**EXHIBIT NO. ___(EMM-6)**
**DOCKET NO. _____________**
**2005 POWER COST ONLY RATE CASE**
**WITNESS: ERIC M. MARKELL**

**BEFORE THE**
**WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION**

| | |
|---|---|
| **WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION,**<br><br>**Complainant,**<br><br>**v.**<br><br>**PUGET SOUND ENERGY, INC.,**<br><br>**Respondent.** | **Docket No. UE-_______** |

**FIFTH EXHIBIT TO THE PREFILED DIRECT TESTIMONY OF**
**ERIC M. MARKELL (NONCONFIDENTIAL)**
**ON BEHALF OF PUGET SOUND ENERGY, INC.**

**JUNE 7, 2005**

PUGET SOUND ENERGY

April 29, 2005

Ms. Carole J. Washburn, Executive Secretary
Washington Utilities and Transportation Commission
P.O. Box 47250
Olympia, Washington 98504-7250

Re: Puget Sound Energy's 2005 Least Cost Plan

Dear Ms. Washburn,

Enclosed for filing, please find twelve copies of Puget Sound Energy's ("PSE" or "the Company') Least Cost Plan ("LCP"). This document presents information and analysis to comply with both the electric utility least cost planning requirements under WAC 480-100-238 and the natural gas utility least cost planning requirements under WAC 480-90-238.

Consultation with WUTC Staff and public participation were important parts of this planning process. Numerous meetings were held with Commission Staff to discuss the plan, including details of the analytical approaches that support the action plan. In addition, the Company received extensive feedback from its Least Cost Planning Advisory Group ("LCPAG"). Many of those comments and suggestions were incorporated into the LCP.

PSE looks forward to making a formal presentation of the Company's 2005 LCP to the Commission and receiving feedback from the Commission as soon as practical, to help the Company continue to improve and refine its resource planning process.

Sincerely,

Karl R. Karzmar
Director, Regulatory Relations

Attachments (12 paper copies & 8 cds)

# LEAST COST PLAN

APRIL 2005

PSE PUGET SOUND ENERGY
www.pse.com

# PREFACE

Puget Sound Energy's (PSE) 2005 Least Cost Plan is organized into 18 chapters and 11 appendices. To assist readers with navigating and understanding the 2005 LCP, this Preface discusses the document structure and concludes with brief chapter and appendix summaries.

*Structure*

As shown in Exhibit P-1, the Least Cost Plan chapters are sequentially organized into five categories as follows:

- <u>Summary and Introduction</u> – Chapters I through III contain summary plan information and discuss regulatory requirements and the nature of least cost planning for PSE.

- <u>Joint Gas and Electric Data and Issues</u> – Chapters IV through VIII set forth input data and background issues for the electric and gas analyses. Changes in the marketplace and lessons learned since the 2003 LCP are also discussed here.

- <u>Detailed Data and Analysis</u> – The long-term load and resource outlook, analysis, results, and strategies are set forth in Chapters IX through XI for electric resources, and in Chapters XII through XIV for natural gas resources.

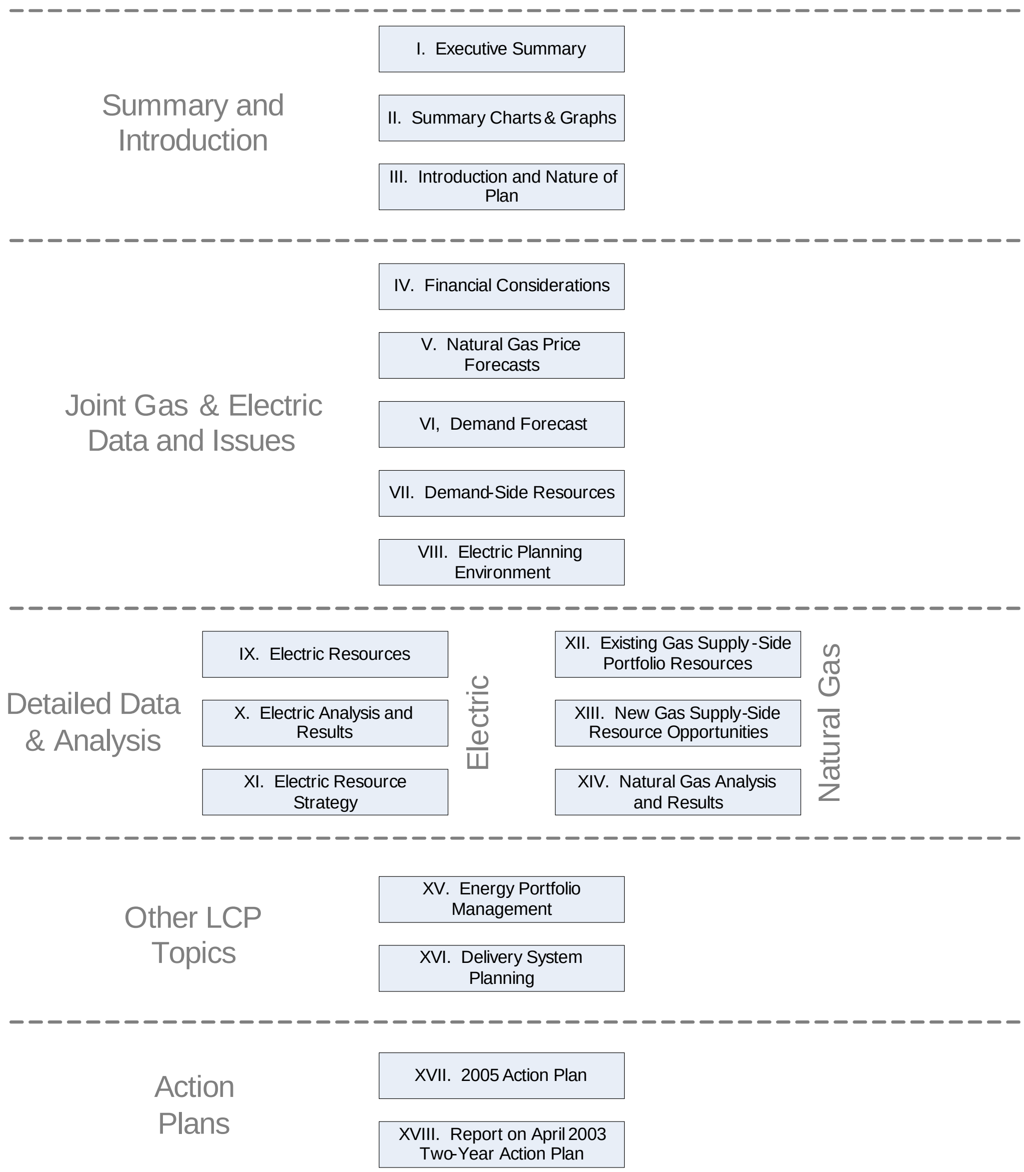
- <u>Other Least Cost Plan Topics</u> – Certain subjects have been added to PSE's Least Cost Plan over time in response to regulatory and stakeholder input. Chapters XV and XVI cover energy portfolio management and delivery system planning, respectively.

- <u>Action Plans</u> – Wrapping up the Least Cost Plan, Chapter XVII presents PSE's two-year action plan for electric and natural gas, and Chapter XVIII updates progress on action plan items from the 2003 Least Cost Plan.

As shown, the document is structured sequentially – *data* leads to *analysis,* then to *analytical results,* and finally to *actions*. Therefore, readers with limited time to review the plan may wish to examine key chapters that occur later in the document, such as the concluding chapters of the electric and gas analyses (Chapters XI and XIV) and the action plan (Chapter XVII).

EXHIBIT P-1

## Least Cost Plan Document Organization



*Chapter Summaries*

**Chapter I – Executive Summary**

Summarizes the plan and provides PSE’s electric and gas resource strategies.

**Chapter II – Summary Charts and Graphs**

Provides a graphical overview of PSE’s existing electric and gas resource situations, and its strategy for addressing needs.

**Chapter III – Introduction and Nature of Plan**

Covers regulatory compliance, stakeholder interaction and the use and relevance of the plan.

**Chapter IV – Financial Situation**

Discusses the key corporate financial considerations for least cost planning.

**Chapter V – Natural Gas Price Forecasts**

Discusses the current natural gas market and the gas price forecasts used in this Least Cost Plan.

**Chapter VI – Demand Forecasting**

Explains PSE’s load forecasting methodology, its key forecast assumptions, and provides electric and gas load and customer forecasts.

**Chapter VII – Demand-Side Resources**

Sets forth the evaluation methodology and results for new energy efficiency, fuel conversion, and demand response resources.

**Chapter VIII – Electric Planning Environment**

Discusses the key issues that impact PSE's electric resource strategy including transmission, environmental initiatives, and demand-side resources implementation issues.

**Chapter IX – Electric Resources**

Provides a recap of PSE’s existing electric supply resources, discusses the expiration of certain resources during the planning period, and presents PSE’s long-term need for resources.

**Chapter X – Electric Analysis and Results**

Presents the analytical methodology, new resource alternatives, and analytical results.

**Chapter XI – Electric Resource Strategy**

Develops the electric resource strategy based upon the analytical results and consideration of key issues.

**Chapter XII – Existing Gas Supply-Side Portfolio Resources**

Presents PSE's existing gas resources, including supply, pipeline capacity, and storage, and provides an overview of the Company's resource need.

**Chapter XIII – New Gas Supply-Side Resource Opportunities**

Identifies new supply-side resource opportunities available to PSE, including supply, storage, transport, and on-system storage.

**Chapter XIV – Natural Gas Analysis and Results**

Results of the gas optimization and Monte Carlo analysis and conclusions are presented in this Chapter.

**Chapter XV – Energy Portfolio Management**

Discusses PSE's management of the electric and gas portfolio, including risk management strategies.

**Chapter XVI – Delivery System Planning**

Provides an overview of PSE's gas and electric delivery systems and the key considerations and benefits of the distribution planning process.

**Chapter XVII – 2005 Action Plan**

Presents the two-year action plan for implementing the gas and electric resource strategies.

**Chapter XVIII – Report on April 2003 Two Year Action Plan**

Updates PSE's two-year action plan from the 2003 Least Cost Plan.

*Appendix Summaries*

**Appendix A – Stakeholder Interaction**

Summarizes the public involvement process involved in this Least Cost Plan including Least Cost Plan Advisory Group and Conservation Resource Advisory Group meetings.

**Appendix B – Demand-Side Resources**

Provides the detailed data and analytical results used to produce the demand-side resource potential estimates presented in Chapter VII. [Appendix B is over 200 pages and therefore is not included in published copies of the plan. Interested readers can either contact PSE directly for a printed copy or visit www.pse.com to view the document.]

**Appendix C – AURORA Dispatch Model**

Provides a description of the AURORA electric simulation model.

**Appendix D – Wind Integration**

Discusses issues and costs for integrating wind resources into the resource portfolio.

**Appendix E – RFP Process and Results**

Summarizes the process and results for the competitive acquisition process that followed the 2003 Least Cost Plan.

**Appendix F – 2003 Greenhouse Gas Emissions Inventory**

Provides emissions data for PSE's existing electric generating resources.

**Appendix G – Electric Results**

Provides detailed electric model results that support the analyses presented in Chapter X.

**Appendix H – Gas Models**

Describes the Sendout and Vector Gas simulation models used for the natural gas analysis and describes the uncertainty factors used for Vector Gas.

**Appendix I – Gas Planning Standard**

Presents the analysis supporting the natural gas planning standard.

**Appendix J – Gas Results**

Provides detailed natural gas model results that support the analyses presented in Chapter XIV.

**Appendix K – Description of Load Forecasting Models**

Describes the econometric models used to produce the demand forecast presented in Chapter VI.

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***Chapter X, Electric Analysis and Results***

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***Chapter XI, Electric Resource Strategy and Action Plan***



***Chapter XII, Existing Gas Supply-Side Portfolio Resources***

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***Chapter XIII, New Gas Supply-Side Resource Opportunities***



***Chapter XIV, Natural Gas Analysis and Results***

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# I. EXECUTIVE SUMMARY

## A. Introduction

Puget Sound Energy (PSE) establishes and periodically updates a Least Cost Plan as part of its long-term resource acquisition and management strategy development. This document satisfies Washington state requirements regarding least cost planning as described in WAC 480-100-238 and WAC 480-90-238 and provides an update of the results of the electric and gas Least Cost Plan analysis process and long-term resource strategic direction. PSE believes its Least Cost Plan meets applicable statutory requirements and seeks a letter from the Washington Utilities and Transportation Commission (WUTC) accepting this Least Cost Plan filing.

*Acknowledgement*

PSE maintains its commitment to actively encourage public involvement in this process. As of April 29, 2005, PSE has hosted ten formal Least Cost Plan meetings. In addition, dozens of informal meetings and communications have taken place. PSE would like to thank the members of the Least Cost Plan Advisory Group for their continuing commitment to this process.

## B. Electric Least Cost Plan

### B.1. Overview and Key Findings

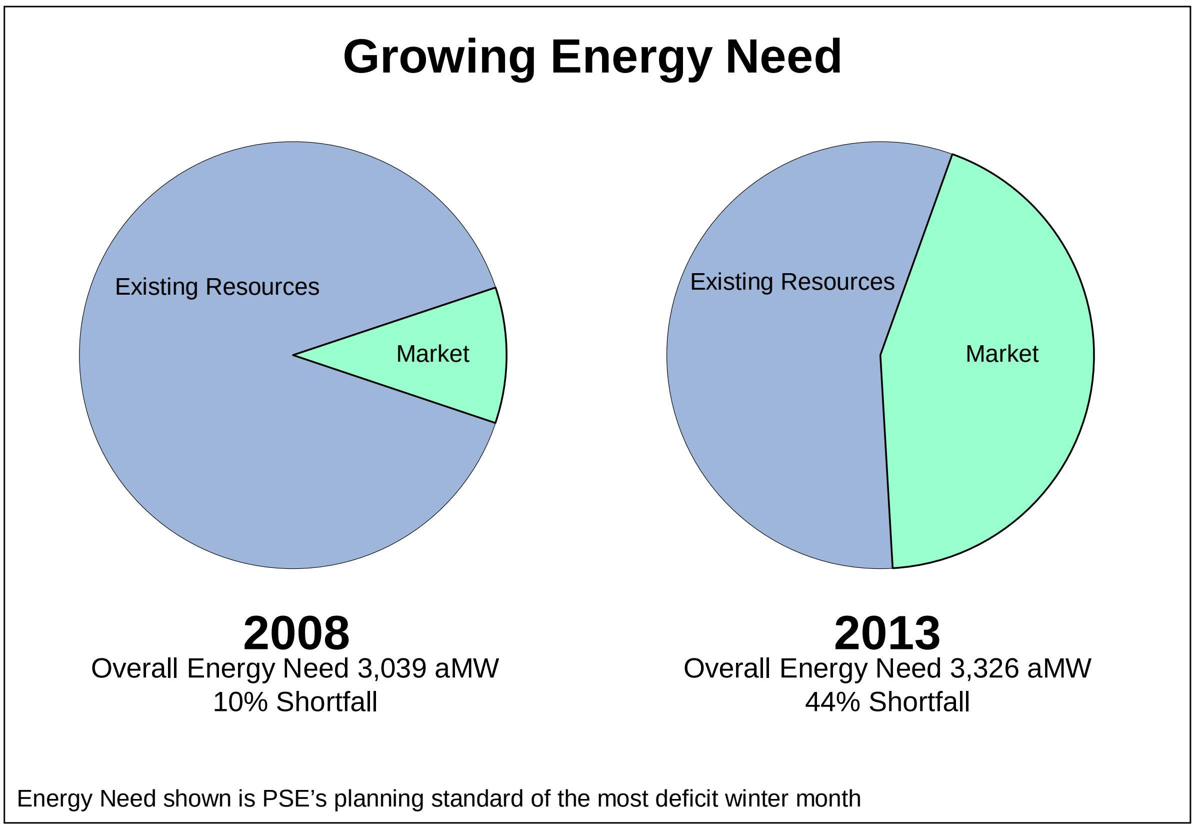
This Least Cost Plan emphasizes PSE's commitment to developing an executable electric resource acquisition strategy. As detailed in this document, PSE has undertaken a thorough least cost analysis including all of the traditional considerations of demand, existing resources, new generation and demand resource alternatives, and the risks and uncertainties for each.

As part of PSE's focus on developing an executable strategy, this Plan also includes an expanded identification of key real-world challenges and uncertainties to electric resource acquisition. Key issues include timely transmission availability and costs, environmental initiatives such as potential greenhouse gas regulation and taxation, natural gas market changes, and corporate financial and credit considerations. By speaking plainly about such issues, PSE seeks to educate stakeholders about the "realities on the ground" that may well preclude PSE and the region from acquisition of the theoretical least cost resources suggested by the analysis.

*Energy Resource Situation*

As shown in Exhibit I-1, absent acquisition of new long-term firm resources, PSE is facing a growing reliance on short-term market purchases.

**Exhibit I-1**

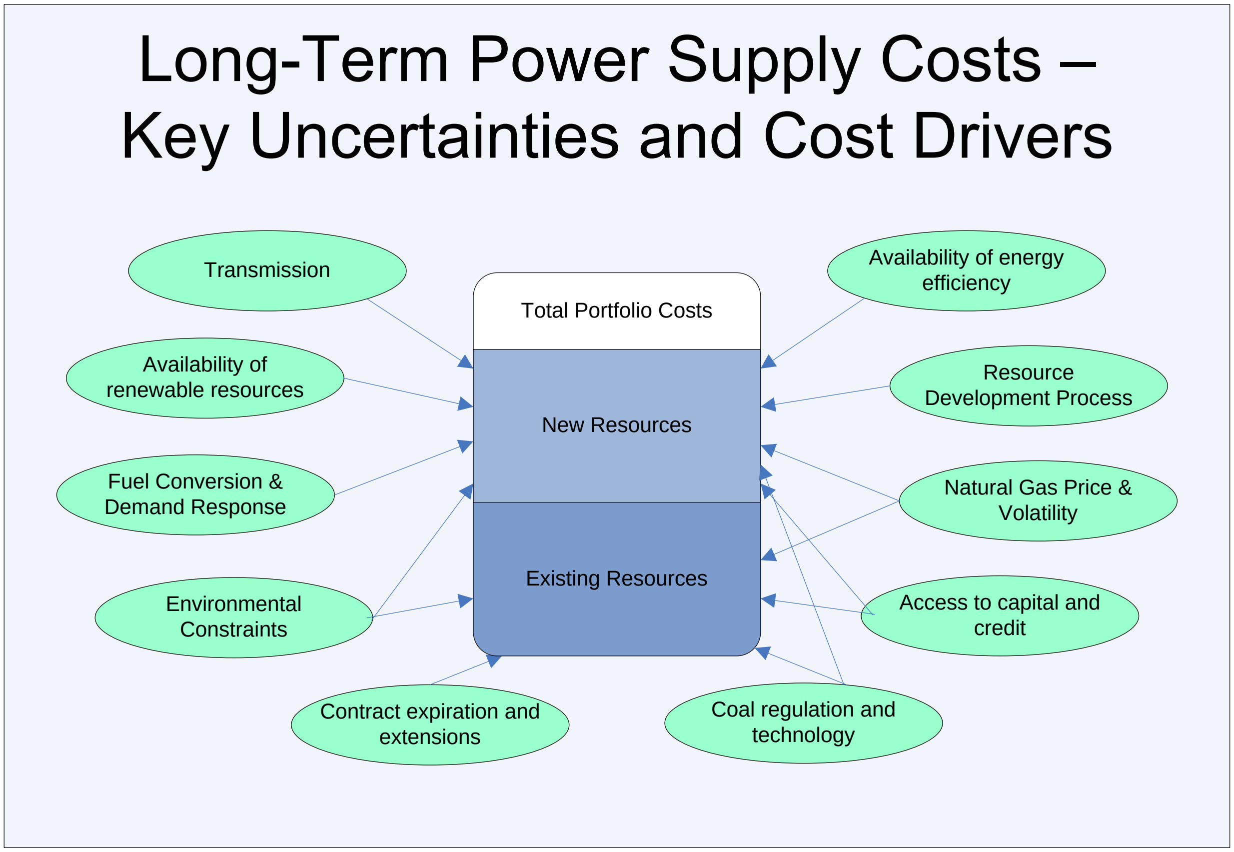



While PSE has a moderate near-term need for new electric resources, several existing power purchase contracts expire between 2011 and 2012, raising expected energy need to approximately 1500 aMW. Developing an understanding of resource options to meet this growing shortfall is the objective of this plan.

*Resource Acquisition Challenges*

This Least Cost Plan confirms the strategy developed in the 2003 Least Cost Plan to meet needs with a diverse portfolio of demand and supply resources. However, PSE is acutely aware that public policy initiatives, legacy institutional roles, emerging market forces, and commercial considerations will challenge the Company's ability to achieve an economically optimal mix. Exhibit I-2 illustrates the key uncertainties that impact PSE's long-term power costs and resource acquisition strategy.

**Exhibit I-2**




The following summaries provide detail about each of these key issues.

**Natural Gas Price and Volatility:** Since 2003, the natural gas market has experienced a fundamental upward price shift. A tighter North American supply situation, coupled with global energy demand growth exceeding productive capacity, puts upward pressure on natural gas prices. The prospects for future gas price moderation depend upon potential supply increases from expanded liquefied natural gas import facilities and the construction of new pipelines to access the McKenzie Delta and Alaska supply basins. Both of these supply solutions face significant political and environmental challenges.

Tighter supplies have also led to increased price volatility and to the need for expanded price risk management. Higher prices place greater financial burdens and credit requirements on market participants.

**Transmission:** The key to establishing access to a diverse range of resources is to address uncertainties about the cost and availability of transmission. Currently, the regional transmission system is heavily constrained in its ability to move new power resources from likely new supply locations such as eastern Washington and Montana to PSE's service area.

Efforts to establish a cooperative regional transmission planning and development entity have encountered objections related to, among other reasons, cost and control. Currently, there is no clear path or timetable for resolving diverse regional views about transmission or for constructing needed transmission infrastructure.

**Environmental Constraints:** All resource types face environmental siting and operational issues, including those that are generally considered environmentally desirable. Potential future regulation of emissions adds cost and operational uncertainty to existing and potential resources, especially coal-fueled generation.

**Energy Efficiency:** PSE has a long and successful history of implementing energy efficiency. The Company's current resource strategy continues to take an aggressive approach to conservation acquisition. However, energy efficiency is a limited resource and many of the most cost-effective opportunities are found in retrofitting older end-uses. As new building codes and equipment standards have emphasized energy efficiency, PSE's overall use per customer is dropping and the pool of inefficient end-uses is decreasing over time. New technology is expected to provide some new opportunities.

**Fuel Conversion and Demand Response:** PSE conducted expanded evaluations of fuel conversion and demand response potential for this Least Cost Plan. However, while energy efficiency is a proven resource with established regulatory mechanisms for cost recovery, implementation processes, and evaluation methodology, such processes are not established for fuel conversion and demand response. The development of such processes will require collaborative discussions with regulators and key stakeholders.

**Contract Expirations and Extensions:** A large driver of PSE's rapidly growing resource need over 2011-2012 is the expiration of power purchase contracts with three large natural gas cogeneration projects built in the early 1990s. Over time, generation technology has advanced, making some of these resources relatively inefficient compared to new plants. The approaching expiration of these contracts may provide an opportunity for renegotiated terms, acquisition at attractive prices or replacement with lower-cost resources.

Over this same time period, PSE is also facing the expiration of low-cost hydroelectric purchase contracts with a mid-Columbia Public Utility District. PSE is pursuing contract renewal discussions.

**Renewable Resources:** Several years of dialogue with market developers and two formal rounds of resource solicitation have confirmed that viable renewable energy projects with available transmission are limited in number, and relatively small in size. While the Company has successfully acquired two new wind resources, additional wind projects will likely encounter significant transmission constraints and higher costs.

The year-to-year uncertainty of continuing federal production tax credits has greatly complicated project development and financing, slowing the construction of wind projects nationwide. Currently, wind projects starting production in calendar year 2005 are eligible for 10 years of tax credits but, as of the date of this report, tax credits have not been renewed for projects starting in 2006 and beyond. As a result, project developers cannot commit to projects with uncertain economics, and manufacturers cannot commit to increased production with uncertain future demand.

**Coal Regulation and Technology:** The potential regulation of greenhouse gasses and other emissions impacts coal generation costs and availability to a greater degree than other resources. Promising new technology, such as integrated gasification combined cycle (IGCC), has the potential to effectively address most environmental concerns. IGCC technology cost, performance, and vendor warranties are improving. Constructing an IGCC plant near PSE's service area would greatly reduce the transmission construction challenge.

**Resource Development Process:** Potential new resources face a gauntlet of local, state, and federal siting and permitting processes which often are misaligned. Resources that require new transmission facilities face combined transmission and resource development risks.

**Access to Capital and Credit:** An increasingly challenging investment environment means that corporate financial strategy and corporate resource strategy are inter-dependent. PSE considers credit requirements, imputed debt costs and financing requirements when making future resource decisions.

*Meeting the Challenges*

The resource acquisition strategy has two key objectives: 1) acquiring the least cost mix of readily available resources to meet near-term needs and 2) addressing uncertainties and barriers to acquiring the least cost mix of resources for the long term. PSE will use multiple tactics in order to meet the challenges enumerated above and to acquire resources to serve its customers at the least cost. PSE's actions will include the following:

- Establish and implement new programs to achieve energy efficiency goals.
- Acquire cost-effective renewable resources to achieve PSE's target of 10 percent by 2013.
- Initiate competitive acquisition process (RFP) for new long-term resources.
- Initiate competitive acquisition process for bridging power purchase agreements.
- Evaluate self-build and joint ownership opportunities.
- Initiate discussions regarding contract extensions for existing resources.
- Explore feasibility and pursue partnering opportunities and transmission alternatives for remote-located coal and renewable generation.
- Work to be a constructive voice in the federal, regional, and state dialogue about transmission investment, operation, and control.

In the near-term, PSE expects to select resources from a mix of energy efficiency, small to medium-scale local renewable generation, wind generation or project expansion (provided reasonably-priced transmission solutions are available), ownership or contract shares of existing resources, and possibly natural gas-fueled resources currently existing or under development. Recognizing that near-term resource availability may be limited and that market purchases are expected to be competitive with project-specific resources, PSE may execute a limited number of "power bridging agreements" to cover a portion of the shortfall until long-term resources are available.

For the long term, PSE expects to select resources from a mix of energy efficiency, renewable energy resources, natural gas-fueled resources, and new conventional or IGCC coal projects.

### B.2. Electric Resource Need

*Accomplishments since 2003 Least Cost Plan*

A number of strategies identified in the April 2003 Least Cost Plan have been successfully implemented. This was accomplished through a variety of actions, including the competitive solicitation and resource acquisition process. As shown in Exhibit I-3 below, PSE has reduced its resource needs through the acquisition of conservation, wind energy and generating resources.

**Exhibit I-3**

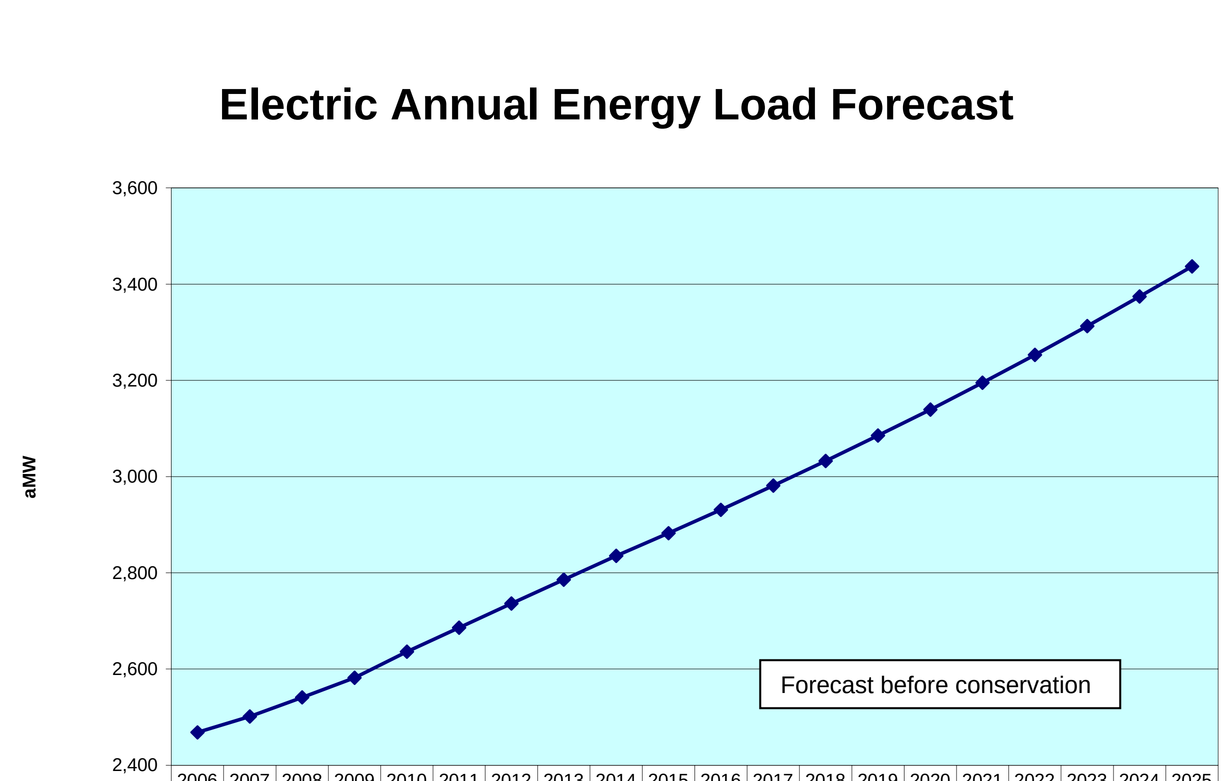
| **ACQUISITIONS SINCE APRIL 2003 LEAST COST PLAN** | | |
|---|---|---|
| **PROJECT** | **CAPACITY** | **ENERGY** |
| Frederickson 1 Combustion Turbine | 125 MW | 123 aMW |
| Hopkins Ridge Wind | 150 MW | 52 aMW |
| Wild Horse Wind | 229 MW | 77 aMW |
| APS Purchase Contract | 85 MW | 85 aMW |
| Ormat Recovered Energy | 5 MW | 5 aMW |
| Colstrip Turbine Upgrade | 28 MW | 23 aMW |
| Energy Efficiency[1] | 79 MW | 38 aMW |
| TOTAL | 701 MW | 403 aMW |
| 1. Savings for 2003-04 calendar years | | |

Improvements to PSE's in-house ability to analyze and acquire conservation and generating resources have contributed significantly to these accomplishments.

*Future Demand Forecast*

While individual electric use per customer continues to decline, demand as a whole is forecast to increase due to population growth in the service territory. PSE forecasts that the electric load, absent conservation, will grow at 1.8 percent annually over the 20-year planning period. This equates to a load growth of approximately 970 average annual megawatts. Exhibit I-4 shows PSE's annual energy load forecast through the year 2025.

**Exhibit I-4**




| | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Ann Avg | 2,468 | 2,501 | 2,541 | 2,582 | 2,636 | 2,686 | 2,736 | 2,786 | 2,835 | 2,882 | 2,931 | 2,981 | 3,033 | 3,085 | 3,139 | 3,195 | 3,253 | 3,313 | 3,374 | 3,437 |

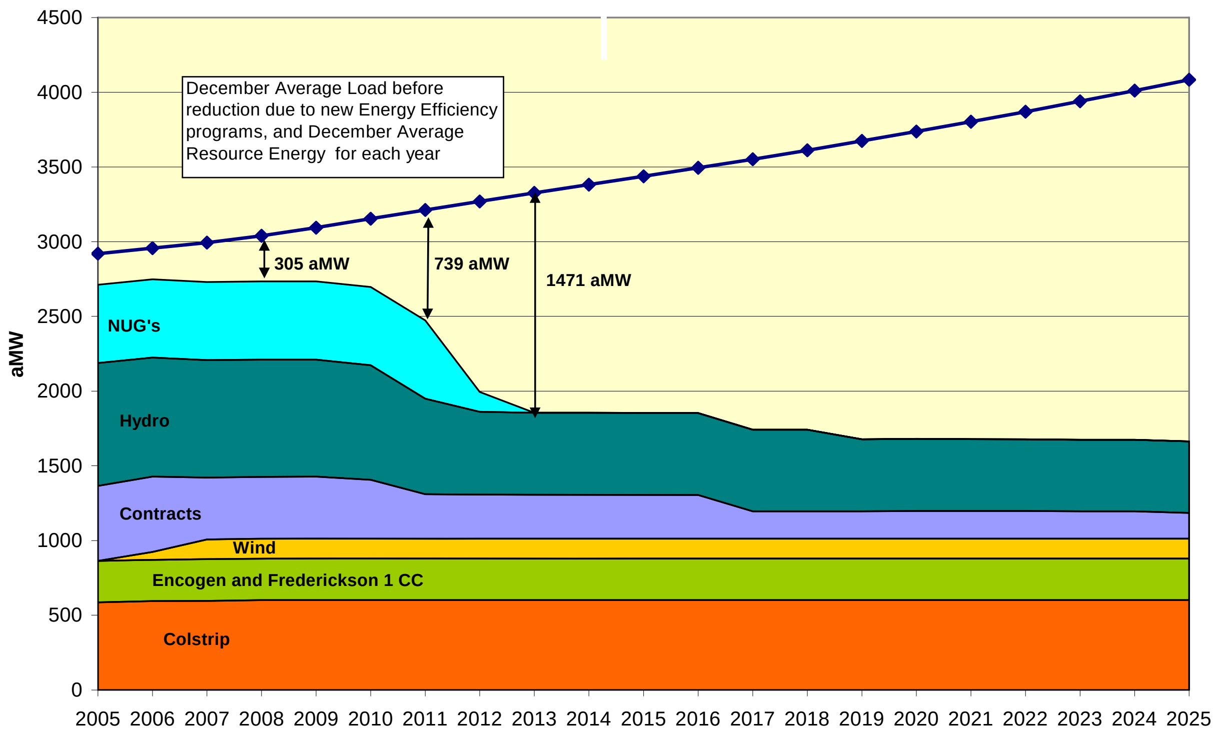
*Resource Need*

Even more than load growth, expiring power purchase agreements create a need for new resources. Between 2011 and 2013, three major non-utility generator contracts will expire, removing 523 aMW from PSE's portfolio. At the same time, some of PSE's long-term purchase agreements with the mid-Columbia Public Utility Districts (PUDs) also expire. Negotiating extensions of the mid-Columbia purchase contracts is a priority in this plan in order to ensure continuing access to these valuable resources.

In its 2003 Least Cost Plan analysis, PSE conducted extensive quantitative studies of various electric resource planning standards. Based upon those studies, PSE calculates its energy need to be the resources required to meet average monthly load during the heating season month with the greatest demand.

As shown in Exhibit I-5, PSE has a moderate near-term need, and a much greater need in the future, primarily due to the expiration of significant resource contracts between 2011-2012. As a result, the resource need increases dramatically within the time frame of the plan.

**Exhibit I-5**
**Long Run Load-Resource Balance**




### B.3. Electric Planning Considerations

The 2005 Least Cost Plan identifies several major electric industry and Company issues that create risk and uncertainty related to resource decisions. Much of the analysis and forecasting used to develop this plan was created to explore the impact of these issues. Key planning considerations were identified in section B.1 and include regional transmission system capacity, environmental issues, corporate financial condition and financial market uncertainties, access to capital and credit, natural gas prices and volatility, and the development process for new resources.

### B.4. Electric Resource Options: Demand Side and Generating Resources

*Demand Side Resources*

As part of the 2005 Least Cost Plan development process, PSE hired Quantec, LLC, a leading demand-side technical consultant, to develop updated supply potential estimates for energy efficiency, fuel conversion, and demand management. The 20-year estimate of cost-effective conservation, 13 aMW per year, is similar to the value from the 2003 Least Cost Plan and is consistent with the regional estimate by the Northwest Power and Conservation Council. The new estimate was informed by data from PSE's residential end-use survey completed in 2004.

Quantec's fuel conversion supply analysis indicates that much of the current cost-effective fuel conversion is taking place without a utility incentive program driven by economic considerations. The 20-year estimate of residential fuel conversion potential is 3 aMW per year. The electric savings and costs for a potential utility fuel conversion program are modeled as an energy efficiency measure in the electric analytics. The additional gas usage for converted end-uses is modeled as a load increase in the gas analytics.

The demand management analysis looked at the cost and resource contribution of a variety of voluntary (incentive-based) and utility-controlled programs. Quantec's analysis was based upon PSE's customer data and the program performance history of other utilities. While the analysis indicates some potentially cost-effective resources, there remain many program design and regulatory issues regarding demand management. PSE views the Quantec analysis as a technical base for further discussions.

*Generating Resource Alternatives*

The generating resources modeled in the Least Cost Plan represent generic resources that could reasonably be included in PSE's portfolio. Supply side resources include natural gas-fueled combined cycle combustion turbines (CCCTs); coal-fuel thermal plants; renewable energy resources including wind and biomass; power bridging agreements and a winter call option contract to cover the winter peak energy needs.

A primary source for generic generating resource information was the U.S. Department of Energy's, Energy Information Agency's (EIA) table of "Cost and Performance Characteristics of New Central Station Electricity Generating Technologies" from the Annual Energy Outlook, 2004. The EIA provides basic information about plant characteristics at the national level, such as plant capacity, heat rates, capital costs, variable costs and fixed costs. This information was augmented with cost data gleaned from PSE's recent resource acquisition process for capital costs, power transmission development and gas fuel transportation, among others. PSE evaluated but did not model emerging technologies for which the costs and performance are less certain because the data would not support an accurate cost tradeoff analysis.

While generic plant information is available from a number of sources including the Energy Information Administration and the Northwest Power and Conservation Council, general industry transmission information is much harder to develop. The nature of the transmission system requires a specific resource location and a transmission study to develop the scope and costs of transmission from that specific location to the customer base. PSE produced two transmission cost scenarios - one assuming regional pricing (wherein the costs for transmission system upgrades are recovered through rolled-in rates charged to all system users) and one assuming direct participant funding (wherein the costs for necessary transmission upgrades are added to the cost of the resource regardless of the regional benefits to the transmission system).

### B.5. Electric Analytic Approach

*Improvements from Previous Plan*

PSE's 2003 Least Cost Plan introduced new modeling tools and established a solid analytical base for this 2005 plan. Like the 2003 plan, this plan developed its analytical approach to fully explore (i) demand and factors influencing demand, (ii) supply options, (iii) natural gas and electric market prices and volatility, (iv) demand-side and renewable generating resources, and (v) mixes of potential resources in integrated supply and demand portfolios. PSE continues to develop its resource strategy using updated versions of the same process tools: AURORA, the Portfolio Screening Model and the Conservation Screening Model.

For this plan, one of the most important improvements for the quantitative analysis is the inclusion of scenarios. A scenario is a consistent set of data assumptions to define a specific future. The Least Cost Plan scenarios are designed to answer "what if" questions regarding the key issues.

The shift to scenarios reflects current uncertainty about energy policy, environmental issues and the macro economy. In the 2003 Least Cost Plan, PSE analyzed uncertainty using Monte Carlo analyses that covered a range of possible prices, shaped around a mean or expected level. Monte Carlo uncertainty is based on quantifiable variability found in historical statistics for which a distribution can be derived. The 2005 Least Cost Plan continues the Monte Carlo analysis and adds an additional level of uncertainty analysis with scenarios.

One important aspect to scenario analysis is that it takes a holistic approach to the important variables. For example, rather than looking only at the impact of an exogenous CO2 charge on portfolio resource selection, the process includes a long-term analysis for power prices based on optimal regional new resource construction which takes the charge into account.

*Scenario Analysis*

In order to meet the complex and varying range of potential outcomes related to future demand and capacity, PSE developed six scenarios to explore the uncertainties around a number of key issues. The six scenarios include varying assumptions regarding gas price forecasts, carbon emission costs, transmission availability and costs, load forecasts, and renewable energy policy.

The scenario assumptions were first used to develop regional electric price forecasts using the AURORA electric market simulation model for the western region. PSE selected gas price scenarios from CERA that were consistent with the overall scenario description. The energy price forecasts and detailed scenario descriptions are detailed in the plan.

*Portfolio Performance*

PSE analyzed resource options against the six scenarios to determine portfolio performance across the range of futures. PSE used its Portfolio Screening Model to examine the present value costs and the cost variability of each portfolio against a wide array of anticipated market and technical developments.

### B.6. Electric Findings: Results of Analysis

This Least Cost Plan concludes that PSE should acquire a diverse mix of generating and demand-side resources. Key analytical findings include:

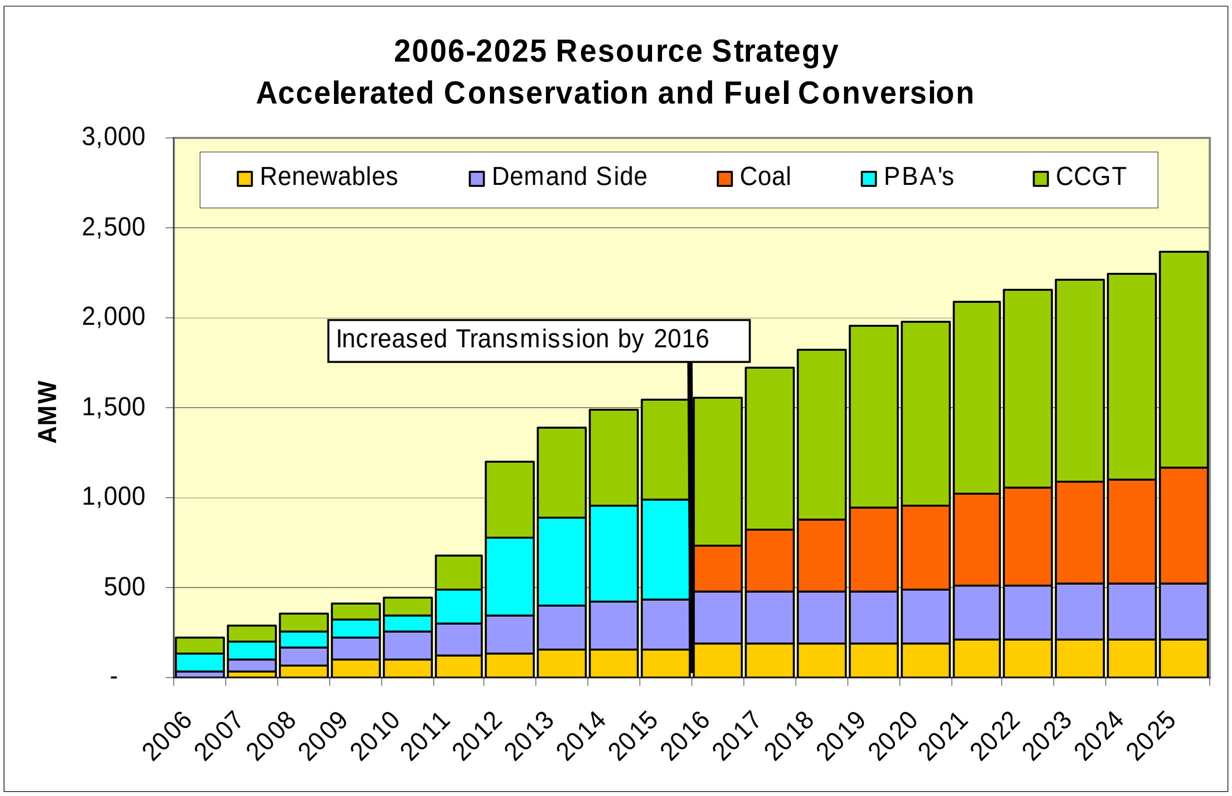
- With a regional transmission solution, portfolios with coal resources reduce portfolio costs.
- Absent a regional transmission solution, portfolio costs are generally higher but, despite high transmission costs, portfolios with coal resources remain cost competitive in many scenarios.
- Scenarios with quantified carbon dioxide emissions costs cause portfolios that include gas resources to be cost-competitive with portfolios that include coal resources.
- Accelerated energy efficiency provides more benefit to the portfolio than a constant rate of energy efficiency.
- Considering all scenarios, the lowest risk (but not necessarily the lowest cost) incremental portfolio is the 15 percent Renewable and 50/50 Coal & Gas.
- Under current market price assumptions, near-term power bridging agreements reduce portfolio cost compared to gas resources. However, the market availability of power bridging agreements needs to be confirmed.
- Under the Least Cost Plan assumptions, early fuel conversion could provide more benefit to the portfolio than normal fuel conversion.
- Overall, considering both cost and risk, the analysis supports the selection of a portfolio including accelerated energy efficiency, early fuel conversion, 10 percent renewable generation, and 50/50 gas and coal. This portfolio performs well across all the scenarios.

The least cost portfolio mix varies across scenarios, reflecting the differing assumptions behind each potential range of outcomes. As the scenario changes, and thus assumptions such as transmission capacity, so does the most advantageous plan for operating in that environment. By examining a range of scenarios, the plan's analysis yields a portfolio mix that is able to accommodate a variety of scenarios.

Transmission availability and cost is a significant factor, with high transmission costs favoring local natural gas generation and low transmission costs allowing for a wider range of generation options. Potential carbon emissions costs also factor into the long-term difference between gas and coal resources, but have a lesser impact than transmission considerations.

Exhibit I-6 shows how the long-term energy need could be theoretically filled in a least cost manner given the assumptions described throughout this Least Cost Plan. The chart shows the least cost mix of additional resources to meet the planning standard under the base energy forecast. The portfolio includes renewable resource additions to achieve 10 percent of load by 2013. Also included are accelerated energy efficiency and early fuel conversion.

**Exhibit I-6**




### C. Natural Gas Least Cost Plan

Overview and Key Findings

PSE's gas resource planning generally focuses on ensuring the Company can meet the needs of our firm gas sales customers in a way that minimizes costs over the long-term. By the

2007/08 winter heating season, PSE's capacity will fall short of its design-peak day demand forecast. Thus, PSE is entering a period where the Company will need to acquire resources to meet the growing needs of its customers. The following summarizes key findings from this plan.

### C.1. Adequacy of Gas Supply

Physical gas supply is expected to be adequate to meet growing demand in the Pacific Northwest and North America generally. To meet growing demands for end-use and generation fuel, many industry experts predict imports of liquefied natural gas (LNG) will be needed, and will be developed, on a nation-wide basis to allow supply to keep pace with growing demand. Additionally, many experts anticipate that a pipeline to bring Alaskan gas into the North American market will also be completed within the Company's planning period. While there does appear to be sufficient supply to meet growing demands, long-term gas prices are expected to be higher than prior long-term forecasts, and prices are expected to continue to be quite volatile. Higher prices provide the financial incentive for development of new North American sources and imported LNG.

### C.2. Access to Upstream Canadian Supply

PSE currently acquires roughly 40 percent of its gas supply on Northwest Pipeline via the Sumas, Wa. interconnect point at the Canadian border, though that ratio could increase in the future. There has generally been a liquid market for natural gas at the Sumas, Wa. market hub. However, capacity held by Canadian marketers and producers to move gas south in British Columbia from the producing fields to the market on Duke Energy Gas Transmission (Westcoast Pipeline) has been diminishing. This decline in contracted capacity is expected to continue as producers seek more flexibility in order to move gas supplies east to the very liquid Alberta (AECO) market from the production zone.

As a result, PSE will consider acquiring additional long-term transportation capacity on upstream pipelines to ensure access to firm supplies at liquid markets. Acquiring additional capacity on Westcoast Pipeline from Station 2 in Northeast British Columbia to access British Columbia gas supply basins is an example. Additionally, PSE also has an opportunity to diversify its supply risk by accessing Alberta gas (AECO) supplies via Terasen Gas's Southern Crossing Pipeline. This pipeline can move gas from AECO via TransCanada's Alberta Natural Gas (ANG) and Nova systems (See Gas Resources and Transportation Map in Chapter II.).

While this alternative is not currently a least cost solution, it may be an important means of enhancing geographical diversity and minimizing risk.

### C.3. Load-Resource Balance

During this planning cycle, PSE re-examined both its loads and resources to update its long-term projected load-resource balance position. The design-day planning criterion was updated from 51 to 52 heating degree days[1] (from 14 degrees Fahrenheit to 13 degrees Fahrenheit) and design day demand forecasting methodology was tested and modified. PSE also updated assumptions on availability of resources to meet its customers' firm demand under design day conditions. Based on this analysis, PSE's long-term gas supply portfolio is projected to become deficit by the 2007-08 heating season.

### C.4. Analytical Methods

PSE has enhanced its ability to model gas resources for long-term planning and long-term gas resource acquisition activities since the 2003 Least Cost Plan and Update were filed. The Company acquired SENDOUT® and VectorGas™ from New Energy Associates in August of 2004. SENDOUT® is a widely used model that helps identify the long-term least cost combination of resources to meet stated loads using a linear programming model. The model determines the optimal portfolio of resources that will minimize costs over the planning horizon, based on a set of assumptions regarding resource alternatives, resource costs, demand growth, and gas prices. SENDOUT® has the capability to integrate demand side resources alongside supply side resources in determining the optimal resource portfolio.

Because decisions must be made in the context of uncertainty about the future, PSE acquired VectorGas™ along with SENDOUT®. VectorGas™ is an add-in product that facilitates the ability to model gas price and load (driven by weather) uncertainty into the future, using a Monte Carlo approach in combination with the linear programming approach in SENDOUT®. This increased modeling capability will provide additional information to decision-makers under conditions of uncertainty. VectorGas™ was used in this plan to test the physical and financial risks associated with the optimal portfolio from the Base Case planning scenario and to test the sensitivity of optimal resource additions in deriving the optimal Base Case portfolio. These new

[1] See Appendix I for a detailed discussion of the design-day planning criterion update.

tools provide valuable enhancements to the robustness of the Company's long-term resource planning and acquisition activities.

**C.5. Generic Resources**

One purpose of the Least Cost Plan is to identify an illustrative resource portfolio to help guide specific resource acquisitions. In this planning cycle, the Company considered a host of resource alternatives that can be added to its resource portfolio, including additional energy efficiency programs, Jackson Prairie storage deliverability expansion, additional transportation capacity, LNG imports with transportation capacity, satellite LNG storage, and on-system LNG storage including liquefaction facilities. Generally, utility infrastructure projects are "lumpy," while demand grows annually at a small percentage rate, capacity is typically added on a project by project basis. Gas utilities often have surplus supply and "grow into" their new pipeline capacity, because it is more cost effective for pipelines to build for several years' worth of load growth at one time than to make small additions each year. For the purposes of this plan, however, the Company determined a theoretical cost-minimizing portfolio that is not constrained by this lumpiness issue. While it is anticipated that actual capacity acquisitions will be lumpy, this theoretically ideal portfolio provides a reasonable basis from which the Company can consider specific resource acquisitions.

**C.6. Analytical Frameworks**

Traditional gas least cost plans would include analysis targeted at identifying the optimal long-term resource portfolio to meet the demands of the gas utility's customers across a few customer growth and gas price scenarios. In this plan, PSE's gas resource analysis includes four different scenarios that focus solely on gas utility operations and a fifth analysis to support decisions regarding electric-to-gas fuel conversions. In addition to scenario analysis, PSE performed two different kinds of Monte Carlo analysis to examine a variety of risks (as noted above).

For this plan, PSE's gas resource analysis goes beyond the analysis of a gas Local Distribution Company ("LDC"). PSE used the same gas resource planning tools in its analysis of optimal resources to supply gas as electric generation fuel, based on results from the electric plan. Additionally, the Company analyzed whether cost savings via economies of scale and scope could be captured by planning to meet growing gas LDC needs and growing gas for electric generation fuel supply needs on a combined basis. This analysis determined the long-term cost of the optimal portfolio designed to meet the joint demands of gas LDC sales and gas generation fuel. It then compared that long-term optimal portfolio cost to the combined costs of the stand-alone optimal portfolios for the gas LDC, and to the gas for generation fuel, separately.

### C.7 Summary of Key Findings

*Summary of Key Analytical Results—LDC Analysis*

- Higher gas prices relative to the last Least Cost Plan indicate PSE should consider expanding its level of natural gas energy efficiency programs.
- PSE should work with Jackson Prairie co-owners to expand deliverability and work with Northwest Pipeline to obtain seasonal delivery rights similar to today's TF-2 service.
- PSE should consider acquiring upstream capacity on Westcoast from Station 2, though maintaining diversity of supply from AECO is an important qualitative factor for consideration.
- Additional load from a fuel conversion program does not appear to put upward pressure on average gas costs to existing customers.
- Monte Carlo analysis to examine physical supply risk indicates that a portfolio designed to meet PSE's design-day peak forecast in an otherwise normal temperature winter is sufficient to meet its obligations under a variety of possible winter conditions.
- With regard to cost risk, the 20-year Monte Carlo analysis demonstrates that viewing risk over a 20-year horizon tends to mute the effects of price and volumetric variability. Shorter time periods, such as annual variability, should be considered when examining the impact of different resources on cost variability.
- Monte Carlo analysis on optimal portfolio construction highlights that timing of certain resource additions are highly sensitive to Base Case assumptions.

