7 * GASPOOL\_AVG * 365$

$AverageUsePerCustomer\_SAUNA = \beta_8 * GASSAUNA\_AVG * 365$

$AverageUsePerCustomer\_COOKDRY = \beta_9 * GASCOOK\_DRY\_AVG * 365$

UECs for end use *e* are obtained from the average use per customer by dividing by the end use saturation,

$$UEC_e = AverageUsePerCustomer_e \, / \, \text{End use Saturation}_e$$

Table 4 summarizes the average base 65 TMY3 heating degree averages for each end-use category. The normal TMY3 heating degree days for the final gas RES analysis sample range from 4,477 to 5,371 HDDs.

Table 4. Gas TMY3 HDD Normals

	Single Family	Single Family (No Pools)	Multifamily	Manufactured homes
End Use	**HDD**	**HDD**	**HDD**	**HDD**
Heat Central Furnace	4,867	4,868	4,813	5,180
Heat Central Boiler	4,626	4,613	4,477	
Heat Other	4,878	4,878	4,621	
Fireplace	5,045	5,041	4,591	4,776
Water heating	4,880	4,881	4,821	5,137
Spa	4,767			
Pool	5,074			
Sauna	5,371			
Drying + Cooking	4,815	4,813	4,667	4,927
Weighted Average HDD	4,873	4,778	4,778	5,088

Table 5 summarizes the average home heated square footage and the average number of occupants for each end-use category. The average single family, multifamily, and manufactured home sizes used in the conditional demand models are 2,140, 1,330, and 1,530 square feet respectively. The average number of occupants range from 1.0 to 3.2.

Table 5. **Gas RES Analysis Sample Characteristics**

	Single Family		Single Family (No Pools)		Multifamily		Manufactured homes	
End Use	**Sq. Ft.**	**Occupants**	**Sq. Ft.**	**Occupants**	**Sq. Ft.**	**Occ**	**Sq. Ft.**	**Occupants**
Heat Central Furnace	2,167	2.8	2,150	2.8	1,381	2.0	1,444	1.5
Heat Central Boiler	2,467	2.7	2,482	2.7	1,698	3.2		
Heat Other	1,940	2.0	1,940	2.0	1,250	1.8		
Fireplace	1,818	2.8	1,819	2.8	1,160	2.0	900	1.0
Water heating	2,197	2.8	2,185	2.8	1,379	2.0	1,435	1.9
Spa	2,625	2.6						
Pool	3,285	2.4						
Sauna	2,100	2.0						
Drying + Cooking	2,425	2.8	2,405	2.8	1,337	2.0	1,277	1.9
Weighted Characteristics	2,155	2.8	2,140	2.8	1,330	2.0	1,530	1.8

Table 6 summarizes the saturations and annual UECs for each end use. The furnace UECS for single family including pools are 690 therms, for multifamily they are 365 therms, while for manufactured homes they are 421 therms. The gas water heating UECs range from 201-240 therms.

Table 6. Gas End Use UEC

	Single Family		Single Family (No Pools)		Multifamily		Manufactured homes	
End Use	**Saturation**	**UEC**	**Saturation**	**UEC**	**Saturation**	**UEC**	**Saturation**	**UEC**
Heat Central Furnace	87.73%	690	87.81%	687	69.43%	365	68.75%	421
Heat Central Boiler	1.39%	919	1.71%	922	2.62%	663		
Heat Other	0.46%	970	0.48%	968	1.44%	433		
Fireplace	3.13%	592	3.17%	592	8.14%	195	6.25%	328
Water heating	84.00%	239	84.07%	240	76.14%	206	81.25%	201
Spa	1.90%	202						
Pool	1.09%	699						
Sauna	0.04%	869						
Drying + Cooking	43.23%	61	42.65%	64	45.01%	74	*37.50%*[12]	*332*
Weighted UEC	100%	**880**	100%	**871**	100%	**483**	100%	**598**

Table 7 summarizes the average use per customer, applying the associated saturations to each end-use level UEC. The space heating usage ranges from 48% to 69% of the total average usage, while water heating usage ranges from 23% to 33% of the total average customer usage.