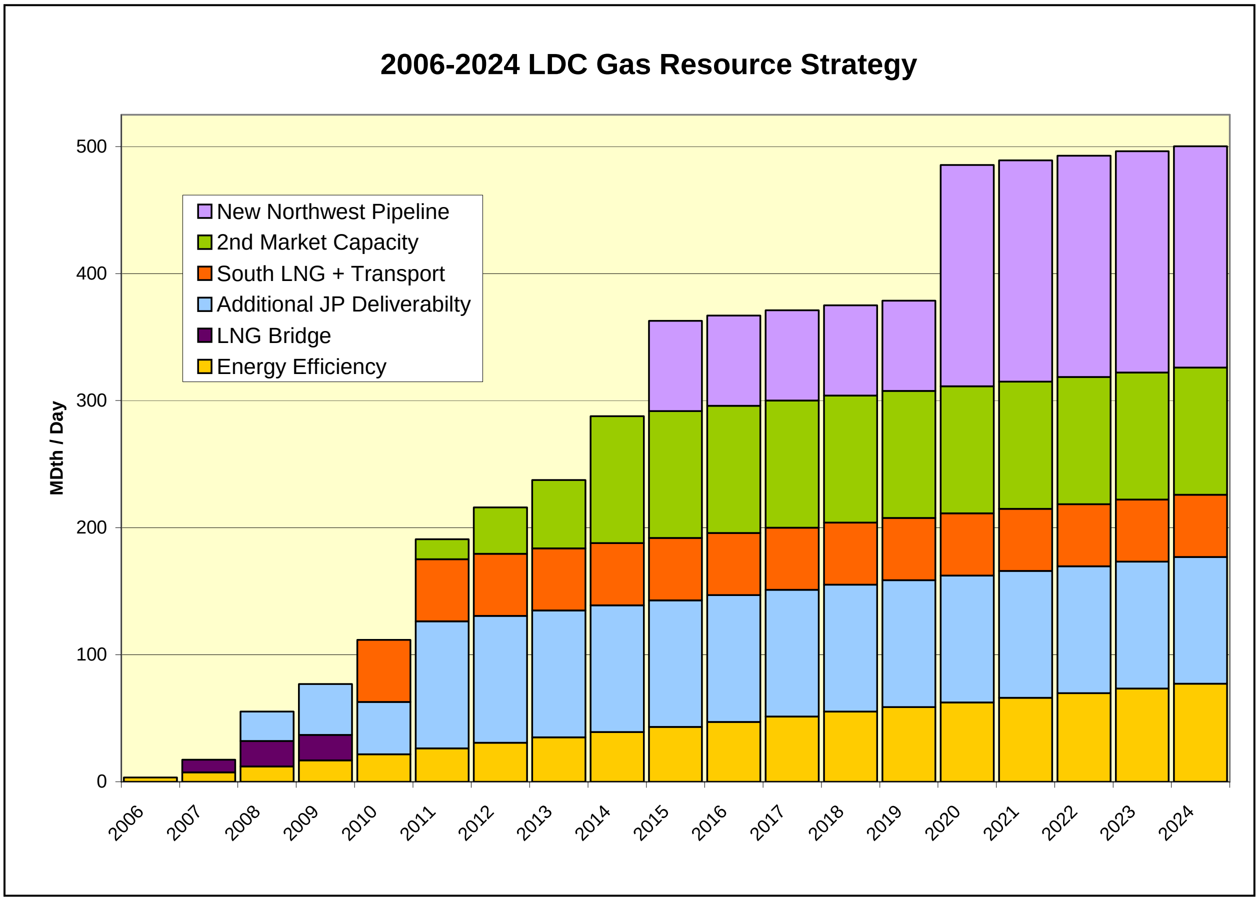
*Key Results from Generation Fuel Analysis*

- Based on the electric Business as Usual gas-fired generation resources, PSE's gas portfolio for power generation appears to have sufficient firm Northwest Pipeline capacity through 2009.
- Like the sales portfolio, additional upstream transportation capacity to Station 2 may need to be acquired as gas producers and marketers hold less capacity on Westcoast to move gas south to Sumas.

*Key Results from Joint LDC and Generation Fuel Analysis*

- Analysis showed potential savings of approximately 1 percent per year on an annualized basis relative to the combined stand-alone portfolio costs, a large portion of which would be achievable through short-term optimization without significant changes in long-term planning.

**Exhibit I-7**




## D. Public Involvement and Use of Plan

*Public Involvement*

PSE maintains an open commitment to actively encouraging public involvement in this process. As of April 29, 2005, ten formal Least Cost Plan meetings, in addition to dozens of informal meetings and communications have taken place. A number of stakeholders including WUTC Staff, the Public Counsel, consumer advocates, individual customers from industrial, commercial and residential classes, conservation and renewable resource advocates, the

Northwest Power and Conservation Council, Northwest Industrial Gas Users (NWIGU), Industrial Customers of Northwest Utilities (ICNU), project developers, capital market participants and Washington state's Department of Community, Trade and Economic Development have actively participated in these meetings. The stakeholder meetings provide an avenue for constructive feedback and useful information to guide the Least Cost Plan process. Stakeholder suggestions and practical information were invaluable in developing this Least Cost Plan. PSE thanks all those who attended the Least Cost Plan meetings for their time and energy. PSE encourages the continuation of this active participation as the Company's planning process proceeds.

*Use and Relevance of PSE's Least Cost Plan*

PSE's Least Cost Plan provides the strategic direction guiding the Company's long-term resource acquisition process. The Least Cost Plan does not commit PSE to the acquisition of a specific resource type or facility, nor does it preclude PSE from pursuing a particular resource or technology. Rather, the Least Cost Plan identifies key factors related to resource decisions and provides a method for evaluating resources in terms of their cost and risk. PSE recognizes that least cost planning is a dynamic process reflecting changing market forces and a changing regulatory environment.

# II. SUMMARY CHARTS AND GRAPHS

**A. Electric**

II-1. Energy: 2006-2025 Load-Resource Balance (Chapters VI, IX)

II-2. 2006 Monthly Load-Resource Balance (Chapter IX)

II-3. December 2006 Supply Resource Mix (Chapter IX)

II-4. Peak: 2006-2025 Load-Resource Balance (Chapter IX)

II-5. Historical Energy Efficiency Programs (Chapter VII)

II-6. Reduced Need for New Resources 2003 LCP vs. 2005 LCP (Chapter I)

II-7. Transmission Cut Planes (Chapter VIII)

II-8. Electric Scenarios Price Forecasts (Chapter X, Appendix C)

II-9. 2006-2025 Resource Strategy (Chapter X)

**B. Natural Gas**

II-10. Pacific Northwest Gas Industry (Chapter XII)

II-11. PSE's Gas Sales Portfolio Resource Map (Chapter XII)

II-12. Determination of PSE's Peak Day Planning Standard (Chap. XIV, Appendix I)

II-13. Natural Gas Load-Resource Balance – Base Case (Chapter XII)

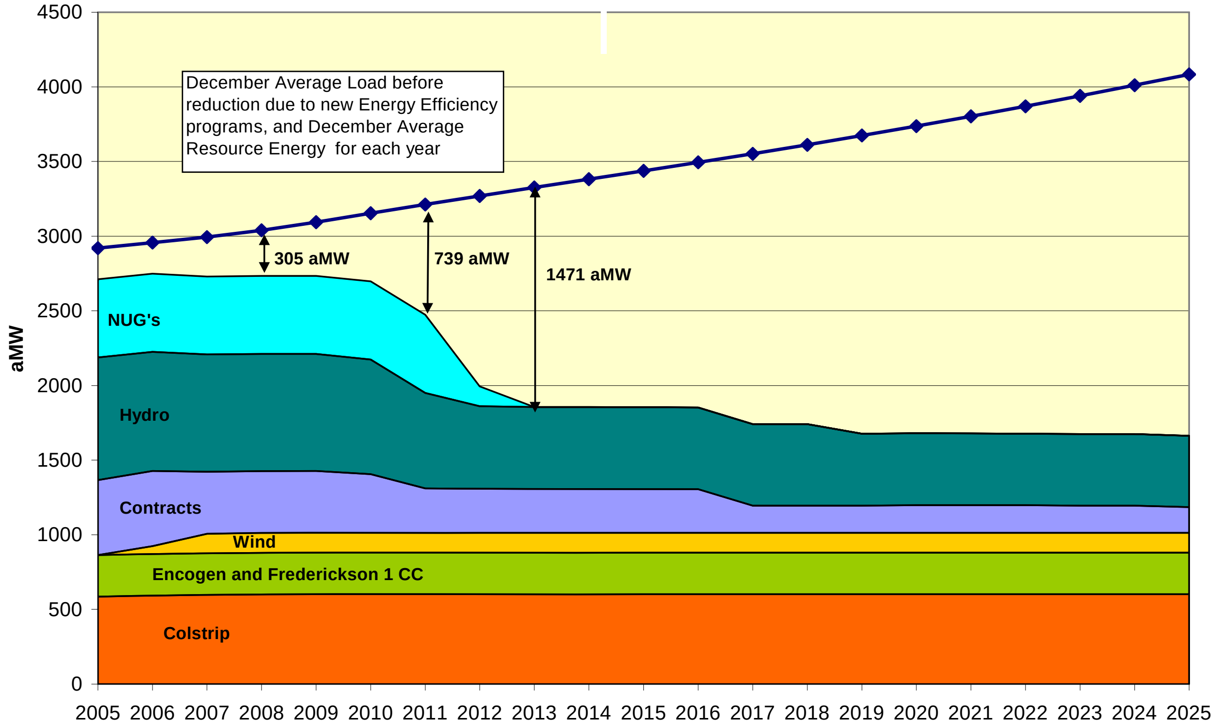
II-14. Optimized Portfolio – Base Case (Chapter XIV)

II-15. Range of Costs for Optimal Portfolios Across Scenarios (Chapter XIV)

II-16. Results of Base Case Monte Carlo Analysis (Chapter XIV)

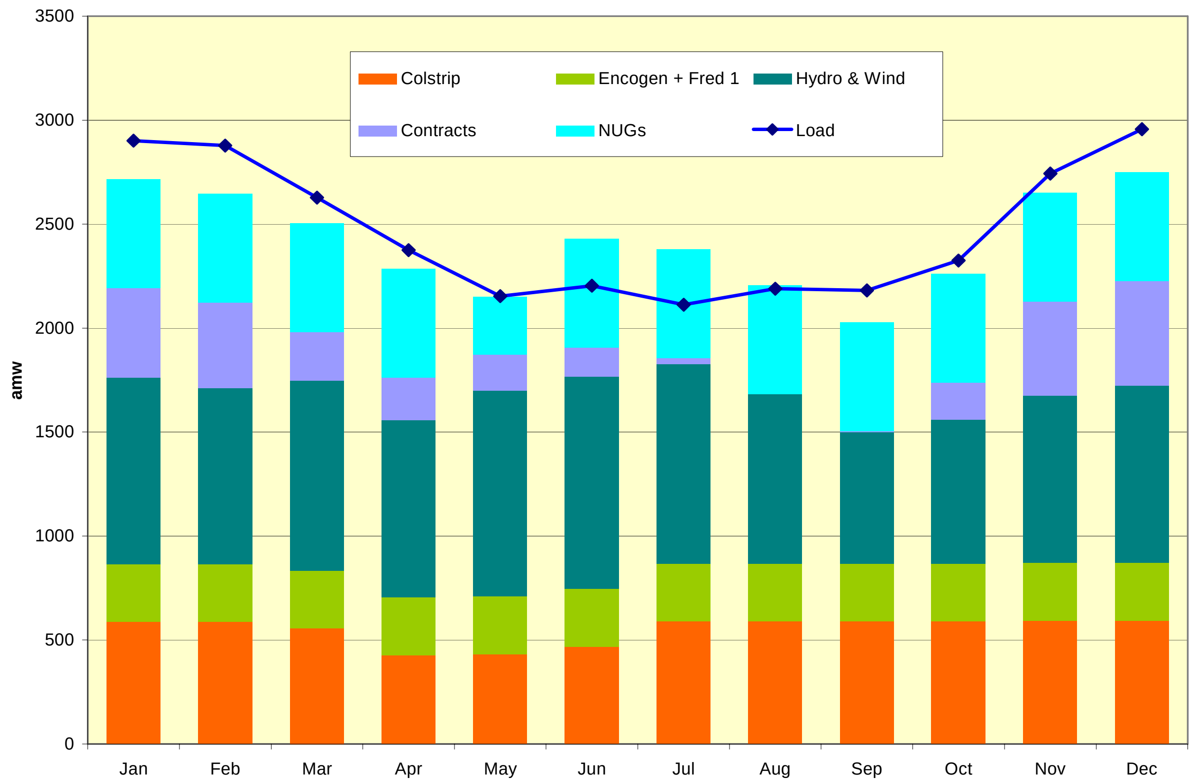
II-17. 2006-2024 Gas Resource Strategy (Chapter XIV)

**Exhibit II-1**
**Energy: 2006-2025 Load-Resource Balance**



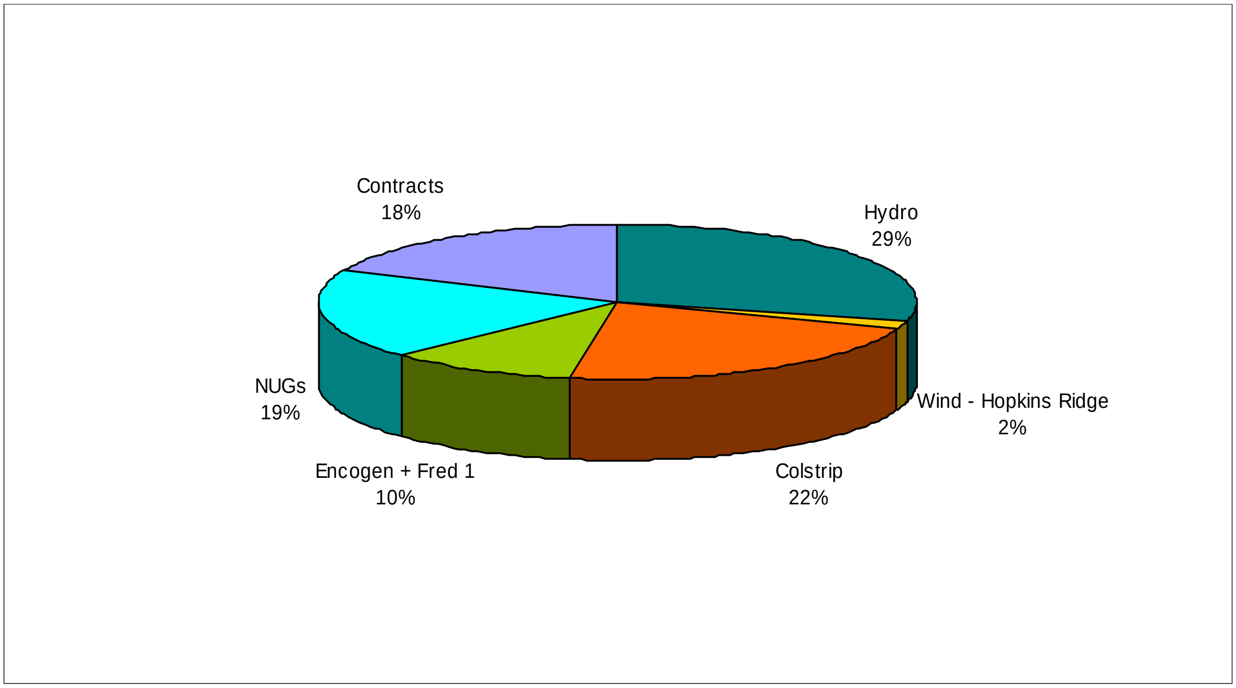

- Chart illustrates PSE's energy need
- Load growth is 1.8 percent per year
- The energy planning standard established in the 2003 LCP is continued in this plan
- Expiring NUG contracts include Sumas, Tenaska and March Point
- The forecast has not been reduced to account for new energy efficiency programs

## Exhibit II-2
## 2006 Monthly Load-Resource Balance



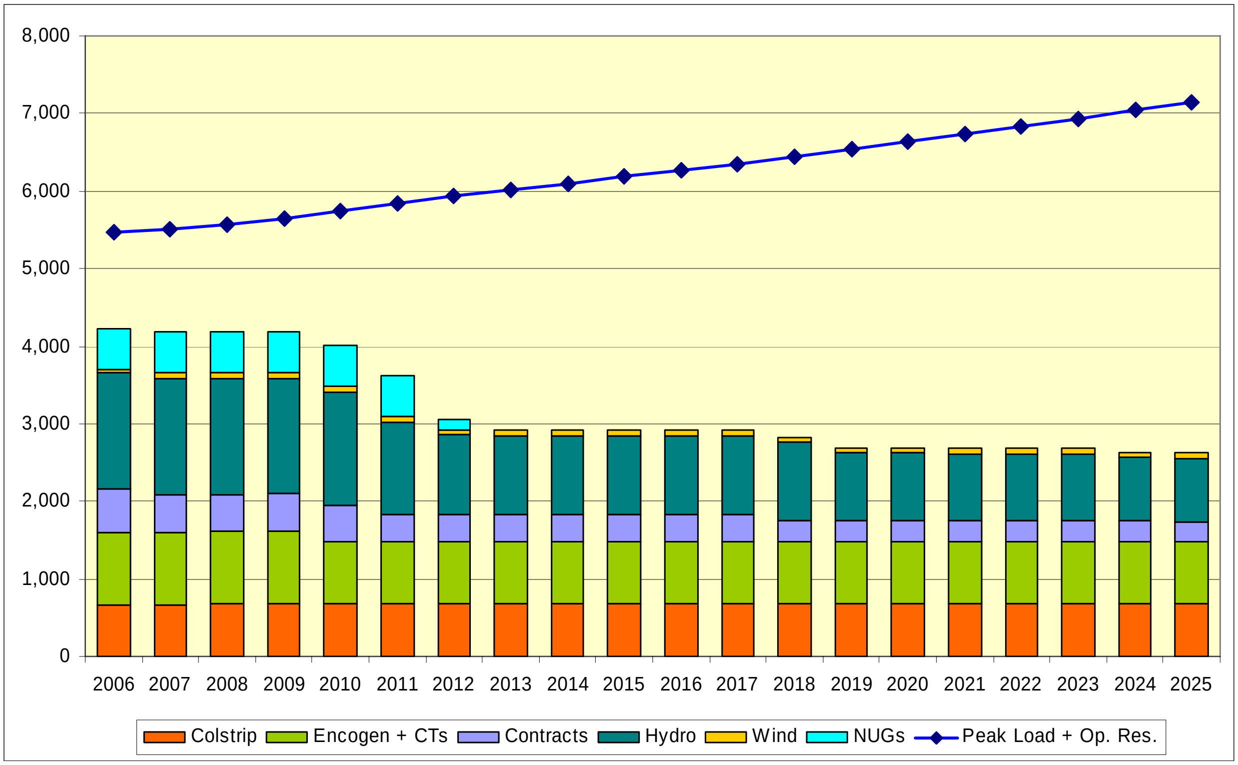

- Load and Resources are both higher in the winter season and lower in the summer season
- Balance shows net deficit in winter
- The forecast has not been reduced to account for new energy efficiency programs

# Exhibit II-3
# December 2006 Supply Resource Mix



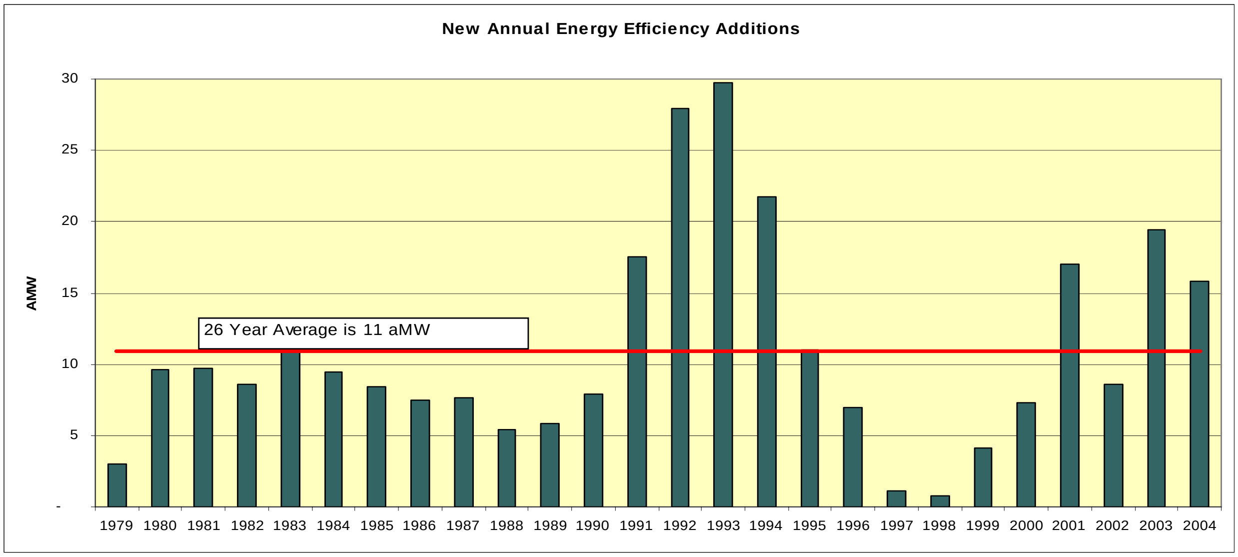

- Chart shows the share of average megawatts by source
- PSE has a diverse mix of supply resources today
- Frederickson 1, Encogen and non-utility generators (NUGs) are all natural gas fueled
- Contracts represent a mix of fuel types including hydro, natural gas and coal
- Wind percentage reflects only Hopkins Ridge but PSE expects to have 5 percent wind with the addition of Wild Horse by 2007

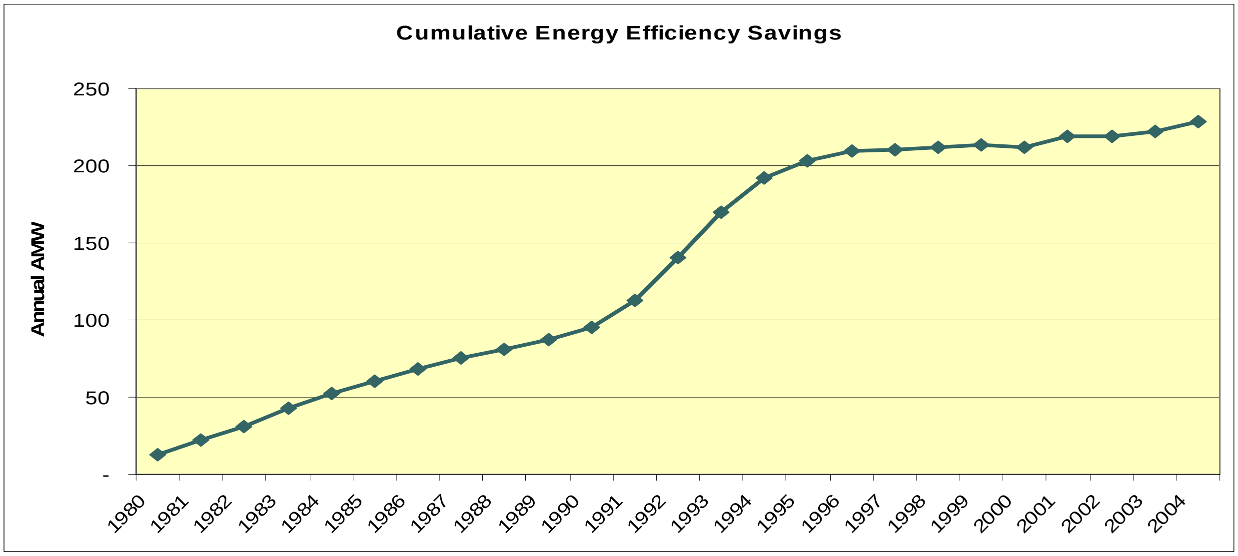
# Exhibit II-4
# Peak: 2006-2025 Load-Resource Balance




- Peak load is based on a 16 degrees planning standard
- Peak load includes operating reserves
- Resources include simple cycle combustion turbines
- Shortfall is currently met with a mix of firm winter supply contracts, winter call options, and market purchases
- The peak forecast has not been reduced to account for new energy efficiency programs

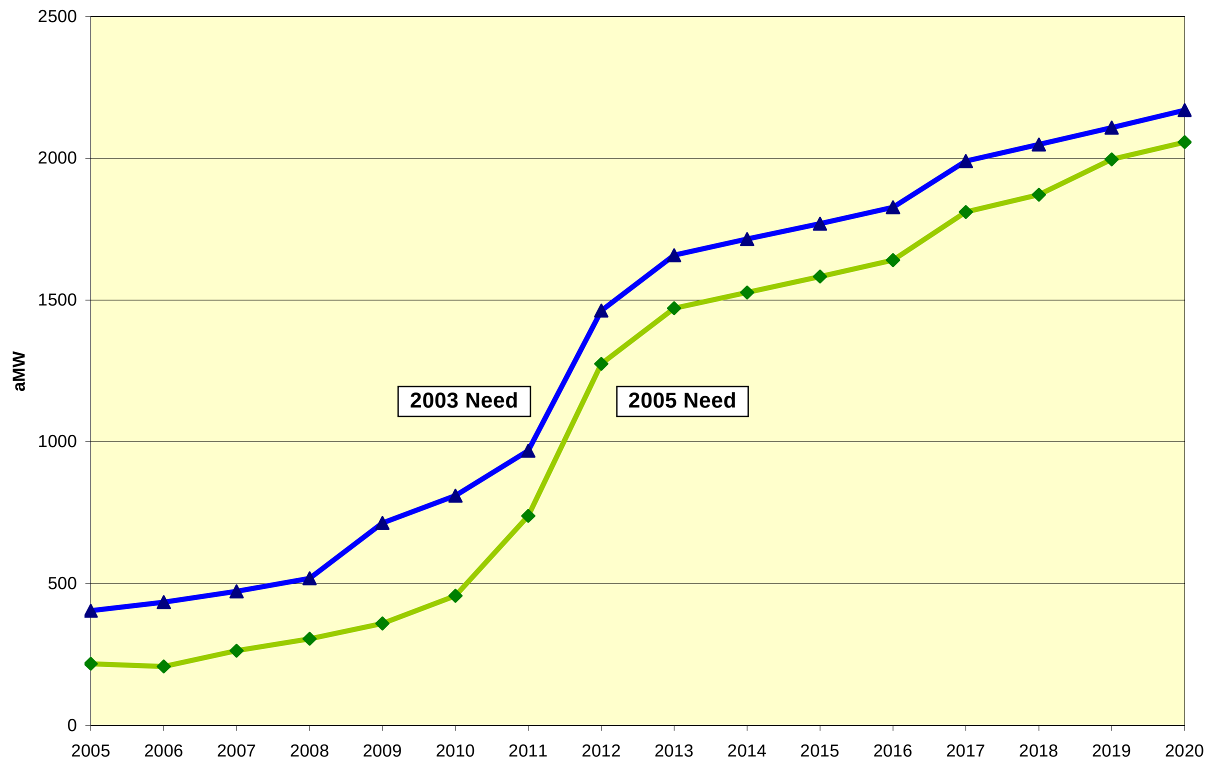
# Exhibit II-5
# Historical Energy Efficiency Programs




- Upper chart shows energy efficiency savings added for each year
- Lower chart shows cumulative energy efficiency savings assuming an average measure life of twenty years
- Without energy efficiency programs, PSE's load would be approximately 10 percent higher

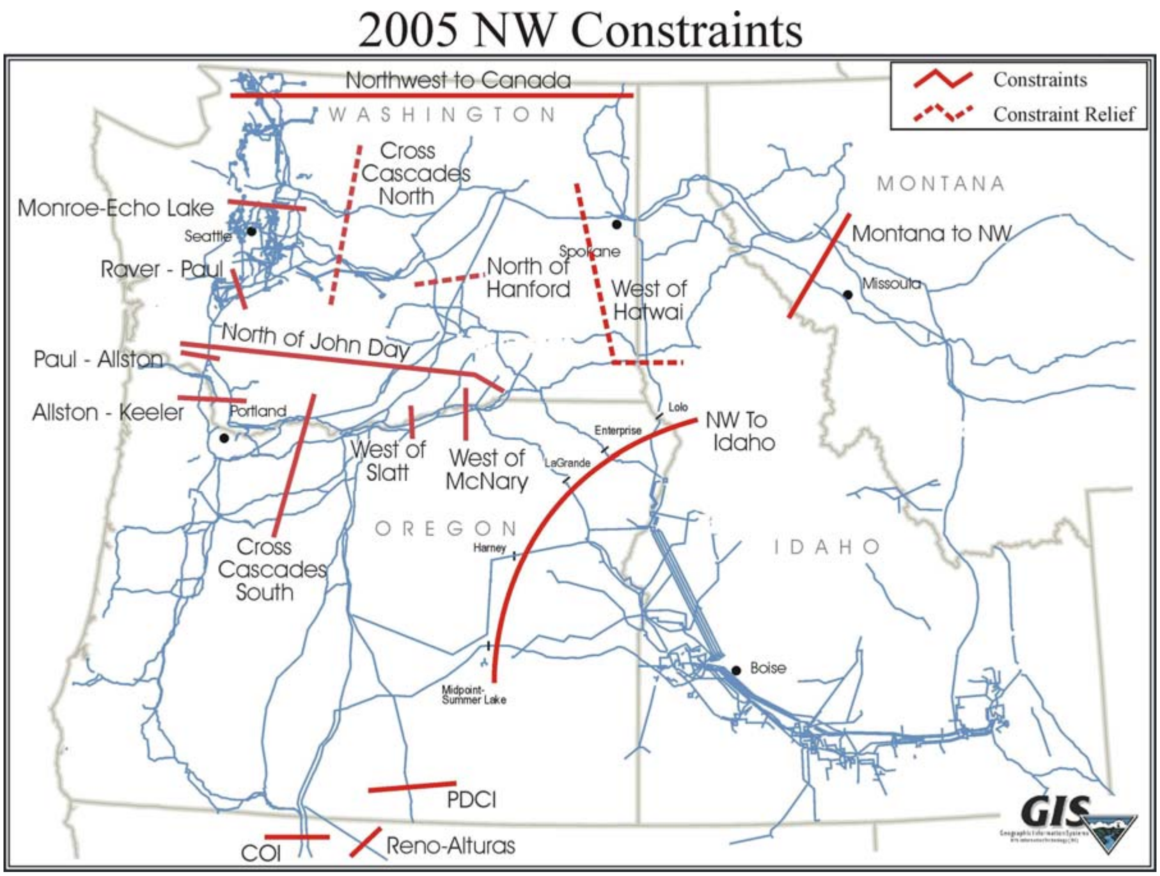
## Exhibit II-6
## Reduced Need for New Resources: 2003 LCP vs. 2005 LCP




| ACQUISITIONS SINCE APRIL 2003 LEAST COST PLAN | | |
|---|---|---|
| PROJECT | CAPACITY | ENERGY |
| Frederickson 1 | 125 MW | 123 aMW |
| Hopkins Ridge Wind | 150 MW | 52 aMW |
| Wild Horse Wind | 229 MW | 77 aMW |
| APS Purchase Contract | 85 MW | 85 aMW |
| Ormat Recovered Energy | 5 MW | 5 aMW |
| Colstrip Turbine Upgrade | 28 MW | 23 aMW |
| Energy Efficiency | 79 MW | 38 aMW |
| TOTAL | 701 MW | 403 aMW |

- Energy efficiency for calendar years 2003-2004
- Resource additions are offset by higher load forecast and updated hydro assumptions

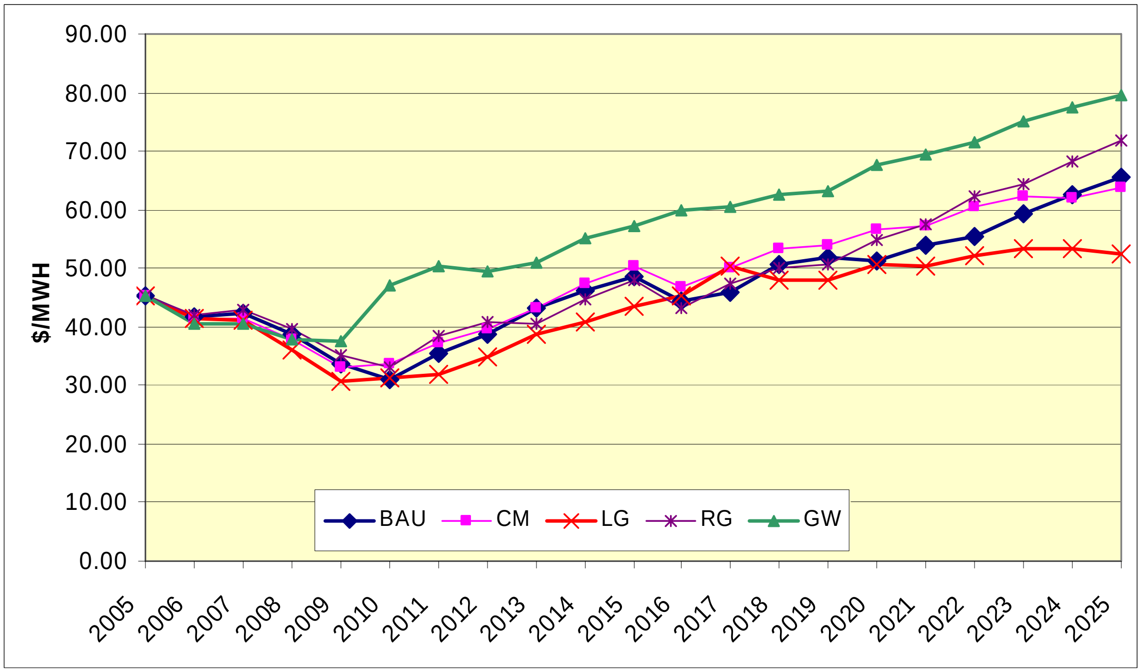
**Exhibit II-7**
**Transmission Cut Planes[1]**




- Transmission constraints ("Cut Planes") limit energy transmission into the Puget Sound Region
- Upgrades by BPA are primarily intended to meet and maintain its current obligations, not to provide for new bulk power transmission
- Recent upgrades include: West of Hatwai, North of Hanford, and Cross Cascades North

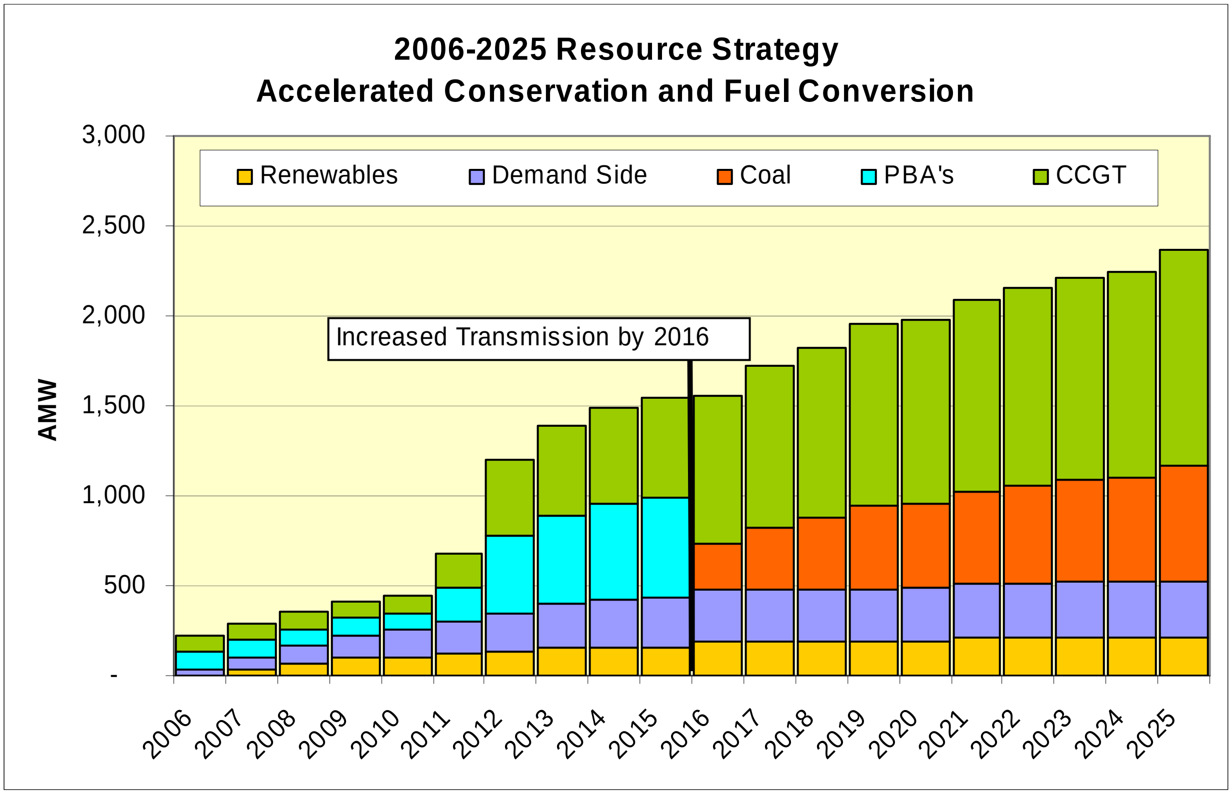
[1] Map used with permission from the Bonneville Power Administration.

## Exhibit II-8
## Electric Scenarios Price Forecasts



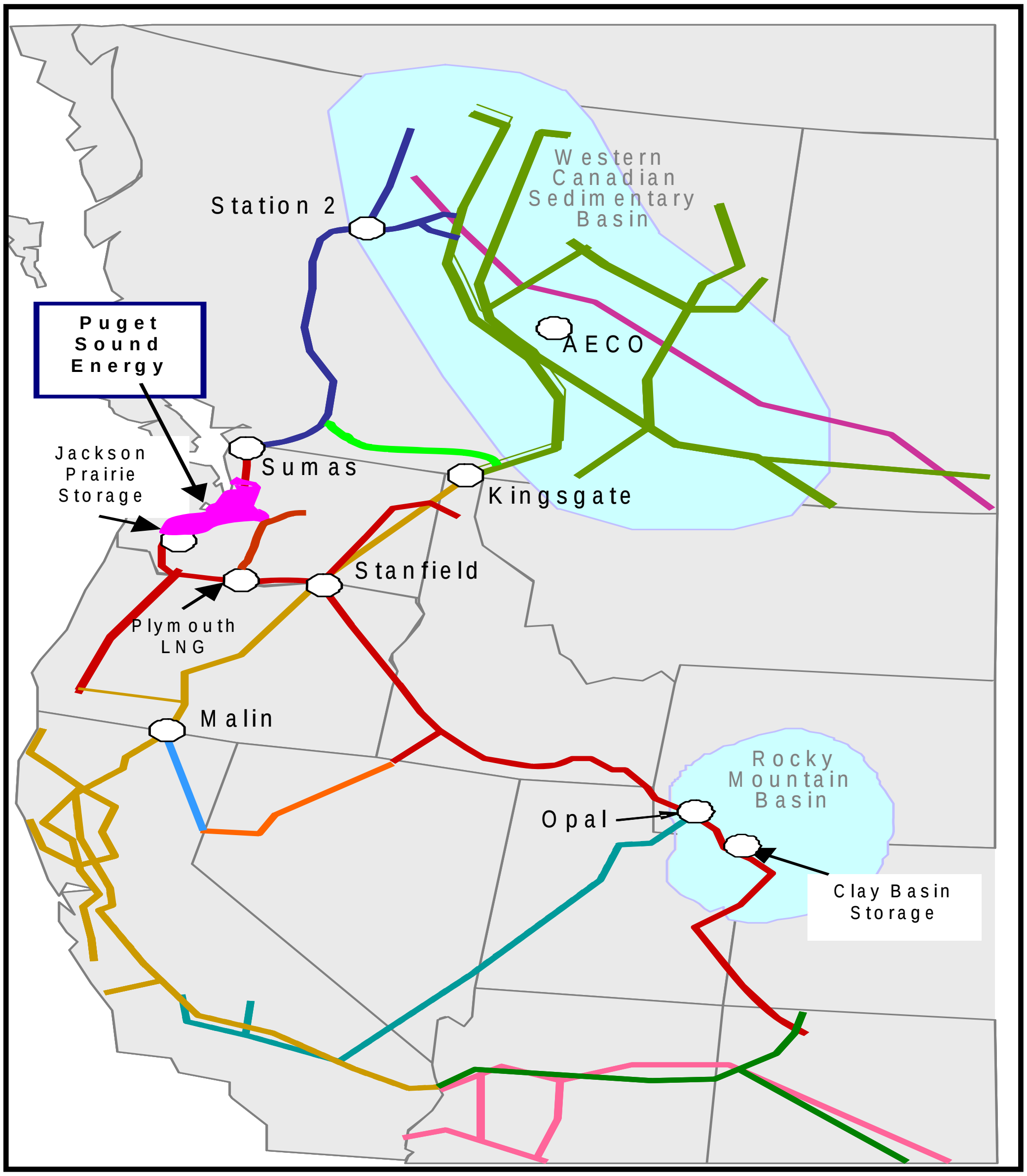

- Forecasts represent annual average price at Mid-C, based on average hydro and using the AURORA model
- Business as Usual (BAU), Current Momentum (CM) and Robust Growth (RG) are all based on the CERA Rearview Mirror gas forecast
- Green World (GW) is based on the CERA Shades of Green gas forecast with relatively higher prices
- Low Growth (LG) is based on the CERA World in Turmoil with relatively lower gas prices

# Exhibit II-9



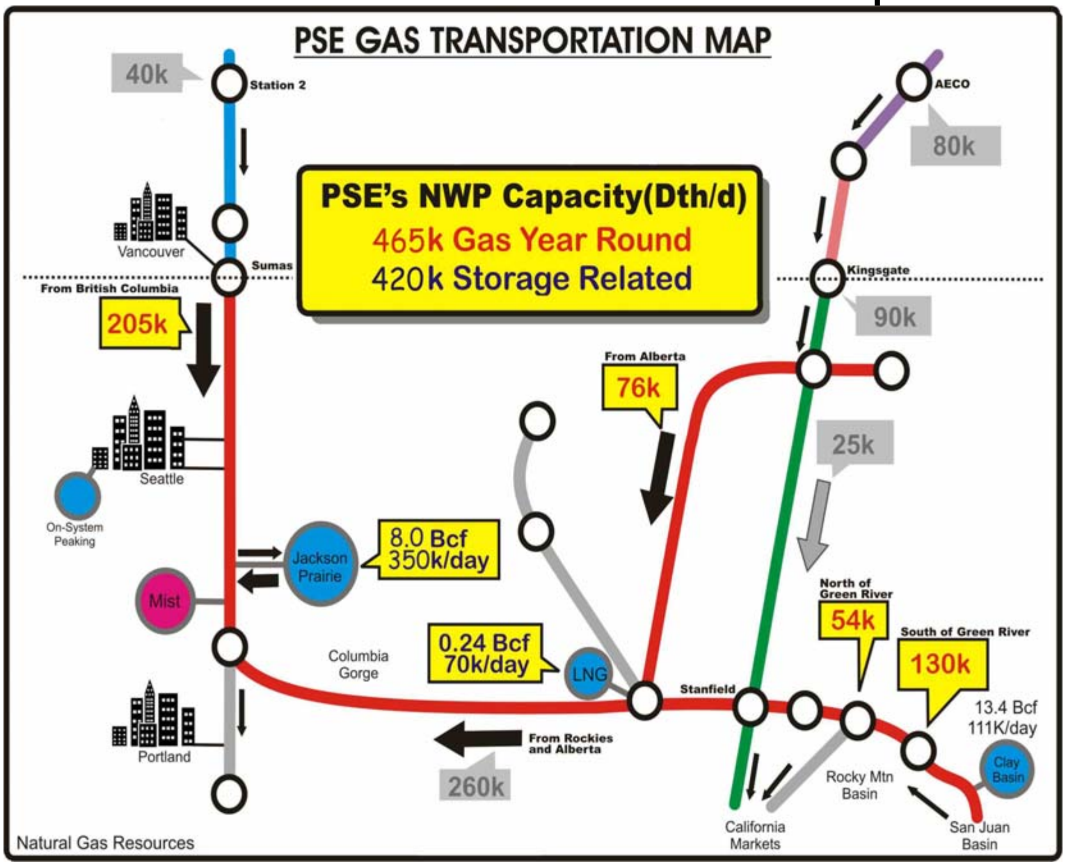

- 10 percent renewable energy goal by 2013
- Demand Side category includes accelerated energy efficiency and early fuel conversion
- 50/50 mix of gas-fueled assets and Power Bridging Agreements until transmission is constructed
- 50/50 mix of gas-fueled and coal-fueled assets when transmission is available

## Exhibit II-10
## Pacific Northwest Gas Industry



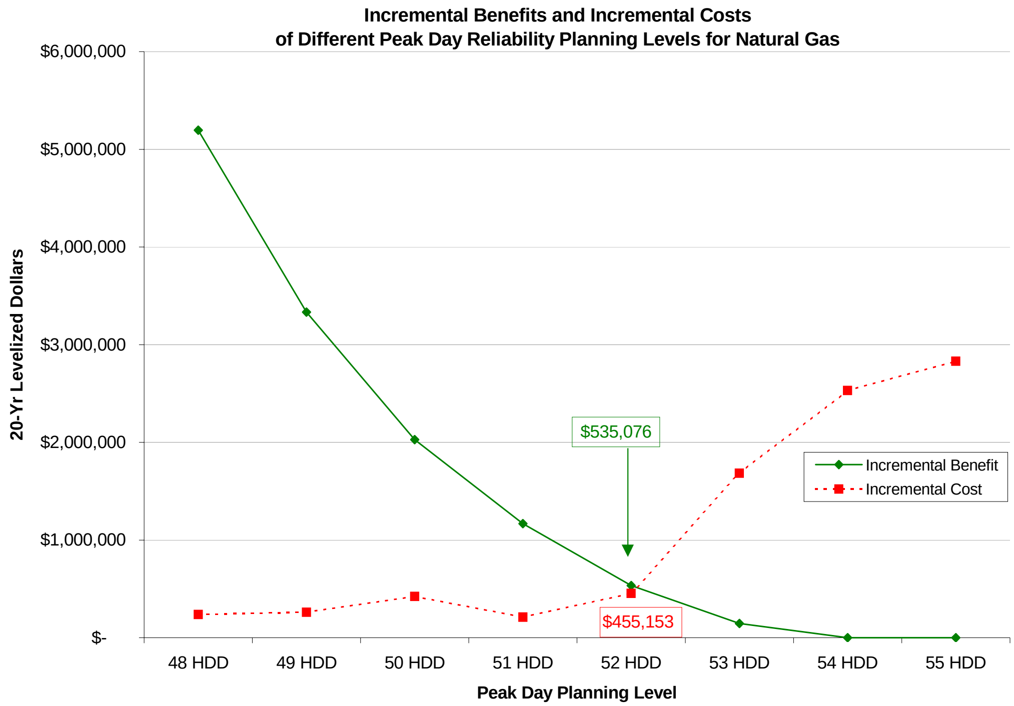

- PSE currently acquires gas supply from British Columbia at both Station 2 and Sumas, from Alberta at AECO, and from the Rocky Mountain region in Southwestern Wyoming, Colorado and Utah.
- As gas suppliers decontract for transportation capacity on Westcoast Pipeline from Station 2 to Sumas, PSE anticipates having to acquire additional upstream capacity in Canada to buy gas directly at Station 2 or across the Southern Crossing pipeline and up to AECO in Alberta.

**Exhibit II-11**
**PSE's Gas Sales Portfolio Resource Map**




- Overview of PSE's firm transportation and storage capacity. The red lines indicate transportation capacity on Northwest Pipeline.
- Transport from Rocky Mountain region is 130 MDth/day + 54 MDth/day or 184 MDth/day, total.
- From Alberta, 76 MDth/day flows on Northwest Pipeline's Spokane lateral, for a total of 260 MDth/day of capacity through the Columbia River Gorge to PSE's loads.
- Transport from Sumas to PSE's sales load is 205 MDth/day.
- Seasonal transport capacity of 350 MDth/day from Jackson Prairie and 70 MDth/day from the Plymouth LNG storage facility is used to deliver gas to PSE's gas sales loads.
- PSE holds 40 MDth/day on Westcoast pipeline to transport gas from Station 2 to Sumas. PSE holds 80-90 MDth/day on TransCanada's BC, Alberta and GTN systems to move gas from Alberta.

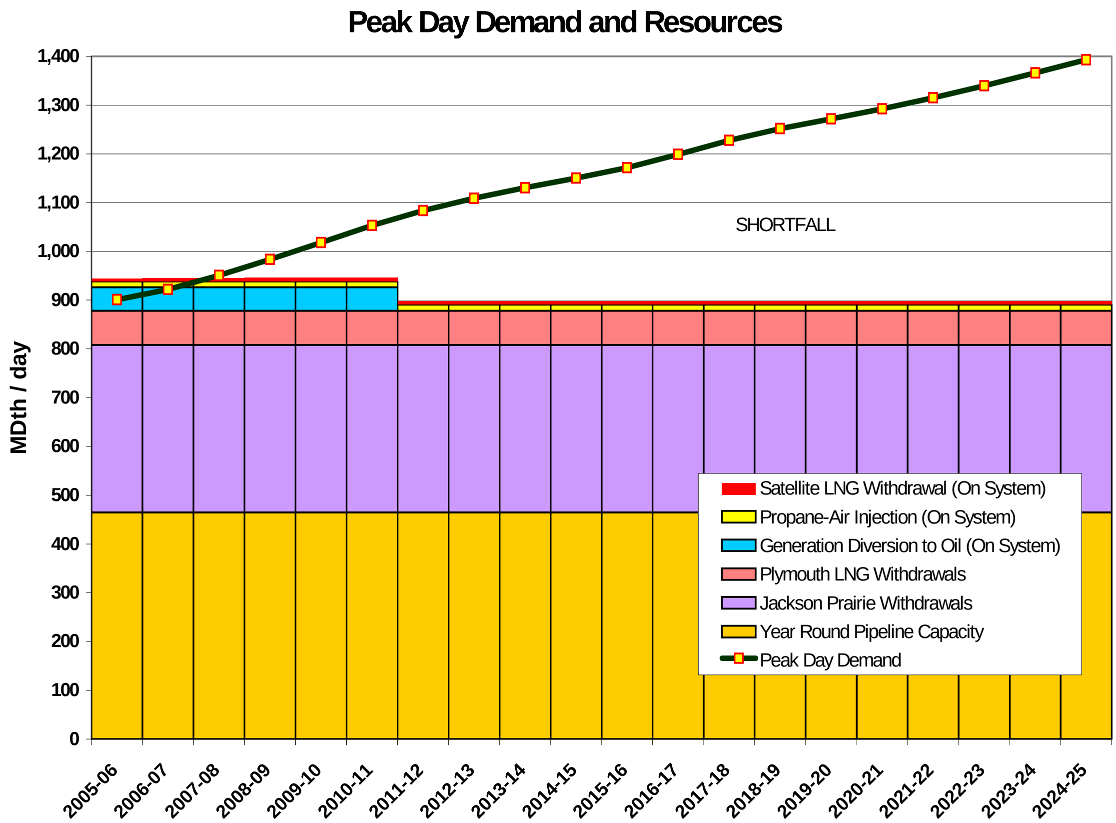
# Exhibit II-12
# Determination of PSE's Peak Day Planning Standard




**Note:** Up to 52 HDD the Incremental Benefit of Reliability > Incremental Cost. Beyond 52 HDD the incremental cost of increasing reliability is greater than the additional benefit, indicating further increases in planning standard would not be worth the expenditure.

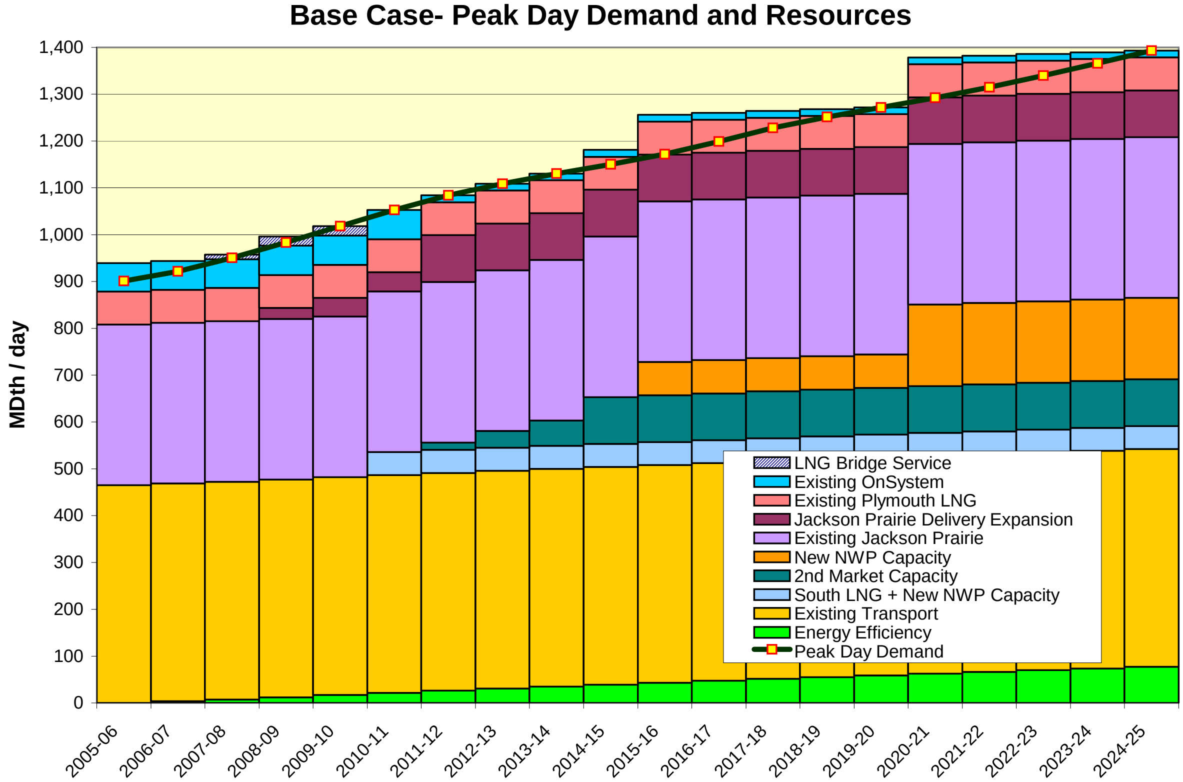
- Benefit/Cost analysis indicates 52 HDD ($13^{O}$ F average daily temperature) is PSE's efficient peak-day planning standard.
- Incremental cost of reliability is estimated as the 20-year optimized portfolio cost of meeting colder planning standards from 48 HDD to 54 HDD ($17^{O}$ to $11^{O}$).
- Incremental benefit of reliability is estimated as the cost of avoided outages for each planning standard.
- Benefit of avoiding outages based on customer's value of avoiding an outage, the cost of relights, and lost revenue.
- Probabilistic analysis in that the benefit of avoiding an outage is weighted by the probability that temperatures would fall below each planning standard examined.
- See Appendix I for additional information.