Table 7. **Gas End Use Average Usage Per Customer**

	Single Family		Single Family (No Pools)		Multifamily		Manufactured homes	
End Use	**% Use**	**Avg. Use**	**% Use**	**Avg. Use**	**% Use**	**Avg. Use**	**% Use**	**Avg. Use**
Heat Central Furnace	69%	606	69%	603	52%	254	48%	289
Heat Central Boiler	1%	13	2%	16	4%	17		
Heat Other	1%	5	1%	5	1%	6		
Fireplace	2%	19	2%	19	3%	16	3%	21
Water heating	23%	201	23%	202	33%	157	27%	164
Spa	0%	4						
Pool	1%	8						
Sauna	0%	0						
Drying + Cooking	3%	26	3%	27	7%	33	*21%*	*124*
Weighted Use	100%	**880**	100%	**871**	100%	**483**	100%	**598**

Table 8 compares the overall gas CDA and PRISM based usages per customer to the home type level PSE averages for 2009. Both the CDA and PRISM averages are slightly higher than the PSE averages. The PRISM estimates are generally higher than the CDA estimates. The multifamily and manufactured home averages are higher but the sample sizes for these home types are very small in the RES surveys. Moreover, given that the CDA and PRISM estimates

[12] The manufactured home UEC for drying and cooking was unreliably high at 332 therms. This is likely due to the small sample sizes used in the model and the coolinearity of these end uses with water heating and space heating. The single family drying/cooking UECs should be used instead.

are weather normalized, the weighted average CDA/PRISM UECs are not necessarily expected to match the 2009 actuals.

Table 8. **Gas UEC Calibration Checking**

Home Type	PSE Customers	PSE Total Therms	PSE per customer	CDA per customer[13]	PRISM per customer	Raw Usage per customer
Single Family	593,298	518,207,037	873	902	902	922
Multifamily	50,715	22,481,243	443	483	513	556
Manufactured homes	2,167	1,108,951	512	598	681	699
All Residential	646,180	541,797,231	838	868	871	893

[13] The 90% confidence level CDA relative precisions for single family, multifamily and manufactured homes were 1.4%, 5.11%, and 8.55% respectively. The CDA 90% confidence intervals for single family, multifamily and manufactured homes are 889-914, 458-508, and 547-649, respectively. These don't overlap with the PSE annual usage therms, however it is uncertain what the confidence bounds are on the PSE usage estimates since only average usages were provided.

Electric Conditional Demand Modeling Results

Single Family

The final single family electric conditional demand specification was[14]:

For each customer i and calendar month t in 2009,

$$ADC\_KWH_{it} = \alpha + \beta_1 CENTRAL\_AC_i * CDD65_{it} + \beta_2 HPAC_i * CDD65_{it} + \beta_3 ROOMAC_i * CDD65_{it} + \beta_4 ELECRESISTANCE_i * HDD65_{it} + \beta_5 ELECFURNACE_i * HDD65_{it} + \beta_6 ELECHP_i * HDD65_{it} + \beta_7 ELECOTHER_i * HDD65_{it} + \beta_8 ELECWATERHEAT * OCCTOT_i + \beta_9 ELECSPA_i + \beta_{10} ELECPOOL_i + \beta_{11} ELECSAUNA_i + \beta_{12} FREEZER_i + \varepsilon_{it}$$

where

ADC_THERMS_{it} = Average daily kWh for customer i in month t

$HDD65_{it}$ = Average daily heating degree days (base 65) for customer i in month t

$CDD65_{it}$ = Average daily cooling degree days (base 65) for customer i in month t

$OCCTOT_i$= Total number of occupants in home for customer i

$CENTRAL\_AC_i$= 1 if customer i has a central air conditioner, 0 otherwise

$HPAC_i$= 1 if customer i has a heat pump air conditioner, 0 otherwise

$ROOMAC_i$= 1 if customer i has a room air conditioner, 0 otherwise

$ELECRESISTANCE_i$= 1 if customer i uses electric resistance (baseboards/wall) space heating, 0 otherwise

$ELECFURNACE_i$= 1 if customer i uses electric furnace space heating, 0 otherwise

$ELECHP_i$= 1 if customer i uses a heat pump for space heating, 0 otherwise

$ELECOTHER_i$= 1 if customer i uses a miscellaneous electric system for space heating, 0 otherwise

$ELECWATERHEAT_i$= 1 if customer i has electric water heating, 0 otherwise

$ELECSPA_i$ = 1 if customer i has an electrically heated spa, 0 otherwise

$ELECPOOL_i$ = 1 if customer i has an electrically heated pool, 0 otherwise

$ELECSAUNA_i$ = 1 if customer i has an electrically heated sauna, 0 otherwise

$FREEZER_i$ = 1 if customer i has a freezer, 0 otherwise

ε_{it} = Error term for customer i and month t.