# Exhibit II-13
# Natural Gas Load/Resource Balance—Base Case



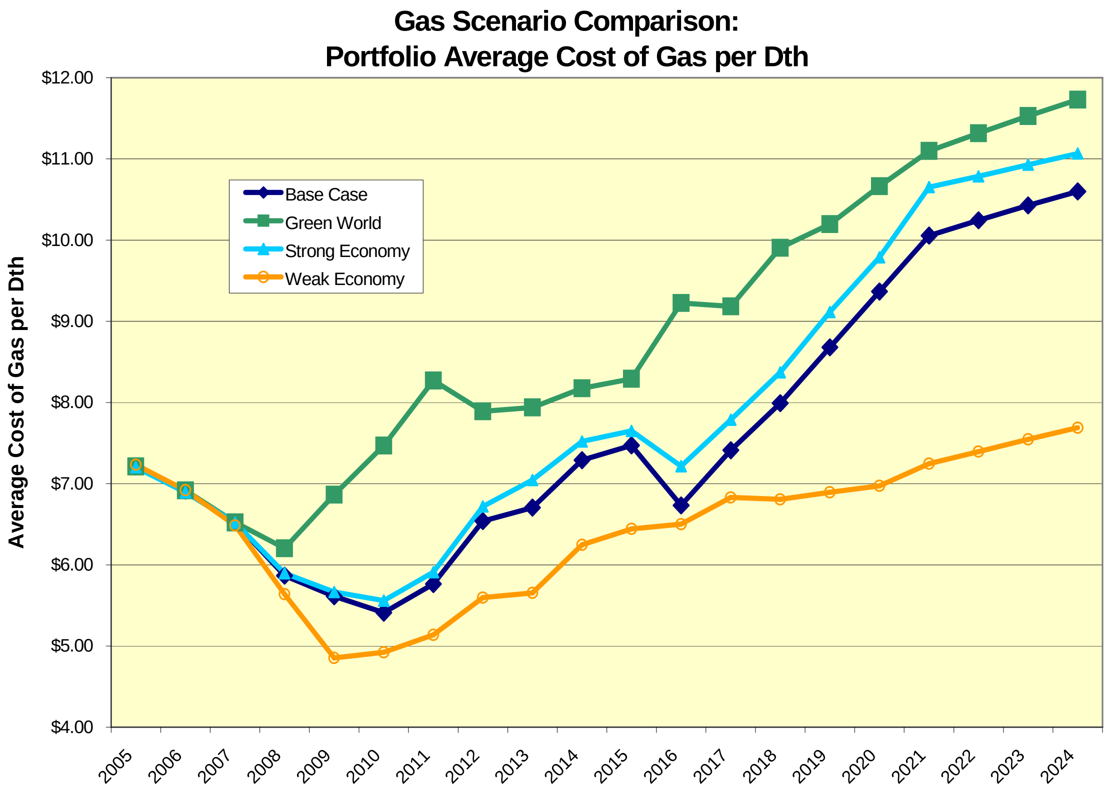

- This chart shows how the Company's existing resources would be used to meet design peak loads.
- Under the Base Case design day forecast scenario, peak demand on a 52 HDD is expected to exceed the Company's capacity to deliver gas to customers by the winter heating season of 2007/08.

# Exhibit II-14
# Optimized Portfolio—Base Case



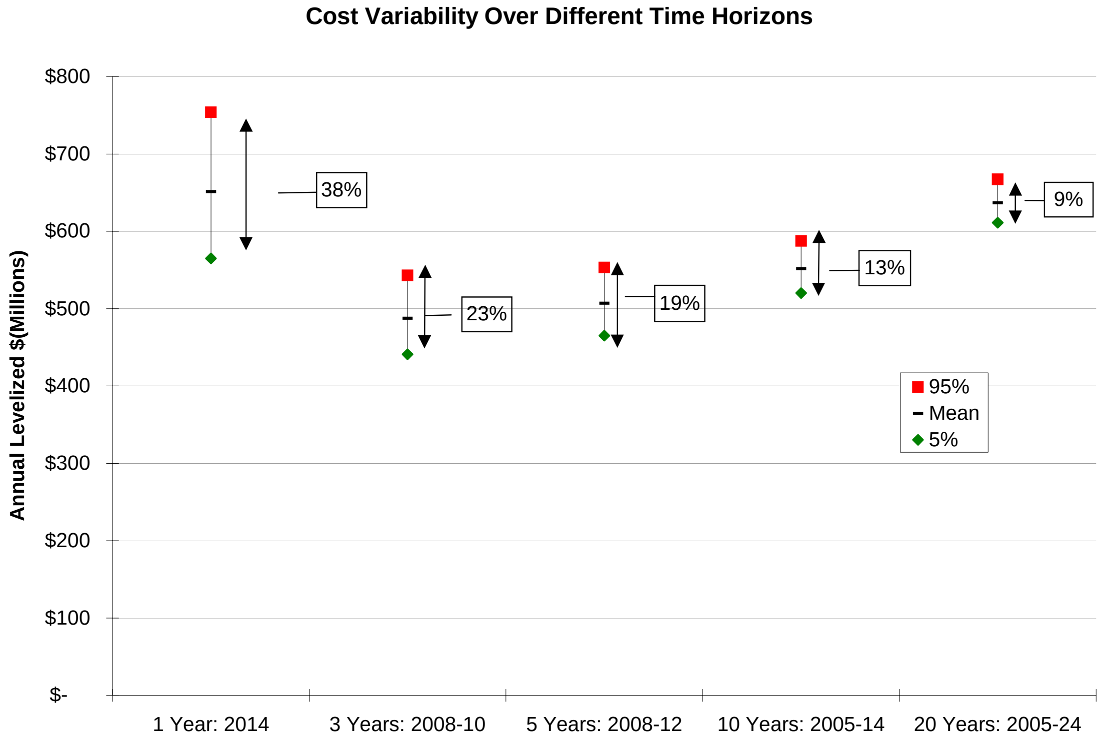

- Through 2015, resources were assumed to be very incremental, that is, small amounts of capacity were assumed available to demonstrate how the Company would like to acquire resources. Since capacity projects are generally lumpy, this is not a realistic portrayal of how PSE could actually acquire resources.
- This optimized approach, while not attainable, does provide guidance for acquisition of actual resources by identifying the optimal theoretical adding of resources and the related cost.
- The lumpiness shown in the period beyond 2015, where the Company has to acquire resources in lumps before it is needed, is more indicative of what PSE's physical position will look like in the 2006-15 period, based on actual acquisitions.

# Exhibit II-15
# Range of Costs-Optimal Portfolios Across Scenarios



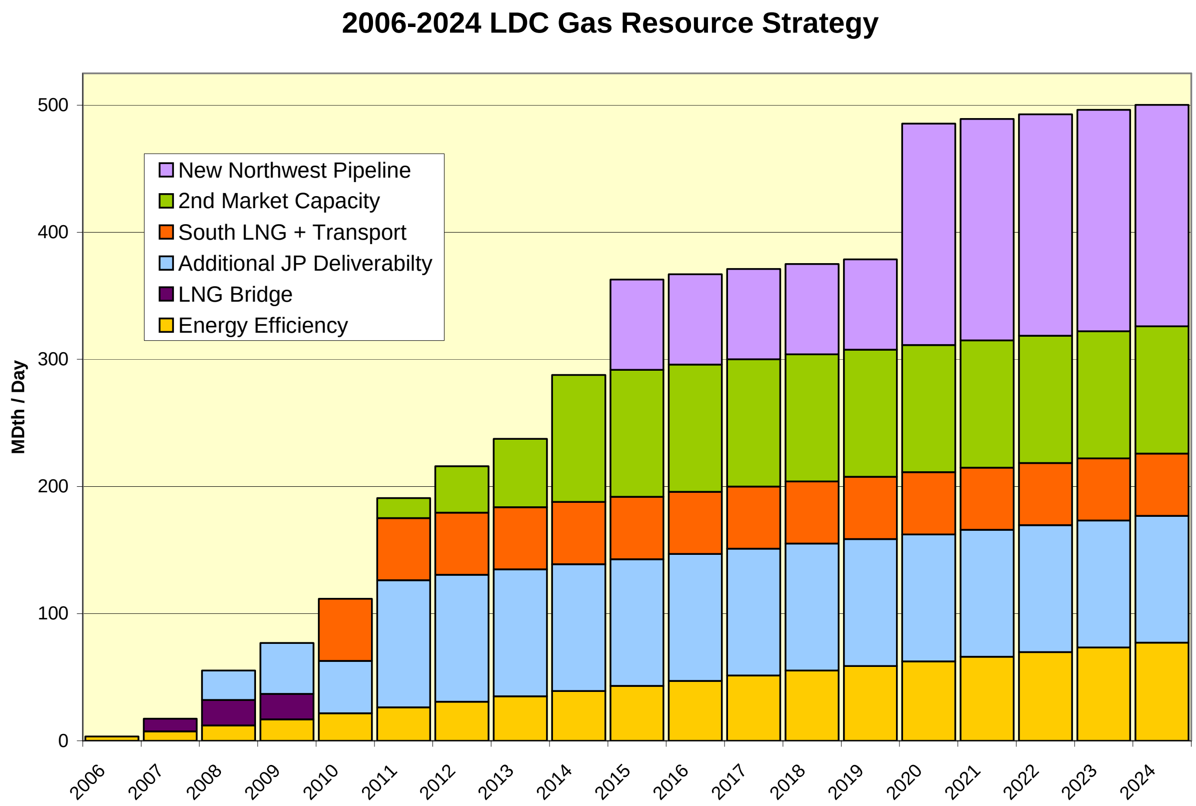

- Differences in average portfolio costs are driven by differences in underlying gas price forecasts and the fixed costs of resources needed to meet the different demand forecasts.
- This chart includes more resource costs than typically included in the Company's Purchased Gas Adjustment (PGA) rates, so is not a good projection of rates in the future. However. it does provide a reasonable trend based on planning assumptions and analysis in this Plan.

# Exhibit II-16
# Results of Base Case Monte Carlo Analysis




- Over the long-term, risk factors in this gas analysis tend to cancel each other out. As more time is considered, there is a greater chance that high market prices will be offset by potential low market prices in the future.
- Over a 20-year period, the range between the 5$^{th}$ and 95$^{th}$ percentile is only 9 percent but cost variability for just one year (in this case, 2014) is 38 percent.

# Exhibit II-17
# 2006-2024 Gas Resource Strategy




- Consider expanded Energy Efficiency programs
- Arrange for Jackson Prairie deliverability expansion
- Interest in import LNG, if appropriately located
- Additional year-round pipeline capacity will be needed

# III. INTRODUCTION AND NATURE OF PLAN

## A. Regulatory Compliance

PSE develops a Least Cost Plan as part of its long-term resource strategy development. This document provides a current perspective of this process and its outcomes. PSE has prepared and is submitting this Least Cost Plan pursuant to state regulations regarding least cost planning as contained in WAC 480-100-238 and WAC 480-90-238. Exhibits III-3 and III-4 at the end of this chapter delineate the regulatory requirements for electric and natural gas least cost plans respectively and reference the chapters of this plan that address each requirement.

PSE has developed this plan through a robust analysis that considered a wide range of future risks and uncertainties. PSE believes this Least Cost Plan meets applicable statutory requirements, and seeks a letter from the WUTC accepting this Least Cost Plan filing.

## B. Overview of Resource Planning Process

Exhibit III-1 shows a simplified map of resource planning. Every two years a Least Cost Plan is produced. If the plan identifies a resource need, PSE conducts a competitive solicitation for new energy resources and evaluates self-build options. If all proceeds well, PSE acquires the resources identified as top options. Those resources are either built or acquired and PSE seeks regulatory recovery for the resource costs. Finally, the new resources are included in the next Least Cost Plan, and the cycle continues.

While Exhibit III-1 suggests a linear path for least cost planning, energy supply planning is actually far more complex, dynamic and continuous. PSE's resource strategy must constantly evolve to reflect dynamic market forces and a continually changing regulatory environment. Using the Least Cost Plan as a guideline, PSE must remain agile and prepared to adapt to change quickly.

**Exhibit III - 1**

## Least Cost Plan Cycle

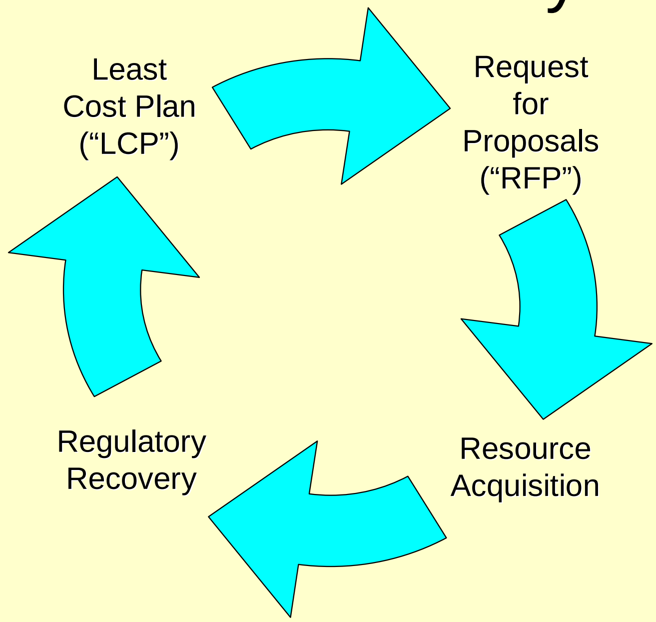



Exhibit III-2 illustrates the relationship between the continuous nature of energy planning and the more specific purpose of the Least Cost Plan.

| **Exhibit III-2: Energy Resource Planning Process** | |
|---|---|
| **CONTINUOUS ACTIVITIES** | **DISCRETE PRODUCTS** |
| Evaluation of resource opportunities<br>Management of resource portfolio<br>Implementation and modification of risk and resource strategy<br>Analysis of energy markets<br>Identification and evaluation of resource issues, risks, and uncertainties<br>Participation in regional planning and initiatives<br>Tracking and participation in state and federal energy policy initiatives. | **Least Cost Plan Document**<br>RFP Process<br>Specific Resource Acquisitions<br>Regulatory Proceedings |

### C. Use and Relevance of PSE's Least Cost Plan

PSE's Least Cost Plan is a snapshot taken every two years as part of a perpetual energy resource planning process. Accordingly, the Least Cost Plan is an important milestone for the identification and acquisition of long-range resources, as well as more specific short-term resource actions. Least cost planning is not appropriate for making decisions related to particular energy resources. Nor does it provide cost information associated with specific resources and transmission.

Instead, PSE's Least Cost Plan provides the most value when it is used to investigate demand and supply side opportunities, to examine demand forecasts, and to explore complex energy issues involving PSE, the region and the industry. It provides the means and method to evaluate costs and risks associated with potential new resources. In addition, the Least Cost Plan provides an opportunity for significant public involvement that is less costly and less formal than other proceedings involving rates and permitting.

### D. Stakeholder Interaction

PSE maintains a continuing commitment to actively encouraging public involvement in its Least Cost Plan process. While the Least Cost Plan Advisory Group (LCPAG) and Conservation Resource Advisory Group (CRAG) meet separately, they share many common members. The LCPAG's scope includes all elements of the Least Cost Plan, while the CRAG is more narrowly focused on energy efficiency and demand-side resources. As of April 30, 2005, ten formal LCPAG meetings, four CRAG meetings, as well as numerous informal meetings and communications have taken place. Stakeholders that have actively participated in one or more meetings include: WUTC Staff; the Public Counsel; individual customers from industrial and commercial classes; Northwest Pipeline; conservation and renewable resource advocates; the Northwest Power Planning Council; project developers; other utilities; and the Washington State Department of Community, Trade and Economic Development.

Appendix A provides more detail on the meetings over the last year, as well as written responses to the letter of October 3, 2003 from the Commission regarding specific issues of interest.

### E. Disclaimer – Important Notice

Puget Sound Energy (PSE) makes the following cautionary statements in its Least Cost Plan and Appendices (filed with the Washington Utilities and Transportation Commission pursuant to state regulations regarding least cost planning as contained in WAC 480-100-238 and WAC 480-90-238) to make applicable and to take advantage of the safe harbor provisions of the Private Securities Litigation Reform Act of 1995 for any forward-looking statements made by or on behalf of PSE. This Least Cost Plan, its Appendices, and any amendments or supplements to it, include forward-looking statements, which are statements of expectations, beliefs, plans, objectives, assumptions of future events or performance. Words or phrases such as "anticipates," "believes," "estimates," "expects," "intends," "plans," "predicts," "projects," "will likely result," "will continue" or similar expressions identify forward-looking statements.

Forward-looking statements involve risks and uncertainties which could cause actual results or outcomes to differ materially from those expressed. PSE's expectations, beliefs and projections are expressed in good faith and are believed by PSE to have a reasonable basis, including without limitation management's examination of historical operating trends and data contained in records and other data available from third parties, but there can be no assurance that PSE's expectations, beliefs or projections will be achieved or accomplished.

Any forward-looking statement speaks only as of the date on which such statement is made, and, except as required by law, PSE undertakes no obligation to update any forward-looking statement to reflect events or circumstances after the date on which such statement is made or to reflect the occurrence of unanticipated events. New factors emerge from time to time and it is not possible for management to predict all such factors, nor can it assess the impact of any such factor on the business or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statement. These materials and any forward-looking statements within them should not be construed as either projections or predictions or as business, legal, tax, financial or accounting advice and should not be relied upon for any such purpose.

**Exhibit III-3**
**Electric Least Cost 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 impact of economic forces on the consumption of electricity and that address changes in the number, type and efficiency of electrical end-uses. | • Chapter VI, Demand Forecast<br>• Chapter X, Electric Analysis and Results |
| ***WAC 480-100-238 (3) (b)*** An assessment of technically feasible improvements in the efficient use of electricity, including load management, as well as currently employed and new policies and programs needed to obtain the efficiency improvements. | • Chapter VII, Demand Side Resources<br>• Chapter VIII, Electric Planning Environment<br>• Chapter X, Electric Analysis and Results |
| ***WAC 480-100-238 (3) (c)*** An assessment of technically feasible generating technologies including renewable resources, cogeneration, power purchases from other utilities, and thermal resources (including the use of combustion turbines to utilize better the hydroelectric system). | • Chapter VIII, Electric Planning Environment<br>• Chapter X, Electric Analysis and Results<br>• Chapter XI, Electric Resource Strategy and Action Plan |
| ***WAC 480-100-238 (3) (d)*** A comparative evaluation of generating resources and improvements in the efficient use of electricity based on a consistent method, developed in consultation with commission staff, for calculating cost-effectiveness. | • Chapter X, Electric Analysis and Results<br>• Chapter XI, Electric Resource Strategy and Action Plan |
| ***WAC 480-100-238 (3) (e)*** The integration of demand-side forecasts and resource evaluations into a long-range (e.g., twenty years) least cost plan describing the mix of resources that will meet current and future needs at the lowest costs to the utility and its ratepayers. | • Chapter X, Electric Analysis and Results<br>• Chapter XI, Electric Resource Strategy and Action Plan |
| ***WAC 480-100-238 (3) (f)*** A short-term (e.g., two-year) plan outlining the specific actions to be taken by the utility in implementing the long-range least cost plan. | • Chapter XI, Electric Resource Strategy and Action Plan<br>• Chapter XVII, Action Plan |
| ***WAC 480-100-238 (4)*** Progress report that relates the new plan to the previously filed plan. | • Chapter XVII, Action Plan |

**Exhibit III-4**
**Gas Least Cost Plan Regulatory Requirements**

| STATUTORY/REGULATORY REQUIREMENT | CHAPTER |
|---|---|
| ***WAC 480-90-238 (3) (a)*** –A range of forecasts of future gas demand in firm and interruptible markets for each customer class for one, five, and twenty years using methods that examine the impact of economic forces on the consumption of gas and that address changes in the number, type, and efficiency of gas end-uses | • Chapter VI, Load Forecasting |
| ***WAC 480-90-238 (3) (b)*** An assessment for each customer class of the technically feasible improvements in the efficient use of gas, including load management, as well as the policies and programs needed to obtain the efficiency improvements. | • Chapter VII, Demand-Side Resources<br>• Chapter XIV, Natural Gas Analysis and Results |
| ***WAC 480-90-238 (3) (c)*** An analysis for each customer class of gas supply options, including:<br>(i) A projection of spot market versus long-term purchases for both firm and interruptible markets;<br>(ii) An evaluation of the opportunities for using company-owned or contracted storage or production;<br>(iii) An analysis of prospects for company participation in a gas futures market; and<br>(iv) An assessment of opportunities for access to multiple pipeline suppliers or direct purchases from producers. | • Chapter XIII, New Gas Supply Side Opportunities<br>• Chapter XVI, Natural Gas Analysis and Results<br>• Chapter XV, Energy Risk Management |
| ***WAC 480-90-238 (3) (d)*** A comparative evaluation of gas purchasing options and improvements in the efficient use of gas based on a consistent method, developed in consultation with commission staff, for calculating cost-effectiveness | • Chapter XVI, Natural Gas Analysis and Results |
| ***WAC 480-90-238 (3) (e)*** The integration of the demand forecasts and resource evaluations into a long-range (e.g., twenty-year) least cost plan describing the strategies designed to meet current and future needs at the lowest cost to the utility and its ratepayers. | • Chapter XVI, Natural Gas Analysis and Results |
| ***WAC 480-90-238 (3) (f)*** A short-term (e.g., two-year) plan outlining the specific actions to be taken by the utility in implementing the long-range least cost plan | • Chapter XVII, 2005 Action Plan |
| ***WAC 480-90-238 (4)*** Progress report that relates the new plan to the previously filed plan. | • Chapter XVIII, Report on April 2003 Two-Year Action Plan |

# IV. FINANCIAL CONSIDERATIONS

## A. Overview

This chapter outlines the interrelationship of PSE's financial needs and capabilities and its resource strategies. Compared to previous Least Cost Plans, this plan provides greater information about corporate financial considerations for the following reasons:

- An increased focus on the financial quality of trading partners that determines both access and pricing in power and natural gas markets,
- An increase in the anticipated level of capital requirements needed to fund energy delivery infrastructure growth and replacements in addition to PSE's acquisition of new resources,
- PSE's relatively low credit rating ("BBB-"/"Baa3"),
- Mounting and more stringent financial regulation and accounting requirements, such as the Financial Accounting Standard Board's (FASB) Statements 149 and 133 concerning accounting for derivatives and FASB Interpretation, FIN 46, concerning consolidation of variable interest entities.
- Credit and cost impacts of certain resource structures (e.g. imputed debt and credit needs associated with purchased power agreements)

In support of PSE's overall mission to provide customers with reliable energy at reasonable, stable prices, the Company's financial strategy strives to:

- Ensure continuous access to the capital markets on reasonable terms
- Increase the availability of credit to operate the business
- Expand risk management capabilities to reduce volatility
- Provide competitive return to investors

## B. Utility Financial Environment

This section reviews the key financial considerations of energy supply planning and how financial markets view utilities. To some extent, PSE and other electric utilities are still experiencing repercussions from the Western energy crisis of 2000-01. That period of very high and volatile power pricing resulted in several large and well established companies defaulting on obligations.

Energy market participants and the financial markets have since become much more aware of risk and mindful of the energy supply impacts on financial performance.

Key financial considerations for energy supply planning include purchased power and imputed debt costs, credit and risk management:

### *B.1. Purchased Power and Imputed Debt*

Credit rating agencies view electric utility purchased power payments as fixed commitments that impact a company's ability to cover debt. Consequently, the credit agencies calculate (impute) debt associated with the capacity portion of payments made under power purchase agreements. Utilities have used purchase power agreements (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 create fixed obligations that can increase a utility's market, operating and financial risks.

Both Moody's Investor 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 versus those that contract for power.

Generally, because they are not a physical asset and do not have an equity component, PPAs do not contribute to earnings, and the payments related to them are viewed as a fixed obligation, much as the interest on a bond is viewed as a fixed obligation. The rating agency application of imputed debt on PPAs decreases interest coverage ratios and is a negative factor in determining the overall credit rating. Without offsetting this imputed debt with increased equity, the impact is to increase the leverage in the balance sheet and reduce credit quality.

### *B.2. Credit*

In the energy industry, credit risk is defined as the potential loss resulting from a counterparty's failure to perform under one or more agreements for the purchase or sale of an energy service, energy product, or derivative thereof. Credit risk is typically calculated as the sum of amounts currently due and the positive replacement value of the energy under various contracts.

All energy transactions contain credit risk. Parties that transact in the energy markets typically grant a certain level of unsecured credit risk exposure to the other parties. Firms use, among other things, the credit ratings provided by S&P and Moody's to compare the relative creditworthiness of their counterparties and to determine the amount of unsecured credit to grant another party. Firms with higher credit ratings are typically granted more credit and are also able to transact with more counterparties in comparison with lower-rated companies. Transacting with a limited number of counterparties can lead to a concentration of credit risk.

Since lower-rated firms tend to receive relatively small unsecured credit lines, they may be forced to rely upon secured credit lines. Collateral backs a secured credit line so that the creditor will not incur a credit loss if the debtor fails to perform its obligations. Common forms of security used in the energy industry include cash collateral and letters of credit issued by financial institutions such as commercial or investment banks.

Clearly, firms with higher credit ratings are better positioned than firms with lower credit ratings. Firms with higher credit ratings benefit from increased trading liquidity (more counterparties), increased financial liquidity (less funds diverted towards collateral), and lower costs (decreased use of costly letters of credit, for example).

Before the energy crisis, credit was less of an issue, especially for agreements between utilities. Now, credit has attained a much greater importance. Increased concern about credit risk has led to increased credit costs.

### *B.3. Risk Management*

Starting with the Western energy crisis, and continuing through the recent escalation in natural gas prices, energy markets have experienced substantial volatility. Consequently, market participants have taken steps to improve their risk management. This includes taking a more structured approach to managing price exposure, and the use of better modeling tools.

The market offers a variety of fixed priced contracts and financial instruments to hedge a company's price risk exposure.

### *B.4. Financial Accounting*

In June 1998, The Financial Accounting Standards Board (FASB) issued Statement 133 (FAS 133), *Accounting for Derivative Instruments and Hedging Activities,* which established accounting and reporting standards for derivative contracts and hedging activities. The purpose of FAS 133 is to improve the quality of financial reporting by requiring that contracts with comparable characteristics be accounted for similarly. The impact of FAS 133 is the potential for increased volatility of reported earnings due to the requirement for recording the unrealized gains and losses from derivatives on a company's books. In April 2003, the FASB issued Statement 149, an amendment to FAS 133 that clarified the definition of derivatives and the implementation of this statement for financial instruments.

In December 2003, the Financial Accounting Standards Board issued a revision to Interpretation 46 (FIN 46), *Consolidation of Variable Interest Entities*. Consolidated financial statements are to include subsidiaries in which the enterprise has a controlling financial interest. That requirement has usually been applied to subsidiaries in which an enterprise has a majority voting interest, but in many circumstances the enterprise's consolidated financial statements do not include variable interest entities with which it has similar relationships. The primary objective of FIN 46R is to provide guidance on the identification of and the financial reporting for entities over which control is achieved through means other than voting rights: such entities are known as Variable Interest Entities. The potential impact of FIN 46 on PSE may, depending upon specified criteria, require the consolidation of entities providing long-term power purchase agreements (PPAs). Such consolidation requires PPA suppliers to provide their detailed financial information for determination of applicability of FIN 46 and, if necessary, consolidation of their financial statements. Depending upon the capital structure of the PPA supplier, the consolidation may adversely impact PSE's corporate credit rating and the ultimate cost of the PPA to PSE customers.

## C. Financing

Electric utilities are capital-intensive companies and PSE's capital needs for resource additions must be considered in addition to PSE's other financing needs. PSE's specific investment challenges are:

- A growing customer base,
- A growing short resource position,
- Infrastructure expansion, replacements, and improvements,
- A historic high reliance on PPAs, and
- A relatively weak financial position and reliance on external capital markets.

PSE's overall mission is to reliably and safely serve customers and to deliver a fair return to shareholders. To accomplish this mission, the Company is focusing on three general goals: increased self-sufficiency in energy generation through an expanded resource base; minimized power and gas cost volatility through portfolio and risk management initiatives; and investments in delivery infrastructure.

Taking into account PSE's current and projected financial strength, as well as its credit capabilities and other considerations, PSE must determine how it will finance ongoing operations and capital requirements. Financing will come from the Company's capacity to generate funds internally through operating cash flows and from its ability to attract investors in the capital markets. In order to access capital on reasonable terms, PSE must maintain strong credit fundamentals that will be viewed favorably by the rating agencies and investors.

The Company's historic reliance on purchased power does not provide depreciation as a source of cash flow. Without this cash inflow from the recovery of depreciation through rates, PSE is a net borrower. As a net borrower, the Company currently relies on capital markets to fund planned capital investments. After the payment of dividends, which is integral to attracting equity investors, internal operating cash flows are not sufficient to fund near-term planned capital requirements. As a result, PSE must attract capital from the financial markets. This means it is important for PSE to maintain an attractive credit and investment profile to allow for adequate and reasonable external financing options.

Presently, the Company's corporate credit rating ("BBB-"/"Baa3") is the lowest in the investment grade category. Credit rating agencies examine a number of qualitative and quantitative factors in determining a credit rating. While there is no formula for combining assessments of these factors to arrive at a specific credit rating, capital structure, as measured by a debt to total capitalization ratio, and consistent earnings commensurate with a company's business risk, as measured by ratios such as pre-tax interest coverage, are critical factors.

At a credit rating of "BBB-"/"Baa3", the Company's debt costs are higher than they would be at a stronger rating, such as "BBB+"/"Baa1". Higher debt costs represent a burden to customers over time. Furthermore, with a weak rating, access to the financial markets can be limited during periods of economic downturn or market stress. In general, investors are wary of investing in companies that must undertake large capital projects while rated one step above non-investment grade status.

In addition, the Company's current credit rating provides limited safety or cushion from a potential downgrade to non-investment grade status. There are many risk factors that can lead to downgrades in a company's credit rating. One notch above non-investment grade provides little to no flexibility to deal with the following factors: credit market events, fluctuations in power costs, regulatory and political events, changes in tax laws, unanticipated wholesale market developments, and force majeure events.

Achieving a "BBB+"/"Baa1" corporate credit rating, which is three notches above non-investment grade status, is integral to the Company's financial strategy. A higher credit rating results in better access to the capital markets and a lower overall cost of capital. A lower overall cost of capital provides direct benefits to customers through lower rates over time. This is particularly true for PSE, with its significant infrastructure investment requirements. A strong capital structure will also provide PSE with greater ability to access long-term fuel supply contracts, as well as physical and financial hedging products to manage the price volatility associated with its power and natural gas portfolio.

PSE has taken substantial steps to strengthen its capital structure to achieve a higher credit rating. Between September 30, 2001 and December 31, 2004, the Company increased its equity ratio from 31.7 percent to 40 percent. In doing so, the Company has been able to meet the equity structure targets established in the 2002 general rate case settlement with the Washington Utilities and Transportation Commission (WUTC) well ahead of schedule. Puget Energy reduced its common stock dividend, invested earnings in excess of that dividend in PSE, issued common stock to fund the requirements of the dividend reinvestment plan (DRIP), and completed two significant common stock offerings in 2002 and 2003. In total, the Company increased its common equity by more than $250 million during this period. Furthermore, the Company refinanced its high cost preferred stock and reduced total debt by more than $300 million.

However, to achieve its "BBB+"/"Baa1" target, PSE must do more to improve its financial health. The Company has developed a financial plan that is reasonably expected to result in an improved equity ratio. In its February 18, 2005 order, the WUTC set rates on a 43 percent equity ratio – a level that PSE plans to achieve. Through a balanced approach to managing its debt portfolio, growth of equity through the sale of stock, and earnings retention, the Company plans to meet the requirements for a higher corporate credit rating. Thus, as it makes new resource acquisitions and funds other operations, PSE will actively strive to maintain this appropriate balance between debt and equity in its financing decisions. The Company's goal is to manage this balance in its capital structure so that it will achieve and maintain at least a "BBB+" rating.

**D. Credit and Liquidity**

As discussed in section B, PSE has made significant progress in dealing with the challenging times following the Western energy crisis. However, continued careful management of liquidity and effective hedging techniques remain integral aspects of PSE's strategy aimed at shoring up credit quality.

As shown in Exhibit IV-1, PSE's liquidity facilities consist of a $500 million bank line of credit and an accounts receivable securitization program. Availability of credit through the accounts receivable securitization program varies from $75 million to $150 million, depending on the size of the Company's accounts receivable and unbilled revenue balances. These facilities are primarily used to fund PSE's working capital needs. If necessary and if available, these facilities may be used to provide security to PSE's counterparties.

PSE's other source of credit is the unsecured credit limits provided by its trading counterparties. Generally, these credit limits may be increased or decreased at any time. Changes in the Company's credit limits are made in response to changes in the perceived risk of transacting with PSE.

**Exhibit IV-1**

| SOURCES OF CREDIT (representative values in millions of $) | | |
|---|---|---|
| Liquidity Facilities (# of counterparties) | | **$650** |
| Receivables Securitization | $150 | |
| Credit Agreement | $500 | |
| Trading Counterparty Credit | | **$444** |
| Gas | $150 | |
| Power | $149 | |
| Financial | $145 | |
| Total Sources | | **$1,094** |

PSE conducted an informal survey of its major counterparties to better understand the relationship between the Company's S&P and Moody's ratings, and the credit lines extended to PSE. A number of surveyed counterparties were not able to indicate the exact amount of the increase or decrease to PSE's credit limits, as they would have to consider the factors causing the credit rating change. Nevertheless, the results of this survey show directionally that an improved credit rating can be expected to expand PSE's ability to enter into hedging transactions. Also of note is that a downgrade to the Company would result in the loss of a substantial amount of unsecured credit. According to the survey results, a downgrade in credit rating is greater than the impact of an increase in credit rating. For physical gas transactions, a downgrade would reduce credit by 60 percent while an upgrade of one rating notch would increase credit by 49 percent. For physical power transactions, a downgrade would reduce credit by 73 percent while an upgrade would increase credit by 67 percent. And for financial power or gas transactions, a downgrade of one notch reduces credit by 49 percent while an upgrade of two notches to BBB+ increases credit by 62 percent.

Credit will be an increasingly important issue for PSE, as a number of PPAs will expire over the next few years. Entering into new PPAs, like any market transaction, requires the use of PSE's credit. The Company's relatively low credit rating coupled with the tighter credit risk standards now common in the industry, should make replacement of the expiring PPAs more expensive than ownership options.

An increase in the Company's credit rating would improve PSE's bargaining position and motivate counterparties to extend higher credit limits to PSE, thereby increasing the company's trading liquidity. Improved credit ratings would also reduce the need to post security, resulting in improved financial liquidity and reduced costs.

Furthermore, a non-investment grade rating would significantly impact the Company's risk management activities. Parties with which the Company currently contracts would constrain open credit extended to PSE, and would likely require the Company to post collateral to maintain its transacting activity. A downgrade would also trigger requirements to post collateral under several financial hedging instruments to which the Company is already a party. While the Company may be able to access additional credit or equity at such a time to cover these cash requirements, it would be forced to do so at the worst time, because its weakened financial condition would significantly increase the cost of such capital.

Because of the negative consequences of a potential downgrade, PSE takes a more conservative approach to issues, such as credit policy, than it might if it had a stronger credit rating. For example, PSE must be vigilant to reserve its current credit facilities to meet working capital needs and the variability associated with such needs rather than using up that credit by posting collateral or letters of credit to support wholesale gas and power market hedging activities.

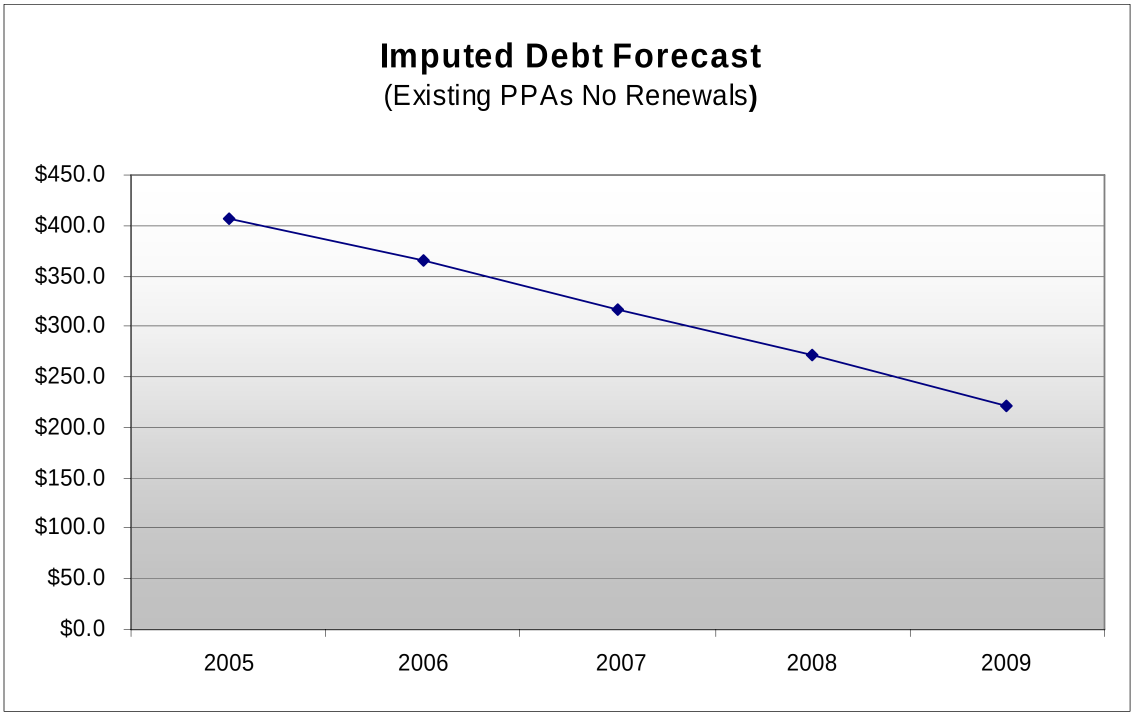
**E. Imputed Debt**

PSE, like all electric utilities, faces the challenge of maintaining financial strength to attract capital investment. But unlike many other utilities, PSE has the added burden of over $400 million of imputed debt, using the S&P methodology (see Exhibit IV-2). PSE acquires a majority of its energy and capacity supply from power purchase agreements and thus is subject to significant downward pressure on its credit rating resulting from imputed debt. PSE has been working with the rating agencies since the early 1990s to ensure that they understand the Company's contracts and, in particular, that the imputed debt is mitigated somewhat by the low cost structure of the hydro-based contracts from the Mid-Columbia Public Utility Districts.

PSE has a number of PPAs outstanding, with termination dates extending from 2006 through 2037. In aggregate, these PPAs result in imputed debt of approximately $400 million in 2005.

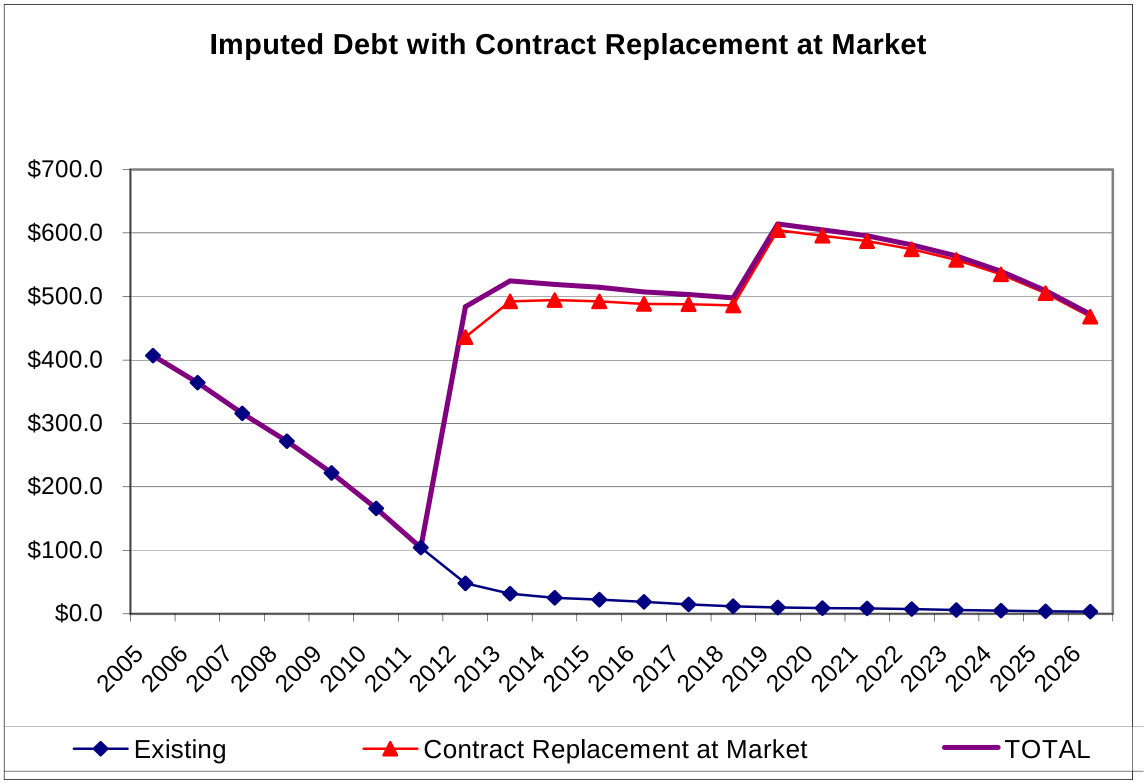
The graph in Exhibit IV-2 reflects existing contracts and excludes the imputed debt associated with possible renewal for a number of PPAs that expire between 2011 and 2019.

**Exhibit IV-2**




PSE has numerous large contracts with Public Utility Districts on the Columbia River and with Non Utility Generators in Northwest Washington that expire between 2011 and 2019. If PSE were to replace these expiring contracts with new 20-year contracts, priced at the Aurora forecast prices, the imputed debt could increase to over $500 million in 2013 and over $600 million in 2019. This is likely a low estimate of imputed debt because prices for fixed rate contracts will generally have a forward premium and a credit premium that would increase contract payments. In addition, the estimate may be low because the assumption for replacement of non-utility generator contracts was at 60 percent of existing capability. And finally, the estimate may also be low because it does not include the imputed debt from possible power bridging agreements (PBAs) that may be used to partially fill the resource need in the near term. The chart in Exhibit IV-3 illustrates future imputed debt under these circumstances.

**Exhibit IV-3**
**Imputed Debt with Selected Contracts Replaced at Market Prices**




*Regulatory Treatment of Imputed Debt*

Replacing expiring contracts with new long-term PPAs priced at AURORA forecast prices, depicted as "market" in Exhibit IV-3, would place significantly greater downward pressure on PSE's credit ratings than exists today. Public Utility Commissions in California and Florida have recognized the impact of imputed debt on utility credit ratios.

The Public Utilities Commission of the state of California ruled on the question of imputed debt or debt equivalence of PPAs in Decision 04-12-047 dated December 16, 2004. In that decision it states:

> We decline to adopt a formal debt equivalence policy. However, we do recognize that debt equivalence associated with PPAs can affect utility credit ratios, credit ratings, and capital structure. Credit rating agencies have long recognized debt equivalence as a risk factor and we have and will continue to reflect the impact of such risk in establishing a fair and reasonable ROE and in approving a balanced ratemaking capital structure. In that regard, we have identified information that

> the utilities should provide in their annual cost of capital applications to enable us to better assess debt equivalence risks. Our goal is to provide the utilities with a fair and reasonable ROE and ratemaking capital structure that, among other matters, support investment-grade credit ratings.

The Florida Public Service Commission, in a decision in March 2004 (Docket 031093-EQ), ruled that it is appropriate for Florida Power and Light to account for imputed debt and make an equity adjustment to reduce the price paid for power purchase from small QFs under PURPA.

> We have repeatedly found that consideration of any application of an equity adjustment should be evaluated on a case-by-case basis. We have reviewed FPL's petition, the cited S&P article, and past Commission decisions regarding the application of an equity adjustment in general, and for purposes of determining capacity payments under a Standard Offer Contract, in particular. At our request, FPL provided additional support for its position in the form of a second S&P report dated October 21, 2003. In this report, S&P indicates that it applies a 30% risk factor in its evaluation of purchased power obligations as part of its determination of the consolidated credit profile of FPL Group. Based on the above, we believe it is appropriate in this instance for FPL to make an equity adjustment as stated in the determination of capacity payments in its Standard Offer Contract.

*S&P Imputed Debt Methodology*

In general, imputed debt is described in the 1994 update of S&P 1992 Corporate Finance Criteria.

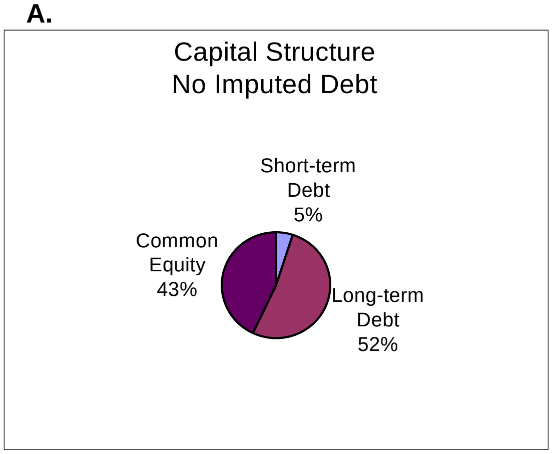
> To analyze the financial impact of purchased power, S&P employs the following financial methodology. The net present value of future annual capacity payments (discounted at 10 percent), multiplied by a "risk factor" (which in PSE's case is 30 percent) represents a potential debt equivalent—the off-balance sheet obligation that a utility incurs when it enters into a long-term purchase power contract.

PSE's Least Cost Plan, and screening of potential resource acquisitions, will include 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 Least Cost Plan 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 30 percent, a change that occurred in May 2004. Prior to this recent change, PSE contracts had risk factors between 15 percent and 40 percent. Imputed debt is the sum of the present value, using a 10 percent discount rate and a mid-year cash flow convention, of this risk adjusted fixed obligation. The cost of imputed debt is the equity 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.

Including $400 million of imputed debt into an illustrative capital structure reduces the equity component from 43 percent to 39 percent. See Exhibit IV-4 for the calculations contained in Exhibits IV-5.1 and IV-5.2.

**Exhibit IV-4**

**A.**




**B.**

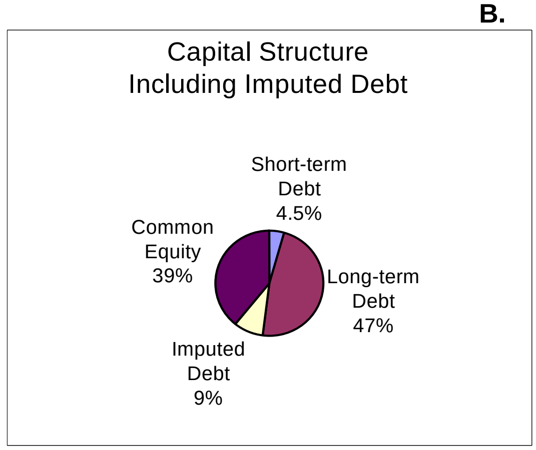


**Exhibit IV-5.1**
**PSE Illustrative Base Case - Excluding Imputed Debt**

| Capital Component | Illustrative Amount | Capital Structure | Cost Rate | Pre-tax WACC | WACC | After-tax WACC |
|---|---|---|---|---|---|---|
| Short-term Debt | $200,000 | 5.00% | 5.00% | 0.25% | 0.25% | 0.16% |
| Long-term Debt | $2,080,000 | 52.00% | 7.15% | 3.72% | 3.72% | 2.42% |
| Imputed Debt | | | | | | |
| Common Equity | $1,720,000 | **43.00%** | **10.30%** | **6.81%** | 4.43% | 4.43% |
| Total | $4,000,000 | 100.00% | | **10.78%** | **8.40%** | **7.01%** |

**Exhibit IV-5.2**
**PSE Illustrative Base Case - Including Imputed Debt**

| Capital Component | Illustrative Amount | Capital Structure | Cost Rate | Pre-tax WACC | WACC | After-tax WACC |
|---|---|---|---|---|---|---|
| Short-term Debt | $200,000 | 4.55% | 5.00% | 0.23% | 0.23% | 0.15% |
| Long-term Debt | $2,080,000 | 47.27% | 7.15% | 3.38% | 3.38% | 2.20% |
| Imputed Debt | **$400,000** | 9.09% | 10.00% | 0.91% | 0.91% | 0.59% |
| Common Equity | $1,720,000 | **39.09%** | **10.30%** | **6.19%** | 4.03% | 4.03% |
| Total | $4,400,000 | 100.00% | | **10.71%** | **8.55%** | **6.97%** |

Exhibit IV-6 shows that the financial ratios with imputed debt are eroding PSE's financial strength as measured by the credit rating agencies. The pre-tax interest coverage ratio is reduced from 2.7 to 2.4, and the ratio of debt to capital is increased from 57 percent to almost 61 percent.

**Exhibit IV-6**

| | **No Imputed Debt** | **Includes Imputed Debt** |
|---|---|---|
| Weighted Return on Equity | 4.43% | 4.03% |
| Tax impact | / 65% | / 65% |
| Pre-tax Weighted ROE | = 6.82% | = 6.20% |
| Cost of Debt | + 3.97% | + 4.52% |
| Pre-tax Cost of Capital | = 10.79% | = 10.72% |
| Cost of Debt | / 3.97% | / 4.52% |
| Pre-tax Interest Coverage | **2.7 x** | **2.4 x** |
| S&P Benchmark for "BBB" rating | 2.2x - 3.3x | 2.2x - 3.3x |
| Ratio Debt to Capital | **57.0%** | **60.9%** |
| S&P Benchmark for "BBB" rating | 50% to 60% | 50% to 60% |

## F. Risk Management

PSE must balance numerous risk factors when obtaining energy resources to meet customer load. PSE must analyze these factors to (1) deliver reliable energy when our customers demand it, (2) serve our customers at a reasonably low cost while mitigating price volatility, and (3) enhance the value of PSE's energy resources to reduce power and gas costs. PSE utilizes risk management strategies to reduce volatility in power and gas costs, manage unused capacity, and increase the operational flexibility of assets.

The Company uses a variety of hedging tools to reduce price volatility for power customers. The Company engages in forward market fixed-price purchases (both in physical gas and power purchase contracts and through financial market derivatives) to lock in gas prices, to purchase power as needed and to acquire winter-peaking capacity hedges. In addition, PSE utilizes flexibility in its resources to store hydro energy where possible, to dispatch and displace generation as market conditions provide economic signals, and to utilize transmission to move energy from resources to load.

PSE's strategic options are constrained by several factors. Market liquidity is one constraint, as there may not be sellers of the hedge transactions sought by the Company. Market conditions may also make certain products very expensive. For example, an option contract such as a call, which is the right, but not the obligation, to purchase energy at a predetermined price, might be very attractive as a means to manage load variability risk. But in volatile markets, the cost of that option might be prohibitive. PSE's strategic options are also constrained by counterparty issues. The Company seeks to enter into transactions with a range of financially strong counterparties to reduce the risk of default by any one counterparty. Finally, as described below, PSE's own credit position can limit its ability to enter into hedging transactions.

If the Company had a higher credit rating, counterparties would extend more open credit to the Company, thereby enabling the utility to expand its hedging capacity for the power and gas portfolios without incurring costs to post collateral and without increasing debt. This benefits customers as the Company has an increased hedging capacity, without additional credit costs. With a better credit rating, PSE anticipates counterparties would be willing to sell more fixed-price supply or other hedge transactions to the Company, thereby expanding PSE’s hedging capability. While PSE would continue to develop strategy for hedging linked to price signals, fundamental analysis and risk analysis, when prices were opportunistic, PSE believes it is important to have the capacity and flexibility to hedge more, and further forward in time.

## G. Financial Consideration of Resource Types

This chapter has discussed PSE’s corporate financial challenges with regard to financial strength, credit, risk management, and imputed debt. In the course of developing its resource strategy, PSE considers how the selected resource portfolio and the individual resources impact the Company’s financial situation and conversely whether the Company's financial situation supports the resource choices.

For the generic evaluation considered in least cost planning, resources are compared on the basis of their impact to present value portfolio costs. The overall goal is to include all costs with each resource including not only direct costs like equipment, fuel, and operating costs but also quantification of financial considerations.

*Capital Requirements (Financing)*

PSE's capital requirements for resource additions need to be combined with the capital requirements for electric and gas infrastructure and other corporate needs to determine the Company's overall financing requirements.

At the expiration of non-utility generator (NUG) contracts in 2011-12, PSE could have a large capital need for resources concentrated over a short period. PSE will need to examine the timing of the acquisitions to determine whether the Company has the financial strength to support rapid-owned resource additions. Also, short-term retail rate impacts are another potential concern.

For this Least Cost Plan, PSE includes the use of short-term PBAs to cover need until long-lead time resources become available. PBAs may also be used to "stagger" resource additions to moderate the year-to-year financing requirements of owned resources.

The least cost planning analysis doesn't explicitly model the timing of regulatory recovery but this will be a consideration for specific resource acquisitions. For long-lead time resources, especially coal and possibly transmission, PSE may pursue recovery of construction work in progress.

*Credit*

Credit requirements generally apply to power purchase agreements. For this Least Cost Plan, PSE has included a monetized adder of 5 percent of the payments under a power purchase agreement to cover the credit costs for the generic PBAs. The amount is based upon the estimated cost of a letter of credit to cover PSE's credit obligations.

Credit can also apply to the fuel purchase arrangements for a natural gas plant. However, since most fuel purchase arrangements are priced at index, and the risk of non-performance is relatively low for both parties, PSE has not added a credit premium to gas resources.

Although credit is not usually a concern with coal-fueled generation, the coal industry is showing signs of developing a more robust spot price market. If the future coal market more closely resembles the natural gas market model, then credit could become an issue for coal-fueled resources. For the development model where the coal plant owner also owns the coal reserves, credit would not apply. This Least Cost Plan does not include a credit adder for coal plants.

*Price Risk*

Price risk management costs apply to resources with high price volatility – primarily index-priced power purchase agreements and natural gas-fired generation. Through the Long-term Risk Management Project, PSE is currently evaluating customer-perceived value in mitigating energy price volatility. PSE plans to use the results of this study to inform its short- and long-term price risk management strategy.

For this Least Cost Plan's generic resource evaluation, both power purchase contracts and natural gas fuel were priced at spot market without a risk management adder. This issue will be re-examined during the evaluation of specific resource acquisitions.

*Imputed Debt Cost*

Imputed debt is an indirect cost specific to power purchase agreements. PSE computed imputed debt and the associated equity offset cost adder for the generic power bridging agreements analyzed in the portfolios. A similar approach will be applied to the evaluation of specific power purchase agreements in the resource acquisition process.

# V. NATURAL GAS PRICE FORECASTS

Long-term energy resource planning requires a number of key assumptions. One of the most important assumptions, for both gas and electric resource planning, is associated with long-term natural gas prices.

The ability to accurately forecast long-term gas prices is influenced by two different types of uncertainty: uncertainty related to long-term changes in the industry, and uncertainty related to short-term gas price variability. Contributing to long-term uncertainty are long-term demand and supply issues, including growth in gas demand for generation fuel; changes in LNG import infrastructure; and pipelines to bring Alaskan and other frontier supplies to market. Short-term gas price variability also affects the long-term predictability of gas prices. Even if long-term supply and demand outcomes are exactly as projected, and their effects on gas prices are also accurately predicted, actual gas prices in future months will still reflect variability due to short-term conditions. Examples of short-term supply and demand factors that can significantly affect prices include actual weather conditions in various demand and supply areas, expected short-term future weather conditions, and storage inventory balances. In other words, even with accurate long-term projection, the actual price of natural gas in the future will be influenced by impending short-term market fundamentals.

Although gas price assumptions are important for long-term resource planning, both long- and short-term uncertainties make accurate natural gas price forecasting nearly impossible. This means analysis must take these uncertainties into consideration. This section of the Least Cost Plan explains how PSE addresses uncertainty associated with forecast gas prices, describes the gas price forecasts PSE uses for analysis, provides a range of gas price forecasts available from the Department of Energy's Energy Information Administration, and illustrates the range of gas prices PSE is using in its uncertainty analysis.

## A. Addressing Gas Price Uncertainty

Both long- and short-term uncertainties, as described above, have important implications for long-term resource planning. Different methods can be used to analyze these uncertainties.

Long-Term: Scenarios — The Company's electric and gas resource planning analyses use two methods to analyze the impacts of gas price uncertainty on long-term resource planning.

First, PSE uses scenario analysis. Scenario analysis is helpful because it takes into consideration the potential for entirely different gas market conditions in the future. That is, scenarios are used to define different potential gas price paths into the future. PSE's use of the Cambridge Economic Research Associates (CERA) scenario for gas prices provides a reasonable and robust range of potential market conditions. The levelized difference between the CERA gas price scenarios is approximately 27 percent of the low price scenario. This range of potential prices is considerably wider than the 9 percent range in estimated AECO prices based on the Energy Information Administration's (EIA's) 2005 Annual Energy Outlook scenarios shown in Exhibit V-2 (below).

Short-Term: Monte Carlo Analysis — As described above, scenario analysis is helpful in examining the impacts of possible alternative price paths into the future. However, Monte Carlo analysis, by modeling uncertainty as a probability distribution, is helpful for analyzing the effect that short-term market conditions can have on a particular long-term price path. Exhibit V-3 illustrates the approximate range of uncertainty from PSE's gas resource planning analysis using Vector Gas (Details of the Monte Carlo analysis are presented in Appendix H.). The spread between the 5$^{th}$ and 95$^{th}$ percentiles shown is approximately $6.37, or 240 percent of the 5$^{th}$ percentile price.

## B. Gas Price Forecasts Used by PSE

PSE, like many utilities, uses forward market prices for a period of time into the future, then switches over to a long-term fundamental gas price forecast. The Company uses forward market quotes for the first two years of the planning horizon, then relies on long-term fundamental forecasts for periods beyond the first two years. Markets for the first two years are reasonably liquid, and provide reasonable forward price expectations. Also, this two-year time frame lines up with PSE's short-term energy management period, thus information out two years is collected, analyzed regularly, and used for managing the portfolio.

In relying on forward market prices, the Company does not use a single point estimate of forward prices on a given day. During the Company's recent General Rate Case, both PSE and Washington Utilities and Transportation Commission (WUTC) staff performed detailed analysis to identify a reasonable method for using forward price information to project gas prices. Consistent with the results of the General Rate Case, PSE is using a three month average of forward prices collected during December 2004 as the basis for its gas prices for 2005-06. The same short-term prices are used in each scenario.

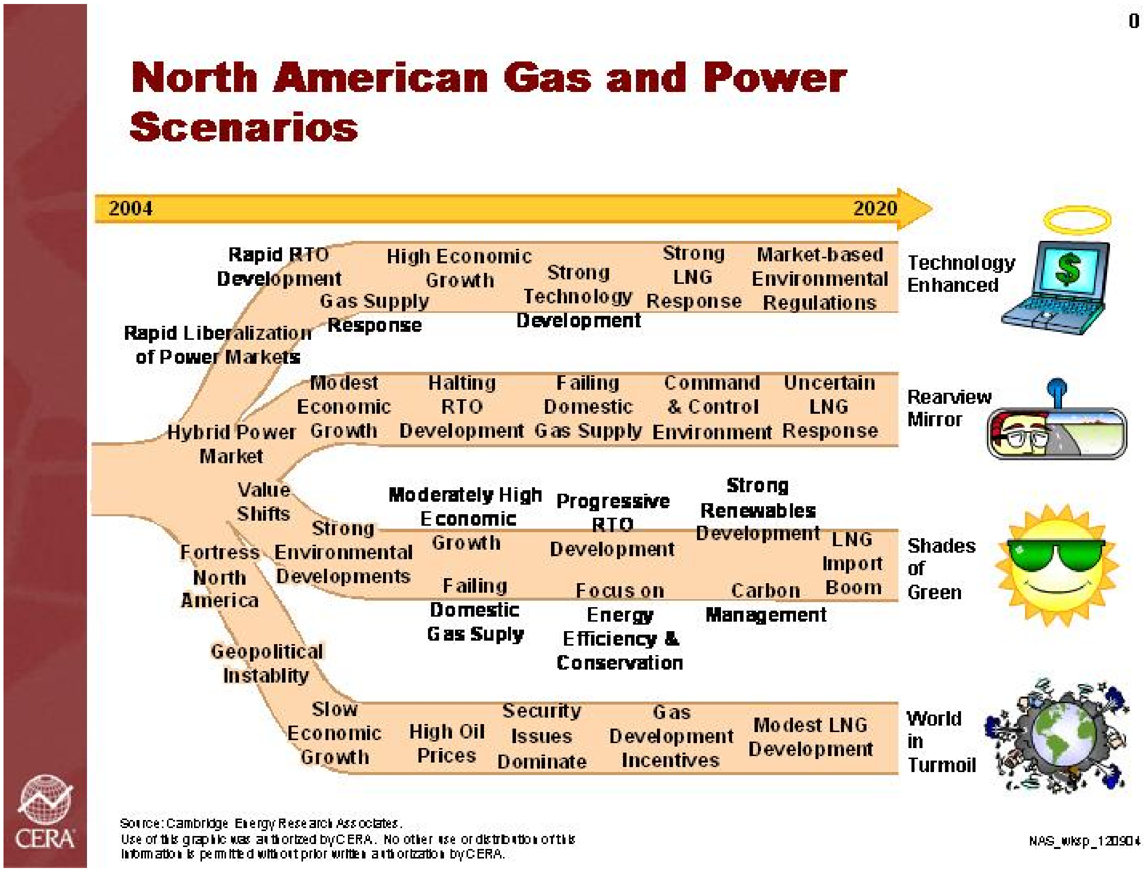
For the long-term period (2007 and beyond), PSE is using a set of fundamental gas price forecasts for its scenario analysis. A "fundamental gas price forecast" means the Company is using gas prices that result from a comprehensive analysis of supply and demand balances at regional, North American, and international (pertaining to Canadian markets and international LNG) levels. Gas prices in the Pacific Northwest are affected by regional changes in supply and demand. Changes in demand and natural gas infrastructure across North America also affect the region's gas prices, particularly in the long run. For example, additional LNG imports in the Gulf of Mexico could increase the supply of gas to Chicago, decreasing the demand for Alberta and Rockies gas to flow east out of AECO and Southwestern Wyoming. Similarly, changes in Eastern U.S. coal prices could affect the demand for gas generation fuel in that region, the demand implications of which would likewise ripple through the Midwest, into the Rockies, and to AECO. A comprehensive long-term gas price model requires analysis of each element of supply and each element of demand, including an analysis of the supply and demand of gas substitute fuels (such as coal), an analysis of how the supply and demand issues are related across the entire North American continent given changing energy infrastructure, and consideration of changing global LNG infrastructure.

PSE does not maintain a large staff of energy economists and engineers to perform this comprehensive analysis. There are many international consulting firms, each staffed with economists and engineers, whose sole focus is to gather data and forecast both short- and long-run energy prices. Purchasing long-term price forecasts from these firms allows PSE to obtain the results of their expertise at a fraction of what it would cost to develop and maintain a long-term fundamental price forecasting model internally. Additionally, there are publicly available long-term gas price forecasts that are published annually, such as the Energy Information Adminstration's Annual Energy Outlook. The trade-off for this efficiency is that PSE is not entitled to review the proprietary details of how each forecast is calculated.

Although the Company cannot review proprietary details of gas price forecasts, PSE does supplement such price forecasts with additional analysis of its own. For example, PSE performs two different kinds of uncertainty analysis—scenarios and Monte Carlo analysis. Thus, while PSE performs resource analysis that assumes forecast prices will follow the Company's expectations, the Company also performs analysis of the implications of gas prices that do *not* do as the Company expects. These uncertainty analyses are supplemented with PSE's review of different long-term gas price forecasts, a comparison of important assumptions, a comparison of results, and the application of judgment by experienced PSE analysts and senior management. In short, PSE's use of externally generated long-term gas price forecasts and the manner in which those forecasts are reviewed and used combine the best of internal analysis with external analysis to derive gas price forecasts.

After reviewing a number of long-term gas price forecasts, PSE chose to use long-term fundamental gas price forecasts from Cambridge Economic Research Associates (CERA). Two years ago, PSE participated in a published multi-client- study titled "New Realities, New Risks: North American Power and Gas Scenarios through 2020," which is updated by CERA annually and funded by clients. The study includes a comprehensive set of fundamental gas price forecasts based on different but plausible worldwide circumstances. The strength of the CERA scenarios study is that expertise from CERA's natural gas consulting section, the coal consulting section, electricity consulting section, world LNG consulting section, and world petroleum consulting section were brought together to provide a consistent set of assumptions for each of four different scenarios. Additionally, CERA's study provides monthly gas price forecasts for each of the pricing points needed for PSE's electric and gas resource planning analysis. Monthly shaping or non-fundamental analysis to create basis differentials to other price points is unnecessary. Overall, the CERA study provides a reasonable set of widely divergent potential outcomes well suited for PSE's scenario analysis. Exhibit V-1 briefly summarizes the concepts underlying each scenario from the CERA study.

**Exhibit V-1**




PSE's resource planning analysis uses three of the four CERA scenarios. For the gas Base Case and power Business as Usual case, PSE is using the CERA Rearview Mirror forecast. Shades of Green and World in Turmoil are higher and lower price forecasts, and are used consistently in PSE's planning scenarios. For an explanation of how the specific gas price forecast was used in the context of each scenario, please refer to the sections of this Least Cost Plan that describe the electric and gas planning scenarios.

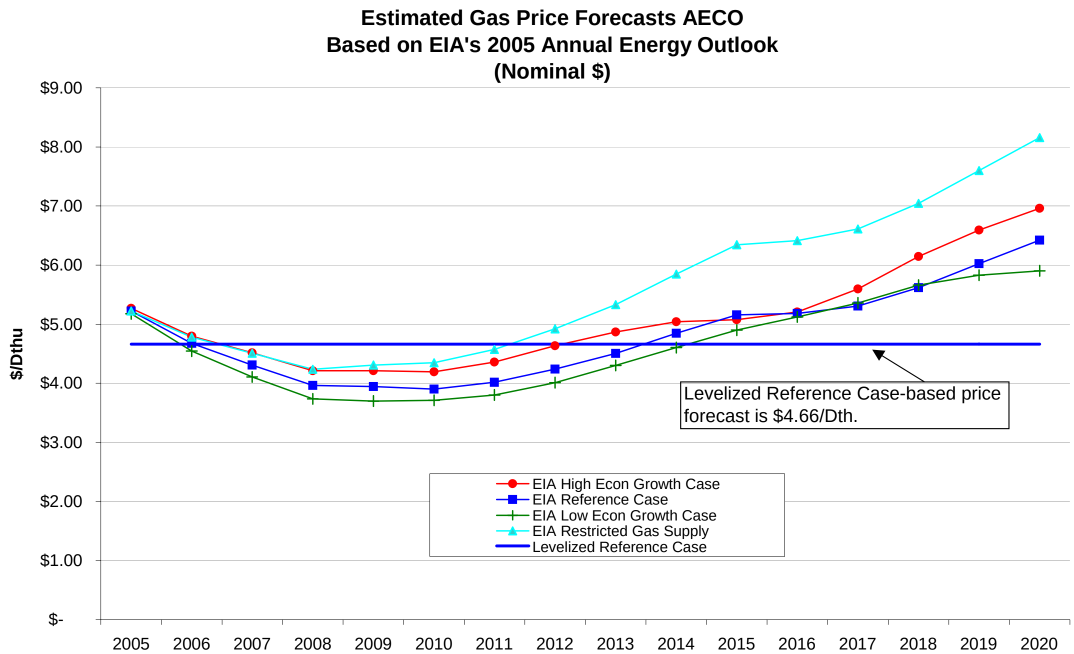
## C. Gas Prices

PSE believes that the CERA gas price forecasts are reasonable, and that they offer advantages not found in publicly-available gas price forecasts. However, by using a proprietary gas price forecast, the Company is precluded from disclosing the forecast to the public. Failure to protect the intellectual property rights of proprietary forecasts would undermine the economic basis of the forecasting industry. PSE weighed the disadvantages and inconvenience of withholding the proprietary long-term gas price forecast used in its long-term planning with the consequences of using a forecast that the Company considers less reasonable. It is not practical for PSE to use a long-term gas price forecast for least cost planning efforts if that same forecast is not used to make resource acquisition decisions. Such an exercise would render the long-term planning process useless to the Company. However, a brief discussion and presentation of publicly-available gas prices published by the EIA in its 2005 Annual Energy Outlook is provided here (see Exhibit V-2). While these gas price scenarios are not used in PSE's analysis, they are generally representative of PSE's long-term gas price expectations, and may be informative.

North American gas supply and demand is essentially at equilibrium. Robust demand growth, primarily in electric generation, declines in the growth rate of new supplies, and continued drop-off in production of existing supplies have eliminated the overall surplus that kept prices low for nearly a decade. While overall supplies are adequate, current market prices rise and fall to ration supply regionally. Long-term gas prices in this Least Cost Plan analysis are about 44 percent higher than those reflected in the Company's April 2003 Least Cost Plan, and 29 percent higher than the August 2003 Least Cost Plan Update. The higher forecast prices reflect the economics needed to continue to ration capacity, while providing the necessary incentive to increase the rate of new supply development.

In general, gas prices are expected to remain relatively high. However, the long-term fundamental price path is expected to begin falling off as increased LNG imports affect gas prices. EIA's report shows LNG imports in 2005 at .75 BCF per day (3.3 percent of supply), and growing to 2.5 BCF per day by 2010 (nearly 10 percent of total supply). Prices are then expected to rise again, as demand growth increases, until about 2015, when Alaska Frontier, Alaskan gas and additional LNG supplies stabilize prices for a few years. After that, prices will continue to climb.

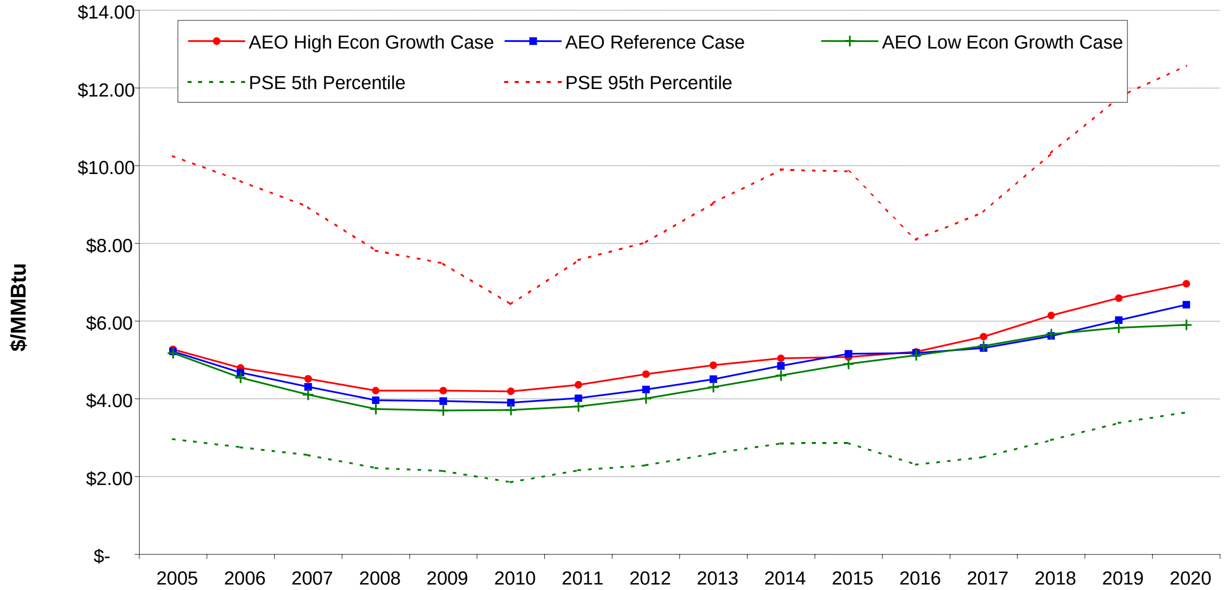
# Exhibit V-2
# AECO Gas Price Forecast Based on EIA 2005 Annual Energy Outlook




Note: AEO 2005 real prices adjusted to AECO using the NWPPC factor of EIA -$0.33/Dth and an assumed inflation factor of 2.5% to convert from real 2003$ to nominal $.

Prices for Restricted Gas Supply based on increases reported in AEO for 2015 and 2025.

**Exhibit V-3**
**Gas Price Forecasts AECO (Nominal $)**




Note: AEO 2005 real prices adjusted to AECO using the NWPPC factor of EIA -$0.33. MMBtu and an assumed inflation factor of 2.5% to convert from real 2003$ to nominal $.

Note: The PSE 5th and 95th percentiles do not represent CERA scenarios. These represent the range of variability around PSE's long-term expected price forecast based on Monte Carlo analysis using Vector Gas.

## Exhibit V-4
## EIA Long-Term Gas Price Forecast Scenarios

Estimated Nominal AECO Prices

| | AEO High Econ Growth Case | AEO High Oil Price Case | AEO Reference Case | AEO Low Oil Price Case | AEO Low Econ Growth Case |
|---|---|---|---|---|---|
| 2005 | $ 5.27 | $ 5.22 | $ 5.22 | $ 5.22 | $ 5.18 |
| 2006 | $ 4.80 | $ 4.67 | $ 4.67 | $ 4.68 | $ 4.55 |
| 2007 | $ 4.52 | $ 4.33 | $ 4.31 | $ 4.30 | $ 4.11 |
| 2008 | $ 4.21 | $ 3.98 | $ 3.96 | $ 3.93 | $ 3.74 |
| 2009 | $ 4.21 | $ 3.95 | $ 3.94 | $ 3.89 | $ 3.70 |
| 2010 | $ 4.19 | $ 3.94 | $ 3.90 | $ 3.87 | $ 3.71 |
| 2011 | $ 4.36 | $ 4.08 | $ 4.02 | $ 3.99 | $ 3.80 |
| 2012 | $ 4.64 | $ 4.29 | $ 4.24 | $ 4.20 | $ 4.01 |
| 2013 | $ 4.87 | $ 4.56 | $ 4.50 | $ 4.42 | $ 4.30 |
| 2014 | $ 5.04 | $ 4.87 | $ 4.85 | $ 4.74 | $ 4.60 |
| 2015 | $ 5.08 | $ 5.14 | $ 5.16 | $ 5.02 | $ 4.90 |
| 2016 | $ 5.21 | $ 5.28 | $ 5.18 | $ 5.30 | $ 5.12 |
| 2017 | $ 5.60 | $ 5.29 | $ 5.31 | $ 5.49 | $ 5.36 |
| 2018 | $ 6.14 | $ 5.51 | $ 5.62 | $ 5.52 | $ 5.66 |
| 2019 | $ 6.59 | $ 5.89 | $ 6.02 | $ 5.78 | $ 5.83 |
| 2020 | $ 6.96 | $ 6.46 | $ 6.42 | $ 6.10 | $ 5.90 |

## Exhibit V-5
## EIA Gas Supply Table—Reference Case

| | Production | | Imports | | | | |
|---|---|---|---|---|---|---|---|
| | Dry Gas Production 1/ | Supp Natural Gas 2/ | Canada | Mexico | Liquefied Natural Gas 3/ | Net Imports | Total Supply |
| 2002 | 18.96 | 0.07 | 3.60 | -0.26 | 0.17 | 3.50 | 22.53 |
| 2003 | 19.07 | 0.06 | 3.13 | -0.33 | 0.44 | 3.24 | 22.37 |
| 2004 | 18.91 | 0.07 | 2.99 | -0.34 | 0.63 | 3.28 | 22.26 |
| 2005 | 19.27 | 0.07 | 3.00 | -0.38 | 0.75 | 3.37 | 22.72 |
| 2006 | 19.24 | 0.08 | 2.89 | -0.39 | 1.14 | 3.64 | 22.96 |
| 2007 | 19.49 | 0.08 | 2.74 | -0.29 | 1.30 | 3.75 | 23.31 |
| 2008 | 19.90 | 0.08 | 2.56 | -0.18 | 1.76 | 4.13 | 24.11 |
| 2009 | 20.44 | 0.08 | 2.47 | -0.08 | 1.80 | 4.20 | 24.72 |
| 2010 | 20.42 | 0.08 | 2.57 | -0.14 | 2.50 | 4.94 | 25.44 |
| 2011 | 20.91 | 0.08 | 2.69 | -0.20 | 2.67 | 5.16 | 26.14 |
| 2012 | 21.17 | 0.08 | 2.73 | -0.22 | 2.99 | 5.50 | 26.75 |
| 2013 | 21.07 | 0.08 | 2.75 | -0.25 | 3.55 | 6.05 | 27.20 |
| 2014 | 21.16 | 0.08 | 2.83 | -0.27 | 3.82 | 6.38 | 27.61 |
| 2015 | 20.77 | 0.08 | 2.98 | -0.29 | 4.33 | 7.02 | 27.86 |
| 2016 | 20.85 | 0.08 | 2.97 | -0.32 | 4.78 | 7.43 | 28.35 |
| 2017 | 21.63 | 0.08 | 2.81 | -0.34 | 4.78 | 7.26 | 28.96 |
| 2018 | 22.06 | 0.08 | 2.82 | -0.36 | 4.79 | 7.25 | 29.38 |
| 2019 | 22.05 | 0.08 | 2.76 | -0.38 | 5.16 | 7.54 | 29.66 |
| 2020 | 21.89 | 0.08 | 2.69 | -0.35 | 5.54 | 7.89 | 29.85 |
| 2021 | 21.77 | 0.08 | 2.77 | -0.31 | 5.65 | 8.11 | 29.96 |
| 2022 | 21.54 | 0.08 | 2.80 | -0.26 | 5.94 | 8.48 | 30.10 |
| 2023 | 21.41 | 0.08 | 2.70 | -0.28 | 6.27 | 8.69 | 30.17 |
| 2024 | 21.69 | 0.08 | 2.64 | -0.30 | 6.37 | 8.71 | 30.47 |
| 2025 | 21.83 | 0.08 | 2.55 | -0.25 | 6.37 | 8.66 | 30.56 |
| 2025 | 0.6% | 0.7% | -0.9% | -1.2% | 12.9% | | 1.4% |

1/ Marketed production (wet) minus extraction losses.
2/ Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, commingled and distributed air injected for Btu stabilization, and manufactured gas with natural gas.
3/ Includes any natural gas regasified in the Bahamas and transported via pipeline to Florida.

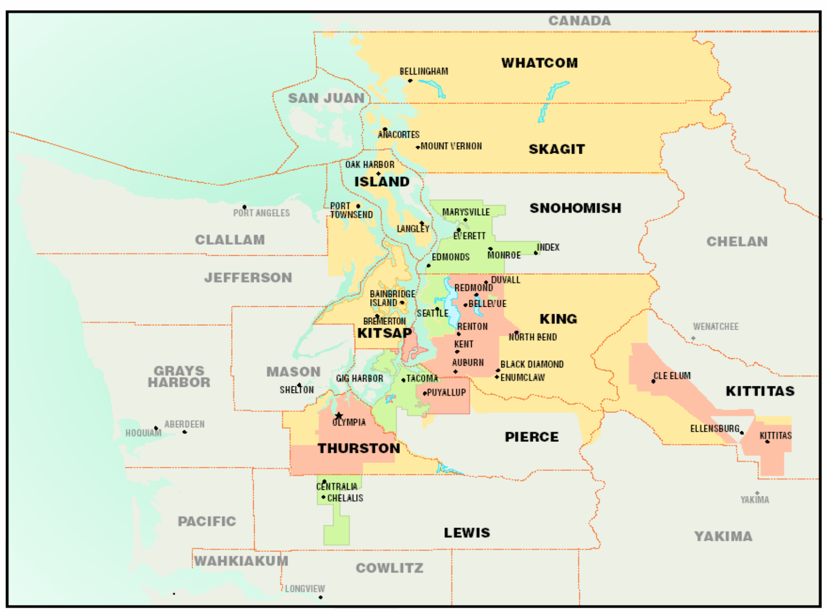
# VI. DEMAND FORECAST

## A. Overview

Each year, PSE develops a 20-year forecast of customers, energy sales and peak demand for its electric and gas service territories. PSE uses the forecast for short-term planning activities such as the annual revenue forecast, marketing and operations plans, and in various long-term planning activities such as the Least Cost Plan, and in its transmission and distribution planning. This chapter provides a description of the Company's long term load forecasting process. It provides an explanation of the forecast methodology for its customer counts, sales and peak demand forecasts and explains the sources of forecast inputs. This chapter concludes by discussing the electric and gas load forecasts for the next 20 years. Appendix K provides a more in-depth discussion of the technical forecast methodology, followed by a discussion of the methodology used to convert a monthly billed sales forecast to an hourly delivered load forecast.

PSE's electric service territory covers nine counties in the state (Whatcom, Skagit, Island, King, Kittitas, Pierce, Thurston, Kitsap and Jefferson), while the gas service territory covers six counties (King, Snohomish, Pierce, Thurston, a small portion of Kittitas, and Lewis). The residents in these counties account for about two-thirds of the state's population.

**PUGET SOUND ENERGY SERVICE TERRITORY**




Combined electric and natural gas service
Electric service
Natural gas service

Puget Sound Energy's service territories:
**Electric Service**: Island, Jefferson, parts of King (not Seattle), Kitsap, Kittitas, Pierce (not Tacoma), Thurston, Skagit and Whatcom counties. (Public utility districts also serve parts of some counties.)
**Natural Gas Service**: King, Lewis, Pierce, Snohomish, Thurston and parts of Kittitas counties.

Puget Sound Energy is Washington state's largest energy utility, providing electric and natural gas service to more than 1.2 million customers, primarily in Washington state's Puget Sound region.

PSE PUGET SOUND ENERGY

## B. Forecast Methodology

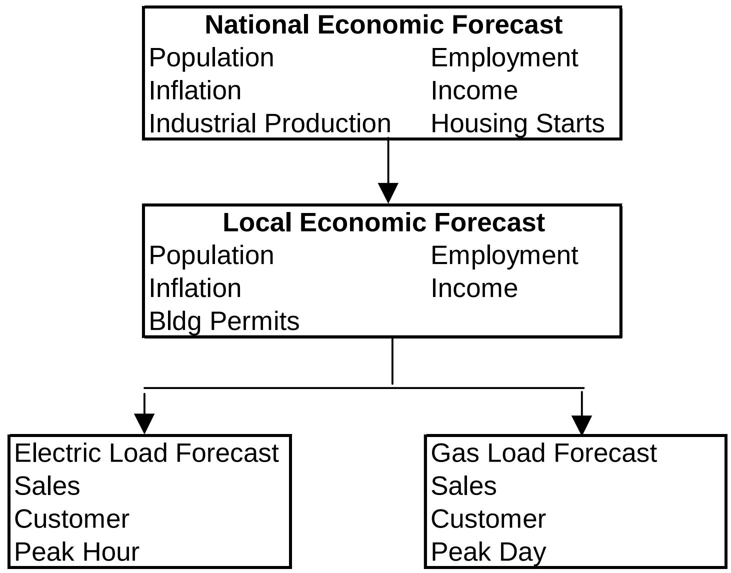
The Company primarily relies on econometric methods to produce its load forecasts. This section provides a general description of the three econometric methodologies used to forecast a) billed energy sales and customer counts, b) system peak loads and c) hourly distribution of loads.

*Billed Energy Sales and Customer Counts Forecasts*

PSE designed its forecasting process to provide monthly forecasts of customers and billed sales at the customer class and service territory levels. The five electric customer classes are residential, commercial, industrial, streetlights and resale. The eleven gas customer classes by customer type are firm (residential, commercial, industrial, commercial large volume, and industrial large volume), interruptible (commercial and industrial interruptible), and transportation (commercial firm, commercial interruptible, industrial firm and industrial interruptible).

The forecasting models are premised upon electricity or gas as inputs into the production of various economic activities. In the case of the residential sector, customer uses include space heating; water heating; lighting; cooking; refrigeration; dish washing; laundry washing; and various other plug loads. In the case of the commercial and industrial sectors, these activities include heating, venting, and air conditioning (HVAC); lighting; computers; and other production processes. Since energy is an input to these economic activities, the economic and demographic conditions at the national and local levels drive the demand for energy. Exhibit VI-1 below provides a general overview of the relationships between the national and local economic inputs vis-à-vis the forecast of energy outputs.

**Exhibit VI-1**
**PSE Forecasting Model Overview**




PSE relies upon an econometric approach to develop the demand for electricity or gas at the customer class level. The forecasting models use historical data to develop trends in average use per customer and customer counts, accounting for economic and demographic changes, temperature sensitivity, responsiveness to rates, and impacts of conservation and other changes in customer usage and behavior, including known near-term load additions or deletions. Billed sales in the month are defined as the sum of the billed sales across all customer classes, where billed sales for each class are estimated from the product of sales per customer equations and the customer count equations. For a more detailed discussion of PSE's billed sales and customer forecast methodology, please refer to Appendix K, Description of the Load Forecasting Models.

*Peak Load Forecasts*

PSE projects peak load forecasts for the next 20 years to support planning for peak capacity requirements, and long-term distribution and transmission planning activities. For electric, the peak hour for the normal and extreme design temperatures represent the relevant range of peak loads. Peak hourly loads for electric are projected for 23-degree, 16-degree, and 13-degree Fahrenheit design temperatures. For gas, PSE uses peak day for the design day temperature to represent its relevant peak for gas using a 52-degree day design temperature. Peak load forecasts are also developed via econometric equations. Observed monthly peak loads are regressed against weather sensitive delivered sales from both residential and non-residential sectors, with deviations of actual peak hour temperature from normal peak temperature for the month, with day of the week effects, and with unique weather events such as a cold snap or El Nino. Given the forecasts of weather and non-weather sensitive delivered sales, normal system peak loads are then developed for the designed temperatures. A more detailed discussion of the peak load forecasting models is presented in Appendix K.

*Hourly Load Profile*

Electricity demand and production has a level of complication beyond that of natural gas demand and production: its lack of storability. Because there is no way to store large amounts of electricity in a practical manner, the momentary 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 electricity demand is required.

The load profile of PSE's system demand was constructed to resemble a typical year of hourly usage incorporating variations due to i) time of day, ii) day of week, iii) month of year, iv) typical temperature variation, v) and holidays. The use of this hourly load profile is different from most load forecasts developed for forecasts. Often it is typical for the forecaster to assume normal temperatures in order to get an "expected" or average load. Because electricity demand is so temperature volatile on a momentary basis, it is important to evaluate how a new resource will impact the supply portfolio in meeting this load. The calculation of the hourly load profile followed these steps:

1. A historical relationship was developed between the components (i-v) listed above and total system load (MWh) for the period 1/1/1994 – 12/16/2004 using an econometric equation.
2. A single year hourly temperature profile (8760 hours) was constructed from NOAA hourly observed data at Seattle-Tacoma International Airport between 1/1/1950 and 12/31/2003. In a process of ranking, sorting and averaging the data the resultant profile provides typically observed temperatures and typically observed times.
3. By forecasting electricity demand using the regression equation developed in step 1 for the year 2005 and using the temperature profile developed in step 2, a profile of electricity load using variable temperature was developed.

A more detailed explanation of the methodology used to develop the hourly load profile is presented in Appendix K.

## C. Key Forecast Assumptions

Energy use forecasts for long-term planning purposes are based primarily on economic activity and fuel prices. Regional economic growth results in increased employment and a greater demand for electricity. Economic growth also increases the number of customers, as more people move to the region for jobs. Retail energy prices affect the type of fuel used in appliances, as well as the efficiency of the appliances and levels of use. Conservation and other programs instituted by PSE and neighboring utilities also affect energy consumption. The following section presents the forecasts of economic and demographic variables, retail prices, conservation savings, and other key assumptions used in this forecast.

*Economic and Demographic Assumptions*

The Puget Sound area is a major commercial and manufacturing center in the Pacific Northwest, with strong links to the national and state economies. These links create jobs not only for directly affected industries, but also indirectly for supporting industries through multiplier effects. This means the performance of the national and regional economies impacts PSE's service territory economy.

*National Economic Outlook.*

The "May 2003 US Forecasts" prepared by Global Insight provides a long-term national economic outlook. The forecast predicts only mild variations in growth over the next 25 years. After recording its first recession in about 10 years in 2001, the national economy grew at about 2.3 percent in 2003, and is projected to follow its historical (1970-2003) growth rate of approximately 3.1 percent over the next 20 years. This projection is based on the expectation that advances in technology will result in higher productivity and efficiencies, even though the percentage of employed Americans will decline as the population ages. Exhibit VI-2 summarizes the national economic forecasts used as inputs to the model.

**Exhibit VI-2**
**National U.S. Economic Outlook**

| | 2004 | 2005 | 2010 | 2015 | 2020 | 2024 | aarg |
|---|---|---|---|---|---|---|---|
| GDP (96$B) | $ 10,161.5 | $ 10,537.7 | $ 12,311.2 | $ 14,184.6 | $ 16,263.4 | $ 17,925.8 | 3.1% |
| Employment (mill) | 131.9 | 134.9 | 144.4 | 152.5 | 160.0 | 164.3 | 1.0% |
| Population (mill) | 294.2 | 296.8 | 309.3 | 322.0 | 334.7 | 345.0 | 0.8% |

*aarg: average annual rate of growth*

A national economic recovery is underway. The U.S. economy experienced one of its more robust growth years in 2004. That trend is expected to continue at a more moderate level in 2005, bolstered by continuing consumer spending, but aided this time by business investment which was not present in the last three years. Federal spending may level off slightly; however, exports are expected to gain ground again. As a result, the Federal Reserve Board recently started increasing the federal funds rate to pre-empt inflation pressures.

*Regional Economic Outlook.* During the next two decades, PSE expects employment in the counties that it serves to grow at a slower rate (1.6 percent) compared to its 30-year historical growth rate of 3.3 percent per year. Factors contributing to the long-term slower growth in employment include not only the recession in 2001 to 2003, but also an expectation that Boeing's more efficient production processes will not provide the historical employment highs of 2000. Even at this rate, the Company projects that local employers will create approximately 630,000 jobs between 2004 and 2024—more than one-third of the jobs in the area today. During this period, 750,000 new residents are expected to live in the counties that PSE currently serves, raising the population to about 4.1 million. At the start of the decade (2001-2003), the regional economy experienced one of its worst recessions in the last 20 years, with employment declining in 2002 by about 2 percent. Nearly 30,000 company-wide layoffs at Boeing, and additional layoffs in the high technology and telecom sectors, contributed to this recession. The 2002 decline in employment impacted the region significantly, with a return to the peak employment levels of 2000 not likely until later in 2005. Employment, however, was expected to grow by a modest 1.6 percent in 2004. Exhibit VI-3 summarizes the employment and population data used as inputs.

**Exhibit VI-3**
**Service Area Economic Growth Assumptions**

| | 2004 | 2005 | 2010 | 2015 | 2020 | 2024 | aarg |
|---|---|---|---|---|---|---|---|
| ***Electric Service Area*** | | | | | | | |
| Employment (thous.) | 1,705.2 | 1,747.3 | 1,949.5 | 2,093.3 | 2,231.9 | 2,343.5 | 1.6% |
| Population (thous.) | 3,415.3 | 3,448.7 | 3,664.7 | 3,835.6 | 4,011.5 | 4,167.7 | 1.0% |
| ***Gas Service Area*** | | | | | | | |
| Employment (thous.) | 1,686.6 | 1,724.8 | 1,924.1 | 2,065.5 | 2,204.9 | 2,317.3 | 1.6% |
| Population (thous.) | 3,393.7 | 3,423.5 | 3,641.3 | 3,816.3 | 3,996.7 | 4,156.6 | 1.0% |

*aarg: average annual rate of growth*

Most of the long-term growth in employment is expected to come from the service sectors, including business services and computer industries. Not all counties will grow at the same pace. Estimates indicate that smaller counties such as Island County and Jefferson County will experience higher percentage growth rates compared to King County. However, the absolute amount of jobs created will still be higher in King County than in the smaller counties.

*Retail Energy Price Assumptions.*

PSE's electric demand models require the forecasting of retail energy prices. The efficiency levels of new appliances, frequency of use, and the type of fuel used to operate them all are affected by energy prices. Exhibit VI-4 shows electric and gas retail rate forecasts over the next 20 years for residential, commercial and industrial customer classes.

**Exhibit VI-4**
**Retail Rate Forecasts**

| (nominal) | 2004 | 2005 | 2010 | 2015 | 2020 | 2024 | aarg |
|---|---|---|---|---|---|---|---|
| ***Residential*** | | | | | | | |
| Electric, cent/kwh | 6.30 | 6.95 | 8.95 | 10.18 | 11.60 | 12.78 | 3.6% |
| Natural Gas, $/therm | 0.90 | 1.10 | 0.93 | 1.17 | 1.34 | 1.41 | 2.3% |
| ***Commercial*** | | | | | | | |
| Electric, cent/kwh | 7.04 | 7.40 | 8.07 | 9.27 | 10.90 | 12.46 | 2.9% |
| Natural Gas, $/therm | 0.80 | 0.98 | 0.80 | 1.04 | 1.20 | 1.27 | 2.4% |
| ***Industrial*** | | | | | | | |
| Electric, cent/kwh | 6.67 | 7.03 | 7.67 | 8.82 | 10.36 | 11.85 | 2.9% |
| Natural Gas, $/therm | 0.73 | 0.92 | 0.73 | 0.97 | 1.14 | 1.20 | 2.5% |

*aarg: average annual rate of growth*

The forecast for electric rates assumes a small rate increase due to a general rate case and due to power cost adjustments over the next two years. To determine long-term retail rates, PSE used Global Insight's forecast of electric rates for the state, and adjusted these rates to provide starting points in line with PSE's retail rates. PSE assumes real electricity prices (i.e., nominal prices adjusted for inflation) will be flat or will grow only moderately over time due to competitive pressures resulting in reduced costs, additional capacity in regions lacking sufficient energy supply, declining coal prices, and greater efficiency in new generation technologies. Based on Global Insight's model, the Northwest is expected to increase generation—mostly in the form of gas-fired facilities, with small amounts of coal and wind power required by governmental mandates. As most of the region continues to rely on gas for new generation, the prices are likely to become more similar to the average for the region. Exhibit VI-4 illustrates that electric rates will grow between 2.9 percent and 3.6 percent over the next 20 years. Given the average rate of inflation (about 3 percent), this means real electric rates will be flat.

Over the next 20 years, gas retail rates are expected to increase from 2.3 percent to 2.5 percent per year, which is slightly lower than the long-term rate of inflation. Near-term, the forecast accounts for the most recent increase in gas cost through the PGA in October 2004, and for a small rate increase due to a general rate case in 2005. PSE bases its long-term growth rates in gas on Global Insight's forecast for the distribution margin and CERA's Rearview Mirror scenario for the gas cost. Chapter V provides a more detailed discussion of the gas cost forecast. CERA's Rearview Mirror scenario assumes that the marginal cost of gas will increase with the depletion of lower cost reserves, and with growing transportation costs as gas becomes available in more remote markets. However, the impact of an increasing supply cost on long-term gas prices will be limited by the potential for higher LNG and Alaskan gas imports, and by the demand response to higher prices. Demand response would include use of alternate fuel, lower thermostat settings, plant shutdowns, and moving gas-intensive industries to countries with lower-cost fuels. In summary, PSE expects gas retail rates to remain virtually unchanged in real terms.

*Conservation Savings Assumptions*

The 2005 Least Cost Plan starts with a no conservation load forecast scenario. Because the start year of the Least Cost Plan analysis is 2006, PSE assumes that conservation targets for 2004 and 2005 established in the 2003 Least Cost Plan are achieved in this scenario. Hence, some conservation is present even in a no conservation scenario for Least Cost Plan analysis.

Exhibit VI-5 illustrates the relative effects of a megawatt of conservation savings achieved from each customer class by month. For example, one megawatt saved by a residential customer in January would reduce on-peak demand by 1.45 aMW. One megawatt saved in January by a commercial customer, on the other hand, would reduce peak by 1.16 aMW.

**Exhibit VI-5**
**Assumed On-Peak Contributions per aMW of Conservation by End-Use Sector**

| Class | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 1.45 | 1.32 | 1.09 | 0.96 | 0.83 | 0.75 | 0.69 | 0.7 | 0.73 | 0.86 | 1.23 | 1.39 |
| Commercial | 1.16 | 1.12 | 0.97 | 0.92 | 0.9 | 0.9 | 0.89 | 0.92 | 0.91 | 0.92 | 1.18 | 1.21 |
| Industrial | 1.05 | 0.91 | 0.96 | 0.98 | 1.05 | 1.01 | 1 | 1.05 | 1 | 0.99 | 0.92 | 1.08 |

*Other Key Assumptions*

***Major Accounts Assumptions*** –

a) Closure of two major production facilities is expected to reduce electric loads in both the near-term and in the future.

b) PSE anticipates completion of a water treatment plant in 2004, adding 2.3 aMW by the middle of the year.

c) Due to the development of fuel cells as an alternative power source for a sewage treatment plant, PSE expects the plant's electric consumption to decline by about 8 aMW by 2005, but gas consumption is expected to increase to 2 million therms a year by 2005.

d) PSE expects a major residential development in Kittitas County to add approximately 150-250 residential customers per year in the next few years.

***Weather*** – PSE based its billed sales forecast on normal weather defined as the average weather using the last 30 years, ending the fourth quarter of 2004.

***Loss Factors*** – Based on more current analysis, the electric loss factor was increased from 6.4 percent to 6.6 percent, while the gas loss factor remains at 0.8 percent of total sales.

## D. Electric Sales and Customer Forecasts

*Base Case Electric Billed Sales Forecasts*

Without conservation savings, PSE's electric sales are expected to grow at an average annual rate of 1.7 percent per year in this forecast, from 2,268 aMW in 2004, to 3,148 aMW in 2024. Even with conservation savings taken into account, PSE expects billed sales to grow approximately 1.3 percent per year in the next 20 years. Compared to the historical growth rate of 2.1 percent per year, this new forecast anticipates lower sales growth as a result of the initial ramp-up in savings from conservation programs, slightly faster growth in retail rates, slower near-term growth in population and employment, and an increase in the construction of multifamily units, with lower use per customer. Exhibit VI-6 shows the forecast of electric sales by class for the next 20 years.

**Exhibit VI-6**
**Electric Sales Forecasts by Class in aMW**

| | 2004 | 2005 | 2010 | 2015 | 2020 | 2024 | aarg |
|---|---|---|---|---|---|---|---|
| ***Base without Conservation*** | | | | | | | |
| Total | 2,268 | 2,282 | 2,460 | 2,690 | 2,929 | 3,148 | 1.7% |
| Residential | 1,136 | 1,137 | 1,175 | 1,261 | 1,348 | 1,429 | 1.2% |
| Commercial | 976 | 989 | 1,118 | 1,258 | 1,407 | 1,542 | 2.3% |
| Industrial | 145 | 144 | 153 | 155 | 156 | 158 | 0.4% |
| Others | 11 | 11 | 13 | 15 | 18 | 20 | 3.0% |

*aarg: average annual rate of growth*

Without conservation, commercial and industrial sales will grow by about 2.3 percent and 0.4 percent per year, respectively. Historically, commercial sales have grown at slightly more than 2 percent per year in the last 10 years. Growth in non-manufacturing employment, which is expected to grow the fastest in the future, drives the growth in commercial sales. Manufacturing employment had been gradually declining in the last few years. However, this sector's employment growth is not expected to grow significantly in the next 20 years as the economy continues to grow. Thus industrial sales is only expected to grow slightly over the next 20 years. The industrial load does not include the large industrial customers who opted to contract with outside parties for their power supplies since 2001, although their power is still transported through PSE's distribution lines. With the fast growth in commercial loads, the share of commercial and industrial sales to total sales increases from 49 percent in 2004 to 54 percent in 2024.

The slower growth in residential billed sales is caused by several factors. Given the declining amount of available land for single-family housing development, single-family home sales growth will slow. However, multifamily housing units, which have lower average energy use per customer, are expected to grow. As a result, average residential use per customer is expected to decline due to construction of multifamily units and use of more efficient appliances. Consequently, the share of the residential sector in total sales is expected to decline by 4 percent from about 50 percent in 2004 to 46 percent in 2023.

Exhibit VI-7 compares the trends in residential use per customer since the 2003 Least Cost Plan. The differences are due to changes in assumptions for electric prices. Projections of electric rates have increased from 3 percent to 3.6 percent per year due to the general rate case, an expected reduction in the Bonneville Power Administration (BPA) residential exchange credit, and higher gas spot prices. Conservation savings have also increased compared to the 2003 Least Cost Plan.

**Exhibit VI-7**
**Comparison of Residential Normalized Electric Use per Customer in MWh**

| | 2004 | 2005 | 2010 | 2015 | 2020 | 2024 | aarg |
|---|---|---|---|---|---|---|---|
| LCP 2003 | 11.184 | 11.024 | 10.510 | 10.607 | 10.724 | | -0.3% |
| LCP 2004 | 11.408 | 11.223 | 10.331 | 9.905 | 9.745 | 9.680 | -0.7% |

*aarg: average annual rate of growth*

*Base Case Electric Customer Forecasts*

As shown in Exhibit VI-8, PSE expects electric customer numbers to grow at an average annual growth rate of 1.7 percent per year between 2004 and 2024, to 1,391,376 customers in 2024. This projection is slightly lower than the average growth rate of about 1.9 percent per year in the last five years. This reflects the slowdown in population growth, a decrease in the amount of affordable land for development, and higher mortgage rates which reduce housing starts.

**Exhibit VI-8**
**Electric Customer Count Forecasts by Class (Year End)**

| | 2004 | 2005 | 2010 | 2015 | 2020 | 2024 | aarg |
|---|---|---|---|---|---|---|---|
| Total | 997,843 | 1,014,691 | 1,106,970 | 1,203,535 | 1,303,956 | 1,391,376 | 1.7% |
| Residential | 879,098 | 893,500 | 970,944 | 1,051,791 | 1,135,018 | 1,207,013 | 1.6% |
| Commercial | 112,586 | 114,910 | 129,130 | 144,190 | 160,501 | 175,076 | 2.2% |
| Industrial | 3,967 | 3,988 | 4,091 | 4,108 | 4,137 | 4,164 | 0.2% |
| Others | 2,192 | 2,294 | 2,805 | 3,446 | 4,300 | 5,124 | 4.3% |

*aarg: average annual rate of growth*

Currently, the residential sector accounts for 88 percent of the total number of customers in PSE's service area. Although the residential sector is growing at a slower rate than the commercial and industrial sectors, it will account for most of the growth in the number of customers (this is with regard to absolute numbers, as the residential sector claims the largest share of the total customer base). The residential growth also reflects a gradually increasing share of multifamily units in the next 20 years. Thus, its share in the total customer base is not expected to change much in the next 20 years.

*Electric Peak Hour Forecast (Normal or Expected)*

PSE also bases the peak load forecast on the system sales forecast. The peak forecasting model uses an econometric equation that allows for different effects of residential vs. non-residential energy loads, in addition to the temperature observed at peak. The annual normal peak load is assumed to occur at 23 degrees Fahrenheit. Exhibit VI-9 below shows the forecast of expected electric peak based on 23 degrees Fahrenheit without conservation for the next 20 years.

**Exhibit VI-9**
**Electric Peak Forecast without Conservation in MWs**

| | 2004 | 2005 | 2010 | 2015 | 2020 | 2024 | aarg |
|---|---|---|---|---|---|---|---|
| Normal Peaks | 4,668 | 4,684 | 4,945 | 5,307 | 5,687 | 6,034 | 1.4% |

*aarg: average annual rate of growth*

PSE expects peak loads to grow by 1.4 percent per year in the next 20 years, with peak load growing slower than total energy sales. Since the residential energy load is growing slower than non-residential energy loads (commercial and industrial), and residential energy contributes more to peak than non-residential energy, the system peak load grows more slowly than the system energy loads, and more similar to the growth rate in residential sales.

*Electric Sales Forecast Scenarios*

In order to capture the range of economic possibilities in the forecast of billed sales, high and low sales forecast scenarios were developed in order to capture the upper and lower possible outcomes. The Base Case long-term sales forecast assumes that the economy grows smoothly over time, with no major shocks or disruptions, where the forecast of sales is expected to fall on the 50th percentile. The High Case forecast assumes a GDP growth rate of 3.6 percent, while the Low Case assumes a 2.6 percent average growth rate compared to 3 percent in the Base Case scenario. The High Case also assumes a low inflation rate and high productivity growth, and vice versa for the Low Case scenario.

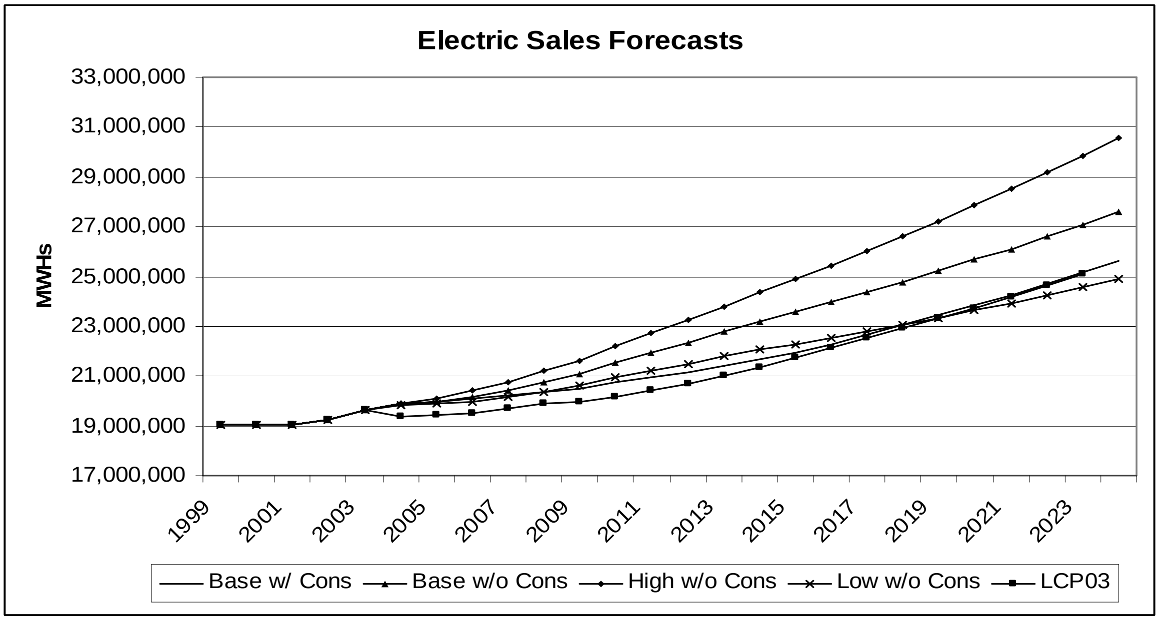
In actual implementation, the High and Low Case sales forecasts were developed using previously developed relationships between base, high and low population and employment variables—the key drivers in the forecast. High-to-base and low-to-base ratios were developed and applied to the current base case forecasts of population and employment. PSE ran the forecasting model with the new set of population and employment forecast scenarios, making no changes to other inputs. Exhibits VI-10 and VI-11 provide a comparison of the Base Case forecast with conservation, to the High and Low Case forecasts.

**Exhibit VI-10**
**Electric Sales Forecast Scenarios in aMW**

| | 2004 | 2005 | 2010 | 2015 | 2020 | 2024 | aarg |
|---|---|---|---|---|---|---|---|
| ***Scenarios*** | | | | | | | |
| Base Case with Conservation | 2,268 | 2,282 | 2,366 | 2,503 | 2,722 | 2,927 | 1.3% |
| Base Case - No Conservation | 2,268 | 2,282 | 2,460 | 2,690 | 2,929 | 3,148 | 1.7% |
| High Case - No Conservation | 2,272 | 2,296 | 2,534 | 2,842 | 3,181 | 3,488 | 2.2% |
| Low Case - No Conservation | 2,264 | 2,268 | 2,388 | 2,546 | 2,697 | 2,842 | 1.1% |
| 2003 LCP | 2,214 | 2,220 | 2,303 | 2,481 | 2,710 | | 1.3% |

*aarg: average annual rate of growth*

**Exhibit VI-11**




The Base Case forecast without conservation shows an annual growth of about 1.7 percent, while the High and Low Case forecasts show annual growth of 2.2 percent and 1.1 percent, respectively. Compared to the forecast in the 2003 Least Cost Plan, the new forecast is slightly higher, but grows at about the same rate primarily due to slightly higher initial population levels and customer growth.