[14] The extreme outlier of usage in a day was 321 kWh.

The electric single family model results are shown in Table 9.[15]

Table 9. Single Family Electric CDA Model

Variable	Parameter Estimate	t Value
Intercept	22.4863	114.33
CENTRAL_AC * CDD65	3.71949	15.42
HP_AC * CDD65	2.42745	8.01
ROOM_AC * CDD65	0.35838	0.88
RESISTANCE_HEAT * HDD65	1.37428	45.55
FURNACE_HEAT * HDD65	2.03771	54.78
HEATPUMP_HEAT * HDD65	1.66435	49.4
OTHER_HEAT * HDD65	1.00463	38.32
ELECWATERHEAT * OCCTOT	3.82295	42.17
SPA	13.01244	35.37
POOL	14.72328	8.6
SAUNA	10.42366	11.98
FREEZER	6.49546	26.7

Multifamily

The final multifamily electric conditional demand specification was identical to the single family conditional demand specification except that it excluded customers with electrically heated spas, pools and saunas[16]:

For each customer i and month t in 2009,

$$ADC\_KWH_{it} = \alpha + \beta_1 CENTRAL\_AC_i * CDD65_{it} + \beta_2 HPAC_i * CDD65_{it} + \beta_3 ROOMAC_i * CDD65_{it} + \beta_4 ELECRESISTANCE_i * HDD65_{it} + \beta_5 ELECFURNACE_i * HDD65_{it} + \beta_6 ELECHP_i * HDD65_{it} + \beta_7 ELECOTHER_i * HDD65_{it} + \beta_8 ELECWATERHEAT * OCCTOT_i + \beta_{12} FREEZER_i + \varepsilon_{it}$$

where

ADC_THERMS_{it} = Average daily kWh for customer i in month t

$HDD65_{it}$ = Average daily heating degree days (base 65) for customer i in month t

$CDD65_{it}$ = Average daily cooling degree days (base 65) for customer i in month t

$OCCTOT_i$= Total number of occupants in home for customer i

$CENTRAL\_AC_i$= 1 if customer i has a central air conditioner, 0 otherwise

$HPAC_i$= 1 if customer i has a heat pump air conditioner, 0 otherwise

$ROOMAC_i$= 1 if customer i has a room air conditioner, 0 otherwise

$ELECRESISTANCE_i$= 1 if customer i uses electric resistance (baseboards/wall) space heating, 0 otherwise

$ELECFURNACE_i$= 1 if customer i uses electric furnace space heating, 0 otherwise

[15] This model has an r-square of 0.33.
[16] The extreme outliers of usage in a day were 148 kWh.

$ELECHP_i$= 1 if customer i uses a heat pump for space heating, 0 otherwise

$ELECOTHER_i$= 1 if customer i uses a miscellaneous electric system for space heating, 0 otherwise

$ELECWATERHEAT_i$= 1 if customer i has electric water heating, 0 otherwise

$FREEZER_i$ = 1 if customer i has a freezer, 0 otherwise

ε_{it} = Error term for customer i and month t.

The multifamily model results are shown in Table 10.[17]

Table 10. Multifamily Electric CDA Model

Variable	Parameter Estimate	t-Value
Intercept	16.98743	58.68
CENTRAL_AC * CDD65	1.97042	2.02
HP_AC * CDD65	2.03173	1.93
ROOM_AC * CDD65	0.83583	1.56
RESISTANCE_HEAT * HDD65	0.49087	24.63
FURNACE_HEAT * HDD65	1.10508	18.51
HEATPUMP_HEAT * HDD65	1.28637	8.64
OTHER_HEAT * HDD65	0.6398	15.64
ELECWATERHEAT * OCCTOT	2.83378	22.17
FREEZER	3.65533	6.84

Manufactured Home

The final manufactured home electric conditional demand specification was identical to the single family conditional demand specification except that it excluded customers with electrically heated spas, pools and saunas[18]:

For each customer i and month t in 2009,

$$ADC\_KWH_{it} = \alpha + \beta_1 CENTRAL\_AC_i * CDD65_{it} + \beta_2 HPAC_i * CDD65_{it} + \beta_3 ROOMAC_i * CDD65_{it} + \beta_4 ELECRESISTANCE_i * HDD65_{it} + \beta_5 ELECFURNACE_i * HDD65_{it} + \beta_6 ELECHP_i * HDD65_{it} + \beta_7 ELECOTHER_i * HDD65_{it} + \beta_8 ELECWATERHEAT * OCCTOT_i + \beta_{12} FREEZER_i + \varepsilon_{it}$$

where

ADC_THERMS_{it} = Average daily kWh for customer i in month t

$HDD65_{it}$ = Average daily heating degree days (base 65) for customer i in month t

$CDD65_{it}$ = Average daily cooling degree days (base 65) for customer i in month t

$OCCTOT_i$= Total number of occupants in home for customer i

$CENTRAL\_AC_i$= 1 if customer i has a central air conditioner, 0 otherwise

$HPAC_i$= 1 if customer i has a heat pump air conditioner, 0 otherwise

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[17] This model has an r-square of 0.22.

[18] The extreme outliers of usage in a day were 174 kWh.

$ROOMAC_i$= 1 if customer i has a room air conditioner, 0 otherwise

$ELECRESISTANCE_i$= 1 if customer i uses electric resistance (baseboards/wall) space heating, 0 otherwise

$ELECFURNACE_i$= 1 if customer i uses electric furnace space heating, 0 otherwise

$ELECHP_i$= 1 if customer i uses a heat pump for space heating, 0 otherwise

$ELECOTHER_i$= 1 if customer i uses a miscellaneous electric system for space heating, 0 otherwise

$ELECWATERHEAT_i$= 1 if customer i has electric water heating, 0 otherwise

$FREEZER_i$ = 1 if customer i has a freezer, 0 otherwise

ε_{it} = Error term for customer i and month t.

The manufactured home model results are shown in Table 11.[19]

Table 11. Manufactured Home Electric CDA Model

Variable	Parameter Estimate	t-Value
Intercept	19.05376	25.04
CENTRAL_AC * CDD65	1.72814	1.32
HP_AC * CDD65	0.16787	0.22
ROOM_AC * CDD65	2.17465	2.94
RESISTANCE_HEAT * HDD65	1.62043	12.94
FURNACE_HEAT * HDD65	1.54556	34.68
HEATPUMP_HEAT * HDD65	1.23914	19.01
OTHER_HEAT * HDD65	1.17648	20.57
ELECWATERHEAT * OCCTOT	4.96869	18.11
FREEZER	3.1894	4.19

Most of the UECs from the three electric home type models show results that are statistically significant. Due to small sample sizes and the difficulty in disaggregating the cooling usage some of the cooling related end-uses are not statistically significant, however they have the correct signs on the coefficients.

UEC and Average Use Per Customer Results

Once the conditional demand models were estimated – the average use per customer was derived by multiplying the coefficients by their averages. For CDD, HDD independent variable interactions – TMY3 normal base 65 heating and cooling degree days were used in place of the actual 2009 averages.

The detailed average use per customer calculations for the model end-uses was calculated as follows:

$$ADC\_KWH_{it} = \alpha + \beta_1 CENTRAL\_AC_i * CDD65_{it} + \beta_2 HPAC_i * CDD65_{it} + \beta_3 ROOMAC_i * CDD65_{it} + \beta_4 ELECRESISTANCE_i * HDD65_{it} + \beta_5 ELECFURNACE_i * HDD65_{it} + {}_{+} \beta_6 ELECHP_i * HDD65_{it}$$

[19] This model has an r-square of 0.41.

$+ \beta_7 ELECOTHER_i * HDD65_{it} + \beta_8 ELECWATERHEAT * OCCTOT_i + \beta_9 ELECSPA_i + \beta_{10} ELECPOOL_i + \beta_{11} ELECSAUNA_i + \beta_{12} FREEZER_i + \varepsilon_{it}$