## E. Gas Sales and Customer Forecasts

*Base Case Gas Billed Sales Forecasts*

PSE's natural gas billed sales (shown in Exhibit VI-12) are expected to grow at an average annual rate of 2 percent per year in the next 20 years, from 1,044,953 Mtherms in 2004 to 1,549,695 Mtherms by 2024. Compared to the historical growth rate of about 2.9 percent per year, this new forecast anticipates a slower growth rate in the future. The slow-down results from reduced customer growth in the residential sector, improved appliance efficiencies, and a slight decline in residential use per customer with conversions to multifamily housing.

**Exhibit VI-12**
**Gas Sales Forecast in Therms (000s)**

| | 2004 | 2005 | 2010 | 2015 | 2020 | 2024 | aarg |
|---|---|---|---|---|---|---|---|
| ***Base without Conservation*** | | | | | | | |
| Total | 1,044,953 | 1,059,254 | 1,204,022 | 1,317,463 | 1,445,096 | 1,549,695 | 2.0% |
| Residential | 520,777 | 527,410 | 600,567 | 659,798 | 708,471 | 743,099 | 1.8% |
| Commercial | 218,568 | 221,953 | 263,717 | 309,591 | 364,049 | 412,936 | 3.2% |
| Industrial | 35,122 | 34,183 | 36,863 | 37,647 | 39,066 | 39,942 | 0.6% |
| Interruptibles | 71,480 | 69,597 | 75,470 | 67,021 | 67,242 | 68,069 | -0.2% |
| Transportation | 199,006 | 206,111 | 227,405 | 243,406 | 266,268 | 285,648 | 1.8% |

*aarg: average annual rate of growth*

Over the next 20 years, PSE expects a slightly faster growth in gas billed sales during the first eight years compared to the remaining 12 years. This is because gas rates remain flat nominal in the next eight years, while the nominal rate grows at approximately the rate of inflation in the long term. While PSE expects most of the growth to occur within the residential sector, mainly from customer growth, the growth in the commercial sector is expected to be faster than the growth in the residential sector. As a result, the share of the residential sector in total sales declines from 50 percent in 2003 to 48 percent in 2024. Growth in the non-residential sector will likely result from increasing penetration of gas in commercial and industrial applications and as the price remains economic relative to other fuels. Thus, use per customer in each of the non-residential sectors is expected to increase, although the number of customers in some sectors might decrease.

*Base Case Gas Customer Forecasts*

PSE projects a gas customer growth rate of 2.5 percent per year in the next 20 years (as shown in Exhibit VI-13). Compared to the historical growth rate of about 4 percent per year, the new forecast reflects slower population growth, hence slower demand for housing, and a declining pool of potential conversion customers.

**Exhibit VI-13**
**Gas Customer Count Forecasts by Class (Year End)**

| | 2004 | 2005 | 2010 | 2015 | 2020 | 2024 | aarg |
|---|---|---|---|---|---|---|---|
| ***Base*** | | | | | | | |
| Total | 666,254 | 683,837 | 782,856 | 890,132 | 994,497 | 1,086,497 | 2.5% |
| Residential | 613,936 | 630,133 | 721,727 | 820,660 | 915,571 | 999,065 | 2.5% |
| Commercial | 48,900 | 50,265 | 57,700 | 66,080 | 75,542 | 84,048 | 2.7% |
| Industrial | 2,719 | 2,761 | 2,796 | 2,778 | 2,773 | 2,770 | 0.1% |
| Interruptibles | 568 | 547 | 501 | 477 | 469 | 467 | -1.0% |
| Transportation | 132 | 131 | 133 | 137 | 142 | 147 | 0.5% |

*aarg: average annual rate of growth*

Currently, the residential sector accounts for about 92 percent of PSE's total customer base. With a growth rate of 2.5 percent per year over the next 20 years, PSE expects the residential share to be about the same by 2024. The decline in the total pool of conversion customers will be limited by the increasing penetration of gas into multifamily buildings (townhomes and condominiums). While the commercial sector will only account for about 7 percent of PSE's total customer base, the Company also expects the commercial sector to grow at approximately 2.7 percent per year in the next 20 years. This is consistent with the expected increased penetration of gas into new buildings. New restrictions on the use of alternative fuels (especially oil and its associated liabilities) will contribute to a gradual decline in the growth rate of interruptible customers. Many of PSE's current interruptible customers, especially those with smaller loads, will choose to "firm-up" their demand by seeking solutions that range from becoming "all-firm" customers to arranging for various combinations of firm, interruptible and transportation services.

*Gas Peak Day Forecasts*

PSE's gas peak day forecast predicts that peak firm gas requirements will increase from 8.9 million therms in 2004 to 13.9 million therms in 2024, for a growth rate of about 2.2 percent per year in the next 20 years (as shown in Exhibit VI-14). This rate is slightly higher than the growth in billed sales because of faster growth in the first 7 years of the forecast, which is due to a flat or declining gas retail rate. The forecasted peak days are estimated to be 90 percent accurate within plus or minus 5.5 percent.[1] PSE expects the residential sector to account for about 70 percent of the peak daily requirement, while the commercial and industrial sectors will account for 26 percent and 3 percent, respectively. The forecasts for peak requirements include large volume commercial and industrial customers. PSE computes losses using 0.8 percent of the peak day requirements from the three customer sectors. The expansion in customer base and

[1] As discussed earlier, the standard error for the peak day estimate is about 3.2 percent.

changes in use per customer are the primary drivers of the growth in peak across all sectors. However, rising base loads also contribute moderately due to increasing saturation of gas in other end-uses such as cooking, clothes drying and fireplaces. This is offset slightly by reductions in heating loads resulting from increasing efficiencies in appliances, as well as the increasing penetration of gas into the multifamily sector, which has a smaller use per customer.

**Exhibit VI-14**
**Gas Peak Day Forecast with Conservation in Therms**

| | 2004 | 2005 | 2010 | 2015 | 2020 | 2024 | aarg |
|---|---|---|---|---|---|---|---|
| ***Base without Conservation*** | | | | | | | |
| Total | 8,977,663 | 9,011,214 | 10,529,014 | 11,716,765 | 12,922,646 | 13,926,527 | 2.2% |
| Residential | 6,210,775 | 6,254,232 | 7,184,115 | 7,855,857 | 8,443,375 | 8,889,133 | 1.7% |
| Commercial | 2,387,771 | 2,395,944 | 2,922,149 | 3,420,907 | 4,015,137 | 4,555,256 | 3.1% |
| Industrial | 307,295 | 288,949 | 338,518 | 346,266 | 360,753 | 370,735 | 0.2% |
| Losses | 71,821 | 72,090 | 84,232 | 93,734 | 103,381 | 111,404 | 2.1% |
| LCP03 | 8,165,536 | 8,322,800 | 9,275,200 | 10,336,500 | 11,438,900 | | 2.0% |

*aarg: average annual rate of growth*

Compared to the peak day forecast produced in the 2003 Least Cost Plan, the new forecast is higher for the following reasons: the current number of customers is greater than that of the previous forecast; the design heating degree day has been revised from 51 HDD to 52 HDD; the equation estimation method has been changed to account for data biases resulting from customers being out of service during cold events; and finally, use per customer does not decline as much in the first few years of the forecast because gas costs are not expected to increase and are even expected to decline slightly (see Chapter V).

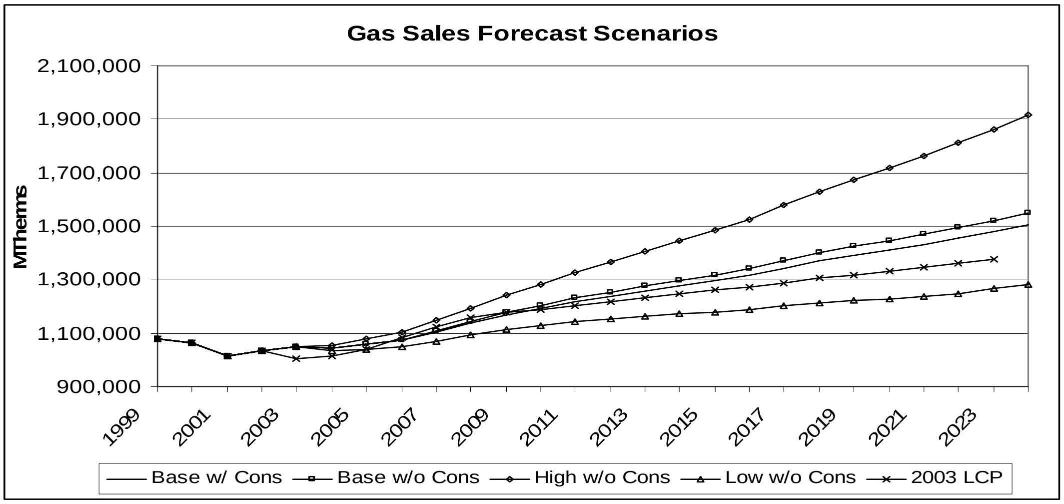
*Gas Sales Forecast Scenarios*

PSE's high and low case economic scenarios for population and employment use the same methodology as the high and low case economic scenarios used for the electric demand forecast. Exhibits VI-15 and VI-16 compare current forecasts with those generated for the 2003 Least Cost Plan.

**Exhibit VI-15**
**Gas Sales Forecast Scenarios in Therms (000s)**

| | 2004 | 2005 | 2010 | 2015 | 2020 | 2024 | aarg |
|---|---|---|---|---|---|---|---|
| ***Scenarios*** | | | | | | | |
| Base Case with Conservation | 1,044,953 | 1,059,254 | 1,192,973 | 1,294,591 | 1,410,944 | 1,506,892 | 1.8% |
| Base Case - No Conservation | 1,044,953 | 1,059,254 | 1,204,022 | 1,317,463 | 1,445,096 | 1,549,695 | 2.0% |
| High Case - No Conservation | 1,055,487 | 1,077,468 | 1,282,806 | 1,483,108 | 1,718,095 | 1,916,352 | 3.0% |
| Low Case - No Conservation | 1,033,222 | 1,040,547 | 1,129,560 | 1,177,180 | 1,229,629 | 1,279,762 | 1.1% |
| 2003 LCP | 1,015,999 | 1,041,013 | 1,189,618 | 1,262,191 | 1,333,354 | | 1.7% |

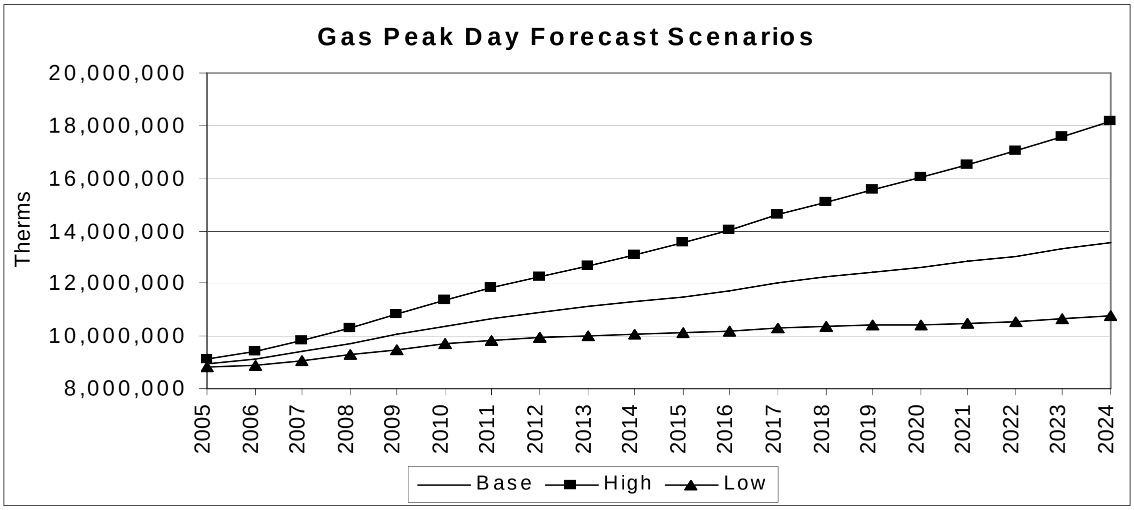
**Exhibit VI-16**




The 2005 Least Cost Plan forecast is higher than the 2003 Least Cost Plan forecast primarily because of higher initial use per customer and also higher use per customer growth in the forecast period. Actual initial use per customer is higher because of slower-than-anticipated growth in actual rates. The higher growth in use per customer arises mainly from flat or declining retail rates assumed in the near term in the 2005 Least Cost Plan forecast. By 2015, the high-case forecast predicts loads that are about 12 percent higher than the base-case forecast, while the low-case forecast anticipates loads about 11 percent lower than the base-case forecast.

Associated with the gas sales forecast scenarios are gas peak-day load forecasts in therms per day. Below is a graph showing the base, high and low peak-day forecast for gas based on 52 HDD, and consistent with the high and low economic and demographic assumptions described above. Note that these scenarios are driven mainly by the high and low economic and demographic forecast scenarios, and not by other inputs such as price or conservation. The average growth per year over the next 20 years for the gas peak day loads are 2.2 percent for the base case, 3.7 percent for the high case, and 1.1 percent for the low case scenarios.

**Exhibit VI-17**



# VII. DEMAND-SIDE RESOURCES

This chapter discusses PSE's current electric and gas energy efficiency programs; the outcome of the 2004 electric efficiency resource acquisition Request for Proposal (RFP) process; and the results of the demand-side resource potentials analysis, which are a key input to the integrated resource analysis described in subsequent chapters.

## A. Existing Energy Efficiency Resources

*Overview*

PSE has provided conservation services for its electricity customers since 1979. The conservation measures installed through PSE programs from 1985 - 2004 are currently saving a cumulative total of approximately 229 aMW (about 2,003,000 MWh) in 2004. These energy savings have been captured through energy efficiency programs designed to serve all customers – including residential, low-income, commercial and industrial. The Company has expended approximately $430 million in electricity conservation since 1985.

On the gas side, PSE has provided energy efficiency services since 1993, installing enough conservation measures through 2004 to be currently saving a cumulative total of 1,114,267 decatherms in 2004 – half of which has been achieved since 2002. These energy savings were captured through energy efficiency programs primarily serving residential and low-income customers through 1998. Beginning in 1999, PSE increased its focus on achieving gas energy savings from commercial and industrial customer facilities. Since 1993, the Company has expended close to $12 million in natural gas conservation.

PSE currently operates its energy efficiency programs in accordance with requirements established as part of the stipulated settlement of PSE's 2001 general rate case (WUTC Docket Nos. UE-11570 and UG011571).

In its August 2003 Least Cost Plan Update, PSE completed an extensive analysis of energy efficiency savings potential and its contribution to the Company's electric and gas resource portfolios. The results were used to develop PSE's energy efficiency program targets for 2004 and 2005. This assessment was the culmination of a collaborative effort between PSE and key external stakeholders represented in the Conservation Resource Advisory Group (CRAG) and the Least Cost Plan Advisory Group (LCPAG).

The outcome of this process was the development of a two-year target for energy savings of approximately 39 aMW of electric energy efficiency and 500,000 decatherms of natural gas energy efficiency by the end of 2005, to be achieved through a variety of program offerings to all customer classes. Such targets represent an increase over 2002-2003 targets, which in turn represented a significant ramp-up over previous levels. The Company also issued an RFP to acquire electric efficiency resources, consistent with the findings of the August 2003 Least Cost Plan Update. The status and results of PSE's conservation programs and RFP process are presented below.

*Current Energy Efficiency Programs*

PSE currently offers electric energy efficiency programs under tariffs effective from January 1, 2004 through December 31, 2005. Programs provide for energy savings from all customer sectors, including both electricity and natural gas. PSE funds the majority of its energy efficiency programs using electric "Rider" and gas "Tracker" funds, collected from all customers. A portion of electric program funding also occurs through arrangements with the Bonneville Power Administration (BPA) to provide Conservation and Renewable Discount (C&RD) credits. Based on best current estimates of costs and savings projections, these conservation programs provide a cost-effective resource.

The year 2004 marked the beginning of a new conservation tariff period spanning 2004 and 2005 that continues ongoing programs and initiates a number of new pilot programs. Exhibit VII-1 shows how PSE has done in 2004 compared to two-year budget and savings goals for electric energy efficiency programs (including BPA C&RD programs). Based on jobs in progress and program status, current projections are that PSE will achieve 100 percent of the two-year savings goals on or under budget by the end of 2005.

During 2004, PSE's electric energy efficiency programs saved a total of 19.8 aMW of electricity, putting the Company on track to achieve its two-year electric savings goal of 39,2 aMW by the end of 2005. Programs under the electric Rider achieved total savings of 138,288 MWh (15.79 aMW) at a cost of $20,869,462. In addition, under BPA's C&RD program, PSE saved an additional 34,927 MWh (3.99 aMW) in first-year savings at a cost of $4,126,802 (does not include cost of renewables). The 2004 savings achievement is 14 percent higher than the 2003 total of 17.3 aMW saved.

PSE’s 2004 gas efficiency programs saved a total of 318,000 decatherms, putting the Company on track to achieve its two-year gas savings goal of 500,000 decatherms by the end of 2005. Natural gas energy efficiency savings were achieved at a cost of $3,781,810. The 2004 achievement is a 47 percent increase over the 2003 total of 217,500 decatherms saved.

**Exhibit VII-1**
**Annual (Jan. 2004 – Dec. 2004) Energy Efficiency**
**Program Summary**

| Tariff + C&RD Programs | 2004 ACTUALS | 2 YEAR BDGT./GOAL | ’04 vs. ‘04/05 % Total |
|---|---|---|---|
| Electric Program Costs | $24,996,264 | $52,218,000 | 47.9% |
| MWh Savings | 173,215 | 343,080 | 50.5% |
| Gas Program Costs* | $3,781,810 | $9,106,000 | 41.5% |
| Decatherm Savings | 318,982 | 501,348 | 63.6% |

* Does not include Low Income Weatherization O&M funding of $300k per year.

*Electric Energy Efficiency RFP*

In February 2004, PSE issued an ”all-comers” RFP for acquisition of electric energy efficiency resources, consistent with 2003 Least Cost Plan findings of a short-term need for electric energy resources (with energy efficiency included as a least-cost option), as well as with WAC 480-107 requirements. The Energy Efficiency RFP process was run in parallel with the RFPs for wind and all generation resources.

The Energy Efficiency RFP sought two types of proposals:

- *Resource Programs:* Programs to acquire energy savings via installation of high-efficiency equipment and technologies at customer premises, with a minimum project size of 5,000 MWh/year delivered within two years.
- *Pilot Projects:* Small-scale programs designed to introduce energy efficiency measures not yet widely adopted in PSE's service territory, and/or to demonstrate program delivery to market segments that have experienced low participation in energy efficiency programs.

The primary implementation period targeted by the RFP was 2006-2007, with earlier implementation as an option, if appropriate. The long lead time was driven by the fact that 2004

– 2005 targets, programs, and a regulatory penalty mechanism were established through consensus agreement with the CRAG prior to development of the RFP process. This was pursuant to conditions stipulated in the Conservation Agreement as part of PSE's 2001 General Rate Case (WUTC Docket Nos. UE-11570 and UG011571). Therefore, a proposal had to align very closely with PSE's current established mix of programs to be selected for implementation prior to 2006.

In April 2004, PSE received bids for 29 efficiency projects, totaling 30 aMW. These bids underwent an extensive, two-stage structured evaluation process, focusing on cost-effectiveness, technical merits, compatibility with existing PSE programs, and the risk of not delivering projects as proposed. PSE also sought to choose a variety of proposals such that all customer classes were included. The first stage of the evaluation process was completed in June 2004, resulting in the selection of a short list of 12 proposed projects. The second evaluation phase was completed in August 2004 to select finalists. The results of this evaluation process have been reviewed with the CRAG.

Five projects, totaling 7 aMW, were selected to receive Letters of Interest to pursue final contracts. Three of the finalists target the commercial/industrial sector (1 pilot and 2 resource programs), while the other two finalists address the residential sector (1 pilot and 1 resource program). The two residential projects are being considered for implementation starting in 2005, while the commercial/industrial projects are more likely to be implemented in 2006-2007. Contract negotiations are in progress and will be completed by mid-2005.

Given PSE's extensive experience in operating energy efficiency programs, the Company has determined that a "targeted" approach to acquiring energy efficiency resources from third-party providers would be more effective than the "all-comers" approach. The 2004 RFP process found few new technologies or innovative service delivery mechanisms, and no respondent could match PSE's current programs in terms of delivery efficiency and cost-effectiveness (some of which already utilize third-party providers). PSE (supported by bidder comments and questions during the RFP process) would prefer to focus future RFPs on specific customer segments, end uses, or technologies that would enhance or expand its current program mix. Such a targeted process would likely yield more competitive bids that best meet PSE's needs at potentially lower costs to its customers, and provide bidders with more structure and guidance.

PSE also found that the misalignment between the program implementation cycle, required by its 2001 General Rate Case stipulation, and the electric resource RFP process mandated by the WAC, created an extremely long lead time between issuance of the RFP and implementation of selected projects. As explained above, PSE had to set targets and commit to programs and budgets before the RFP process could be completed. Projects selected by the RFP process were thus pushed into the next "open" program implementation cycle by this timing conflict, putting them more than a year out. Public comments on the RFP indicated that such a long lead time greatly increases the risk and uncertainty faced by bidders about future costs and market conditions, which could be reflected in higher bid prices or their decision to bid at all. PSE would like to explore alternatives to reduce this timing conflict in future RFPs, which should encourage more cost-effective bid submittals.

## B. Demand-Side Resources – Potential

*Overview*

Developing reliable estimates of the magnitude, timing, and price of alternative demand-side resources is a critical first step in a least-cost, integrated resource planning process. These estimates also help to guide and inform demand-side planning and inform conservation program development efforts.

As part of its 2003 least cost planning process, PSE commissioned a study to investigate the "technical" and "achievable" electric and gas conservation potentials in its service area for the 2004-2023, 20-year planning horizon. The results of that study were filed with the Washington Utilities and Transportation Commission (WUTC) in the August 2003 update to PSE's Least Cost Plan, originally filed in April 2003 under Docket UE-030594.

In an effort for the 2005 Least Cost Plan to more fully consider the potentials for demand-side resources within PSE's service territory, the Company engaged Quantec, LLC, an energy and environmental consultancy in Portland, Oregon, to conduct a comprehensive assessment of all achievable demand-side resources, including energy-efficiency, fuel conversion, and demand-response options. A detailed report on this demand-side potential assessment is included as Appendix B. The principal goal of this study was four-fold:

1. To update the results of the 2004-2023 conservation potentials study using more recent market data for the residential, commercial, and industrial sectors in the Company's service area; and to extend the analysis to the 2006-2025 planning period.
2. To investigate the potentials for additional demand-side resource options including electric-to-gas fuel conversion and demand response, taking into account the interactions among various resource options and resource acquisition scenarios.
3. To employ a simple, flexible, and transparent approach consistent with the methods used by the Northwest Power and Conservation Council, relying on the most recent market data.
4. To create discrete "bundles" of demand-side resource potentials comprised of groups of homogeneous measures, and to provide supply curves for each bundle that would allow the demand-side resource options to be evaluated against supply options on an equal basis in PSE's least cost, integrated resource planning process.

Estimates of long-term, demand-side resource potentials in this study were derived with standard practices and methods in the utility industry, using the most recent data. Studies such as this require compilation of large amounts of data from multiple sources on existing demand management strategies, technologies, and market dynamics that affect their adoption. They also rely on assumptions concerning the future, particularly changes in demand for energy, codes and standards, energy efficiency technologies, market conditions, and consumer behavior. It is, therefore, inevitable that the findings of this study will have to be revisited periodically to take into account the impacts of emerging technologies and the changing dynamics of the energy markets.

*General Methodology*

Concurrent assessment of demand-side resources poses significant analytic challenges. Due to their inherently unique characteristics and the types of load impacts that they generate, analyses of energy-efficiency, fuel conversion, and demand-response potentials require different methodologies and data. While these methodologies are capable of producing reliable estimates for each demand-side resource individually, they must also have the capability to accurately account for interactions among these resources, particularly capturing the effects of fuel conversion on energy efficiency potentials.

This study incorporated significant improvements over the 2004-2023 assessment with respect to both methodology and data quality. Due to the more complex nature of the assessment, largely arising from the interactions between energy efficiency and fuel conversion, a more advanced and more flexible methodology and modeling approach had to be adopted. The study also relied on substantially more accurate and more recent market data on market characteristics, conservation measure impacts, and costs, especially in the residential and commercial sectors.

The overall approach in this study distinguishes between two distinct, yet related, definitions of resource potential that are widely used in utility resource planning. The first is "technical potential," and the second is "achievable potential." Technical potential assumes that all demand-side resource opportunities may be captured regardless of their costs or market barriers. Achievable potential, on the other hand, represents that portion of technical potential that is likely to be available over the planning horizon given prevailing market barriers and administrative program costs that may limit the implementation of demand-side measures. For the purpose of this study, "achievable" energy efficiency and fuel conversion potentials are defined as that portion of technical savings potential remaining after factoring in market penetration rates, and which has a levelized per unit cost of less than $115 per MWh for electricity and less than $10.50 per decatherm for gas, inclusive of program administration and delivery costs.

Estimates of technical energy efficiency and fuel conversion potential for the residential and commercial sectors were derived using Quantec's QuantSim model, an electric and gas end-use forecasting model. For each customer class, application of the model involves three steps: 1) producing separate, end-use specific forecasts of loads over the 20-year planning horizon, and calibrating the end-use forecasts to PSE's 20-year aggregate customer class forecasts to ensure consistency between the two, 2) producing a second forecast for each end-use that incorporates the saturations and energy impacts of all feasible energy efficiency measures, and 3) calculating technical potentials by end-use, and measure as the difference between the two forecasts.

Due to the more complex nature of the industrial market, end-uses and equipment, on the one hand, and the lack of reliable information on measure-specific saturations, on the other hand, energy efficiency potentials in the industrial sector were analyzed using an alternative, "top-down" approach. Application of this method involved two steps. First, total firm industrial loads were disaggregated into standard classes, and major end-uses within each class based on PSE's latest sales data. Second, for each end-use, potential savings and per unit cost of the potential savings were estimated using available data from industrial energy efficiency programs in the Northwest and California, and market information on PSE's industrial customer accounts.

Given the technical challenges of and market barriers facing fuel conversion in the commercial and industrial sectors, opportunities for electric conservation from fuel conversion were assessed only for the residential sector. Four residential end-uses were considered, namely space heating, water heating, cooking, and clothes drying. In order to account for the effects of fuel conversion on electric and gas conservation opportunities, potentials for energy efficiency and fuel conversion in the residential sector were modeled simultaneously.

As explained later in this chapter, potentials for each demand-response resource acquisition strategy were estimated using a hybrid, top-down, bottom-up approach. It consisted of first disaggregating PSE's total load into customer sectors and end-uses, estimating load reduction potentials for each end-use, and then aggregating end-use impacts to sectors and system level.

The methodologies used to assess the potentials for energy efficiency, fuel conversion, and demand response are described more fully in Appendix B.

*Data Sources*

Implementation of the methodology described above required compilation of a large database of measure-specific technical, economic, and market data from a large number of primary and secondary sources. The main sources used in this study included, but were not limited to, the following

- ***Puget Sound Energy*:** Latest load forecasts, load shapes, economic assumptions, PSE's historical energy efficiency and demand-response program activities, PSE's 2004 residential appliance saturation survey (RASS) designed with a particular emphasis on obtaining market to support this study, and the Commercial Building Stock Assessment (CBSA) - a study of the Northwest's commercial building characteristics sponsored jointly by BPA, the Northwest Energy Efficiency Alliance, and PSE.

- ***Northwest Power Planning Council and the Regional Technical Forum*****:** Technical measure information, measure costs, measure savings, measure life.
- ***California Energy Commission Database for Energy Efficiency Resources (DEER)*****:** Measure costs and savings, measure applicability factors, and technical feasibility factors.
- ***Existing Studies:*** Previous conservation potentials studies and conservation program evaluation reports on energy efficiency programs in the Northwest and California.

*Summary of the Results – Energy Efficiency*

Technical energy efficiency potentials in the residential and commercial sectors were derived based on an analysis of 127 unique electric measures, and 62 unique gas measures. The Northwest Power and Conservation Council was the primary source for electric measures in the residential and commercial sectors. This list was augmented by additional measures from DEER. The list of gas measures in all sectors was compiled mainly from DEER.

Under consideration were six residential segments (existing single-family, existing multi-family, existing manufactured homes, new-construction single-family, new-construction multi-family, new-construction manufactured homes) and 20 commercial segments (10 building types within the existing and new structure segments). Since many energy efficiency measures are applied to multiple segments and building types, a total of 1,756 electric and 736 gas measure/segment/structure combinations were included in the analysis. All major end-uses in all 15 major industrial segments in PSE's service area, including wastewater treatment, were analyzed. The measure/segment/structure combinations were then grouped into "bundles" with similar cost and load shape characteristics, as described later in this chapter.

Based on the results of this study, cumulative 20-year technical conservation potentials in PSE's service area are estimated at 895.5 aMW megawatts of electricity and 38,223,912 decatherms of natural gas savings, of which 297 aMW (33 percent) and 10,788,029 decatherms (28 percent) are expected to be achievable. Achievable savings represent 9.3 percent of the electric load and 8.6 percent of projected gas use over the 2006-2025, 20-year planning period.

As shown in Exhibit VII-2, the commercial sector accounts for the largest share of achievable electricity savings (147.6 aMW), followed by the residential sector with an achievable savings potential of 133.4 aMW over 20 years. The industrial sector accounts for 15.9 aMW of electricity savings during the same period.

**Exhibit VII-2**
**2006 - 2025 Electric Technical and Achievable Potential**

| Sector | 2025 Total Load (a) | 20-Year Cumulative Potential (a/% of Baseline) | |
|---|---|---|---|
| | | Technical | Achievable |
| Residential | 1,450 | 375.8 | 133.4 |
| Commercial | 1,578 | 503.7 | 147.6 |
| Industrial | 158 | 15.9 | 15.9 |
| Total | 3,186 | 895.4 | 296.9 |

**Exhibit VII-3**
**2006 – 2025 Natural Gas Technical and Achievable Potential**

| Sector | 2025 Total Gas Sales (Decatherms) | 20-Year Cumulative Potential (Decatherms as % of Baseline) | |
|---|---|---|---|
| | | Technical | Achievable |
| Residential | 75,278,759 | 27,738,747 | 6,334,280 |
| Commercial | 42,637,285 | 10,170,241 | 3,864,537 |
| Industrial | 4,028,666 | 314,924 | 314,924 |
| Total | 121,944,710 | 38,223,912 | 10,513,741 |

The largest share of achievable natural gas potential is expected to occur in the residential sector, which accounts for nearly 60 percent of total achievable natural gas savings. The commercial and industrial sectors respectively account for 37 percent and 3 percent of the achievable gas conservation potential, as shown in Exhibit VII-3.

Distributions of achievable electricity savings in the residential and commercial sectors by end-use are shown in Exhibits VII-4 and VII-5. Savings in lighting (Exhibit VII-4), achieved mainly through installation of energy-efficient lighting technologies such as compact fluorescent light bulbs and fixtures, represents the largest electric conservation potential in the residential sector, accounting for 42 percent of the sector's achievable savings. The results also show that about 24 percent of achievable savings in the residential sector may be obtained through installation of measures to improve space-heating performance, such as insulation, weatherization and equipment replacement. The remaining savings can be achieved through the implementation of water heating measures, such as water heating equipment upgrades (20 percent), installation of Energy Star rated appliances (13 percent), and cooling measures (1 percent).

In the commercial sector (Exhibit VII-5), lighting retrofit represents the largest potential for electricity savings. Nearly 45 percent of potential electricity savings in the commercial sector is attributable to the application of energy-efficient lighting. Retrofit, upgrade and better operation and maintenance of HVAC equipment are also shown to be effective conservation measures, which account for over 38 percent of the total electricity savings potential in this sector. High-efficiency office and cooking equipment (plug loads) account for 14 percent of the savings potential, while water heating measures account for 3 percent of total commercial-sector electricity savings.

**Exhibit VII-4**
**Distribution of Achievable Electric Conservation Potential by End-Use**
**Residential Sector**

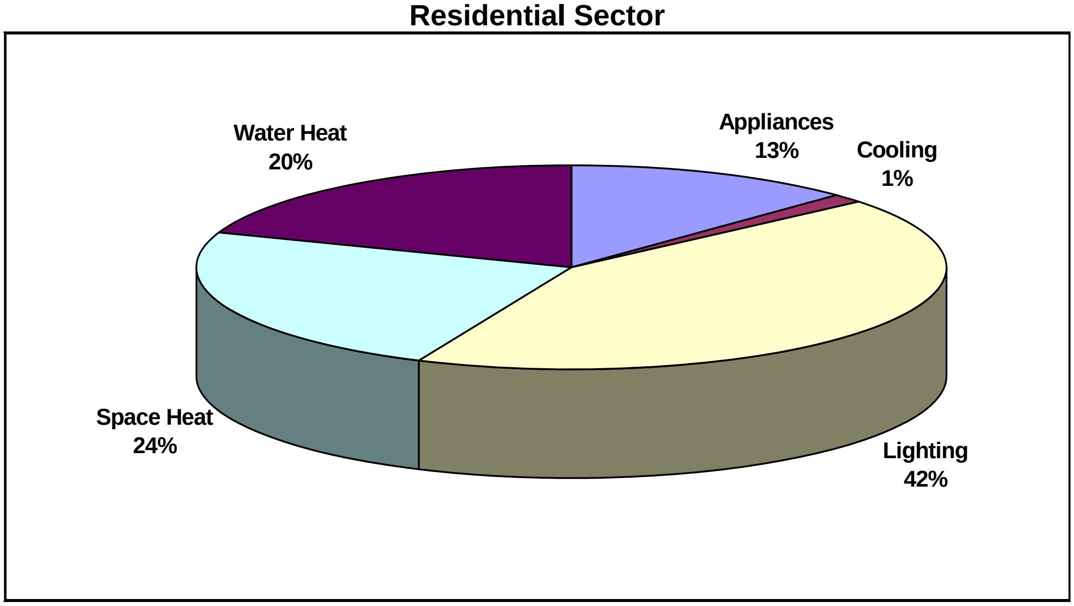
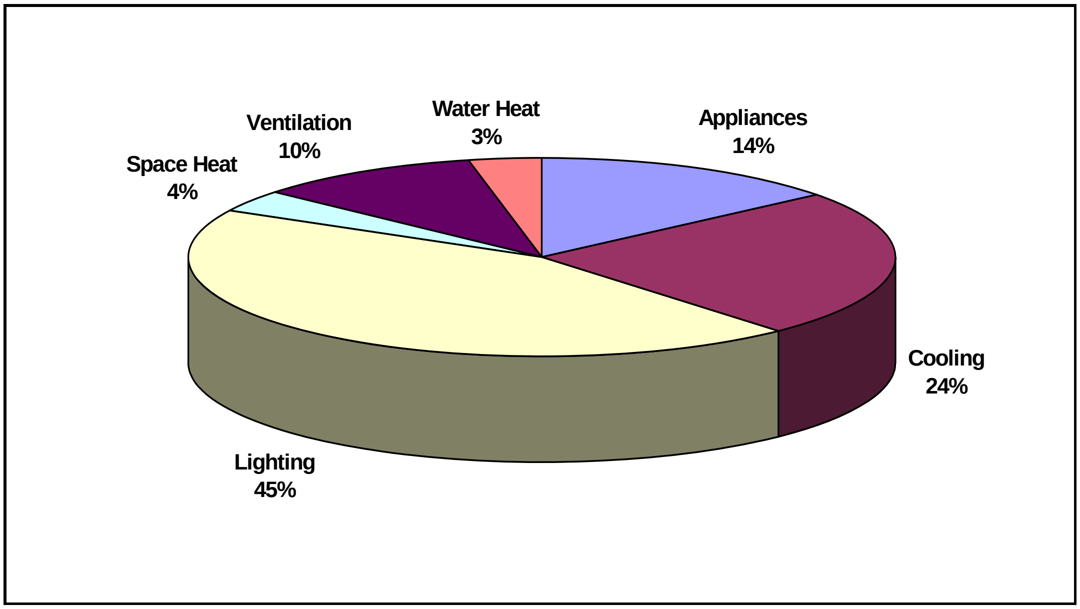


**Exhibit VII-5**
**Distribution of Achievable Electric Conservation Potential by End-Use**
**Commercial Sector**




As shown in Exhibit VII-6, expected savings in space heating is the largest component of the achievable natural gas conservation potential in the residential sector, accounting for nearly 69 percent of the gas savings potential. Upgrade of heating equipment with alternative, more energy-efficient equipment provides the main source for the potential savings. The results also show that installation of more efficient water heaters and application of measures that improve the performance of existing water heating equipment, such as insulation and, to a lesser degree, water-saving measures and home weatherization, together account for over 31 percent of the gas conservation potential in the residential sector.

As Exhibit VII-7 illustrates, space heating, water heating and appliance conservation measures provide the largest potentials for gas savings in the commercial sector. These measures respectively represent 52 percent (space heating), 37 percent (water heating), and 10 percent (appliances – primarily cooking) of the total achievable gas conservation potential in the commercial sector. Pool heating conservation measures account for a small share of the total gas savings potential in this sector.

**Exhibit VII-6**
**Distribution of Achievable Natural Gas Conservation Potential by End-Use Residential Sector**

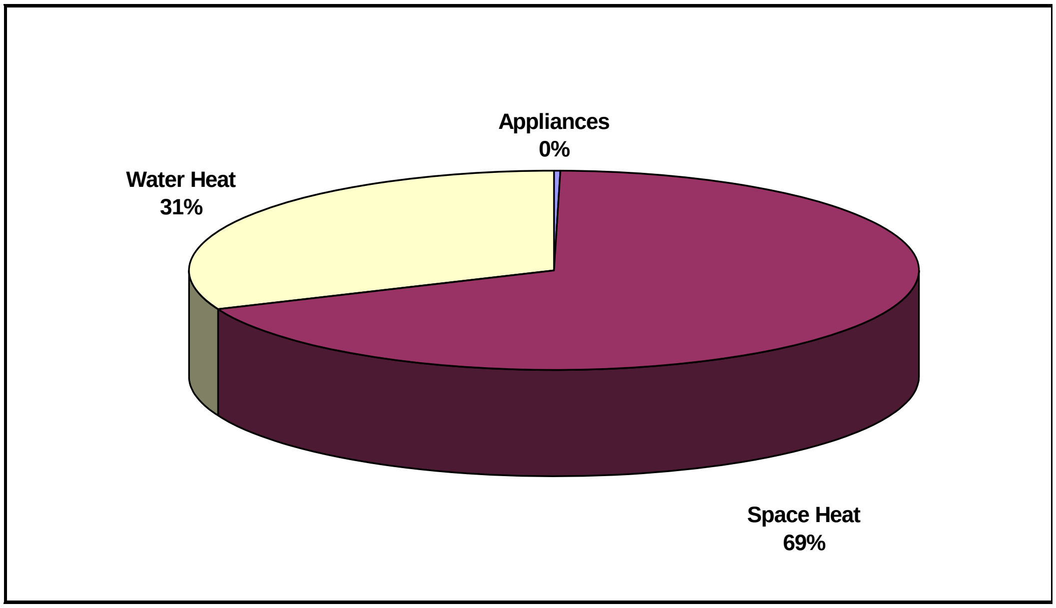
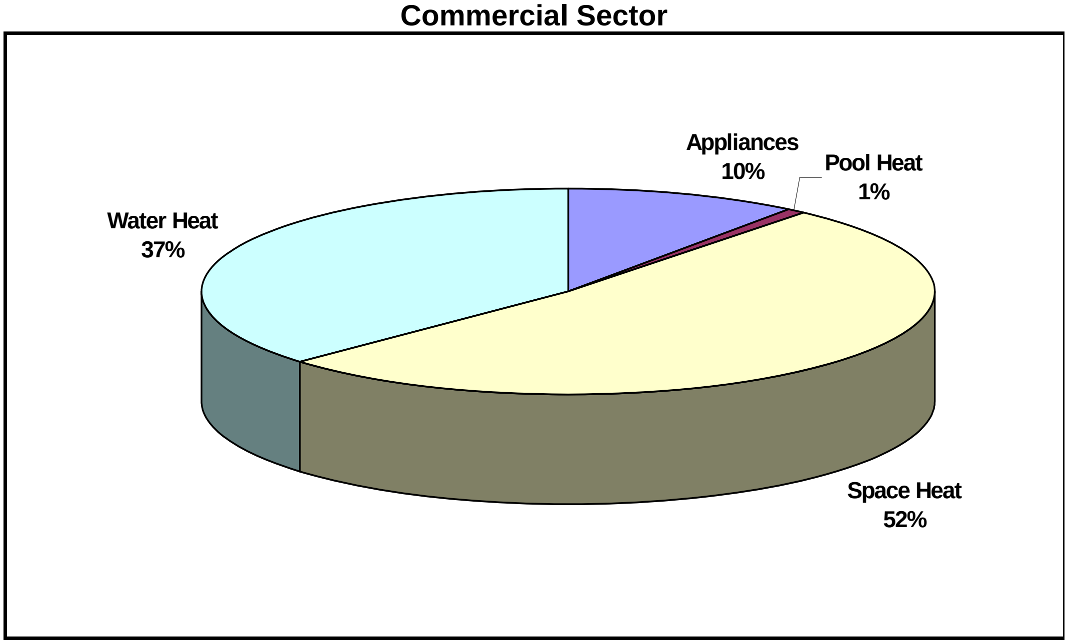



**Exhibit VII-7**
**Distribution of Achievable Natural Gas Conservation Potential Commercial Sector**




Achievable electric conservation potentials in the industrial sector are estimated at 15.9 aMW, which is equivalent to approximately 10 percent of the total industrial load. As shown in Exhibit

VII-8, nearly 70 percent of these savings are attributable to potential efficiency gains in facility improvements, primarily HVAC and lighting retrofits. Energy efficiency improvements in refrigeration and process cooling account for the remaining 30 percent of savings potential. As shown in Exhibit VII-9, boiler (86 percent) and HVAC (14 percent) upgrades account for all of the gas conservation potential in the industrial sector.

**Exhibit VII-8**
**Distribution of Achievable Electric Conservation Potential**
**Industrial Sector**

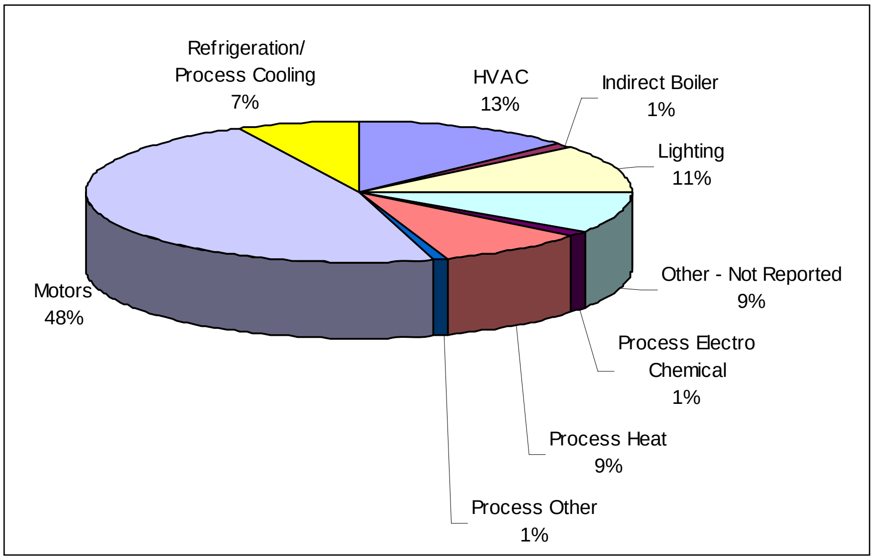
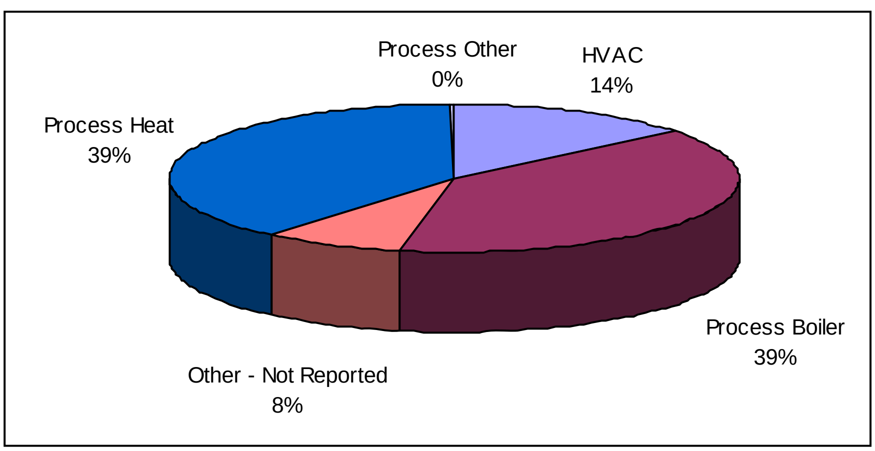



**Exhibit VII-9**
**Distribution of Achievable Natural Gas Conservation Potential**
**Industrial Sector**



Timing is an important element in developing strategies to acquire energy efficiency resources. Consistent with the definitions established by the Northwest Power and Conservation Council, PSE distinguishes between “lost opportunities” and “retrofits” in considering the potentials for conservation. “Lost opportunities,” such as energy efficiency potentials in new construction and upgrades to equipment upon their natural replacement, tend to be timing-dependent and must be captured as they become available. “Retrofits,” on the other hand, are assumed to remain available over time.

The results of this assessment, as shown in Exhibit VII-10, indicate that over two-thirds (68 percent) of achievable electric energy efficiency potentials in the residential sector are comprised of retrofit opportunities, while lost opportunities account for a greater portion of achievable electric energy efficiency potentials in the commercial sector (57 percent compared to 43 percent). With respect to natural gas achievable energy efficiency potentials, however, lost opportunities are larger in both the residential and commercial sectors (see Exhibit VII-11). All of the estimated electric and gas achievable energy efficiency potentials in the industrial sector are shown to result from retrofits.

**Exhibit VII-10**
**Electric Energy Efficiency Potentials: Retrofit vs. Lost Opportunities**

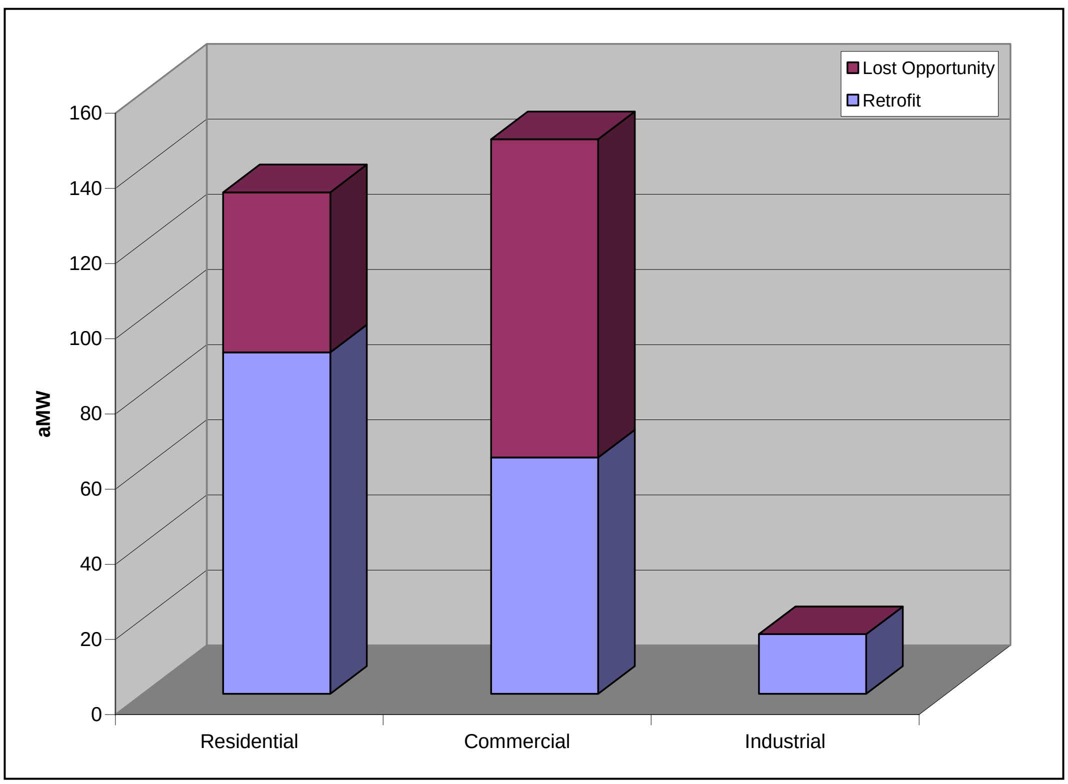
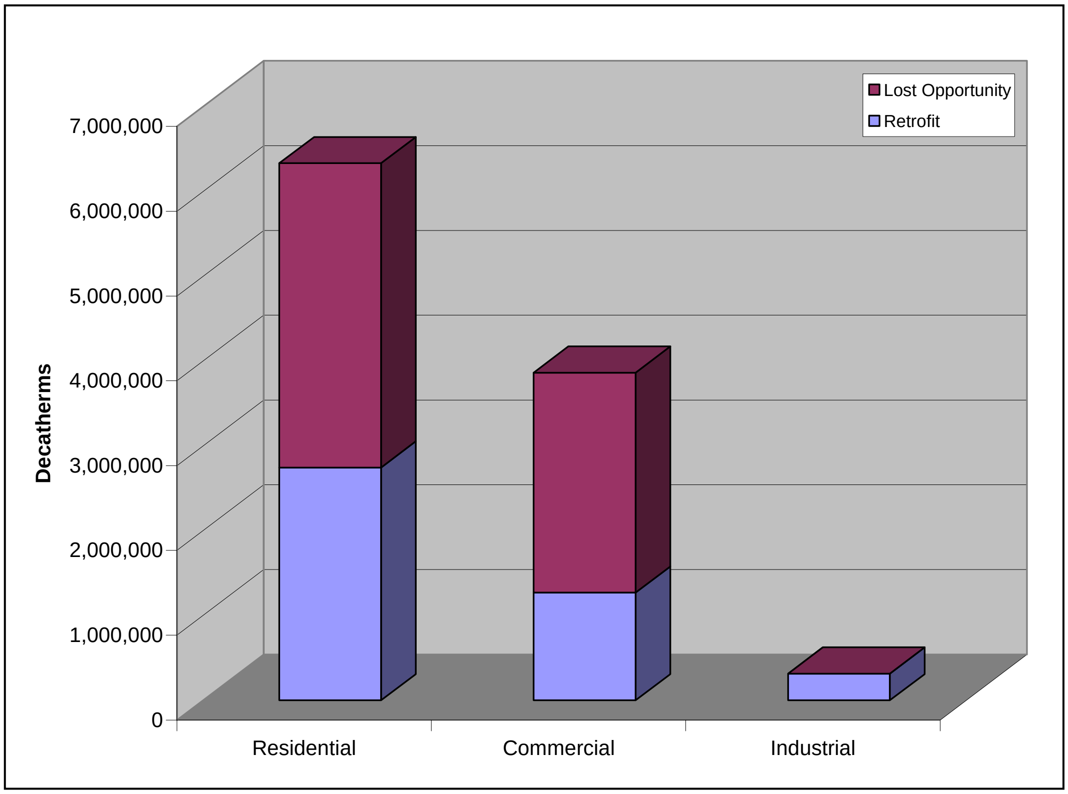


**Exhibit VII-11**
**Gas Energy Efficiency Potentials: Retrofit vs. Lost Opportunities**




Estimates of achievable electric conservation potentials from this study are slightly lower than those reported in the 2003 Least Cost Plan. A comparison of the results of the two studies shows a decline in electric conservation potentials in the residential and commercial sectors and a slight increase in the industrial sector. In aggregate, achievable electric conservation potential decreased by approximately 9.5 percent (from 328 aMW to 297 aMW). This difference is explained by several intervening factors including the effects of PSE's conservation activities in 2003 – 2004 (see Section A), refinements to measure data, changes in assumptions regarding saturation of energy efficient technologies, and, particularly, changes in load forecasts. Gas conservation potentials were nearly unchanged, declining modestly from 10.8 million decatherms in 2003 to 10.6 million decatherms in 2005.

*Fuel Conversion Potentials*

Fuel conversion potential was assessed in conjunction with energy efficiency potential, rather than on a stand-alone basis. Fuel conversion resources augment electric energy efficiency potentials in reducing total electric loads. At the same time, fuel conversion precludes realizing the full electric energy efficiency potentials of affected electric end-uses because the substitution of gas appliances for electric replaces some opportunities to install electric efficiency measures. Fuel conversion also results in increased consumption of natural gas, which, in turn, increases the potential opportunities for gas energy efficiency. Due to this interdependency, analyses of electric conservation and fuel conversion potentials must be performed simultaneously, explicitly taking into account interactions between the two resource options.

Potentials for fuel-conversion were made only for the population of residential customers in PSE's combined electric and gas service area, since fuel conversion is only being considered as an electric resource strategy in this Least Cost Plan. Four end-uses were examined: space heating, water heating, cooking, and clothes drying. For each end-use, conversion potentials were estimated under both "normal" and "early" equipment replacement scenarios. Under the "normal" replacement scenario, it is assumed that conversions would occur at a naturally-occurring pace upon failure of existing equipment. The early replacement scenario assumes a more aggressive approach, where conversions are made during the first ten years of the planning horizon regardless of age and condition of existing equipment. Additional fuel conversion potential, as an electric resource alternative, may be available from PSE electric customers in areas served by other gas utilities. However, lack of data on the ability to serve additional loads, coverage of existing gas distribution systems, and the line extension plans of other gas utilities precludes quantifying this additional potential.

Service availability and distribution system constraints are important considerations in assessing the achievable potentials for fuel conversion. As Exhibit VII-12 demonstrates, PSE provides gas service to 70 percent of residential customers in its electric service area. Of these customers, 62 percent are on gas mains, of which 76 percent are currently receiving gas services from PSE. Moreover, current loads indicate that 24 percent of customers who are served by PSE are on capacity-constrained gas mains, which may limit the ability to add new load in those areas, without significant new investment in distribution facilities. Although in the long term most of these constrained mains would likely be upgraded, the timing of planned upgrades may limit or delay conversions in some areas. New loads could also be added if the gas distribution system were extended into new areas. Based on this data, approximately 33 percent of all customers offer an opportunity for conversions without imposing additional main extension or hook-up costs, because they are already PSE gas customers that are simply converting additional end uses. Another 15 percent of PSE's customers could be converted from all-electric to gas (10 percent in areas where gas is already available and 5 percent through short main extensions), but would incur additional costs associated with new service connections.

**Exhibit VII-12**
**Geographic Distribution of Residential Gas Customers by Utility Service Area, Service Availability, and System Characteristics**

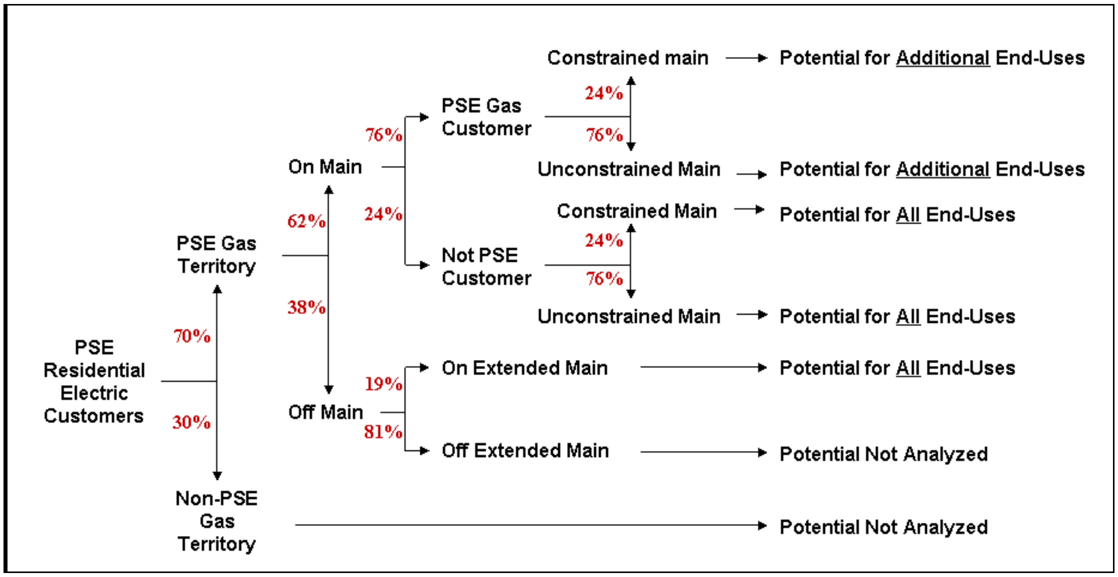



Exhibit VII-13 shows the technical and achievable electricity savings resulting from fuel conversion for the normal and early replacement scenarios. Under the normal replacement scenario, fuel conversion is estimated to provide 132.8 aMW in technical potential, and 62.5 aMW in achievable potential. In an accelerated conversion scenario that assumes early equipment replacement, technical and achievable potentials are expected to increase to 189.5 aMW and 101.5 aMW respectively.

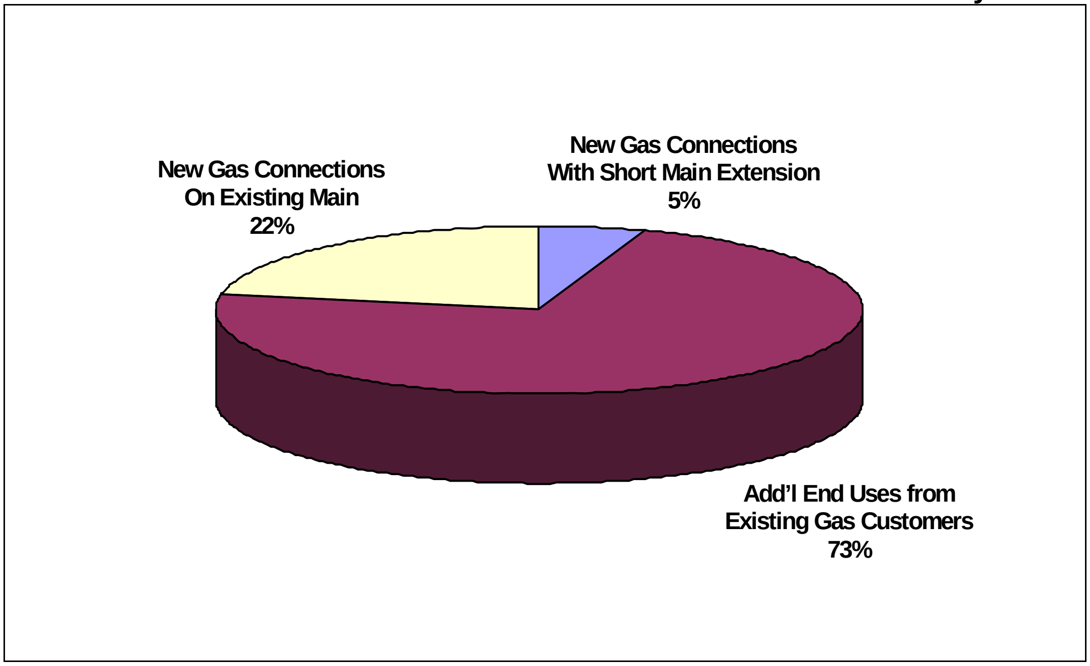
Fuel conversion will slightly diminish the potentials for electric energy efficiency. As can be seen in Exhibit VII-13, achievable electric conservation potentials will be reduced from 133.4 aMW to 127.9 under the normal replacement scenario, and 123.5 aMW under the early replacement scenario.

**Exhibit VII-13**
**Effects of Fuel Conversion on Residential Electric Energy Efficiency Potentials**

| Electric Resource Potential - 2025 | Without Fuel Conversion (aMW) | With Normal Replacement (aMW) | With Early Replacement (aMW) |
|---|---|---|---|
| **Technical** | | | |
| Fuel Conversion Potential (gross) | | 132.8 | 189.5 |
| Energy Efficiency | 375.8 | 338.5 | 321.2 |
| Total Technical Potential | 375.8 | 471.2 | 510.7 |
| As % of Residential Load | 25.9% | 32.5% | 35.2% |
| **Achievable** | | | |
| Fuel Conversion Potential (gross) | | 62.5 | 101.5 |
| Energy Efficiency | 133.4 | 127.9 | 123.5 |
| Total Achievable Potential | 133.4 | 190.4 | 224.9 |
| As % of Residential Load | 9.2% | 13.1% | 15.5% |

As can be seen in Exhibit VII-14, under the normal conversion scenario, most (73 percent) fuel conversion potential comes from existing PSE gas customers that convert additional end-uses, while relatively small proportions of fuel conversion potential are attributable to hook-up of entirely new gas customers.

**Exhibit VII-14**
**Distribution of Electric Conservation Potential from Fuel Conversion by Source**



Increases in gas consumption due to fuel conversions were examined under both “standard” (current state and federal codes) and “high” equipment efficiency levels (the same as those used in energy efficiency potential). As shown in Exhibit VII-15, fuel conversion will result in lowering the technical and achievable gas energy efficiency potentials by nearly 7.8 million decatherms and 4.2 million decatherms under the standard efficiency scenario, and 7 million decatherms and 3.6 million decatherms under the high-efficiency equipment scenarios. The efficiency level of the gas equipment has no impact on the amount of electric load reduction from fuel conversion.

**Exhibit VII-15**
**Effects of Fuel Conversion Potentials on Residential Gas Load**

| Gas Resource Potential – 2025 | Technical (Decatherms) | Achievable (Decatherms) | Technical (Decatherms) | Achievable (Decatherms) |
|---|---|---|---|---|
| **Efficiency Level of New Gas Appliances:** | **Standard** | **Standard** | **High** | **High** |
| Increased Use Due to Fuel Conversion | 7,763,444 | 4,169,422 | 6,987,099 | 3,752,480 |
| Gas Use Increase as % of Residential Load | 10.3% | 5.5% | 9.3% | 5.0% |

Although the amounts of conversion potential per customer tend to be large among customers who are not currently hooked up, capturing such opportunities would require significant additional investments in customer hookup and/or expansion of the existing distribution system. Based on PSE records, average hook-up cost (service line from in-street main to house plus meter) for new customers is currently estimated at over $2,000 per single-family home. The costs of gas line extensions/upgrades can vary widely, depending on the length of the line and the number of new gas customers connected, and therefore were not quantified. Thus, the total costs of hooking up new customers are somewhat underestimated.

Hook-up costs for new customers, combined with the additional gas fuel costs, have important ramifications in terms of overall fuel conversion resource costs. The effects of additional hook-up and fuel costs on overall fuel conversion costs were analyzed under the accelerated and normal conversion scenarios assuming standard and high-efficiency gas equipment. For the purpose of this analysis, hook-up costs were allocated to the three end-uses in proportion to their shares of total potential. Average fuel conversion resource costs for all end-uses can be expected to approximately double once additional fuel costs are taken into account. Inclusion of hook-up costs for new customers will nearly quadruple per MWh cost of fuel conversion resources (see Appendix B for more information).

*Energy Efficiency and Fuel Conversion Resource Portfolios*

While an accurate assessment of achievable demand-side potentials represented an important objective of this study, the paramount consideration was to construct portfolios of electric and natural gas conservation resource options, which could be compared with and evaluated against supply options on a balanced and consistent basis.

To facilitate the incorporation of the results of this study into PSE's least cost, integrated resource planning process, energy efficiency and fuel conversion potential estimates for each fuel type and customer sector were disaggregated into distinct cost-based "bundles" of conservation resource. Eight (8) electric and seven (7) gas cost-group "bundles" were created by grouping 1,756 electric and 736 gas conservation measure/segment/structure combinations with similar cost and load-shape characteristics. The energy savings from each of these bundles were then distributed across seven cost ranges. Electric and gas measures with costs above the thresholds of $115/MWh or $10.50/decatherm were not considered as economic or achievable. Fuel conversion potentials were incorporated into the same end-use bundles as energy efficiency to produce bundles that represent the net combination of energy efficiency and fuel conversion. The costs of the bundles with fuel conversion include PSE's costs to serve the additional natural gas demand (commodity costs and new service hookup costs), as well as the costs of the new gas end-use appliances.

The market segment/end-use bundles and cost range categories used for energy efficiency and fuel conversion resource analysis are listed in Exhibit VII-16 and VII-17, respectively. The segment/end-use bundles for natural gas resources are more simplified that what is shown in Exhibit VII-17, using only two end-uses: space heat (weather sensitive) and base load (non-weather sensitive). Most demand-side energy savings potential falls into the lower cost categories. The distribution of electric and natural gas energy efficiency resource potentials across each market segment/end-use bundle and the associated cost ranges are included in Appendix B.

**Exhibit VII-16**
**Segment/End-Use Bundles for Energy Efficiency and Fuel Conversion Resources**

| Residential | Commercial | Industrial |
|---|---|---|
| Existing Construction- Appliances | Existing Construction- Appliances | Existing Construction- General |
| Existing Construction- HVAC | Existing Construction- HVAC | |
| Existing Construction- Lighting | Existing Construction- Lighting | |
| Existing Construction- Water Heat | Existing Construction- Water Heat | |
| New Construction- Appliances | New Construction- Appliances | |
| New Construction- HVAC | New Construction- HVAC | |
| New Construction- Lighting | New Construction- Lighting | |
| New Construction- Water Heat | New Construction- Water Heat | |

**Exhibit VII-17**
**Cost Groups for Energy Efficiency and Fuel Conversion Resources**

| Electricity Cost Category | Gas Cost Category |
|---|---|
| A: less than $45/MWh | A: less than $4.50/decatherm |
| B: $45 - $$55/MWh | B: $4.50 - $5.50/decatherm |
| C: $55 - $65/MWh | C: $5.50 - $6.50/decatherm |
| D: $65 - $75/MWh | D: $6.50 - $7.50/decatherm |
| E: $75 - $85/MWh | E: $7.50 - $8.50/decatherm |
| F: $85 - $95/MWh | F: $8.50 - $9.50/decatherm |
| G: $95 - $105/MWh | G: >$9.50/decatherm |
| H: >$105/MWh | |

*Electric Demand-Side Resource Acquisition Scenarios*

In assessing long-run, demand-side resource potentials, timing of the resources over the planning period has significant ramifications for the integrated resource planning process. A large portion of energy efficiency and fuel conversion potential is made up of finite resources, particularly savings from retrofits and early replacement. Thus, the amount of demand-side resources already acquired affects current and future potentials. The timing for the acquisition of demand-side resources must also take into account practical administrative and logistical considerations, as well as potential market barriers (see Section C for further discussion).

In this analysis, two alternative scenarios for acquisition of achievable electric energy efficiency resources were considered: “Base Case” and “Accelerated.” The Base Case scenario assumes that energy efficiency potential occurs in equal annual proportions over the 20-year planning horizon, which equates to approximately 15 aMW per year. Under the Accelerated scenario, it is assumed that the timing of energy efficiency potential would be accelerated and all achievable retrofit or early replacement potentials would occur during the first 10 years of the plan. The Accelerated Case results, on average, in 24 aMW per year over the first 10 years and 5 aMW per year over the last 10 years.

Similarly, different scenarios for the timing of fuel conversion resource potential were developed. In the “Normal Replacement” scenario, fuel conversion potential occurs at the time of naturally-occurring appliance turnover, when the useful life of the electric appliance is complete, averaging about 3 aMW per year. This is analogous to the Base Case for energy efficiency. The “Early Replacement” scenario assumes all possible electric appliances are converted in the first 10 years, regardless of age or condition, which is analogous to the Accelerated Case for energy efficiency. The Early Replacement scenario for fuel conversion averages approximately 10 aMW of potential savings per year for the first 10 years and none afterward.

Consistent with PSE’s past experience with energy efficiency programs, the measure costs for demand-side resource potentials were adjusted upward by 10 percent to account for program development, delivery and administrative expenses under the Normal Replacement scenario. Average measure costs were increased by 30 percent under the Accelerated Case to take into account the need for more aggressive market planning, program promotion and product delivery mechanisms, as well as for normal program operation costs. In some cases, inclusion of program operation costs shifts some potential into higher cost categories. For some measures, costs were shifted beyond the achievable potential thresholds of $115/kWh and $10.50/decatherm, but were left as achievable potential in the highest cost bundles.

*Demand-Response Resource Potentials*

Demand-response (or demand-responsive) 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. Acquisition of demand-response resources may be based on either reliability considerations or economic/market objectives.

Objectives of demand response may be met through a broad range of price-based (e.g. time-varying rates and interruptible tariffs) or incentive-based (e.g. direct load control, demand buy-back, demand bidding, and dispatchable stand-by generation) strategies. In this assessment, five demand-response options were considered, similar to those examined in PSE's 2003 Least Cost Plan:

***1) Direct Load Control***: This strategy allows the utility to remotely interrupt or cycle electrical equipment and appliances such as water heaters, space heaters, and central air-conditioners. Direct load control programs are generally best suited for the residential and, to a lesser extent, small commercial sectors.

***2) Time-of-Use Rates***: This demand response option consists of two-part pricing structures designed to encourage customers to curtail consumption during peak, or shift it to off-peak hours. TOU tariffs are designed to reflect the utility's marginal cost of power supply.

***3) Critical Peak Pricing***: Critical peak or extreme-day pricing refers to incentive-based, demand-response strategies that aim to preempt system emergencies by encouraging customers to curtail their loads for a limited number of hours during the year. The amount of incentive is generally based on the utility's avoided cost of supply during extreme peak events.

***4) Curtailment Contracts***: These refer to contractual arrangements between the utility and its large customers who agree to curtail or interrupt their operations for a predetermined period when requested by the utility. The duration and frequency of such requests and levels of load reduction are also stipulated in the contract. Customers who agree to participate are typically compensated either through lower rates or fixed payments.

***5) Demand Buyback***: Under demand buyback arrangements, the utility offers payments to customers for reducing their demand when requested by the utility. The buyback amount generally depends on market prices published by the utility ahead of the curtailment event, and the level of reduction is verified against an agreed upon baseline usage level.

As in the case with energy efficiency and fuel conversion, demand response opportunities were assessed in terms of both "technical" and "achievable" potential.

- ***Technical Potential***: In the context of demand response, technical potential assumes that all applicable end-use loads in all customer sectors are wholly or partially available for curtailment, except for those customer segments (e.g. hospitals) and end-uses (e.g. restaurant cooking loads), which clearly do not lend themselves to interruption.

- ***Achievable Potential***: Achievable potential is a subset of technical potential and takes into account the customers' ability and willingness to participate in load reduction programs subject to their unique business priorities, operating requirements, and economic (price) considerations. Evaluation of achievable potential is a significant refinement of the Company's 2003 Least Cost Plan assessment of demand response, which focused on technical potential. In this assessment, estimates of achievable potentials were derived by adjusting technical potentials by two factors: expected rates of program participation, and expected rates of event participation. Assumed rates of program and event participation were estimated based on the recent experiences of PSE, other utilities in the Northwest, other national utilities, and Regional Transmission Organizations (RTOs) which have offered similar programs. Unlike energy efficiency and fuel conversion, no cost constraints were applied to achievable demand response potentials.

Demand response options are not equally applicable to or effective in all segments of the electricity consumer market, and their impacts tend to be end-use specific. Recognizing this, the study employed a "bottom-up" approach, which involved first breaking down PSE's system load by sector, market segment, and end-use; estimating demand response potentials at the end-use level; and then aggregating the end-use resource potentials estimates to sector and system levels. The approach was implemented in six steps as follows.

***1) Define customer sectors and market segments***. System load was disaggregated into four sectors: 1) residential, 2) commercial, 3) industrial, and 4) other. The commercial sector was further broken down into eleven segments.

***2) Create sector and segment load profiles***. Using PSE's annual hourly interval data, total sales were broken down by sector and segment.

***3) Develop sector- and segment-specific typical peak day load profiles***. "Typical" weekday profiles were developed for winter (January and February), and summer (July and August).

***4) Screen customer segments and end-uses for eligibility.*** This step involved screening customers for applicability of specific demand-response strategies. For example, the hospital segment and certain commercial end-uses such as cooking loads in the restaurant segment were excluded.

***5) Estimate end-use shares by sector and market segments***. End-use shares were estimated by applying annual end-use load profiles obtained from the Northwest Power and Conservation Council.

***6) Estimate technical potential***. For each demand-response strategy, estimates of technical potentials were developed by applying the fraction of load for each end-use that might be curtailed based on available data from the California Energy Commission's recent assessments of load reduction opportunities in commercial and industrial buildings.

***7) Estimate achievable technical potential***. Finally, for each demand response strategy, achievable potential was estimated by taking into account program participation as the fraction of appropriate end-use loads, which may be curtailed or interrupted.

PSE's hourly system load and sales by customer class, and end-use load shapes available from the Northwest Power and Conservation Council, served as the primary sources of data for this assessment. Estimates of expected load impacts resulting from various demand response strategies were based on data available from the commercial and industrial Enhanced Automation Study sponsored by the California Energy Commission, and the experiences of PSE and other utilities in the Northwest with various demand-response programs.

Complete descriptions of the methodology and data sources used to assess demand response potentials are included in Appendix B.

The results of this assessment, as summarized in Exhibit VII-18, indicate that critical peak pricing and direct load control of residential space heating and water heating, with achievable potentials of 155 MW (4.6 percent of system peak) and 95 MW (2.8 percent of system peak) respectively, offer the largest opportunities for demand response interventions. Achievable peak reductions from time-of-use tariffs are estimated at 49 MW, representing 1.5 percent of system peak. Opportunities resulting from curtailment contracts and demand buy-back are expected to be relatively small, averaging between 0.5 percent and 0.8 percent of system peak. Although the potentials for different demand response strategies are not mutually exclusive, hence not additive, it is estimated that selected combinations of these strategies might achieve as much as 200 MW of total peak demand reduction. For example, if Direct Load Control were selected for residential customers, and Critical Peak Pricing for industrial and commercial customers, the total would be 175 MW. There would still be possible additional reductions from programs using Curtailment Contracts and/or Demand Buy-Back.

**Exhibit VII-18**
**Demand-Response Potentials Summary - 2025**

| Sector | Direct Load Control | TOU | Critical Peak Pricing | Curtailment Contracts | Demand Buy-Back |
|---|---|---|---|---|---|
| ***Industrial*** | | | | | |
| *Technical Potential (MW)* | - | 4.9 | 19.8 | 12.2 | 14.8 |
| *Achievable Potential (MW)* | - | 1.7 | 7.4 | 2.7 | 4.4 |
| ***Commercial*** | | | | | |
| *Technical Potential (MW)* | - | 14.8 | 164.5 | 66.4 | 75.5 |
| *Market Potential (MW)* | - | *5.2* | *72.1* | *14.9* | *22.6* |
| ***Residential*** | | | | | |
| *Technical Potential (MW)* | 381.3 | 121.5 | 202.5 | - | - |
| *Achievable Potential (MW)* | *95.3* | *42.5* | *75.9* | - | - |
| **Total*** | | | | | |
| *Technical Potential (MW)* | 381 | 141 | 387 | 79 | 90 |
| % of System Peak | 11.2% | 4.1% | 11.4% | 2.3% | 2.7% |
| *Achievable Potential (MW)* | 95 | 49 | 155 | 18 | 27 |
| % of System Peak | 2.8% | 1.5% | 4.6% | 0.5% | 0.8% |
| **Average Cost ($/kW)** | $55.0 | $44.1 | $21.6 | NA | NA |
| **Average Cost ($/mWh)** | NA | NA | NA | $154.7 | $154.7 |

* Note that strategies are not mutually exclusive, hence potentials are not additive.

The demand-response strategies considered here also vary significantly with respect to their costs. Costs for direct load control, time-of-use tariffs and critical peak pricing were estimated on a kW basis. For direct load control and time-of-use tariffs, costs were estimated using the most recent data from PSE and other regional utilities with experience in similar programs, especially Portland General Electric Company. For both strategies, it was assumed that the total estimated achievable potentials would be captured in five years, and that participants would remain in the program for seven years, after which customers would have to be re-recruited in order to continue to get peak savings. This choice was based on the expectation that most customers tend to relocate after seven years or less.

The results of the analysis show that based on the available data, critical peak pricing, has the lowest average cost at $21.6 per kW. Time-of use-tariffs ($44.1/kW) and direct load control ($55/kW) have the next lowest costs.

Since participant incentives for curtailment contracts and demand-buy-back programs are generally based on reduction in energy, costs for these strategies were estimated on a dollar per MWh basis. Based on the results of the commercial and industrial sector load reduction programs offered by PSE and other regional utilities during the summer of 2001, the achievable potentials for these strategies appear to be relatively small, mainly due to low program and/or event participation. The data shows that of the 457 eligible customers, only 19 (4 percent), representing about 3 percent of the eligible load, participated in PSE's program.

Through its demand buy-back program in 2001, PSE was able to acquire a total of 21.1 MWh (approximately 2 MW) at an average cost of nearly $155 per MWh. Participation levels in such programs are to a large extent a function of incentive amounts; but they also depend on the customers' willingness and ability to commit to curtailment. An analysis of PSE's program activity during the spring and summer of 2001 indicates that load response to prices was indeed relatively in-elastic, with an estimated elasticity of 0.8 percent. This indicates that a 1 percent increase in incentives is likely to increase load reduction by 0.8 percent. The results of this analysis suggest that significantly larger prices must be paid if PSE is to capture all or most of the expected achievable potential for such demand response strategies.

Assessment of demand-response potential poses considerable analytic challenges and tends to be less precise than for energy efficiency. This is particularly the case in assessing achievable potentials for market-based strategies such as curtailment contracts and demand buy-back, due to the lack of sufficient market data on customer willingness to participate in such programs. In its assessment of demand-response strategies, PSE has relied on the best available methods and data. The results of this assessment, therefore, are to be regarded as indicative, rather than conclusive.

## C. Demand-Side Planning and Implementation Issues

This section examines the uncertainties of quantifying demand-side resources, program implementation issues beyond the Least Cost Plan modeling process, and some considerations for accelerated resource acquisition scenarios. Additional implementation issues associated with demand-side resources are discussed in Chapter VIII.

*Uncertainties for Quantifying Demand-Side Resource Potentials*

The amount of demand-side potential identified for the Least Cost Plan relies on the best available information today about prices, efficiency, consumer behavior and preferences, and projects that information 20 years into the future. As with other resources, demand-side resource assessment depends heavily on energy load forecasts and projected growth rates, with all of the associated uncertainty.

Also analogous to supply-side resources, assessments of demand-side potential are limited by what is currently available in the marketplace in terms of cost-effective technologies for improving energy efficiency. The impacts of new technologies and new energy efficiency codes and standards are difficult to accurately predict. This uncertainty is mitigated through biennial updates of the Least Cost Plan, which provides the opportunity to incorporate advances in demand-side technologies and programs.

Somewhat unique to demand-side resources is the utility's dependence on large numbers of very small purchases, each tied to the individual consumer's day-to-day purchasing and behavioral decisions. The utility attempts to influence these decisions through its programs, but the consumer is the ultimate decision-maker regarding the purchase of demand-side resources. PSE's assessments of demand-side resources make the best possible estimates of customers' willingness to participate, based on previous utility program experience. But the actual experience of any new program is likely to vary from planning estimates. The uncertainty about program participation is greater for fuel conversion and demand response than for energy efficiency, which generally has a more extensive track record of actual program operation.

*Implementation Considerations that Extend Beyond Resource Portfolio Modeling*

Many specific details are required to implement successful demand-side programs. As discussed previously, actual implementation design, delivery, and market conditions will cause energy-efficiency program savings and costs to vary. Customer participation in a program is heavily influenced by the level of incentive paid by the utility vs. the cost to the customer. Program implementation depends on staff with the appropriate skills and tools to be able to provide customer service, sales, engineering, database use, marketing, evaluation, and management. A number of program support services need to be in place for collecting customer-specific information, monitoring/reporting performance metrics, and evaluation of cost-effectiveness. External infrastructure considerations must also be addressed, such as product availability to utility customers and an adequate network of contractors, retailers, and other trade allies to support a program.

As new measures or expanded programs are developed and added to the current program mix, internal and external resources and capabilities need to grow accordingly and progress through a "learning curve." Small pilot programs often precede full-scale programs to test the performance of demand-side technologies and customer acceptance of a particular market delivery mechanism.

In short, a utility cannot immediately launch into full-scale deployment of all the demand-side measures identified by its Least Cost Plan, nor should such results be expected. The estimates of fuel conversion resource potentials in this Least Cost Plan do not account for any "ramp-up" that would be required to reach the savings levels achievable from fully mature programs.

*Accelerated Scenarios for Electric Demand-Side Resources*

For the 2005 Least Cost Plan, PSE examined several demand-side resource acquisition scenarios focused on constant or "normal" rates of acquisition and accelerated or "early replacement" cases for energy efficiency and fuel conversion. While the difference between these scenarios is significant in terms of short-term energy-efficiency program activity, it is fairly minor in terms of the magnitude of the resource need PSE will experience in the next several years. The process of determining an optimal level of demand-side resource acquisition for the short term should consider the advantages of steady, consistent levels of annual energy-efficiency acquisition vs. a mode that would have the utility ramp-up market-place activity for a few years, and ramp-down in later periods. There are additional costs associated with the delivery of higher levels of efficiency in a shorter time frame, including acquiring the necessary resources, training personnel and trade allies, and more intensive promotional activities. Ramping up also depends on sufficient lead times to ensure the proper infrastructure development.

# VII. DEMAND-SIDE RESOURCES

This chapter discusses PSE's current electric and gas energy efficiency programs; the outcome of the 2004 electric efficiency resource acquisition Request for Proposal (RFP) process; and the results of the demand-side resource potentials analysis, which are a key input to the integrated resource analysis described in subsequent chapters.

## A. Existing Energy Efficiency Resources

*Overview*

PSE has provided conservation services for its electricity customers since 1979. The conservation measures installed through PSE programs from 1985 - 2004 are currently saving a cumulative total of approximately 229 aMW (about 2,003,000 MWh) in 2004. These energy savings have been captured through energy efficiency programs designed to serve all customers – including residential, low-income, commercial and industrial. The Company has expended approximately $430 million in electricity conservation since 1985.

On the gas side, PSE has provided energy efficiency services since 1993, installing enough conservation measures through 2004 to be currently saving a cumulative total of 1,114,267 decatherms in 2004 – half of which has been achieved since 2002. These energy savings were captured through energy efficiency programs primarily serving residential and low-income customers through 1998. Beginning in 1999, PSE increased its focus on achieving gas energy savings from commercial and industrial customer facilities. Since 1993, the Company has expended close to $12 million in natural gas conservation.

PSE currently operates its energy efficiency programs in accordance with requirements established as part of the stipulated settlement of PSE's 2001 general rate case (WUTC Docket Nos. UE-11570 and UG011571).

In its August 2003 Least Cost Plan Update, PSE completed an extensive analysis of energy efficiency savings potential and its contribution to the Company's electric and gas resource portfolios. The results were used to develop PSE's energy efficiency program targets for 2004 and 2005. This assessment was the culmination of a collaborative effort between PSE and key external stakeholders represented in the Conservation Resource Advisory Group (CRAG) and the Least Cost Plan Advisory Group (LCPAG).

The outcome of this process was the development of a two-year target for energy savings of approximately 39 aMW of electric energy efficiency and 500,000 decatherms of natural gas energy efficiency by the end of 2005, to be achieved through a variety of program offerings to all customer classes. Such targets represent an increase over 2002-2003 targets, which in turn represented a significant ramp-up over previous levels. The Company also issued an RFP to acquire electric efficiency resources, consistent with the findings of the August 2003 Least Cost Plan Update. The status and results of PSE's conservation programs and RFP process are presented below.

*Current Energy Efficiency Programs*

PSE currently offers electric energy efficiency programs under tariffs effective from January 1, 2004 through December 31, 2005. Programs provide for energy savings from all customer sectors, including both electricity and natural gas. PSE funds the majority of its energy efficiency programs using electric "Rider" and gas "Tracker" funds, collected from all customers. A portion of electric program funding also occurs through arrangements with the Bonneville Power Administration (BPA) to provide Conservation and Renewable Discount (C&RD) credits. Based on best current estimates of costs and savings projections, these conservation programs provide a cost-effective resource.

The year 2004 marked the beginning of a new conservation tariff period spanning 2004 and 2005 that continues ongoing programs and initiates a number of new pilot programs. Exhibit VII-1 shows how PSE has done in 2004 compared to two-year budget and savings goals for electric energy efficiency programs (including BPA C&RD programs). Based on jobs in progress and program status, current projections are that PSE will achieve 100 percent of the two-year savings goals on or under budget by the end of 2005.

During 2004, PSE's electric energy efficiency programs saved a total of 19.8 aMW of electricity, putting the Company on track to achieve its two-year electric savings goal of 39,2 aMW by the end of 2005. Programs under the electric Rider achieved total savings of 138,288 MWh (15.79 aMW) at a cost of $20,869,462. In addition, under BPA's C&RD program, PSE saved an additional 34,927 MWh (3.99 aMW) in first-year savings at a cost of $4,126,802 (does not include cost of renewables). The 2004 savings achievement is 14 percent higher than the 2003 total of 17.3 aMW saved.

PSE's 2004 gas efficiency programs saved a total of 318,000 decatherms, putting the Company on track to achieve its two-year gas savings goal of 500,000 decatherms by the end of 2005. Natural gas energy efficiency savings were achieved at a cost of $3,781,810. The 2004 achievement is a 47 percent increase over the 2003 total of 217,500 decatherms saved.

**Exhibit VII-1**
**Annual (Jan. 2004 – Dec. 2004) Energy Efficiency Program Summary**

| Tariff + C&RD Programs | 2004 ACTUALS | 2 YEAR BDGT./GOAL | '04 vs. '04/05 % Total |
|---|---|---|---|
| Electric Program Costs | $24,996,264 | $52,218,000 | 47.9% |
| MWh Savings | 173,215 | 343,080 | 50.5% |
| Gas Program Costs* | $3,781,810 | $9,106,000 | 41.5% |
| Decatherm Savings | 318,982 | 501,348 | 63.6% |

* Does not include Low Income Weatherization O&M funding of $300k per year.

*Electric Energy Efficiency RFP*

In February 2004, PSE issued an "all-comers" RFP for acquisition of electric energy efficiency resources, consistent with 2003 Least Cost Plan findings of a short-term need for electric energy resources (with energy efficiency included as a least-cost option), as well as with WAC 480-107 requirements. The Energy Efficiency RFP process was run in parallel with the RFPs for wind and all generation resources.

The Energy Efficiency RFP sought two types of proposals:

- *Resource Programs:* Programs to acquire energy savings via installation of high-efficiency equipment and technologies at customer premises, with a minimum project size of 5,000 MWh/year delivered within two years.
- *Pilot Projects:* Small-scale programs designed to introduce energy efficiency measures not yet widely adopted in PSE's service territory, and/or to demonstrate program delivery to market segments that have experienced low participation in energy efficiency programs.

The primary implementation period targeted by the RFP was 2006-2007, with earlier implementation as an option, if appropriate. The long lead time was driven by the fact that 2004

– 2005 targets, programs, and a regulatory penalty mechanism were established through consensus agreement with the CRAG prior to development of the RFP process. This was pursuant to conditions stipulated in the Conservation Agreement as part of PSE's 2001 General Rate Case (WUTC Docket Nos. UE-11570 and UG011571). Therefore, a proposal had to align very closely with PSE's current established mix of programs to be selected for implementation prior to 2006.

In April 2004, PSE received bids for 29 efficiency projects, totaling 30 aMW. These bids underwent an extensive, two-stage structured evaluation process, focusing on cost-effectiveness, technical merits, compatibility with existing PSE programs, and the risk of not delivering projects as proposed. PSE also sought to choose a variety of proposals such that all customer classes were included. The first stage of the evaluation process was completed in June 2004, resulting in the selection of a short list of 12 proposed projects. The second evaluation phase was completed in August 2004 to select finalists. The results of this evaluation process have been reviewed with the CRAG.

Five projects, totaling 7 aMW, were selected to receive Letters of Interest to pursue final contracts. Three of the finalists target the commercial/industrial sector (1 pilot and 2 resource programs), while the other two finalists address the residential sector (1 pilot and 1 resource program). The two residential projects are being considered for implementation starting in 2005, while the commercial/industrial projects are more likely to be implemented in 2006-2007. Contract negotiations are in progress and will be completed by mid-2005.

Given PSE's extensive experience in operating energy efficiency programs, the Company has determined that a "targeted" approach to acquiring energy efficiency resources from third-party providers would be more effective than the "all-comers" approach. The 2004 RFP process found few new technologies or innovative service delivery mechanisms, and no respondent could match PSE's current programs in terms of delivery efficiency and cost-effectiveness (some of which already utilize third-party providers). PSE (supported by bidder comments and questions during the RFP process) would prefer to focus future RFPs on specific customer segments, end uses, or technologies that would enhance or expand its current program mix. Such a targeted process would likely yield more competitive bids that best meet PSE's needs at potentially lower costs to its customers, and provide bidders with more structure and guidance.

PSE also found that the misalignment between the program implementation cycle, required by its 2001 General Rate Case stipulation, and the electric resource RFP process mandated by the WAC, created an extremely long lead time between issuance of the RFP and implementation of selected projects. As explained above, PSE had to set targets and commit to programs and budgets before the RFP process could be completed. Projects selected by the RFP process were thus pushed into the next "open" program implementation cycle by this timing conflict, putting them more than a year out. Public comments on the RFP indicated that such a long lead time greatly increases the risk and uncertainty faced by bidders about future costs and market conditions, which could be reflected in higher bid prices or their decision to bid at all. PSE would like to explore alternatives to reduce this timing conflict in future RFPs, which should encourage more cost-effective bid submittals.

## B. Demand-Side Resources – Potential

*Overview*

Developing reliable estimates of the magnitude, timing, and price of alternative demand-side resources is a critical first step in a least-cost, integrated resource planning process. These estimates also help to guide and inform demand-side planning and inform conservation program development efforts.

As part of its 2003 least cost planning process, PSE commissioned a study to investigate the "technical" and "achievable" electric and gas conservation potentials in its service area for the 2004-2023, 20-year planning horizon. The results of that study were filed with the Washington Utilities and Transportation Commission (WUTC) in the August 2003 update to PSE's Least Cost Plan, originally filed in April 2003 under Docket UE-030594.

In an effort for the 2005 Least Cost Plan to more fully consider the potentials for demand-side resources within PSE's service territory, the Company engaged Quantec, LLC, an energy and environmental consultancy in Portland, Oregon, to conduct a comprehensive assessment of all achievable demand-side resources, including energy-efficiency, fuel conversion, and demand-response options. A detailed report on this demand-side potential assessment is included as Appendix B. The principal goal of this study was four-fold:

1. To update the results of the 2004-2023 conservation potentials study using more recent market data for the residential, commercial, and industrial sectors in the Company's service area; and to extend the analysis to the 2006-2025 planning period.
2. To investigate the potentials for additional demand-side resource options including electric-to-gas fuel conversion and demand response, taking into account the interactions among various resource options and resource acquisition scenarios.
3. To employ a simple, flexible, and transparent approach consistent with the methods used by the Northwest Power and Conservation Council, relying on the most recent market data.
4. To create discrete "bundles" of demand-side resource potentials comprised of groups of homogeneous measures, and to provide supply curves for each bundle that would allow the demand-side resource options to be evaluated against supply options on an equal basis in PSE's least cost, integrated resource planning process.

Estimates of long-term, demand-side resource potentials in this study were derived with standard practices and methods in the utility industry, using the most recent data. Studies such as this require compilation of large amounts of data from multiple sources on existing demand management strategies, technologies, and market dynamics that affect their adoption. They also rely on assumptions concerning the future, particularly changes in demand for energy, codes and standards, energy efficiency technologies, market conditions, and consumer behavior. It is, therefore, inevitable that the findings of this study will have to be revisited periodically to take into account the impacts of emerging technologies and the changing dynamics of the energy markets.

*General Methodology*

Concurrent assessment of demand-side resources poses significant analytic challenges. Due to their inherently unique characteristics and the types of load impacts that they generate, analyses of energy-efficiency, fuel conversion, and demand-response potentials require different methodologies and data. While these methodologies are capable of producing reliable estimates for each demand-side resource individually, they must also have the capability to accurately account for interactions among these resources, particularly capturing the effects of fuel conversion on energy efficiency potentials.

This study incorporated significant improvements over the 2004-2023 assessment with respect to both methodology and data quality. Due to the more complex nature of the assessment, largely arising from the interactions between energy efficiency and fuel conversion, a more advanced and more flexible methodology and modeling approach had to be adopted. The study also relied on substantially more accurate and more recent market data on market characteristics, conservation measure impacts, and costs, especially in the residential and commercial sectors.

The overall approach in this study distinguishes between two distinct, yet related, definitions of resource potential that are widely used in utility resource planning. The first is “technical potential,” and the second is “achievable potential.” Technical potential assumes that all demand-side resource opportunities may be captured regardless of their costs or market barriers. Achievable potential, on the other hand, represents that portion of technical potential that is likely to be available over the planning horizon given prevailing market barriers and administrative program costs that may limit the implementation of demand-side measures. For the purpose of this study, “achievable” energy efficiency and fuel conversion potentials are defined as that portion of technical savings potential remaining after factoring in market penetration rates, and which has a levelized per unit cost of less than $115 per MWh for electricity and less than $10.50 per decatherm for gas, inclusive of program administration and delivery costs.

Estimates of technical energy efficiency and fuel conversion potential for the residential and commercial sectors were derived using Quantec’s QuantSim model, an electric and gas end-use forecasting model. For each customer class, application of the model involves three steps: 1) producing separate, end-use specific forecasts of loads over the 20-year planning horizon, and calibrating the end-use forecasts to PSE’s 20-year aggregate customer class forecasts to ensure consistency between the two, 2) producing a second forecast for each end-use that incorporates the saturations and energy impacts of all feasible energy efficiency measures, and 3) calculating technical potentials by end-use, and measure as the difference between the two forecasts.

Due to the more complex nature of the industrial market, end-uses and equipment, on the one hand, and the lack of reliable information on measure-specific saturations, on the other hand, energy efficiency potentials in the industrial sector were analyzed using an alternative, “top-down" approach. Application of this method involved two steps. First, total firm industrial loads were disaggregated into standard classes, and major end-uses within each class based on PSE's latest sales data. Second, for each end-use, potential savings and per unit cost of the potential savings were estimated using available data from industrial energy efficiency programs in the Northwest and California, and market information on PSE's industrial customer accounts.

Given the technical challenges of and market barriers facing fuel conversion in the commercial and industrial sectors, opportunities for electric conservation from fuel conversion were assessed only for the residential sector. Four residential end-uses were considered, namely space heating, water heating, cooking, and clothes drying. In order to account for the effects of fuel conversion on electric and gas conservation opportunities, potentials for energy efficiency and fuel conversion in the residential sector were modeled simultaneously.

As explained later in this chapter, potentials for each demand-response resource acquisition strategy were estimated using a hybrid, top-down, bottom-up approach. It consisted of first disaggregating PSE's total load into customer sectors and end-uses, estimating load reduction potentials for each end-use, and then aggregating end-use impacts to sectors and system level.

The methodologies used to assess the potentials for energy efficiency, fuel conversion, and demand response are described more fully in Appendix B.

*Data Sources*

Implementation of the methodology described above required compilation of a large database of measure-specific technical, economic, and market data from a large number of primary and secondary sources. The main sources used in this study included, but were not limited to, the following

- ***Puget Sound Energy*****:** Latest load forecasts, load shapes, economic assumptions, PSE's historical energy efficiency and demand-response program activities, PSE's 2004 residential appliance saturation survey (RASS) designed with a particular emphasis on obtaining market to support this study, and the Commercial Building Stock Assessment (CBSA) - a study of the Northwest's commercial building characteristics sponsored jointly by BPA, the Northwest Energy Efficiency Alliance, and PSE.

- ***Northwest Power Planning Council and the Regional Technical Forum*****:** Technical measure information, measure costs, measure savings, measure life.
- ***California Energy Commission Database for Energy Efficiency Resources (DEER)*****:** Measure costs and savings, measure applicability factors, and technical feasibility factors.
- ***Existing Studies:*** Previous conservation potentials studies and conservation program evaluation reports on energy efficiency programs in the Northwest and California.

*Summary of the Results – Energy Efficiency*

Technical energy efficiency potentials in the residential and commercial sectors were derived based on an analysis of 127 unique electric measures, and 62 unique gas measures. The Northwest Power and Conservation Council was the primary source for electric measures in the residential and commercial sectors. This list was augmented by additional measures from DEER. The list of gas measures in all sectors was compiled mainly from DEER.

Under consideration were six residential segments (existing single-family, existing multi-family, existing manufactured homes, new-construction single-family, new-construction multi-family, new-construction manufactured homes) and 20 commercial segments (10 building types within the existing and new structure segments). Since many energy efficiency measures are applied to multiple segments and building types, a total of 1,756 electric and 736 gas measure/segment/structure combinations were included in the analysis. All major end-uses in all 15 major industrial segments in PSE's service area, including wastewater treatment, were analyzed. The measure/segment/structure combinations were then grouped into "bundles" with similar cost and load shape characteristics, as described later in this chapter.

Based on the results of this study, cumulative 20-year technical conservation potentials in PSE's service area are estimated at 895.5 aMW megawatts of electricity and 38,223,912 decatherms of natural gas savings, of which 297 aMW (33 percent) and 10,788,029 decatherms (28 percent) are expected to be achievable. Achievable savings represent 9.3 percent of the electric load and 8.6 percent of projected gas use over the 2006-2025, 20-year planning period.

As shown in Exhibit VII-2, the commercial sector accounts for the largest share of achievable electricity savings (147.6 aMW), followed by the residential sector with an achievable savings potential of 133.4 aMW over 20 years. The industrial sector accounts for 15.9 aMW of electricity savings during the same period.

**Exhibit VII-2**
**2006 - 2025 Electric Technical and Achievable Potential**

| Sector | 2025 Total Load (a) | 20-Year Cumulative Potential (a/% of Baseline) | |
|---|---|---|---|
| | | Technical | Achievable |
| Residential | 1,450 | 375.8 | 133.4 |
| Commercial | 1,578 | 503.7 | 147.6 |
| Industrial | 158 | 15.9 | 15.9 |
| Total | 3,186 | 895.4 | 296.9 |

**Exhibit VII-3**
**2006 – 2025 Natural Gas Technical and Achievable Potential**

| Sector | 2025 Total Gas Sales (Decatherms) | 20-Year Cumulative Potential (Decatherms as % of Baseline) | |
|---|---|---|---|
| | | Technical | Achievable |
| Residential | 75,278,759 | 27,738,747 | 6,334,280 |
| Commercial | 42,637,285 | 10,170,241 | 3,864,537 |
| Industrial | 4,028,666 | 314,924 | 314,924 |
| Total | 121,944,710 | 38,223,912 | 10,513,741 |

The largest share of achievable natural gas potential is expected to occur in the residential sector, which accounts for nearly 60 percent of total achievable natural gas savings. The commercial and industrial sectors respectively account for 37 percent and 3 percent of the achievable gas conservation potential, as shown in Exhibit VII-3.

Distributions of achievable electricity savings in the residential and commercial sectors by end-use are shown in Exhibits VII-4 and VII-5. Savings in lighting (Exhibit VII-4), achieved mainly through installation of energy-efficient lighting technologies such as compact fluorescent light bulbs and fixtures, represents the largest electric conservation potential in the residential sector, accounting for 42 percent of the sector's achievable savings. The results also show that about 24 percent of achievable savings in the residential sector may be obtained through installation of measures to improve space-heating performance, such as insulation, weatherization and equipment replacement. The remaining savings can be achieved through the implementation of water heating measures, such as water heating equipment upgrades (20 percent), installation of Energy Star rated appliances (13 percent), and cooling measures (1 percent).

In the commercial sector (Exhibit VII-5), lighting retrofit represents the largest potential for electricity savings. Nearly 45 percent of potential electricity savings in the commercial sector is attributable to the application of energy-efficient lighting. Retrofit, upgrade and better operation and maintenance of HVAC equipment are also shown to be effective conservation measures, which account for over 38 percent of the total electricity savings potential in this sector. High-efficiency office and cooking equipment (plug loads) account for 14 percent of the savings potential, while water heating measures account for 3 percent of total commercial-sector electricity savings.

**Exhibit VII-4**
**Distribution of Achievable Electric Conservation Potential by End-Use**
**Residential Sector**

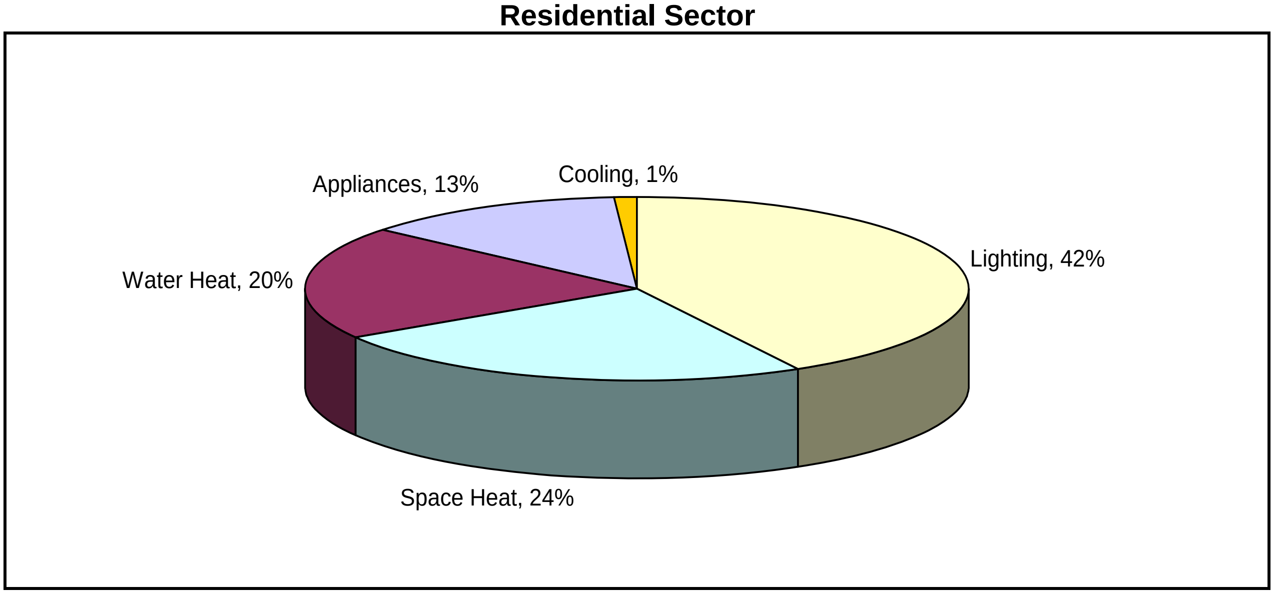
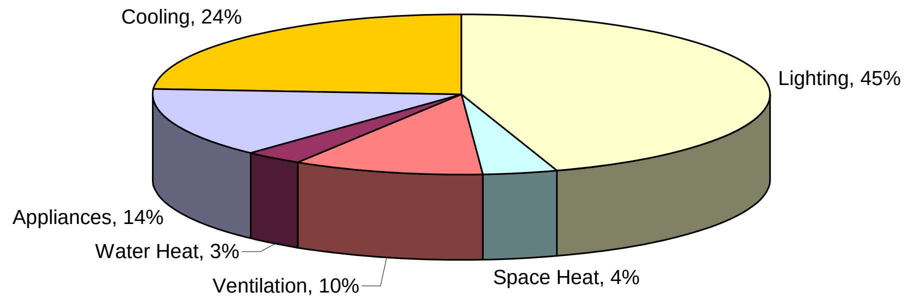


**Exhibit VII-5**
**Distribution of Achievable Electric Conservation Potential by End-Use**
**Commercial Sector**




As shown in Exhibit VII-6, expected savings in space heating is the largest component of the achievable natural gas conservation potential in the residential sector, accounting for nearly 69 percent of the gas savings potential. Upgrade of heating equipment with alternative, more energy-efficient equipment provides the main source for the potential savings. The results also show that installation of more efficient water heaters and application of measures that improve the performance of existing water heating equipment, such as insulation and, to a lesser degree, water-saving measures and home weatherization, together account for over 31 percent of the gas conservation potential in the residential sector.

As Exhibit VII-7 illustrates, space heating, water heating and appliance conservation measures provide the largest potentials for gas savings in the commercial sector. These measures respectively represent 52 percent (space heating), 37 percent (water heating), and 10 percent (appliances – primarily cooking) of the total achievable gas conservation potential in the commercial sector. Pool heating conservation measures account for a small share of the total gas savings potential in this sector.

**Exhibit VII-6**
**Distribution of Achievable Natural Gas Conservation Potential by End-Use Residential Sector**

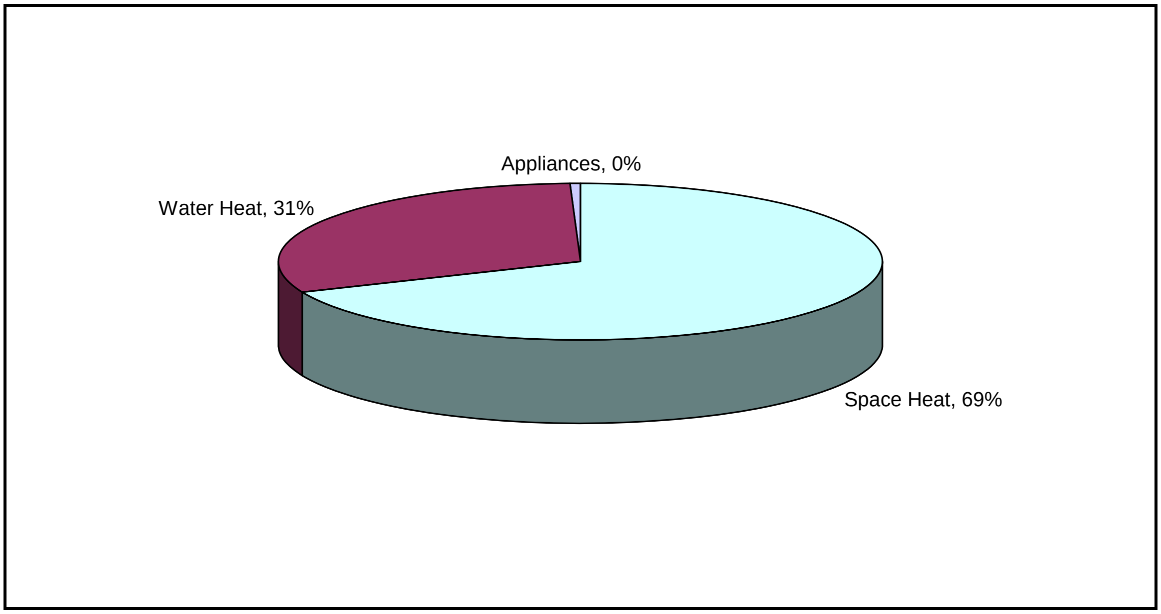
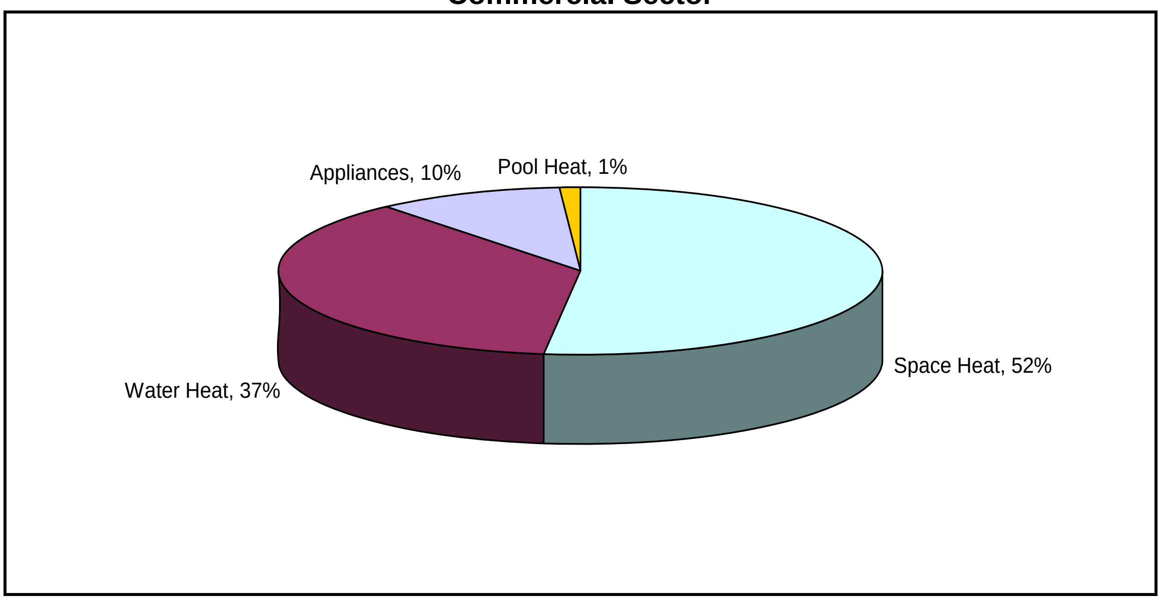



**Exhibit VII-7**
**Distribution of Achievable Natural Gas Conservation Potential Commercial Sector**




Achievable electric conservation potentials in the industrial sector are estimated at 15.9 aMW, which is equivalent to approximately 10 percent of the total industrial load. As shown in Exhibit

VII-8, nearly 70 percent of these savings are attributable to potential efficiency gains in facility improvements, primarily HVAC and lighting retrofits. Energy efficiency improvements in refrigeration and process cooling account for the remaining 30 percent of savings potential. As shown in Exhibit VII-9, boiler (86 percent) and HVAC (14 percent) upgrades account for all of the gas conservation potential in the industrial sector.