$AverageUsePerCustomer\_Central\ AC = \beta_1 * CENTRAL\_AC * TMY3CDD65\_AVG$

$AverageUsePerCustomer\_HeatPump\ AC = \beta_2 * HEATPUMP\_AC * TMY3CDD65\_AVG$

$AverageUsePerCustomer\_Room\ AC = \beta_3 * ROOM\_AC * TMY3CDD65\_AVG$

$AverageUsePerCustomer\_Resistance = \beta_4 * ELECRESISTANCE * TMY3HDD65\_AVG$

$AverageUsePerCustomer\_Furnace = \beta_5 * ELECFURNACE * TMY3HDD65\_AVG$

$AverageUsePerCustomer\_HeatPump\ Heat = \beta_6 * ELECHP * TMY3HDD65\_AVG$

$AverageUsePerCustomer\_Other = \beta_7 * ELECOTHER * TMY3HDD65\_AVG$

$AverageUsePerCustomer\_Waterheat = \beta_8 * ELECWATERHEAT * OCCTOT * 365$

$AverageUsePerCustomer\_Spa = \beta_9 * ELECSPA\_AVG * 365$

$AverageUsePerCustomer\_Pool = \beta_{10} * ELECPOOL\_AVG * 365$

$AverageUsePerCustomer\_Sauna = \beta_{11} * ELECSAUNA\_AVG * 365$

$AverageUsePerCustomer\_Freezer = \beta_{12} * FREEZER\_AVG * 365$

UECs for end use *e* are obtained from the average use per customer by dividing by the end use saturation,

$UEC_e = AverageUsePerCustomer_e / End\ use\ Saturation_e$

The following tables summarize the electric end-use UECs and characteristics.

Table 12 summarizes the average base 65 TMY3 heating and cooling degree averages for each end-use category. The normal TMY3 heating degree days for the final electric RES analysis sample range from 4,414 to 5,990 HDDs. The normal TMY3 cooling degree days range from 76 to 163 CDDs.

Table 12. Electric TMY3 HDD & CDD Normals

	Single Family		Multifamily		Manufactured homes	
End Use	HDD	CDD	HDD	CDD	HDD	CDD
Cooling Central	4,888	163	4,885	160	5,990	160
Cooling HP	5,126	143	4,945	157	5,298	136
Cooling Room	5,047	163	4,921	136	5,065	143
Elec Heat: Baseboard/Wall Heat	5,125	114	4,859	136	5,600	76
Elec Heat: Furnace	5,083	135	4,739	151	5,177	120
Elec Heat: HP	5,173	131	4,414	153	5,129	138
Elec Heat: Other	5,117	123	4,867	140	5,287	117
Elec Water Heat	5,143	121	4,847	140	5,247	120
Elec Spa	5,042	134				
Elec Pool	5,083	149				
Elec Sauna	5,068	131				
Elec Freezer	5,106	124	4,917	141	5,354	111

All Other End Uses[20]	5,045	129	4,857	139	5,293	113
Weighted Average Degree Days	5,045	129	4,857	139	5,293	113

Table 13 summarizes the average home heated square footage and the average number of occupants for each end-use category. The average single family, multifamily, and manufactured home sizes used in the conditional demand models are 2,099, 992, and 1,433 square feet, respectively. The average number of occupants ranges from 1.6 to 3.2.

Table 13. Electric RES Analysis Sample Characteristics

	Single Family		Multifamily		Manufactured homes	
End Use	**Sq. Ft.**	**Occupants**	**Sq. Ft.**	**Occupants**	**Sq. Ft.**	**Occupants**
Cooling Central	2,667	2.8	1,307	1.9	4,044	2.2
Cooling HP	2,428	2.8	1,651	2.0	1,496	1.6
Cooling Room	1,916	3.2	1,039	1.9	1,147	2.0
Elec Heat: Baseboard/Wall Heat	1,574	2.6	866	2.1	1,062	2.1
Elec Heat: Furnace	1,911	2.8	995	1.8	1,313	2.1
Elec Heat: HP	2,342	2.7	1,375	2.0	1,375	1.9
Elec Heat: Other	2,019	2.7	1,087	2.2	1,528	1.8
Elec Water Heat	1,885	2.5	913	2.1	1,378	2.1
Elec Spa	2,388	2.8				
Elec Pool	2,658	2.7				
Elec Sauna	2,745	2.3				
Elec Freezer	2,132	2.7	1,176	2.5	1,681	2.1
All Other End Uses	2,099	2.6	992	2.2	1,433	2.0
Weighted Characteristics	2,099	2.6	992	2.2	1,433	2.0

Table 14 summarizes the saturations and UECs for each end use.