**Exhibit VII-8**
**Distribution of Achievable Electric Conservation Potential**
**Industrial Sector**

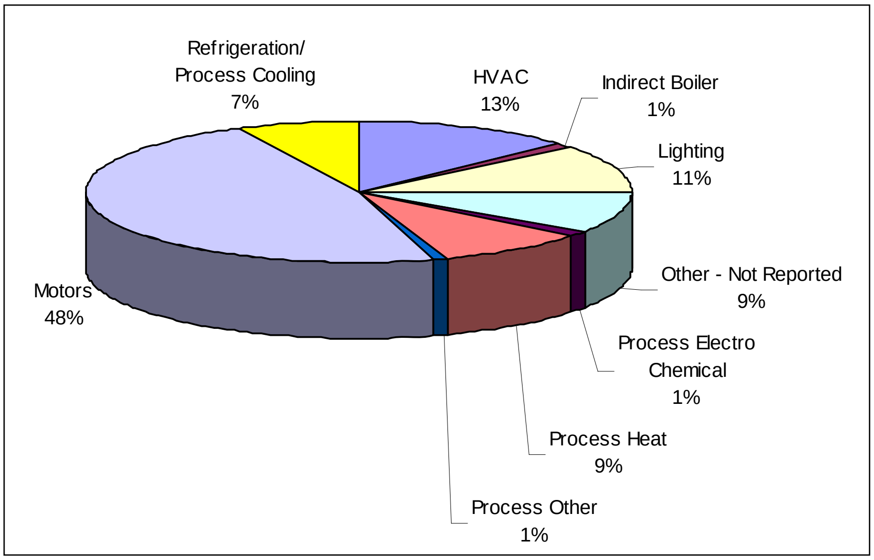
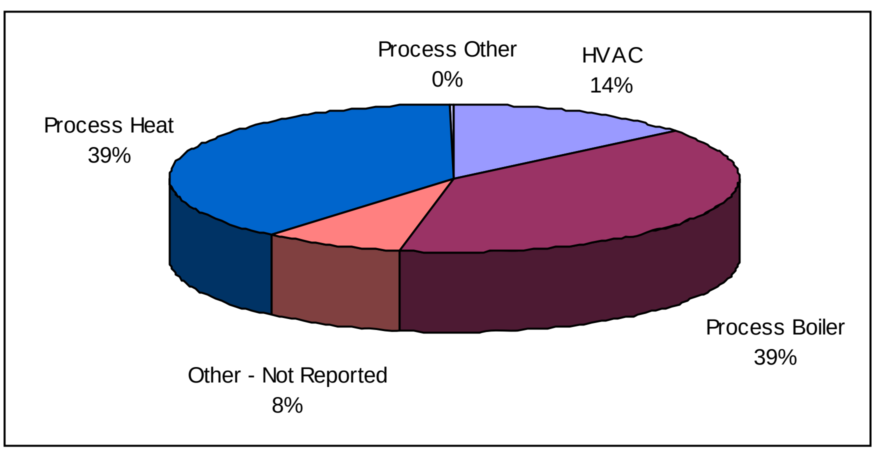



**Exhibit VII-9**
**Distribution of Achievable Natural Gas Conservation Potential**
**Industrial Sector**



Timing is an important element in developing strategies to acquire energy efficiency resources. Consistent with the definitions established by the Northwest Power and Conservation Council, PSE distinguishes between "lost opportunities" and "retrofits" in considering the potentials for conservation. "Lost opportunities," such as energy efficiency potentials in new construction and upgrades to equipment upon their natural replacement, tend to be timing-dependent and must be captured as they become available. "Retrofits," on the other hand, are assumed to remain available over time.

The results of this assessment, as shown in Exhibit VII-10, indicate that over two-thirds (68 percent) of achievable electric energy efficiency potentials in the residential sector are comprised of retrofit opportunities, while lost opportunities account for a greater portion of achievable electric energy efficiency potentials in the commercial sector (57 percent compared to 43 percent). With respect to natural gas achievable energy efficiency potentials, however, lost opportunities are larger in both the residential and commercial sectors (see Exhibit VII-11). All of the estimated electric and gas achievable energy efficiency potentials in the industrial sector are shown to result from retrofits.

**Exhibit VII-10**
**Electric Energy Efficiency Potentials: Retrofit vs. Lost Opportunities**

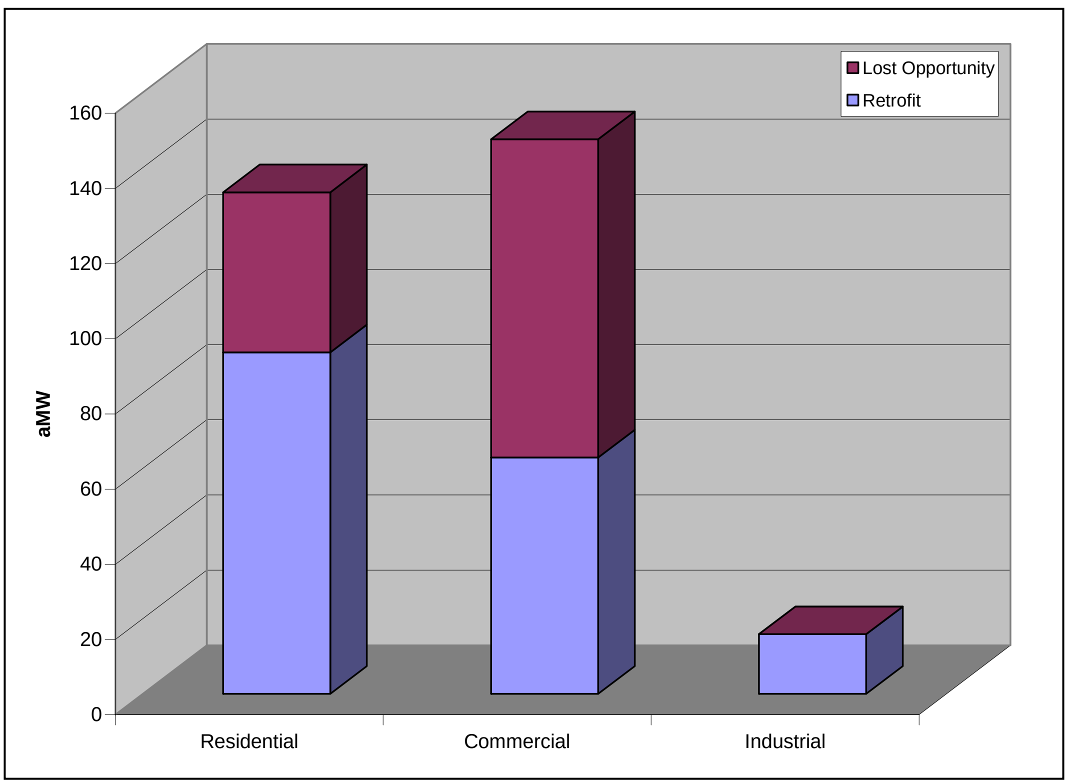
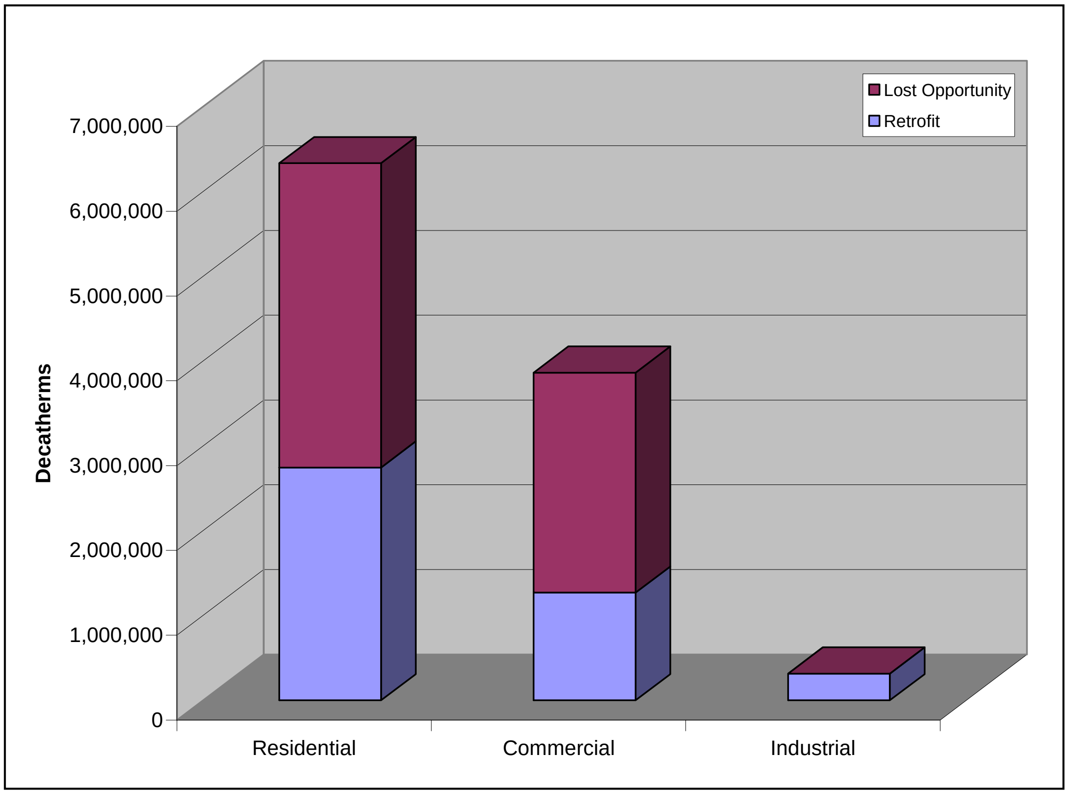


**Exhibit VII-11**
**Gas Energy Efficiency Potentials: Retrofit vs. Lost Opportunities**




Estimates of achievable electric conservation potentials from this study are slightly lower than those reported in the 2003 Least Cost Plan. A comparison of the results of the two studies shows a decline in electric conservation potentials in the residential and commercial sectors and a slight increase in the industrial sector. In aggregate, achievable electric conservation potential decreased by approximately 9.5 percent (from 328 aMW to 297 aMW). This difference is explained by several intervening factors including the effects of PSE's conservation activities in 2003 – 2004 (see Section A), refinements to measure data, changes in assumptions regarding saturation of energy efficient technologies, and, particularly, changes in load forecasts. Gas conservation potentials were nearly unchanged, declining modestly from 10.8 million decatherms in 2003 to 10.6 million decatherms in 2005.

*Fuel Conversion Potentials*

Fuel conversion potential was assessed in conjunction with energy efficiency potential, rather than on a stand-alone basis. Fuel conversion resources augment electric energy efficiency potentials in reducing total electric loads. At the same time, fuel conversion precludes realizing the full electric energy efficiency potentials of affected electric end-uses because the substitution of gas appliances for electric replaces some opportunities to install electric efficiency measures. Fuel conversion also results in increased consumption of natural gas, which, in turn, increases the potential opportunities for gas energy efficiency. Due to this interdependency, analyses of electric conservation and fuel conversion potentials must be performed simultaneously, explicitly taking into account interactions between the two resource options.

Potentials for fuel-conversion were made only for the population of residential customers in PSE's combined electric and gas service area, since fuel conversion is only being considered as an electric resource strategy in this Least Cost Plan. Four end-uses were examined: space heating, water heating, cooking, and clothes drying. For each end-use, conversion potentials were estimated under both "normal" and "early" equipment replacement scenarios. Under the "normal" replacement scenario, it is assumed that conversions would occur at a naturally-occurring pace upon failure of existing equipment. The early replacement scenario assumes a more aggressive approach, where conversions are made during the first ten years of the planning horizon regardless of age and condition of existing equipment. Additional fuel conversion potential, as an electric resource alternative, may be available from PSE electric customers in areas served by other gas utilities. However, lack of data on the ability to serve additional loads, coverage of existing gas distribution systems, and the line extension plans of other gas utilities precludes quantifying this additional potential.

Service availability and distribution system constraints are important considerations in assessing the achievable potentials for fuel conversion. As Exhibit VII-12 demonstrates, PSE provides gas service to 70 percent of residential customers in its electric service area. Of these customers, 62 percent are on gas mains, of which 76 percent are currently receiving gas services from PSE. Moreover, current loads indicate that 24 percent of customers who are served by PSE are on capacity-constrained gas mains, which may limit the ability to add new load in those areas, without significant new investment in distribution facilities. Although in the long term most of these constrained mains would likely be upgraded, the timing of planned upgrades may limit or delay conversions in some areas. New loads could also be added if the gas distribution system were extended into new areas. Based on this data, approximately 33 percent of all customers offer an opportunity for conversions without imposing additional main extension or hook-up costs, because they are already PSE gas customers that are simply converting additional end uses. Another 15 percent of PSE's customers could be converted from all-electric to gas (10 percent in areas where gas is already available and 5 percent through short main extensions), but would incur additional costs associated with new service connections.

**Exhibit VII-12**
**Geographic Distribution of Residential Gas Customers by Utility Service Area, Service Availability, and System Characteristics**

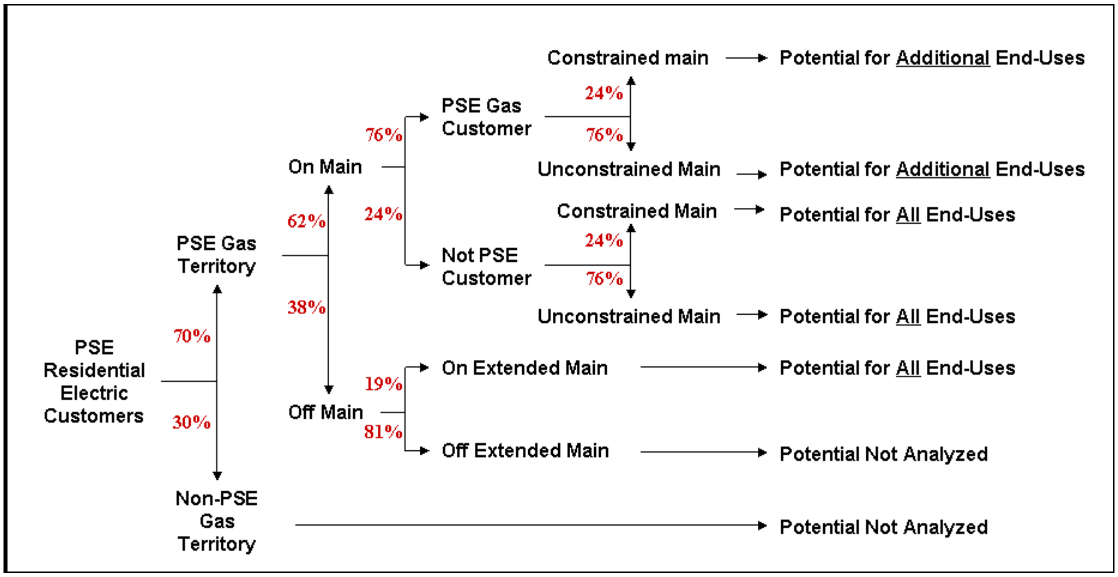



Exhibit VII-13 shows the technical and achievable electricity savings resulting from fuel conversion for the normal and early replacement scenarios. Under the normal replacement scenario, fuel conversion is estimated to provide 132.8 aMW in technical potential, and 62.5 aMW in achievable potential. In an accelerated conversion scenario that assumes early equipment replacement, technical and achievable potentials are expected to increase to 189.5 aMW and 101.5 aMW respectively.

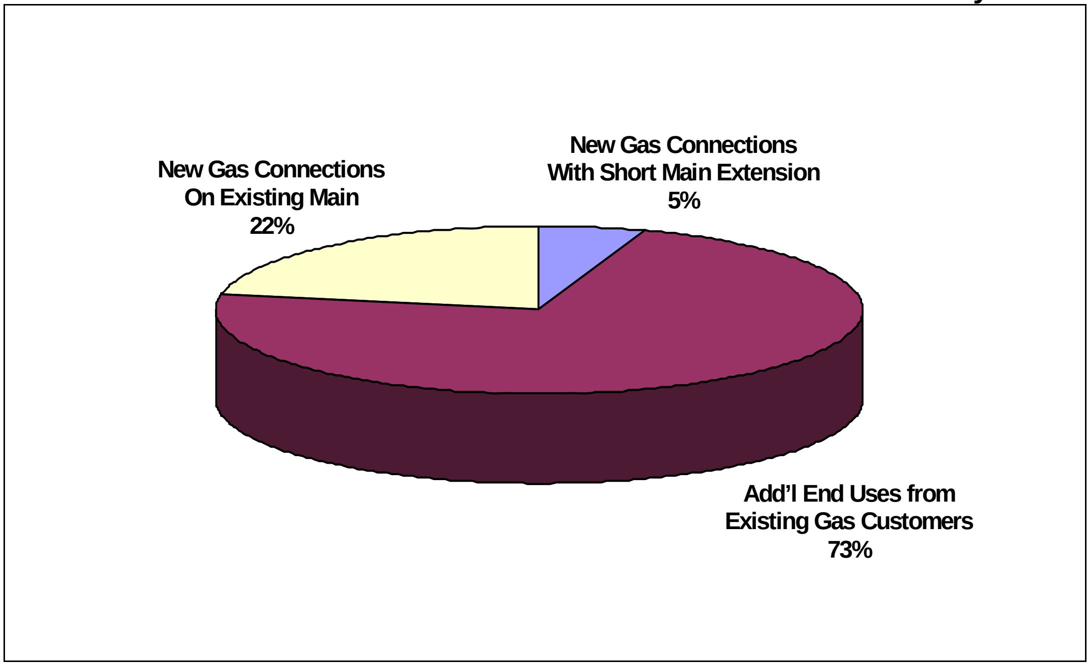
Fuel conversion will slightly diminish the potentials for electric energy efficiency. As can be seen in Exhibit VII-13, achievable electric conservation potentials will be reduced from 133.4 aMW to 127.9 under the normal replacement scenario, and 123.5 aMW under the early replacement scenario.

**Exhibit VII-13**
**Effects of Fuel Conversion on Residential Electric Energy Efficiency Potentials**

| Electric Resource Potential - 2025 | Without Fuel Conversion (aMW) | With Normal Replacement (aMW) | With Early Replacement (aMW) |
|---|---|---|---|
| **Technical** | | | |
| Fuel Conversion Potential (gross) | | 132.8 | 189.5 |
| Energy Efficiency | 375.8 | 338.5 | 321.2 |
| Total Technical Potential | 375.8 | 471.2 | 510.7 |
| As % of Residential Load | 25.9% | 32.5% | 35.2% |
| **Achievable** | | | |
| Fuel Conversion Potential (gross) | | 62.5 | 101.5 |
| Energy Efficiency | 133.4 | 127.9 | 123.5 |
| Total Achievable Potential | 133.4 | 190.4 | 224.9 |
| As % of Residential Load | 9.2% | 13.1% | 15.5% |

As can be seen in Exhibit VII-14, under the normal conversion scenario, most (73 percent) fuel conversion potential comes from existing PSE gas customers that convert additional end-uses, while relatively small proportions of fuel conversion potential are attributable to hook-up of entirely new gas customers.

**Exhibit VII-14**
**Distribution of Electric Conservation Potential from Fuel Conversion by Source**



Increases in gas consumption due to fuel conversions were examined under both "standard" (current state and federal codes) and "high" equipment efficiency levels (the same as those used in energy efficiency potential). As shown in Exhibit VII-15, fuel conversion will result in lowering the technical and achievable gas energy efficiency potentials by nearly 7.8 million decatherms and 4.2 million decatherms under the standard efficiency scenario, and 7 million decatherms and 3.6 million decatherms under the high-efficiency equipment scenarios. The efficiency level of the gas equipment has no impact on the amount of electric load reduction from fuel conversion.

**Exhibit VII-15**
**Effects of Fuel Conversion Potentials on Residential Gas Load**

| Gas Resource Potential – 2025 | Technical (Decatherms) | Achievable (Decatherms) | Technical (Decatherms) | Achievable (Decatherms) |
|---|---|---|---|---|
| **Efficiency Level of New Gas Appliances:** | **Standard** | **Standard** | **High** | **High** |
| Increased Use Due to Fuel Conversion | 7,763,444 | 4,169,422 | 6,987,099 | 3,752,480 |
| Gas Use Increase as % of Residential Load | 10.3% | 5.5% | 9.3% | 5.0% |

Although the amounts of conversion potential per customer tend to be large among customers who are not currently hooked up, capturing such opportunities would require significant additional investments in customer hookup and/or expansion of the existing distribution system. Based on PSE records, average hook-up cost (service line from in-street main to house plus meter) for new customers is currently estimated at over $2,000 per single-family home. The costs of gas line extensions/upgrades can vary widely, depending on the length of the line and the number of new gas customers connected, and therefore were not quantified. Thus, the total costs of hooking up new customers are somewhat underestimated.

Hook-up costs for new customers, combined with the additional gas fuel costs, have important ramifications in terms of overall fuel conversion resource costs. The effects of additional hook-up and fuel costs on overall fuel conversion costs were analyzed under the accelerated and normal conversion scenarios assuming standard and high-efficiency gas equipment. For the purpose of this analysis, hook-up costs were allocated to the three end-uses in proportion to their shares of total potential. Average fuel conversion resource costs for all end-uses can be expected to approximately double once additional fuel costs are taken into account. Inclusion of hook-up costs for new customers will nearly quadruple per MWh cost of fuel conversion resources (see Appendix B for more information).

*Energy Efficiency and Fuel Conversion Resource Portfolios*

While an accurate assessment of achievable demand-side potentials represented an important objective of this study, the paramount consideration was to construct portfolios of electric and natural gas conservation resource options, which could be compared with and evaluated against supply options on a balanced and consistent basis.

To facilitate the incorporation of the results of this study into PSE's least cost, integrated resource planning process, energy efficiency and fuel conversion potential estimates for each fuel type and customer sector were disaggregated into distinct cost-based "bundles" of conservation resource. Eight (8) electric and seven (7) gas cost-group "bundles" were created by grouping 1,756 electric and 736 gas conservation measure/segment/structure combinations with similar cost and load-shape characteristics. The energy savings from each of these bundles were then distributed across seven cost ranges. Electric and gas measures with costs above the thresholds of $115/MWh or $10.50/decatherm were not considered as economic or achievable. Fuel conversion potentials were incorporated into the same end-use bundles as energy efficiency to produce bundles that represent the net combination of energy efficiency and fuel conversion. The costs of the bundles with fuel conversion include PSE's costs to serve the additional natural gas demand (commodity costs and new service hookup costs), as well as the costs of the new gas end-use appliances.

The market segment/end-use bundles and cost range categories used for energy efficiency and fuel conversion resource analysis are listed in Exhibit VII-16 and VII-17, respectively. The segment/end-use bundles for natural gas resources are more simplified that what is shown in Exhibit VII-17, using only two end-uses: space heat (weather sensitive) and base load (non-weather sensitive). Most demand-side energy savings potential falls into the lower cost categories. The distribution of electric and natural gas energy efficiency resource potentials across each market segment/end-use bundle and the associated cost ranges are included in Appendix B.

**Exhibit VII-16**
**Segment/End-Use Bundles for Energy Efficiency and Fuel Conversion Resources**

| Residential | Commercial | Industrial |
|---|---|---|
| Existing Construction- Appliances | Existing Construction- Appliances | Existing Construction- General |
| Existing Construction- HVAC | Existing Construction- HVAC | |
| Existing Construction- Lighting | Existing Construction- Lighting | |
| Existing Construction- Water Heat | Existing Construction- Water Heat | |
| New Construction- Appliances | New Construction- Appliances | |
| New Construction- HVAC | New Construction- HVAC | |
| New Construction- Lighting | New Construction- Lighting | |
| New Construction- Water Heat | New Construction- Water Heat | |

**Exhibit VII-17**
**Cost Groups for Energy Efficiency and Fuel Conversion Resources**

| Electricity Cost Category | Gas Cost Category |
|---|---|
| A: less than $45/MWh | A: less than $4.50/decatherm |
| B: $45 - $$55/MWh | B: $4.50 - $5.50/decatherm |
| C: $55 - $65/MWh | C: $5.50 - $6.50/decatherm |
| D: $65 - $75/MWh | D: $6.50 - $7.50/decatherm |
| E: $75 - $85/MWh | E: $7.50 - $8.50/decatherm |
| F: $85 - $95/MWh | F: $8.50 - $9.50/decatherm |
| G: $95 - $105/MWh | G: >$9.50/decatherm |
| H: >$105/MWh | |

*Electric Demand-Side Resource Acquisition Scenarios*

In assessing long-run, demand-side resource potentials, timing of the resources over the planning period has significant ramifications for the integrated resource planning process. A large portion of energy efficiency and fuel conversion potential is made up of finite resources, particularly savings from retrofits and early replacement. Thus, the amount of demand-side resources already acquired affects current and future potentials. The timing for the acquisition of demand-side resources must also take into account practical administrative and logistical considerations, as well as potential market barriers (see Section C for further discussion).

In this analysis, two alternative scenarios for acquisition of achievable electric energy efficiency resources were considered: “Base Case” and “Accelerated.” The Base Case scenario assumes that energy efficiency potential occurs in equal annual proportions over the 20-year planning horizon, which equates to approximately 15 aMW per year. Under the Accelerated scenario, it is assumed that the timing of energy efficiency potential would be accelerated and all achievable retrofit or early replacement potentials would occur during the first 10 years of the plan. The Accelerated Case results, on average, in 24 aMW per year over the first 10 years and 5 aMW per year over the last 10 years.

Similarly, different scenarios for the timing of fuel conversion resource potential were developed. In the “Normal Replacement” scenario, fuel conversion potential occurs at the time of naturally-occurring appliance turnover, when the useful life of the electric appliance is complete, averaging about 3 aMW per year. This is analogous to the Base Case for energy efficiency. The “Early Replacement” scenario assumes all possible electric appliances are converted in the first 10 years, regardless of age or condition, which is analogous to the Accelerated Case for energy efficiency. The Early Replacement scenario for fuel conversion averages approximately 10 aMW of potential savings per year for the first 10 years and none afterward.

Consistent with PSE’s past experience with energy efficiency programs, the measure costs for demand-side resource potentials were adjusted upward by 10 percent to account for program development, delivery and administrative expenses under the Normal Replacement scenario. Average measure costs were increased by 30 percent under the Accelerated Case to take into account the need for more aggressive market planning, program promotion and product delivery mechanisms, as well as for normal program operation costs. In some cases, inclusion of program operation costs shifts some potential into higher cost categories. For some measures, costs were shifted beyond the achievable potential thresholds of $115/kWh and $10.50/decatherm, but were left as achievable potential in the highest cost bundles.

*Demand-Response Resource Potentials*

Demand-response (or demand-responsive) 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. Acquisition of demand-response resources may be based on either reliability considerations or economic/market objectives.

Objectives of demand response may be met through a broad range of price-based (e.g. time-varying rates and interruptible tariffs) or incentive-based (e.g. direct load control, demand buy-back, demand bidding, and dispatchable stand-by generation) strategies. In this assessment, five demand-response options were considered, similar to those examined in PSE's 2003 Least Cost Plan:

***1) Direct Load Control***: This strategy allows the utility to remotely interrupt or cycle electrical equipment and appliances such as water heaters, space heaters, and central air-conditioners. Direct load control programs are generally best suited for the residential and, to a lesser extent, small commercial sectors.

***2) Time-of-Use Rates***: This demand response option consists of two-part pricing structures designed to encourage customers to curtail consumption during peak, or shift it to off-peak hours. TOU tariffs are designed to reflect the utility's marginal cost of power supply.

***3) Critical Peak Pricing***: Critical peak or extreme-day pricing refers to incentive-based, demand-response strategies that aim to preempt system emergencies by encouraging customers to curtail their loads for a limited number of hours during the year. The amount of incentive is generally based on the utility's avoided cost of supply during extreme peak events.

***4) Curtailment Contracts***: These refer to contractual arrangements between the utility and its large customers who agree to curtail or interrupt their operations for a predetermined period when requested by the utility. The duration and frequency of such requests and levels of load reduction are also stipulated in the contract. Customers who agree to participate are typically compensated either through lower rates or fixed payments.

***5) Demand Buyback***: Under demand buyback arrangements, the utility offers payments to customers for reducing their demand when requested by the utility. The buyback amount generally depends on market prices published by the utility ahead of the curtailment event, and the level of reduction is verified against an agreed upon baseline usage level.

As in the case with energy efficiency and fuel conversion, demand response opportunities were assessed in terms of both "technical" and "achievable" potential.

- ***Technical Potential***: In the context of demand response, technical potential assumes that all applicable end-use loads in all customer sectors are wholly or partially available for curtailment, except for those customer segments (e.g. hospitals) and end-uses (e.g. restaurant cooking loads), which clearly do not lend themselves to interruption.

- ***Achievable Potential***: Achievable potential is a subset of technical potential and takes into account the customers' ability and willingness to participate in load reduction programs subject to their unique business priorities, operating requirements, and economic (price) considerations. Evaluation of achievable potential is a significant refinement of the Company's 2003 Least Cost Plan assessment of demand response, which focused on technical potential. In this assessment, estimates of achievable potentials were derived by adjusting technical potentials by two factors: expected rates of <u>program</u> participation, and expected rates of <u>event</u> participation. Assumed rates of program and event participation were estimated based on the recent experiences of PSE, other utilities in the Northwest, other national utilities, and Regional Transmission Organizations (RTOs) which have offered similar programs. Unlike energy efficiency and fuel conversion, no cost constraints were applied to achievable demand response potentials.

Demand response options are not equally applicable to or effective in all segments of the electricity consumer market, and their impacts tend to be end-use specific. Recognizing this, the study employed a "bottom-up" approach, which involved first breaking down PSE's system load by sector, market segment, and end-use; estimating demand response potentials at the end-use level; and then aggregating the end-use resource potentials estimates to sector and system levels. The approach was implemented in six steps as follows.

***1) Define customer sectors and market segments***. System load was disaggregated into four sectors: 1) residential, 2) commercial, 3) industrial, and 4) other. The commercial sector was further broken down into eleven segments.

***2) Create sector and segment load profiles***. Using PSE's annual hourly interval data, total sales were broken down by sector and segment.

***3) Develop sector- and segment-specific typical peak day load profiles***. "Typical" weekday profiles were developed for winter (January and February), and summer (July and August).

***4) Screen customer segments and end-uses for eligibility.*** This step involved screening customers for applicability of specific demand-response strategies. For example, the hospital segment and certain commercial end-uses such as cooking loads in the restaurant segment were excluded.

***5) Estimate end-use shares by sector and market segments***. End-use shares were estimated by applying annual end-use load profiles obtained from the Northwest Power and Conservation Council.

***6) Estimate technical potential***. For each demand-response strategy, estimates of technical potentials were developed by applying the fraction of load for each end-use that might be curtailed based on available data from the California Energy Commission's recent assessments of load reduction opportunities in commercial and industrial buildings.

***7) Estimate achievable technical potential***. Finally, for each demand response strategy, achievable potential was estimated by taking into account program participation as the fraction of appropriate end-use loads, which may be curtailed or interrupted.

PSE's hourly system load and sales by customer class, and end-use load shapes available from the Northwest Power and Conservation Council, served as the primary sources of data for this assessment. Estimates of expected load impacts resulting from various demand response strategies were based on data available from the commercial and industrial Enhanced Automation Study sponsored by the California Energy Commission, and the experiences of PSE and other utilities in the Northwest with various demand-response programs.

Complete descriptions of the methodology and data sources used to assess demand response potentials are included in Appendix B.

The results of this assessment, as summarized in Exhibit VII-18, indicate that critical peak pricing and direct load control of residential space heating and water heating, with achievable potentials of 155 MW (4.6 percent of system peak) and 95 MW (2.8 percent of system peak) respectively, offer the largest opportunities for demand response interventions. Achievable peak reductions from time-of-use tariffs are estimated at 49 MW, representing 1.5 percent of system peak. Opportunities resulting from curtailment contracts and demand buy-back are expected to be relatively small, averaging between 0.5 percent and 0.8 percent of system peak. Although the potentials for different demand response strategies are not mutually exclusive, hence not additive, it is estimated that selected combinations of these strategies might achieve as much as 200 MW of total peak demand reduction. For example, if Direct Load Control were selected for residential customers, and Critical Peak Pricing for industrial and commercial customers, the total would be 175 MW. There would still be possible additional reductions from programs using Curtailment Contracts and/or Demand Buy-Back.

**Exhibit VII-18**
**Demand-Response Potentials Summary - 2025**

| Sector | Direct Load Control | TOU | Critical Peak Pricing | Curtailment Contracts | Demand Buy-Back |
|---|---|---|---|---|---|
| ***Industrial*** | | | | | |
| *Technical Potential (MW)* | - | 4.9 | 19.8 | 12.2 | 14.8 |
| *Achievable Potential (MW)* | - | 1.7 | 7.4 | 2.7 | 4.4 |
| ***Commercial*** | | | | | |
| *Technical Potential (MW)* | - | 14.8 | 164.5 | 66.4 | 75.5 |
| *Market Potential (MW)* | - | *5.2* | *72.1* | *14.9* | *22.6* |
| ***Residential*** | | | | | |
| *Technical Potential (MW)* | 381.3 | 121.5 | 202.5 | - | - |
| *Achievable Potential (MW)* | *95.3* | *42.5* | *75.9* | - | - |
| **Total*** | | | | | |
| *Technical Potential (MW)* | 381 | 141 | 387 | 79 | 90 |
| % of System Peak | 11.2% | 4.1% | 11.4% | 2.3% | 2.7% |
| *Achievable Potential (MW)* | 95 | 49 | 155 | 18 | 27 |
| % of System Peak | 2.8% | 1.5% | 4.6% | 0.5% | 0.8% |
| **Average Cost ($/kW)** | $55.0 | $44.1 | $21.6 | NA | NA |
| **Average Cost ($/mWh)** | NA | NA | NA | $154.7 | $154.7 |

* Note that strategies are not mutually exclusive, hence potentials are not additive.

The demand-response strategies considered here also vary significantly with respect to their costs. Costs for direct load control, time-of-use tariffs and critical peak pricing were estimated on a kW basis. For direct load control and time-of-use tariffs, costs were estimated using the most recent data from PSE and other regional utilities with experience in similar programs, especially Portland General Electric Company. For both strategies, it was assumed that the total estimated achievable potentials would be captured in five years, and that participants would remain in the program for seven years, after which customers would have to be re-recruited in order to continue to get peak savings. This choice was based on the expectation that most customers tend to relocate after seven years or less.

The results of the analysis show that based on the available data, critical peak pricing, has the lowest average cost at $21.6 per kW. Time-of use-tariffs ($44.1/kW) and direct load control ($55/kW) have the next lowest costs.

Since participant incentives for curtailment contracts and demand-buy-back programs are generally based on reduction in energy, costs for these strategies were estimated on a dollar per MWh basis. Based on the results of the commercial and industrial sector load reduction programs offered by PSE and other regional utilities during the summer of 2001, the achievable potentials for these strategies appear to be relatively small, mainly due to low program and/or event participation. The data shows that of the 457 eligible customers, only 19 (4 percent), representing about 3 percent of the eligible load, participated in PSE's program.

Through its demand buy-back program in 2001, PSE was able to acquire a total of 21.1 MWh (approximately 2 MW) at an average cost of nearly $155 per MWh. Participation levels in such programs are to a large extent a function of incentive amounts; but they also depend on the customers' willingness and ability to commit to curtailment. An analysis of PSE's program activity during the spring and summer of 2001 indicates that load response to prices was indeed relatively in-elastic, with an estimated elasticity of 0.8 percent. This indicates that a 1 percent increase in incentives is likely to increase load reduction by 0.8 percent. The results of this analysis suggest that significantly larger prices must be paid if PSE is to capture all or most of the expected achievable potential for such demand response strategies.

Assessment of demand-response potential poses considerable analytic challenges and tends to be less precise than for energy efficiency. This is particularly the case in assessing achievable potentials for market-based strategies such as curtailment contracts and demand buy-back, due to the lack of sufficient market data on customer willingness to participate in such programs. In its assessment of demand-response strategies, PSE has relied on the best available methods and data. The results of this assessment, therefore, are to be regarded as indicative, rather than conclusive.

## C. Demand-Side Planning and Implementation Issues

This section examines the uncertainties of quantifying demand-side resources, program implementation issues beyond the Least Cost Plan modeling process, and some considerations for accelerated resource acquisition scenarios. Additional implementation issues associated with demand-side resources are discussed in Chapter VIII.

*Uncertainties for Quantifying Demand-Side Resource Potentials*

The amount of demand-side potential identified for the Least Cost Plan relies on the best available information today about prices, efficiency, consumer behavior and preferences, and projects that information 20 years into the future. As with other resources, demand-side resource assessment depends heavily on energy load forecasts and projected growth rates, with all of the associated uncertainty.

Also analogous to supply-side resources, assessments of demand-side potential are limited by what is currently available in the marketplace in terms of cost-effective technologies for improving energy efficiency. The impacts of new technologies and new energy efficiency codes and standards are difficult to accurately predict. This uncertainty is mitigated through biennial updates of the Least Cost Plan, which provides the opportunity to incorporate advances in demand-side technologies and programs.

Somewhat unique to demand-side resources is the utility's dependence on large numbers of very small purchases, each tied to the individual consumer's day-to-day purchasing and behavioral decisions. The utility attempts to influence these decisions through its programs, but the consumer is the ultimate decision-maker regarding the purchase of demand-side resources. PSE's assessments of demand-side resources make the best possible estimates of customers' willingness to participate, based on previous utility program experience. But the actual experience of any new program is likely to vary from planning estimates. The uncertainty about program participation is greater for fuel conversion and demand response than for energy efficiency, which generally has a more extensive track record of actual program operation.

*Implementation Considerations that Extend Beyond Resource Portfolio Modeling*

Many specific details are required to implement successful demand-side programs. As discussed previously, actual implementation design, delivery, and market conditions will cause energy-efficiency program savings and costs to vary. Customer participation in a program is heavily influenced by the level of incentive paid by the utility vs. the cost to the customer. Program implementation depends on staff with the appropriate skills and tools to be able to provide customer service, sales, engineering, database use, marketing, evaluation, and management. A number of program support services need to be in place for collecting customer-specific information, monitoring/reporting performance metrics, and evaluation of cost-effectiveness. External infrastructure considerations must also be addressed, such as product availability to utility customers and an adequate network of contractors, retailers, and other trade allies to support a program.

As new measures or expanded programs are developed and added to the current program mix, internal and external resources and capabilities need to grow accordingly and progress through a "learning curve." Small pilot programs often precede full-scale programs to test the performance of demand-side technologies and customer acceptance of a particular market delivery mechanism.

In short, a utility cannot immediately launch into full-scale deployment of all the demand-side measures identified by its Least Cost Plan, nor should such results be expected. The estimates of fuel conversion resource potentials in this Least Cost Plan do not account for any "ramp-up" that would be required to reach the savings levels achievable from fully mature programs.

*Accelerated Scenarios for Electric Demand-Side Resources*

For the 2005 Least Cost Plan, PSE examined several demand-side resource acquisition scenarios focused on constant or "normal" rates of acquisition and accelerated or "early replacement" cases for energy efficiency and fuel conversion. While the difference between these scenarios is significant in terms of short-term energy-efficiency program activity, it is fairly minor in terms of the magnitude of the resource need PSE will experience in the next several years. The process of determining an optimal level of demand-side resource acquisition for the short term should consider the advantages of steady, consistent levels of annual energy-efficiency acquisition vs. a mode that would have the utility ramp-up market-place activity for a few years, and ramp-down in later periods. There are additional costs associated with the delivery of higher levels of efficiency in a shorter time frame, including acquiring the necessary resources, training personnel and trade allies, and more intensive promotional activities. Ramping up also depends on sufficient lead times to ensure the proper infrastructure development.

# VIII. ELECTRIC PLANNING ENVIRONMENT

This chapter explores the major industry, regional, and Company issues and trends that form the backdrop for PSE's Least Cost Planning process. Current uncertainties in the planning environment create cost risks and can even determine whether a particular resource strategy is executable.

Many of the planning environment issues described below were identified and clarified through PSE's exploration of the long-term energy resource market following its April 2003 Least Cost Plan. In 2004, PSE issued a Request for Proposals (RFP) and from the responses, PSE has identified certain challenges and risks that can cause an otherwise cost-effective resource to be unattainable. Overriding considerations are whether the resource can be permitted and built, and whether the energy can be transmitted to PSE's system.

This chapter discusses seven key issues that can adversely impact resource opportunities. The first issue of importance is transmission, which is heavily constrained throughout the northwest and the topic of much regional debate. The second key issue is environmental initiatives, which can come from all levels of government and a variety of stakeholders. The third issue is the evolving nature of resource development and the current status of the industry. The fourth issue covers the regional load-resource balance, which is important to PSE as an active market participant. The fifth issue concerns the availability and cost of demand-side resources: energy efficiency, fuel conversion, and demand response. The last two key issues are summaries of financial issues and gas-for-power issues that are covered in greater detail elsewhere in the document.

To a large degree, this set of key issues is also the main determinant of PSE's analytic approach. The analytics are designed to explore the range of these issues and how alternate futures impact resource strategy.

## A. Regional Transmission

Currently, PSE's ability to acquire generation outside its service territory is severely constrained due to limitations of the regional transmission system. Factors that are of particular concern to PSE include:

- Lack of existing capacity,

- Uncertainty about the planning process for needed expansions,
- Uncertainty about costs and rate structure for new regional transmission,
- Multi-jurisdictional siting and permitting issues,
- Mismatch of transmission and resource development processes,
- Ultimate form of Federal Energy Regulatory Commission (FERC) regulation and the future of a potential regional transmission organization, and
- Uncertainty about who will finance, build and pay for needed transmission.

If these political and institutional factors are not addressed in a timely manner, PSE will be limited in its ability to acquire certain resources such as wind from the Columbia Gorge, coal plants from Montana, Wyoming, Idaho or Nevada, geothermal power from Oregon and hydroelectric power from British Columbia.

Beginning with an overview of PSE's transmission system, this section looks at the constraints affecting use of the regional transmission grid.

### A.1. Current Situation

*PSE's Transmission System*

PSE operates and maintains an extensive electric system consisting of generating plants, transmission lines, substations, and distribution equipment. For the most part, PSE's transmission system of 115 kV and 230 kV facilities has developed to move power to customers. PSE does not have significant excess transmission capacity either across its service area or outside its service area. To integrate resources outside its service area, PSE has typically contracted for transmission from the Bonneville Power Administration (BPA).

PSE's transmission system interconnects with several utilities including BPA, Seattle City Light, Snohomish PUD, Tacoma Power, British Columbia Transmission Corporation, Chelan County PUD, Douglas County PUD, Grant County PUD and with purchasers of the Centralia project. Most of the interconnections are west of the Cascades.

*Regional Transmission System*

Numerous developments have created pervasive congestion on the grid.

- Current load patterns are significantly different than those used to design the grid.

- Resource operations patterns have changed with the entrance of market participants other than utilities and the construction of new gas-fired generating sources, whose actual operation is highly variable.
- The transmission industry is in the middle of considerable change and it is unclear what the final Northwest transmission structure will look like.

Recent development of gas-fired generation and other intermittent resources has made operation of the transmission system more difficult. The number of market transactions has grown significantly, increasing the complexity of system operations. Consequently, the grid is now being utilized at near-full capability and any forced outage or critical maintenance often places the grid in a “de-rated” condition.

New generation opportunities in PSE’s service area may be limited to natural gas projects and small-scale renewables. In order to diversify with coal or wind resources, PSE must look to the east. However, bringing this new generation to PSE loads will require transmission that, at present, may not be available. Exhibit VIII-1 shows the numerous constrained paths on BPA’s system between the new potential supply and PSE loads while Exhibit VIII-2 summarizes the path constraints that are directly affecting PSE’s ability to import new generation.

**Exhibit VIII-1**[1]

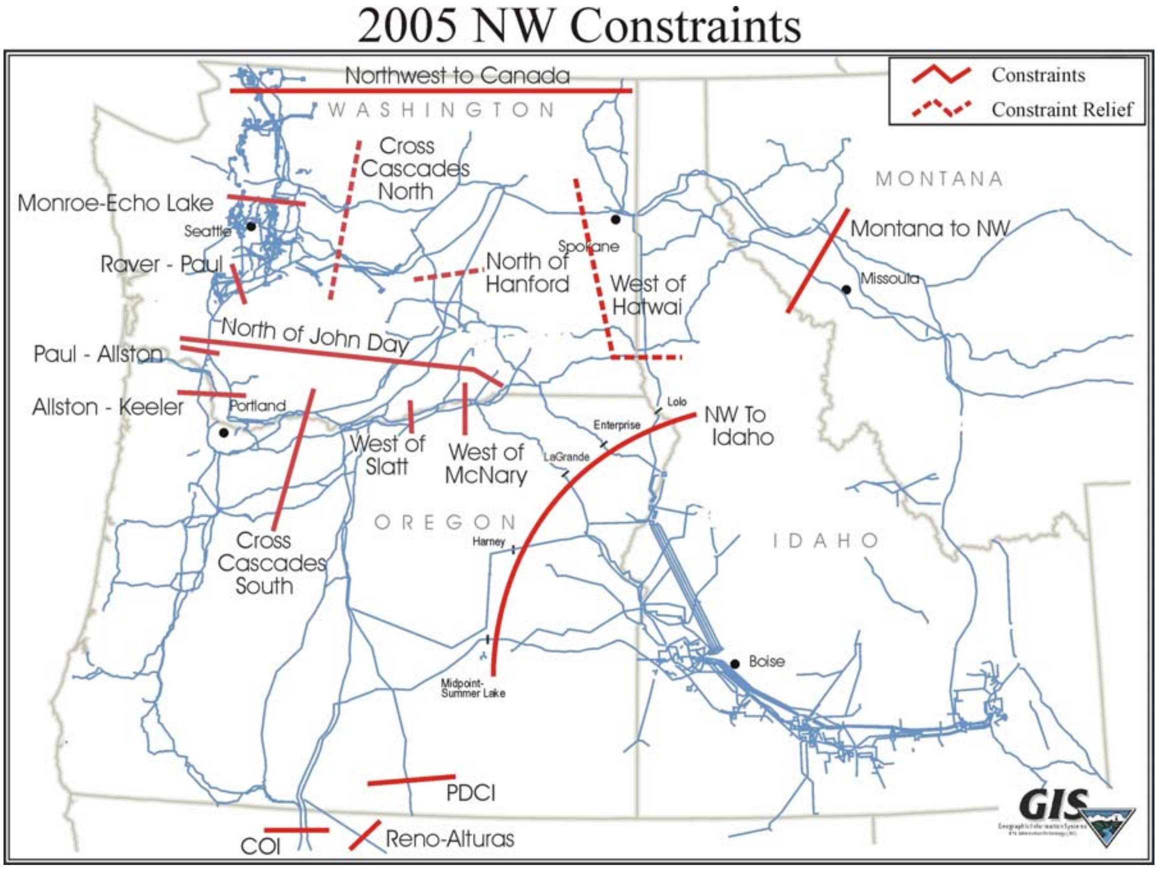



**Exhibit VIII-2**
**Transmission Path Constraints Affecting PSE's Ability to Import New Generation**

| Transmission Path | Where Constrained |
|---|---|
| Across the Cascades | • Washington[2]<br>• Oregon |
| From Montana to the NW | • In Montana west of Garrison<br>• In Washington west of Spokane[3] |
| Along I-5 corridor | • South of Monroe |
| West through the Columbia River Gorge | • McNary<br>• Slatt |

[1] Reprinted with permission from the BPA
[2] Completion of the Schultz series capacitors increases across-the-Cascades capacity in Washington by 300 MW.
[3] The completion of the new Bell-Coulee 500 kV line should reduce congestion in Washington, west of Spokane.

BPA's current transmission system improvements are designed primarily to meet and maintain its current obligations, including an obligation to support load growth where contractually committed. At present, generation planning and transmission planning are not performed in an integrated manner. Thus, new upgrades are not contemplated without a specific request for service from the generation developer. BPA's studies indicate that the agency has little room to grant new firm transmission requests, which means PSE must find a transmission solution for each new generation project. Because of this, the availability and cost of transmission have become key aspects of PSE's decision-making process for acquiring new resources.

### A.2. Process for Acquiring Long-Term Firm Transmission

The Northwest does not currently have a single regional body to coordinate transmission requests. Under current FERC rules, transmission providers sell long-term firm transmission through their Open Access Same-time Information System (OASIS). Resource developers, therefore, must identify and apply to individual transmission providers.

Requesting transmission is a cumbersome process, involving multiple steps and the possibility of one or more studies. Completion of this process can take anywhere from a few months to several years.

If the new transmission requires service from multiple providers, the customer must make requests with each provider. Since the review processes may not match (e.g. one provider can offer immediate service while the other requires facility upgrades), the transmission customer may face the decision to sign up for one section of the transmission before securing rights for the entire route.

In order to site a new resource, the developer needs to know the cost and availability of transmission. As a result, the request queues for key transmission routes become overloaded with applications of varying certainty. After the developer has worked through the process and is offered a service agreement, it will need to either execute the agreement regardless of the project status, or risk losing its place in the queue. Transmission providers often require customers to front the costs of network upgrades prior to undertaking the work.

Once upgrades have been built, the transmission provider must recover the cost. One rate model has the customer prepaying for wheeling and then receiving credits under the provider's tariffed rate until the total amount credited equals the money prepaid by the customer. Under this model, PSE, the customer, would pay for transmission facilities without receiving the asset benefits of ownership. This model also makes transmission upgrades essentially participant-funded without regard to the regional value provided.

### A.3. Long-Term Regional Transmission Structure

The Northwest continues to function without a regional transmission organization, and without workable processes to align generation and transmission development and investment. Since the advent of open access transmission rules in 1996, regional entities have made a number of attempts to form regional transmission organizations such as IndeGO and RTO West. These previous attempts proved unsuccessful.

However, in light of the genuine need to resolve the region's transmission problems, a variety of interested regional parties came together to form two new organizations, Grid West and the Transmission Issues Group. The intention of these groups was to address critical transmission-related issues and search for solutions.

*Grid West*

In late 2004, a group of regional transmission stakeholders wrote and agreed upon bylaws for a new organization called Grid West. Grid West follows earlier work of IndeGO and RTO West in attempting to create an organization meeting FERC's minimum characteristics and functions as laid out in Order 2000. This was the first step in the development of a voluntary organization with regional accountability. Grid West builds upon previous efforts, such as RTO West, to define and solve the region's transmission problems. The organization has identified the following difficulties with regard to regional transmission services today:

- Current rules and practices prevent full utilization of transmission infrastructure.
- Current structure impedes efficient, region-wide transactions.
- Congestion is managed through curtailment.
- Planning and constructing needed transmission infrastructure is not being effectively performed.
- Independent market monitoring is lacking.

The Grid West proposal has the potential to improve transmission service and infrastructure development in the following ways.

- *Improve system planning and expansion procedures to ensure timely replacement and expansion of aging transmission infrastructure*—If the Grid West organization reaches the operational stage, it will be authorized to act as a "backstop" for making sure that transmission infrastructure critical to reliable operations is built when needed.
- *Facilitate multi-party agreements for cost and benefit allocation.*
- *More efficiently manage the operating conditions that affect system reliability.*

*Transmission Issues Group*

In a parallel effort, several regional utilities and agencies that support near-term improvements have come together to form the Transmission Issues Group (TIG). One goal of the TIG is to resolve transmission issues through contractual arrangements among existing entities without the creation of a new organization. Together, they have developed a set of suggested changes that the region could implement in the next two to three years. These changes are based upon the premise that an evolutionary and adaptive approach is the best way to solve regional transmission problems.

*Position of Regional Parties*

All efforts to adopt a regional transmission organization have failed due to disagreements regarding cost and control. Generally, entities without significant future transmission needs believe an RTO would inequitably shift costs from entities with transmission needs to the entire region. Some parties also argue that the costs to establish and operate an RTO are higher than the regional market benefits.

In addition to economic considerations, an RTO changes the level of control exercised by the individual transmission owners. Current transmission owners are concerned about retaining full economic and operational value for their lines after they are turned over to RTO control.

Some parties may also fear losing the local market advantage brought about by a constrained transmission system. For example, gas-fired generation may benefit from grid congestion, because coal, integrated into an unconstrained grid, would likely push market prices lower than would gas-fired generation coupled with grid congestion.

Some local governments in the Pacific Northwest are fighting FERC's transmission initiatives primarily because they oppose the idea that the federal government should usurp their control over local transmission.

Ultimately, in spite of all of the effort that has gone into the development of a regional transmission structure, the future of GridWest and other regional efforts is unknown. Parties generally agree on the problem but not the solution. In short, there are no transmission solutions visible on the horizon.

### A.4. Long-Term Regional Transmission Planning and Expansion

Absent a central planning body, regional parties have formed a number of organizations to study transmission expansions and related transmission issues.

*Northwest Transmission Assessment Committee (NTAC)*

With the establishment of the Northwest Transmission Assessment Committee (NTAC) in 2003, the region gained an organized body that approaches transmission issues from a perspective influenced by both commercial and reliability needs. NTAC functions as an open forum to address forward-looking planning and development for the Northwest Power Pool (NWPP) area transmission system.