Table 14. Electric End Use UECs

	Single Family		Multifamily		Manufactured homes	
End Use	**Saturation**	**UEC**	**Saturation**	**UEC**	**Saturation**	**UEC**
Cooling Central	8.90%	607	1.63%	315	3.15%	277
Cooling HP	7.20%	347	1.63%	320	13.39%	23
Cooling Room	3.52%	58	4.16%	114	9.45%	310
Elec Heat: Baseboard/Wall Heat	6.90%	7,043	51.37%	2,385	3.54%	9,074
Elec Heat: Furnace	3.63%	10,358	3.27%	5,237	30.71%	8,001
Elec Heat: HP	4.77%	8,610	0.36%	5,677	11.02%	6,355
Elec Heat: Other	9.09%	5,141	8.35%	3,114	21.26%	6,220
Elec Water Heat	37.14%	3,502	67.17%	2,134	79.92%	3,791
Elec Spa	12.61%	4,750				
Elec Pool	0.48%	5,374				
Elec Sauna	1.89%	3,805				
Elec Freezer	55.18%	2,371[21]	14.70%	1,334	50.79%	1,164
All Other End Uses	100.00%	8,207	100.00%	6,200	100.00%	6,955
Weighted Use Per Customer	100%	**13,334**	100%	**9,522**	100%	**15,418**

[20] The other end uses are captured in the intercept these include the base load usage of lighting, appliances, and plug loads.

[21] The single family freezer UEC is unusually high at 2,371 kWh per year. This is likely capturing some excess usage that is actually related to the other end use base load usage.

Table 15 summarizes the average use per customer, applying the associated saturations to each end-use level UEC. The miscellaneous base load usage that includes lighting, appliances, computers and other plug loads represents 45% to 65% of the total average usage per customer. Space heating usage ranges from 13% to 31% of the total average usage, while water heating usage ranges from 10% to 20% of the total average customer usage.

Table 15. Electric End Use Average Usage Per Customer

	Single Family		Multifamily		Manufactured homes	
End Use	**% Use**	**Avg. Usage**	**% Use**	**Avg. Usage**	**% Use**	**Avg. Usage**
Cooling Central	0.41%	54	0.05%	5	0.06%	9
Cooling HP	0.19%	25	0.05%	5	0.02%	3
Cooling Room	0.02%	2	0.05%	5	0.19%	29
Elec Heat: Baseboard/Wall Heat	3.64%	486	12.87%	1,225	2.09%	322
Elec Heat: Furnace	2.82%	376	1.80%	171	15.94%	2,457
Elec Heat: HP	3.08%	411	0.22%	21	4.54%	701
Elec Heat: Other	3.50%	467	2.73%	260	8.58%	1,322
Elec Water Heat	9.75%	1,301	15.05%	1,433	19.65%	3,030
Elec Spa	4.49%	599				
Elec Pool	0.19%	26				
Elec Sauna	0.54%	72				
Elec Freezer	9.81%	1,308	2.06%	196	3.83%	591
All Other End Uses	61.55%	8,207	65.12%	6,200	45.11%	6,955
Weighted Use Per Customer	100%	**13,334**	100%	**9,522**	100%	**15,418**

Table 16 compares the overall electric CDA and PRISM based usages per customer to the home type level PSE averages for 2009. Both the CDA and PRISM averages are slightly higher than the PSE averages. The PRISM estimates are considerably higher than the CDA estimates, likely due the misattribution of the space heating usage. Also, given that the CDA and PRISM estimates are weather normalized, the weighted average CDA/PRISM usages per customer are not necessarily expected to match the 2009 actuals.

Table 16. Electric UEC Calibration

Home Type	PSE Customers	PSE Total kWh	PSE kWh per customer	CDA kWh per customer[22]	PRISM kWh per customer	Raw Use kWh per customer
Single Family	626,586	7,834,797,051	12,504	13,334	14,285	13,159
Multifamily	252,715	2,180,393,890	8,628	9,522	9,708	9,504
Manufactured homes	71,398	1,055,667,957	14,786	15,418	17,115	15,733
All Residential	950,699	11,070,858,898	11,645	12,478	13,281	12,381

[22] The 90% confidence level CDA relative precisions for single family, multifamily and manufactured homes were 1.93%, 3.15%, and 4.41% respectively. The CDA 90% confidence intervals for single family, multifamily and manufactured homes are 13,076-13,591, 9,222-9,822, and 14,738-16,098, respectively. It is uncertain what the confidence bounds are on the PSE usage estimates since only average usages were provided.