Specifically, NTAC has formed subcommittees to study congested paths that are of interest to participants. So far, there are subcommittees studying the Puget Sound area, the Montana to Northwest path, the Canada to California path, and the SE Washington/NE Oregon area.

The first study completed by an NTAC subcommittee was the "Puget Sound Area Upgrade Study Report," which was published in November 2004. The goal of this study was

> "to explore options that would make the transmission system in the Puget Sound area more robust when system components are out of service in meeting its current needs and to explore how these improvements may impact future load

service capability, integration of resources, reduction in Remedial Action Schemes (RAS) and higher import capability."

The study identifies problems and describes three portfolios of transmission system upgrades and expansions to fix those problems. However, it "does not make any determination or recommendation regarding the development or requirement for any project. Parties may choose to pursue further planning studies for investment decisions as necessary." In other words, NTAC does not take a role in ensuring that transmission is built.

*The Rocky Mountain Area Transmission Study (RMATS)*

RMATS is another planning effort that could influence PSE's ability to import energy. In RMATS, stakeholders examined the value of potential transmission expansion under different generating scenarios. Feasible transmission additions were identified and selected to proceed to a second phase (Phase II). During Phase II, technical studies will be conducted to address various issues concerning siting, cost assignment and recovery, as well as project sponsors and financing.

The process thus far has identified projects for both short- and long-term improvements. There are two recommendations for long-term improvement. The first involves expansion projects within the Rocky Mountain footprint, while the second involves export projects beyond that footprint, such as a path from Montana to the Northwest.

As a major part of its Phase II initiatives, RMATS recommends that governors of involved states convene with the CEOs of benefiting entities to help foster the development of these projects. A variety of important issues and necessary steps are clearly suggested in the Phase I final report. While the RMATS group is encouraging the construction of transmission, like NTAC, it does not have the authority to make this happen.

*Involvement of Western State Governors*

Western governors, partially in response to FERC's initiatives, launched a new era in transmission planning with the release of the report "Conceptual Plans for Electricity Transmission in the West" and the development of an Energy Policy Roadmap. They also explored related financing issues in a separate report entitled, "Financing Electricity Transmission Expansion in the West."

In the most recent version of the Energy Policy Roadmap, these governors urged the industry, states and provinces to implement a pro-active western interconnection transmission planning process. As a result, a collaborative process has been initiated by the Seam Steering Group-Western Interconnection. In addition, four sub-regional planning efforts are underway:

- Rocky Mountain Area Transmission Planning Study (RMATS)
- Southwest Transmission Expansion Plan
- Northwest Transmission Assessment Committee (NTAC)
- Southwest Area Transmission study

Individual states are also responding. For example, in Wyoming, the governor signed an executive order in 2003 encouraging state agencies to work closely with other states toward the development of electric transmission lines. The order also directed agencies to create efficient processes for environmental review, as well as for siting and permitting transmission lines. The Wyoming Legislature then passed a law in 2004 creating the Wyoming Infrastructure Authority. It has $1 billion in bonding authority and will participate in planning, financing, constructing, developing, acquiring, maintaining and operating electric transmission facilities.

The 2005 Washington state Legislature is also considering a bill to facilitate transmission development. Washington's bill would allow developers of transmission projects to seek permits through the state's Energy Facility Site Evaluation Council.

*Role and Limitations of BPA*

BPA is the only entity in the Northwest with a geographic scope and siting authority that approaches what is needed to build regional transmission. However, BPA does not currently have the borrowing authority to undertake major regional transmission expansion. BPA's scope is also limited by law and policy. Without BPA involvement, a Colstrip like solution will be difficult to organize.

In its *2004 Programs in Review* workshops, BPA discussed its financial situation. The agency has a total of $4.45 billion in borrowing authority for all BPA projects, both power and transmission. By the end of 2002, BPA had $2.77 billion in bonds outstanding, leaving less than $2 billion available. Over the last four years, BPA has invested over $1 billion in transmission infrastructure, including two major transmission line projects. A third will be completed in December. Current projections show BPA's borrowing authority expiring as early as 2007-08. BPA's existing capital plan includes some transmission construction targeted at reducing congestion or aiding economic power transactions.

As an alternative funding arrangement, BPA is attempting participant funding on the McNary–John Day upgrade. The next major step in this process is for BPA to receive signed commitments to participate from interested parties. These signed commitments are due to BPA by June 30, 2005.

BPA is also a key participant in study groups examining the transmission needs of the region. In fact, the agency provides a tremendous amount of study capability for the region. However, study alone is not enough to solve the problem. Without a clear mechanism to ensure that needed transmission is built, the development of new generation will be impeded.

### A.5. Transmission Siting and Development

Transmission siting issues and development risks are commensurate with those for resource development. Developers of new energy resources must be able to bring their generation to load. Without certainty of this, lenders will not finance these efforts. To obtain that certainty, there must be adequate transmission capacity at a reasonable price, or a clear and predictable process for developing and pricing new transmission.

Most PSE construction on its own system of 115 kV and 230 kV lines involves upgrades to existing lines. Only rarely does PSE undertake development of a new line because of the difficulty in siting and permitting. PSE has similar expectations regarding broader regional transmission expansion—that most upgrades and expansions will involve existing lines and rights of way.

In order to construct new transmission, developers must be prepared for the following: working with multiple jurisdictions; observing differing processes for each jurisdiction, at each level of government (local, state and federal); anticipating local issues; working around a lack of central siting or permitting authorities.

The physical reality of electricity flow over long distance transmission lines is that as generation flows to load, the energy will cross several cut-planes and multiple states. Because facility siting lies with each state, transmission lines crossing more than one state (coal and wind, for example) will involve multiple independent, and often disjointed, state processes. These processes are distinct from those of the transmission provider(s). In order to qualify for a new transmission contract, each of the affected paths must have sufficient available transmission capacity (ATC). If the ATC is insufficient, new transmission must be built.

Early assessment of environmental conditions will determine the level of permitting necessary to gain regulatory approval. Common regulatory permits at the federal and state levels include SEPA/NEPA, Endangered Species (biological assessments), Army Corps of Engineers section 404 and 10 permits, Department of Fish/Wildlife HPA and the Department of Ecology (NPDES). At the city or county level, common permitting needs are conditional use permits for shorelines, clearing and grading, critical area review, and right-of-way use.

In addition to these permits, consideration must be made as to whether tribal lands will be affected by proposed transmission line siting, necessitating the need to enter land-use negotiations. Additionally, the company could be required to enter into long-term franchise agreements with local municipalities that are granting operating rights for facilities located in their rights-of-way.

Public involvement should be incorporated throughout the planning and development phases of transmission projects. This involves informing, consulting and involving affected and concerned stakeholders in many of the Company's decisions. Although with transmission, projects usually offer system improvements and limited direct local benefits.

Adding to the complications, there is no central permitting or siting authority, which would move transmission development more quickly through the many processes. Some states may provide a central authority, while others may not. Because the transmission line moves from one state to the next, the benefits of having sporadic central authority are lost.

In many cases, routing of transmission lines can require the use of corridors other than those available via municipal, county or state rights-of-way. In these instances, easements from individual property owners are required. Because negotiation of these rights can become contentious and ultimately result in condemnation, careful consideration is critical. The use of condemnation can prove costly from both a cost/schedule perspective, and a community perception perspective.

### A.6. Transmission Needs for New Resources

For the purpose of modeling in the Least Cost Plan, PSE has created two transmission cost and availability scenarios. One scenario assumes that a regional transmission organization is established and transmission expansions are reflected in system-wide wheeling rates. The other scenario assumes that PSE funds the transmission needed for its resource additions. The first scenario assumes that regional cooperation and a central organization promotes better processes, and that transmission is in place by 2013. The second scenario has new transmission in place by 2016.

Both scenarios use the same basic cost estimates. Based upon Northwest Transmission Assessment Committee information, PSE estimated that transmission for a coal project in Montana to PSE's system would cost about $1 billion dollars to construct. This is primarily a 500 kV solution. To integrate a wind plant from SE Washington, PSE has estimated the cost of a new 230 kV line to be about $250 million.

### A.7. Findings

In order for PSE to continue to provide low-cost, reliable power, it must take several steps to ensure that new energy supply can reach the Company's loads.

*Short Term*

In the near term, PSE must focus on resources that have existing transmission rights to the PSE system. This includes resources located west of the Cascades, resources with transmission rights, and resources obtained through utilities that are directly connected to the PSE system. Other actions that PSE should consider include:

- Retaining existing contract transmission rights
- Investing to upgrade PSE-owned transmission paths

*Long Term*

In order to meet its long-term resource needs, PSE must continue to participate in regional efforts to create a stable, long-lasting transmission structure. Absent a regional solution, PSE must explore acquiring transmission on its own by contracting with a transmission provider, merchant transmission entity, or by building its own transmission.

PSE's current level of participation in the Grid West effort provides on opportunity to analyze transmission options and to determine the cost and benefit of formal participation in Grid West. However, PSE must also consider working with others to jointly build and own transmission and generation.

## B. Environmental Initiatives

PSE faces an uncertain future with respect to renewable energy mandates, potential greenhouse gas (GHG) regulation, and new limits on emissions including NOx, SO2 and mercury (Hg). A number of proposals and studies exist that espouse a range of emission control models with different cost levels and starting years. Washington state has already adapted laws regulating GHG emissions from certain new generating facilities. Mandatory federal regulation or caps on GHG emissions appear to be an increasingly likely part of the future regulatory landscape. Absent federal policy on greenhouse gasses, some states, like Washington, are moving forward with their own regulatory programs, raising the risk that US companies will encounter a patchwork of different restrictions. In its Least Cost Plan analysis, PSE has examined resource portfolio costs over a combination of greenhouse gas cost and renewable portfolio assumptions to determine the long-run cost impact under different futures.

### B.1. Emissions

*Emission Policies at the Federal Level*

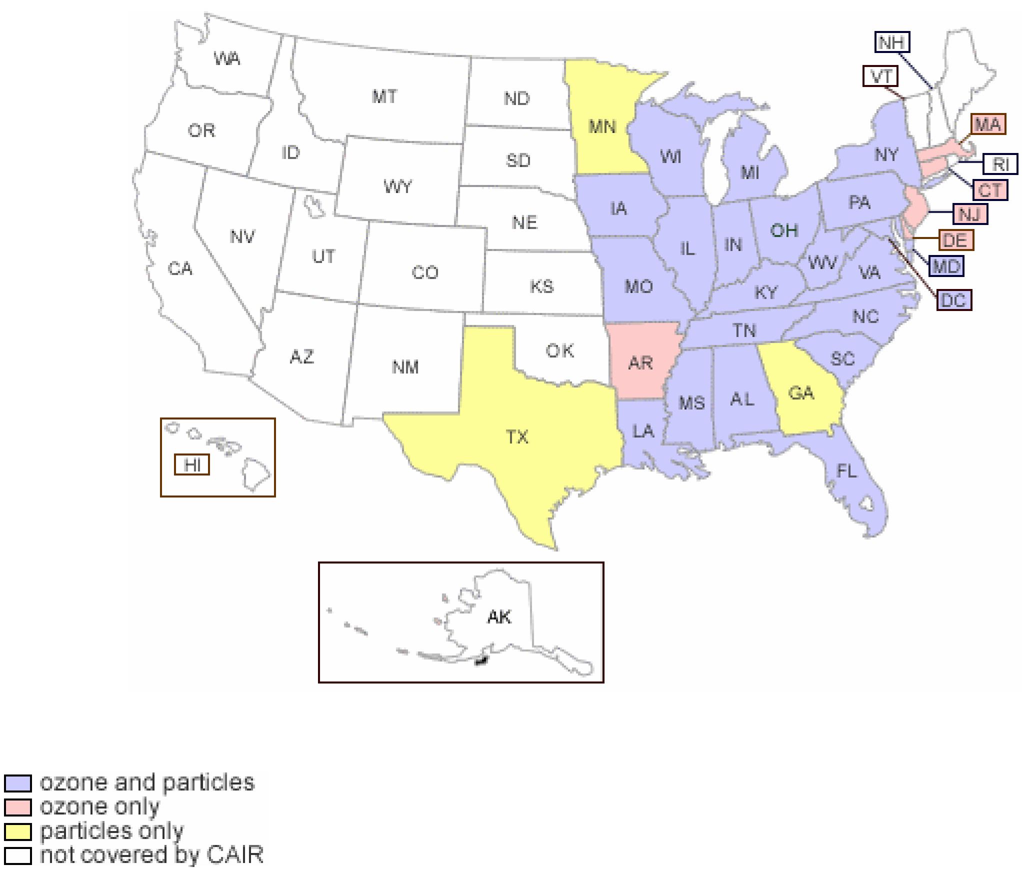
Various legislative bills continue to be introduced at the federal level to reduce GHG emissions from multiple sectors of the economy, including the power sector. Summaries of these rulemaking efforts are given below.

*Two New Rules Finalized by EPA in March 2005*

The EPA finalized the Clean Air Interstate Rule (CAIR) on March 10, 2005. CAIR calls for reductions in SO2 and NOx emissions from power plants in 28 eastern states and the District of

Columbia. The rule calls for reductions in SO2 emissions from power plants in the affected states from 9.4 million tons annually to 3.6 million tons in 2010 and 2.5 million tons in 2015. At full implementation, the rule will result in a 73 percent reduction in SO2 emissions. The rule will reduce NOx emissions in these states from 3.2 million tons annually to 1.5 million tons by 2009, and to 1.3 million tons in 2015. This is a 61 percent reduction. Because PSE does not operate in the CAIR affected states, it is not subject to the required SO2 and NOx reductions called for in the rule.

**Exhibit VIII-3**
**States Affected by CAIR**




On March 15, 2005, the EPA finalized the Clean Air Mercury Rule (CAMR), the intent being that CAMR would be implemented in tandem with CAIR. The CAMR applies to all power plants across the country that emit mercury. Since mercury emissions only occur with coal-fired plants, Colstrip will be the only PSE facility required to meet the mercury reduction requirements proposed in that rule. Reductions will be implemented in two phases with the first phase cap set at 38 tons. Emissions will be reduced by taking advantage of “co-benefit” reductions, that is, mercury reductions achieved by reducing SO2 and NOx emissions under CAIR. In the second phase, due in 2018, plants will be subject to a second cap, which will reduce emissions to 15 tons nationwide.

Both CAIR and CAMR will use cap-and-trade programs to achieve the required emissions reduction requirements. EPA will assign each state an emissions “budget”, and each state will be required to submit a State Plan revision detailing how it will meet its budget. Cap-and-trade programs provide strong incentives for utilities to make reductions at the units where controls are the most cost-effective. They also provide the flexibility necessary to mitigate risk associated with trying innovative control technologies. Experience with the Acid Rain SO2 allowance program has shown that an efficient cap-and-trade program can effectively deliver emissions reductions at a low cost to utilities and their customers, and if a cap-and-trade program is implemented for CAIR and CAMR, it should provide the same benefits.

Because the CAIR rule is layered on top of existing SO2 and NOx requirements and does not provide the regulatory certainty of new legislation, it is susceptible to being overturned judicially. In fact, many in the utility industry expect lawsuits within 60 days of it being published in the Federal Register. Likewise, a report released on March 7, 2005 by the EPA’s inspector general and the nonpartisan Government Accountability Office (GAO), identified four major shortcomings in the economic analysis underlying the CAMR’s proposed control options that said the agency ignored scientific evidence. Lawsuits are also expected within 60 days of the publication of the CAMR rule.

*Federal Legislative Proposals*

The Clean Power Act (S. 150, 1/25/05), sponsored by Senator Jeffords (I-Vt.) and reintroduced on January 25, 2005, would regulate SO2, NOx, mercury, and CO2. The Clean Air Planning Act (S.843) sponsored by Senator Carper (D-Del.), which is to be reintroduced in early 2005, would amend the Clean Air Act to reduce SO2, NOx, and mercury emissions, and would also regulate CO2 emissions. This Carper bill is offered as an alternative to the Bush Administration's Clear Skies Initiative. Both bills are currently subject to hearings by the Senate Environment and Public Works Committee.

On February 10, 2005 Senator McCain (R-Ariz.) and Senator Lieberman (D-Conn.) reintroduced the Climate Stewardship Act (S. 342), legislation that would establish a US GHG emissions cap with an emissions trading system (In the House, Representatives Gilchrest (R-MD) and Olver (D-Mass.) introduced a companion bill the same day.). The Climate Stewardship Act is modeled on the acid rain trading program (outlined in the 1990 amendments to the Clean Air Act). It would require a reduction in CO2 emissions to 2000 levels by 2010 by capping the overall greenhouse gas emissions from the power, transportation, industrial, and commercial sectors, and by creating a market for individual companies to trade pollution credits.

The Clear Skies Initiative (S. 131, 1/24/05) calls for reducing power plant emissions of NOx, SO2, and mercury by roughly 70 percent by 2018. The initiative would achieve reductions through market-based emissions trading, but is currently in a deadlock in the Environment and Public works committee. Many would like to see a GHG or CO2 component included in the bill. To address concerns that GHG provisions are not in the bill, a "mark-up" proposal was drafted in mid-February as an attempt to get the bill out of deadlock. The mark-up offers to include a provision on climate change research, including incentives for GHG reduction technology.

*State and Regional Activities*

To date, only Washington, Maine, Massachusetts, New Hampshire, Oregon and California have enacted laws to regulate GHG emissions. The Washington rule targets only new sources of electric generation and taxes those sources based on expected future CO2 output. No other sector or source is regulated in Washington at this time; however, Washington has been involved in many regional initiatives.

*West Coast Initiative*

In September 2003, the Governors of Washington, Oregon and California committed to a GHG reduction initiative for the West Coast region (West Coast Initiative / WCI). The Governors directed their staffs to work together and develop joint policy measures and recommendations to reduce global warming pollution. The staffs were directed to focus on activities that require regional cooperation and action. In November 2004, the Governors approved a series of detailed recommendations that the three states developed over that year.

WCI Recommendations for Longer-term or More Broadly Focused Actions:

- Set goals and implement strategies and incentives to increase retail energy sales from renewable resources by 1 percent or more annually in each state through 2015.

- Establish energy efficiency incentive standards in Washington that are comparable to Oregon and California.
- Influence the Western Interconnection to place grid expansion investment priority where it supports development of renewable resources.
- Encourage and assist the states' congressional delegations to adopt a national renewable or emissions and efficiency portfolio standard.
- Develop and promote net-zero or premium efficiency homes with integrated renewable resources.

Specific Near-Term Recommended Actions:

- Establish goals and strategies for state and local government purchases of renewable energy.
- Assist the states' congressional delegations to extend the Federal Wind Production Tax Credit for no less than ten years, and expand it to include biomass, biofuels, geothermal, solar, ocean energy, new hydro, and other renewable resources.
- Encourage public utility commissions and local suppliers to adopt Western Renewable Energy Generation Information System reporting requirements for renewable resources.
- Improve renewable resource access on public lands.

The WCI Governors are already moving rapidly into action, and are advancing policies and measures across many key areas. In 2005, many strategies have been introduced as legislation across all three states. This includes GHG vehicle emissions standards in California and Washington and renewable electricity generation in Washington. Others, such as a utility carbon policy (e.g., cap and trade), are only beginning to undergo consideration, despite being actively pursued in other parts of the country such as in the East Coast's Regional Green House Gas Initiative (RGGI).

*The Puget Sound Climate Protection Advisory Committee (CPAC)*

In December 2003, then-Governor Locke requested the Puget Sound Clean Air Agency (PSCAA) to engage in a collaborative effort to formulate additional long-term measures and new initiatives to compliment the West Coast Initiative. As a result, PSCAA created the Puget Sound Climate Protection Advisory Committee. The CPAC included technical working groups, advisory panels and stakeholder interests, and was facilitated by PSCAA. The final CPAC report (issued January 2005) identifies strategies and actions that Puget Sound and Washington state governments, communities, businesses, and private citizens should undertake to reduce GHG emissions.

Key CPAC Energy Sector recommendations:

- Establish an energy portfolio bill that will include both renewable and energy-efficiency portfolio requirements for utilities.
- Establish a GHG emissions cap-and-trade and registry market.
- Establish state energy efficiency standards.

*PSE Initiatives*

PSE began accounting for greenhouse gas (GHG) emissions in 2003. To date, PSE has inventoried GHG emissions for the 2002 and 2003 calendar years. These GHG inventories are based on data generated by PSE, established GHG accounting guidelines, and available Department of Energy and Environmental Protection Agency (EPA) documents. Each inventory accounts for:

- PSE's direct emissions from electrical generation, vehicle fleet, storage and distribution of natural gas, and use of sulfur hexafluoride as an insulating gas;
- PSE's indirect emissions associated with firm contract and non-firm (wholesale market) purchases of electricity; and
- Avoided GHG emissions due to PSE's conservation efforts and other conservation programs.

The inventories are intended to provide PSE with the information to achieve five major goals.

- Maintaining an accurate, transparent estimate of GHG emissions
- Understanding PSE's emissions sources for relative size and importance
- Tracking PSE's GHG emissions over time
- Evaluating PSE's GHG emissions from electric production and purchase relative to other electric generators and electric utilities
- Estimating the emissions avoided through PSE's conservation programs

*Conservation Programs and Emissions Avoided*

PSE runs a variety of electric and natural gas conservation programs, resulting in significant reductions in demand on electric and natural gas resources. These programs led to savings of 131,867,000 kWh of electricity and 2,175,375 therms of natural gas in 2003, amounting to avoided emissions of over 72,000 tons of CO2. PSE's natural gas conservation measures amounted to avoidance of emissions of approximately 15 tons of methane. In addition to these conservation measures, PSE owns and operates a fleet of natural gas-fueled vehicles. Assuming that these vehicles would have operated on gasoline instead of natural gas, it is estimated that approximately 500 tons of CO2 emissions were avoided by using natural gas vehicles.

*Emissions Policy Conclusions*

Absent a clear policy direction, PSE is exploring a range of greenhouse gas costs in developing its resource strategy. PSE will continue to participate in regional initiatives like the Puget Sound Climate Protection Advisory Committee, and PSE is developing a corporate greenhouse gas policy.

With respect to GHG regulation, PSE generally favors:

- A comprehensive plan that looks at all sources, rather than just electric generation
- Flexibility in meeting targets
- A portfolio approach that considers conservation and renewables
- An approach that balances rate impacts

See Appendix F for greater detail on PSE's emission levels today and possible future emission levels.

### B.2. Renewable Portfolio Standards

*Regulatory Environment*

Generally, a renewable portfolio standard (RPS) is a regulation to encourage electric utilities to meet a percentage of their demand with renewable generating resources. To date, these standards have been promulgated at the state level and currently 19 states have enacted renewable portfolio standards. This includes the southwestern states of the WECC.

Since renewable portfolio standards have been enacted on a state-by-state basis, the details of each one can vary. Typically each RPS sets out the following criteria:

- A target percentage of load to be met with renewable generation
- A target date or ramping schedule
- A definition of renewable generation
- Performance incentives or penalties

Some states also specify how much of the portfolio needs to be met with specific resource types (e.g, Colorado specifies solar generation targets). At least one state allows existing renewable resources to be counted but most standards set a date after which new renewable resources count toward the goal.

In Washington, the state legislature has been discussing both renewable portfolio standards and renewable incentives legislation. PSE has been actively participating in the legislative process regarding renewable generation and, while the future of any specific bill is unknown, PSE believes that some form of renewable portfolio standard could be enacted within the next few years.

*Existing Renewable Resources*

It is likely that PSE and other state utilities will not receive credit for existing hydroelectric resources in a renewable portfolio standard. Nevertheless, PSE is well-positioned should a standard be adopted. If the Hopkins Ridge and Wild Horse wind projects are developed and produce as planned, PSE will have achieved its target of approximately 5 percent of its load from new renewables by 2007.

PSE is also maintaining the 10 percent by 2013 renewable resource target that was established in its 2003 Least Cost Plan. The 10 percent level was established by policy to promote the development of renewable generating resources to diversify fuel sources, enhance fuel price stability, provide location-related benefits on the electric grid, reduce incremental air emissions, provide economic solutions to the disposal of various waste streams and stimulate local economic development.

*RPS Conclusions*

PSE continues to actively participate in the development of state RPS legislation. To some extent RPS legislation may have less impact on PSE than other state utilities. PSE has been conducting least cost planning since the late 1980s and has already begun the process of acquiring renewable generation as part of its overall resource strategy.

However, PSE is concerned that a poorly designed RPS could cause rate impacts and not efficiently accomplish the overall goal. In RPS legislation, PSE favors:

- A broad definition of renewable resources.
- A consistent definition of renewable resources throughout the WECC to facilitate trading of renewable credits.
- Flexibility to respond to a dynamic energy market. The RPS should consider cost-effectiveness.
- An RPS that applies to resource need. If a utility doesn't need new resources, then they shouldn't have to buy renewables solely to meet RPS.
- Greater certainty in the renewable resource development process. RPS goals need to be consistent with resource and transmission development processes.

Without legislative mandates PSE will continue with its goal of using cost-effective renewable energy to meet 10 percent of its load by 2013. PSE will already have met about 5 percent of this goal with its two new wind farm developments.

## C. Resource Development and the IPP Industry

### C.1. Introduction

Resource development is a complex undertaking. There are inconsistencies in the siting and permitting process that make it extremely difficult to develop projects with any sense of certainty around timing or outcome. The developer's challenge is to bring a number of disparate elements together at approximately the same time. The developer must find and obtain a permittable site. The developer must also arrange for interconnection and transmission (or sell to a utility that can arrange transmission) and strive to have these arrangements come together with the other pieces of the deal. Because development is time consuming, expensive and risky, the developer must find a financially able purchaser for either the power or the project. All of these things must happen in an ever-changing energy and regulatory market—a market that may not value the project at completion. This is the environment in which today's projects must be undertaken.

This section discusses the changing business model for energy development. The discussion includes the evolution of the IPP (Independent Power Producer) industry as a result of the 2000-2001 West Coast energy crisis. Because of credit and accounting requirements utilities are moving away from power purchase agreements (PPAs) and towards ownership, taking on more development responsibility in the process. This section also discusses the development challenges of the major resource types—gas-fired, wind, and coal. Finally there are discussions of resource acquisition challenges, including the difficulty of designing a resource solicitation process that accommodates long lead time resources, like coal, as well as various forms of PPAs, natural gas combined-cycle combustion turbine projects and small-scale renewable energy projects. The intent of this chapter is to put the environment in which PSE must operate and strive to acquire generating resources into perspective.

### C.2. IPP Industry Status

The business model for energy development is changing yet again. Utilities are playing an increasing role in bringing resources to market. Independent developers are struggling to refine their function and build a business model that provides adequate, consistent financial returns. Utilities are moving away from relying upon the market or upon PPAs and toward ownership. For developers, this may mean a "development for hire" model that results in a development fee and certain contingent payments over the life of the project.

*2003 Least Cost Plan*

Prior to the 2000-2001 western energy crisis[4], IPPs typically developed merchant plants. Under this model, the developer would sell the energy from the facility—typically to an energy marketer. The marketer would then sell the power, under various terms, into the wholesale energy market. The developer relied upon financing to fund the project and used extensive market analysis to demonstrate a revenue stream adequate to maintain acceptable debt coverage to satisfy project lenders.

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[4] See Chapter III of the April 2003 Least Cost Plan for an extensive discussion of this crisis.

The western energy crisis resulted in bankruptcies of major utilities, IPPs, and independent energy developers and, left in its wake, an overbuild of merchant power plants, partially-constructed plants, and a large number of development projects placed on hold.

PSE's 2003 Least Cost Plan was prepared in the aftermath of this crisis, with the expectation that the Company could capitalize on the glut of available projects. In fact, PSE did exactly this when it purchased a 49.85 percent interest in the Frederickson 1 natural gas combined-cycle combustion turbine project. Today, however, wind, other renewable resources, and coal are competitive with gas, due to dramatically increasing long-term gas price forecasts.

*IPP Industry Evolution:*

Following the energy crisis, the major industry participants, to a large extent, have inconsistent objectives. Developers want to continue doing want they know how to do: develop projects and create an asset that will provide value to their investors, preferably an income stream over time. Lenders are requiring more equity in projects and want long-term PPAs with financially viable parties before they are willing to finance projects. Furthermore, lenders are adding a risk premium, in the form of higher interest rates and financing fees, that have the effect of raising the developer's cost of capital to a rate that is appreciably higher than a regulated utility. Independent developers, who must satisfy the requirements of lenders if their projects are to proceed, are attempting to sell utilities on long-term PPAs.

Utilities, on the other hand, are moving away from relying upon PPAs. The credit rating agencies discourage utilities from entering into PPAs by looking at long-term power contracts as debt, judging the utility to have a greater credit risk for bondholders and other creditors. Likewise, accounting regulations discourage PPAs by requiring utilities to consolidate counterparty debt on their balance sheets.[5] These new rules and policies have a tendency to make long-term power purchase contracts uneconomical as compared to utility ownership.

Going forward, a "development for hire" business model may emerge as a response to utility ownership of generation assets. Under this model, projects are proposed in conceptual form but require commitments from buyers to be fully developed and built. The "development for hire" model means additional cost and risk is assumed by the utility in acquiring new generation assets. Developers will strive to recover all of their costs while minimizing their development risks. As a result, PSE would encounter additional risks by committing to a developing project that does not have the necessary permits and agreements for construction and operation, such as transmission rights, an interconnection agreement, real estate rights, supplier agreements, etc.

A “development for hire” model may also have the effect of limiting PSE’s choices. In the 2004 RFPs, numerous gas projects were proposed because of the surplus of projects developed for the merchant plant era. Going forward, if “development for hire” is the primary viable model, the large development companies of a few years ago will disappear and be replaced by fewer small, private partnerships that are undercapitalized.

### C.3. Lessons from the RFP and Resource Acquisitions Process

PSE, like many other regulated utilities, has responded to the changing energy marketplace by becoming a more vertically-integrated utility that is seeking to fulfill its growing energy need and avoid market risks by securing its own generation resources. Following its 2003 Least Cost Plan, PSE conducted two resource solicitations—a request for proposals (RFP) for wind resources and for all generation resources. After receiving nearly 50 proposals, with many different pricing/purchase options from almost 40 owners/developers, PSE has an even better understanding of the resource development landscape and the process for acquiring generation resources.

PSE expects that, in the short term, offerings in the marketplace for new generation resources will be similar to what was offered in the 2004 RFPs—parties offering PPAs, distressed natural gas-fired projects (although fewer in number), early stage wind projects, and conceptual projects for other technologies, including coal.

*PPA financial impacts need to be considered*

In the 2004 RFPs, many bidders proposed PPAs. As indicated previously, credit rating agencies and accounting regulations discourage these transactions. Going forward, PSE expects to receive many more PPA proposals but will continue to systematically evaluate the credit, financial, and economic impacts.

[5] See Chapter IV of this Least Cost Plan for a further discussion of credit and accounting issues related to PPAs.

*Gas Projects are Losing Favor*

In the 2004 RFP, the majority of proposals were either for natural gas-fired projects or wind projects. About half the natural gas-fired proposals were for existing facilities or partially constructed plants; the others were for new development projects. On the other hand, all of the wind proposals were for new development projects. This sheds light on the resource marketplace available to the vertically integrated utility.

As seen in the RFP responses, there were many natural gas-fired projects that were suspended after the energy crisis and the demise of the merchant plant model. Typically, natural gas-fired projects are easier to site and permit in western Washington than other fossil-fueled plants, and due to the proximity to natural gas pipelines and transmission to the major load centers, natural gas projects had been the default choice in new generation. Today, with high natural gas prices, these projects are becoming less economical to own. They typically operate on the margin, and require sophisticated and expensive hedging strategies to manage fuel price risk and related volatility.[6] However, they may still be a resource that is acquired and built due to the challenges associated with other resource types, as discussed below.

*Wind is an Emerging Resource*

Wind projects are becoming much more attractive due to the maturity of wind turbine technology, the adequacy of wind resources in the Northwest, trends toward portfolio renewable standards, and current tax incentives. PSE's experience from the RFP responses was that wind projects are typically immature or early in the development phase and the majority are located outside PSE's service territory. Transmission system constraints that hinder the ability of projects to serve major load centers in the Puget Sound area, as discussed below, make projects outside PSE's service territory less attractive.

Although wind developers are eager to begin the process of siting and performing preliminary studies for their projects, in PSE's experience, they will not fully develop these projects without the security of a buyer. Furthermore, PSE has found that even after committing to a proposed wind project, the Company has had to take on some of the development tasks in order to facilitate the successful development and permitting of the project.

[6] Fuel price and volatility risk is more fully discussed in Chapter V of this Least Cost Plan.

*Coal Generation has Challenges*

Coal-fueled resources are increasingly competitive in this era of high natural gas prices. However, given their long lead-time and high capital costs, few developers, if any, have the financial strength to support a coal project. The development cycle can take seven to ten years beginning with site selection and including permitting, engineering design, procurement, construction, start up, and testing. Permitting a coal mine and related transmission facilities can be a highly complex and lengthy process, subject to unaligned federal, state, and local requirements. Because of these challenges, developers are typically seeking utility partners for an ownership stake or as power purchasers under long-term contracts before they are willing to put much development money at risk.

Furthermore, because of environmental and political pressures, it is unlikely that a coal project will be permitted and built in the State of Washington, especially in western Washington, where transmission constraints to PSE's load centers are less of an issue. Because any new coal project would likely be outside the state, building the associated transmission from the project to PSE's service territory would be a large hurdle to overcome.

*Coal Does Not Work in the Traditional RFP Process*

The state-mandated resource solicitation process is not conducive to the acquisition of long-lead time and capital-intensive projects such as coal resources. In the RFP process one looks to evaluate a fully-developed proposal with tangible costs and a date-certain schedule. Coal proposals are more likely to be submitted in a conceptual form and thus do not evaluate well. This was illustrated by PSE's 2004 RFP process where four coal-fired proposals were offered: two ownership options for new coal development and two power purchase offerings from existing coal plants. Although the power purchase proposals appeared to have low initial costs, credit and accounting issues impacted their viability. One of the ownership options was rejected due to the inability to get transmission from the east to PSE's service territory. The other ownership option was quite immature in its development and deemed to have fatal flaws. In summary, without significant utility involvement, it is unlikely that new coal projects will be built in the current marketplace, and the current RFP process is not the appropriate vehicle to receive and evaluate coal project proposals.

*Unaligned Permitting Processes Add Challenges*

Resource development, which is never an easy task, is made more difficult by unaligned permitting processes. This is probably best illustrated by the following examples. A new transmission line, which might be needed to deliver power from a remotely located generation facility to the load center, provides benefits to those living in the load center but impacts those along its route. Furthermore, permitting requires approval by each county along the way so any one county can derail the project. Generally speaking, county decision-makers make permitting decisions based on local impacts and consistency with surrounding land uses, giving little credence to regional benefits.

A second example of unaligned permitting processes is becoming increasing evident in the development of wind projects. For wind, the county must approve the conditional use permit for the project, but, as in the transmission line example, the county will likely give less weight to the benefits received by citizens of distant counties than they will to impacts incurred locally. In general, because of concerns expressed by local residents to proposed wind projects, the permitting environment for wind seems to be evolving in such a way that permittable sites are located in remote locations. Unfortunately, transmission capacity in these remote locations tends to be unavailable to deliver the power to PSE's load center.

*Transmission Constraints Limit PSE's Options*

As previously described in detail in section A of the Chapter, PSE faces severe limitations to its ability to purchase generation outside of its service territory. Many of the responses to PSE's RFP were for remotely-located projects. These projects were proposed without mature transmission arrangements, leaving PSE to evaluate the likelihood and cost of transmission.

## D. Regional Supply Situation

The regional and WECC load-resource situation can indicate the depth of the energy market. PSE plans to meet its long-term energy load obligation with long-term resources. In addition, the Company will also use medium-term bridging contracts and continue to operate in the energy market, to optimize its portfolio and to take advantage of opportunities. An examination of the overall market situation can indicate the price and availability of surplus energy.

*Regional Energy Supply*

The Northwest Power and Conservation Council's (NPCC's) 5th Power Plan (January, 2005) states that, "On the basis of generation installed in the region, the Pacific Northwest currently has more than enough electricity resources to meet demand." At a "medium" regional load growth rate of 0.95 percent for 2000-2025 the NPCC estimates that the region will be in balance through 2014 under critical water conditions (critical water condition is approximately 4,000 aMW less than average generation). If the load growth rate is 1.5 percent, there are adequate resources through 2008 under critical water conditions, and adequate resources beyond 2015 under average conditions. The current supply surplus is further supported by the Fifth Power Plan's number one recommendation: increase investment in conservation which will offset 2,500 average megawatts over the 20-year planning period.

According to the Fifth Power Plan, two key factors contribute to current and continuing surplus: the closure of aluminum smelters and the development of new gas-fueled resources by independent power producers (IPPs). The aluminum industry situation is reflected in the load forecast, which is 3,000 megawatts lower in 2015 than in the previous plan. The independent power producers have a resource supply of about 3,600 megawatts. If the IPPs sign long-term contracts outside the region, then the Northwest may not be able to depend on their supply. Furthermore, the region's limited transmission supply will be consumed by power flowing away from the northwest.

*Regional Capacity*

In the near-term, PSE relies on its simple-cycle combustion turbines and regional peaking capacity to plan for its potential peak loads. According to the NPCC Fifth Power Plan, "The regional generating capacity, the combined peak generation capability, is over 50,000 megawatts; much larger than current winter peak loads." The region's peak requirement is under 40,000 megawatts including reserves and exports, according to figures from the Pacific Northwest Utilities Conference Committee.

*Regional load diversity (from the NPCC)*

With the growth in population, the resource mix has changed in the northwest. In 1960 most of the region's power came from hydro generation. By 1980 about 15 percent of the region's supply came from coal-fired generation. Recently, most supply additions have been gas-fueled turbines, such that the 2003 supply mix was 52 percent hydro, 21 percent natural gas, 20 percent coal, with other sources accounting for the remaining 7 percent. Wind makes up about 1 percent of the regional supply and there is much interest in seeing that percentage grow.

*Implications for PSE*

PSE will depend, to a certain extent, on the regional market for both energy and peak capacity while it implements its long-term resource acquisition strategy. The fact that the region is surplus, both energy and capacity, provides PSE some flexibility in pursuing its resource strategy, which may include developing new resources, and buying or contracting for existing resources.

However, because the regional surplus is limited in volume and duration, PSE cannot assume that it will be able depend on the regional market to address large, long-term energy needs. Such a strategy could expose the Company and customers to price risk and potential reliability impacts.

## E. Demand-Resources Implementation Issues

Demand resources continue to play a critical role in PSE's portfolio. In this Least Cost Plan, PSE is expanding its consideration of demand-side resources. While the energy efficiency programs are well-proven with accepted measurement, implementation, and regulatory treatment, fuel conversion and demand response are not as well established. This section discusses analytical and implementation issues for demand-side resources

### E.1. Energy Efficiency

PSE has provided conservation services for its electricity customers since 1979 and for its natural gas customers since 1993. PSE offers programs designed to serve all customers – including residential, low-income, commercial and industrial. Savings targets and programs are determined through a collaborative effort between PSE and key external stakeholders represented in the Conservation Resource Advisory Group (CRAG). While energy efficiency is an established resource, the Least Cost Plan identifies the following current issues:

*Cost Effectiveness*

For least cost planning, PSE evaluates energy efficiency resources as a part of new resource portfolios. The results of the portfolio evaluation process identify the levels of energy efficiency to include in the integrated least cost resource strategy.

Outside the Least Cost Plan, PSE evaluates the cost-effectiveness of energy efficiency programs based on the Total Resource Cost (TRC) test. Total costs, which include the utility's costs and any other costs paid by the customer or others (e.g., water rebates from a water utility), must be less than the value of the total benefits. "Total benefits" include energy-savings benefits together with the value of all other benefits (e.g., reduced water use). This definition of cost-effectiveness is different than that used to determine the level of energy efficiency in the Least Cost Plan.

A key element to assessing the cost-effectiveness of demand-side resources is the value of the saved energy, which would otherwise have to be supplied. The Least Cost Plan calculates demand-side resource value using resource portfolios. For evaluating the cost-effectiveness of specific demand-side programs outside the LCP process, PSE's approved regulatory methodology uses the AURORA forecast of power costs to calculate avoided cost for its energy efficiency cost-effectiveness analysis (PSE 2001 General Rate Case, Docket Nos. UE-11570 and UG-11571). Since the cost of the LCP supply portfolio is higher than the AURORA price projection, program cost-effectiveness based on AURORA prices will not match the Least Cost Plan. Consequently, PSE may not be able to cost-effectively obtain all the demand-side savings indicated by the Least Cost Plan. However, this should not diminish the Least Cost Plan's usefulness in providing directional guidance.

*Non-Energy Benefits*

Traditionally energy efficiency measures are granted a credit for non-energy benefits when compared to generation resources. Non-energy benefits may include water savings, reduced carbon emissions, restored structural integrity associated with weatherization improvements, or improved aesthetics or comfort.

The modeling performed for the Least Cost Plan accounts for the non-energy benefits of energy efficiency by assigning the 10 percent cost credit identified in the Northwest Regional Power Act. This credit is used by PSE and other NW utilities in cost-effectiveness analyses of energy efficiency resources. Additional non-energy benefits and costs may be included during individual program development subsequent to the Least Cost Plan.

*Financial Impact*

Existing and future energy efficiency programs cause lost revenue financial impacts. Existing regulatory policies do not allow PSE to implement appropriate lost revenue recovery mechanisms. As the energy efficiency programs have ramped up, lost revenue recovery has risen in importance.

### E.2. Fuel Conversion

As detailed in Chapter VII, PSE developed estimated resource potential for fuel conversion. Fuel conversion involves replacing electrical end-uses with equivalent natural gas equipment. From a macro perspective, there are applications where it is more energy efficient to use natural gas directly than to generate electricity from natural gas and then use the electricity in the end-use application.

A large scale fuel conversion program would be a new undertaking for PSE although two small-scale pilots are underway. As such, there are a number of issues that could impact the scale or the value of such a program. This section discusses many of the potential fuel conversion issues. Resolution of many of the issues will likely require a collaborative effort with regulators and key stakeholders.

*Status of Current Pilots*

A single family fuel conversion pilot is under way. Seventy homes now have natural gas equipment installed. At the end of the current (2004-2005) heating season, PSE will be undertaking an evaluation to determine the energy-savings impacts, review costs in comparison to distribution alternatives, and overall assess program performance. A final report of pilot findings will be available by late summer 2005.

PSE is also conducting studies to determine the feasibility of installing natural gas in multi-family units. This research will provide a better understanding of the multi-family market, including the economics of and barriers to natural gas use in these facilities, enabling the Company to determine the design of any pilot installations. These feasibility studies and a decision to move forward with a multi-family pilot installation program will be complete by mid-2005.

*Value to Customers*

Customer savings are defined as the difference between their utility bills before and after the conversion. The conversion makes economic sense if the savings to the customer over time covers the up-front cost to the customer for the conversion.

With the recent run-up in natural gas prices, the value (savings) to customers has decreased. Electric retail rates are a melded value based upon the fuel mix of the portfolio while natural gas prices are directly reflected in rates. With high gas prices, the net bill savings is lower and the customer value is decreased.

PSE also runs a risk of increasing the volatility of the conversion customers' bills. Following conversion a greater percentage of the customer's total energy bill would be for natural gas and that portion is subject to direct reflection of changing natural gas prices.

Customer costs include not only the cost of the new gas appliances but also costs for new service connections, gas main extensions, or other distribution system upgrade costs set forth in applicable tariffs.

*Market Conversions*

PSE currently experiences 8,000 to 10,000 conversions per year. Presumably, many customers that were planning conversions would take advantage of any utility incentive offered through a new conversion program. These customers, who would have taken action even with the program, are categorized as "free riders" as they would receive an incentive payment for something they were going to do on their own. With respect to fuel conversion, PSE has no track record that would help the Company determine how best to increase the rate of fuel conversions while avoiding free riders. Given that the incentive payment level per customer may be very high for fuel conversions, the risk of subsidizing fuel conversions that would have occurred anyway is substantial.

*Regulatory Mechanism and Financial Impact*

PSE has well-established mechanisms for collecting and distributing funds for energy efficiency programs. No such mechanism has been established for fuel conversion. Such a program could also potentially raise rate design issues and cross-subsidy questions between gas and electric customers. For example, new incremental gas delivery resources are higher cost than

PSE's existing gas delivery resources. To the extent that a fuel conversion program creates a greater need for new resources, existing gas customers could experience higher rates because of the electric fuel conversion program.

PSE will also need to consider the financial impact of such a program. A large scale program without an appropriate cost recovery mechanism and lost revenue recovery mechanism could adversely impact PSE's financial performance.

*Gas System Capacity*

PSE plans its gas and electric system to meet expected demand. Fuel conversion program design must consider the potential system delivery issues and additional system costs. To some extent, increased gas system costs may be offset by electric system savings. However, these costs can vary widely from location to location and are therefore difficult to quantify for general planning analyses.

*Customer Acceptance*

Actual fuel conversion program participation will be affected by timing of appliance replacement, first costs (new appliances plus service hook-up), perceived bill savings, and personal preferences that are unique to each customer and are difficult to model as broad planning assumptions. Customers may balance these factors very differently when making their purchase decision. The utility attempts to influence these decisions through its programs, but the consumer is the ultimate decision-maker regarding the purchase of demand-side resources.

Estimates of program participation rates are more uncertain for fuel conversion than for energy efficiency because of the lack of a program track record with fuel conversion and because fuel conversion requires a higher up-front customer contribution. Any utility program should also ensure that fuel conversion is in the individual customer's best interest. In some cases, an electric technology, such as a heat pump, may be a better alternative. It is impossible to model such tradeoffs for individual customers in the Least Cost Plan.

*Cost-Effectiveness Methodology*

Again, PSE has a well-established cost-effectiveness methodology for energy efficiency but not for fuel conversion. PSE and stakeholders will need to establish the following: the value of the electric savings, cost of gas increase, typical customer costs for different conversion scenarios, electric and gas system impacts, and the consideration of non-quantified environmental savings. Fuel conversion programs should only be pursued after a more thorough assessment of cost-effectiveness.

*Program Implementation*

Program implementation depends on utility staff with the appropriate skills and tools to perform all phases of program design and operation. This program implementation capability is generally well developed for energy efficiency resources, but must be built up for implementing fuel conversion programs. External infrastructure considerations must also be addressed, such as product availability to utility customers, and an adequate network of contractors, retailers, and other trade allies to support a program.

As new measures or expanded programs are developed and added to the current program mix, internal and external resources and capabilities need to grow accordingly, and progress through a “learning curve". In many cases, small pilot programs precede full-scale programs to test the performance of demand-side technologies and customer acceptance of a particular market delivery mechanism. In fact, PSE has a small-scale pilot currently underway.

In short, a utility cannot immediately launch into full-scale deployment of all demand-side measures identified by their Least Cost Plan, nor should such results be expected.

The estimate of fuel conversion resource potentials in this plan does not account for any “ramp-up” that will be required to reach the savings levels achievable from fully mature programs.

### E.3. Demand Response

*Introduction*

As detailed in Chapter VII, PSE developed estimated maximum potential peak demand reductions from demand response. Evaluated demand response tactics include direct load control, time-of-use, critical peak pricing, voluntary curtailment, and demand buyback. Demand response can provide value to the utility by reducing capacity usage on the distribution and transmission system as well as lowering exposure to high cost market prices or generation peaking resources for capacity in critical peak high-cost hours. These products also provide benefits to the wholesale transmission system as well as other regional distribution utilities that share the transmission system.

The demand-response resource potential analysis in Chapter VII represents significant advancement over the analysis in the 2003 LCP. The primary refinement was the evaluation of "achievable" demand-response potential, whereas the 2003 assessment focused solely on "technical" potential. Because "achievable" potential incorporates expected rates of program participation, it is a much more realistic projection of the savings potentially available from demand-response programs. The 2005 demand-response assessment also incorporates new data available since the 2003 analysis on program impacts, program costs, customer participation rates, and customer characteristics. This data comes from PSE, Northwest utilities (such as Portland General Electric), national utilities, and regional transmission organizations (RTOs) that have offered such programs.

While PSE has increased its understanding of the appropriate demand response programs for customers and its understanding of estimated program costs, there are still issues which must be resolved before implementation. This section discusses demand response implications for resource planning, strategy development, and implementation. PSE anticipates discussing many of these issues further in collaboration with regulators and stakeholders.

*Value to Customer - Acceptance*

While PSE has experience with one type of mass-market demand-response product (time-of-use), it does not have extensive experience with all types of demand-response products. Limited information exists on customer participation rates and load reductions for winter-oriented demand response programs under normal market conditions. The value to customers includes lower costs and any utility incentive payments. The cost to customers varies depending upon the demand response program design and the types of actions undertaken by customers to reduce demand. One major issue, beyond the value that customers may place on retail demand-response products, is the value of these programs to the region, including neighboring utilities, regional utilities and regional transmission providers.

*Regulatory Mechanisms*

Unlike energy efficiency programs, there are no regulatory cost recovery mechanisms in place to recover program costs for demand-response programs. There are also no regulatory mechanisms in place to recover lost revenues that result from any demand-side management programs, including energy efficiency programs and fuel conversion programs, as well as demand-response programs. There are currently no regulatory mechanisms that allow PSE and its customers to capture the financial benefits that these types of programs would give to other distribution and transmission utilities in the region.

*Cost-Effectiveness Method*

Unlike energy efficiency programs, there are no WUTC-approved cost-effectiveness methodologies in place for demand-response programs. A methodology needs to be established that considers cost-effectiveness issues such as the value to the utility portfolio (energy and peak), customer direct costs, implementation costs, life and sustainability of programs, environmental considerations, electric transmission and distribution savings, customer costs, and other customer impacts.

Resource Modeling

As with cost-effectiveness, there is no standard method to model demand response for resource planning (for example, the variability in certain demand response programs will impact capacity value or reserve requirements). PSE will need to work with stakeholders to develop an acceptable approach.

*Program Design - Assessment*

To move forward with demand response PSE will need to design some pilot programs and establish assessment criteria. Understanding the recent experience of other utilities and their customers may provide insight and direction for this process.

## F. Financial Considerations

In support of PSE's overall mission to provide customers with reliable energy at reasonable, stable prices, PSE strives for improved risk management and lower credit costs. PSE's financial strategy requires the availability of credit and access to the capital markets on reasonable terms, which in turn require improved financial strength.

PSE is keenly aware of its financial challenges and will be considering the financial impact of resource decisions both in this Least Cost Plan and in any subsequent resource acquisition. To some extent, PSE and other electric utilities are still experiencing some repercussions from the western energy crisis of 2000-2001. The very high and volatile pricing resulted in several large and established companies defaulting on obligations. In the aftermath, energy market participants and the financial markets have become much more aware of risk and mindful of energy supply impacts on financial performance.

In addition to considering the direct cost of the various resource types, PSE will also be evaluating its resource strategy with respect to:

- *Financial strength* – the timing of resource capital expenditures combined with other corporate needs like infrastructure growth and replacement; PSE's cost and ability to finance given financial ratings

- *Credit* – credit requirements, impacts to open credit, and impacts of credit requirements on overall financial strength

- *Risk Management* – energy price risk management costs; overall risk profile for resource strategy

- *Imputed Debt* – added imputed debt for new purchase agreements and renewal of existing contracts; impact of imputed debt on overall financial strength

More in-depth discussion of the importance and significance of financial issues to PSE's least cost strategy can be found in Chapter IV.

### G. Natural Gas for Power Generation

Over the last decade natural gas was the fuel of choice for new power plants. Gas prices were reasonable and gas projects were easier to site and permit. However, over the past few years, the natural gas market has experienced a fundamental upward price shift. Higher domestic demand and rapidly expanding international markets for energy continue to put upward pressure on natural gas prices.

At the same time, North American supplies have stayed flat. The prospects for future gas price moderation depend upon potential supply increases from expanded liquefied natural gas import facilities and the construction of new pipelines to access McKenzie Delta and Alaska supply basins. Both of these solutions face significant political and environmental challenges.

Tighter supplies have also led to increased price volatility and the need for expanded price risk management. Higher prices place greater financial burdens and credit requirements on market participants.

*Implications for PSE*

The net result is a number of outcomes that impede PSE's least cost resource strategy.

- Higher natural gas costs
- Increased price volatility and need for expanded risk management
- Increased credit requirements
- Decreased market liquidity for gas supply
- Increased need for financial strength to meet counterparty credit demands and to lengthen and expand the Company's hedging program for gas-for-power

Power generation has both price and volume risk. For LCP modeling PSE considered gas pricing uncertainty by using a range of CERA price forecasts. (See Chapter V for a discussion of the gas price forecasts.) CERA forecasts represent a compilation of all known market information. Additionally, PSE uses Monte Carlo analysis to determine the impact of price volatility.

# IX. ELECTRIC RESOURCES

This chapter begins with an overview of PSE's existing mix of supply resources for meeting customer demand, including hydro, coal, wind, combustion turbines (CTs) and long-term contracts with both utilities and non-utility generators (NUGs). The next section outlines PSE's Green Power Program, beginning with a discussion of renewable energy options available to PSE customers, including green tags and new small-scale production using biomass and solar. The chapter concludes with a discussion of PSE's projected load resource balance through 2025.

## A. Existing Generation Supply

PSE's generation portfolio currently consists of a mix of resources with both geographical and fuel diversification. Exhibit IX-1 is a map showing the location of PSE's primary resources. Most of the gas-fueled resources are in western Washington, while the major hydro contracts are at the Mid-C in central Washington, outside of PSE's service territory. Furthest away from the load is Colstrip in eastern Montana.

Exhibit IX-2 shows expected energy resource supply under average hydro conditions (60-year) for December 2006. Hydro, PSE's largest energy source, includes both PSE-owned projects and long-term power purchase contracts with the mid-Columbia PUDs. PSE's share of the coal-fueled Colstrip plant makes up the next largest portion. Natural gas generation resources consist of the NUG contracts, which include Tenaska, Sumas and March Point, PSE-owned Encogen, and PSE's share of the Frederickson 1 combined cycle combustion turbine. The new Hopkins Ridge wind power facility is expected to provide 2 percent of PSE's 2006 energy supply, and the Wild Horse project could provide another 3 percent in 2007 (not shown here). Various contracts comprise the remaining resources.

## Exhibit IX-1
## Existing PSE Resources

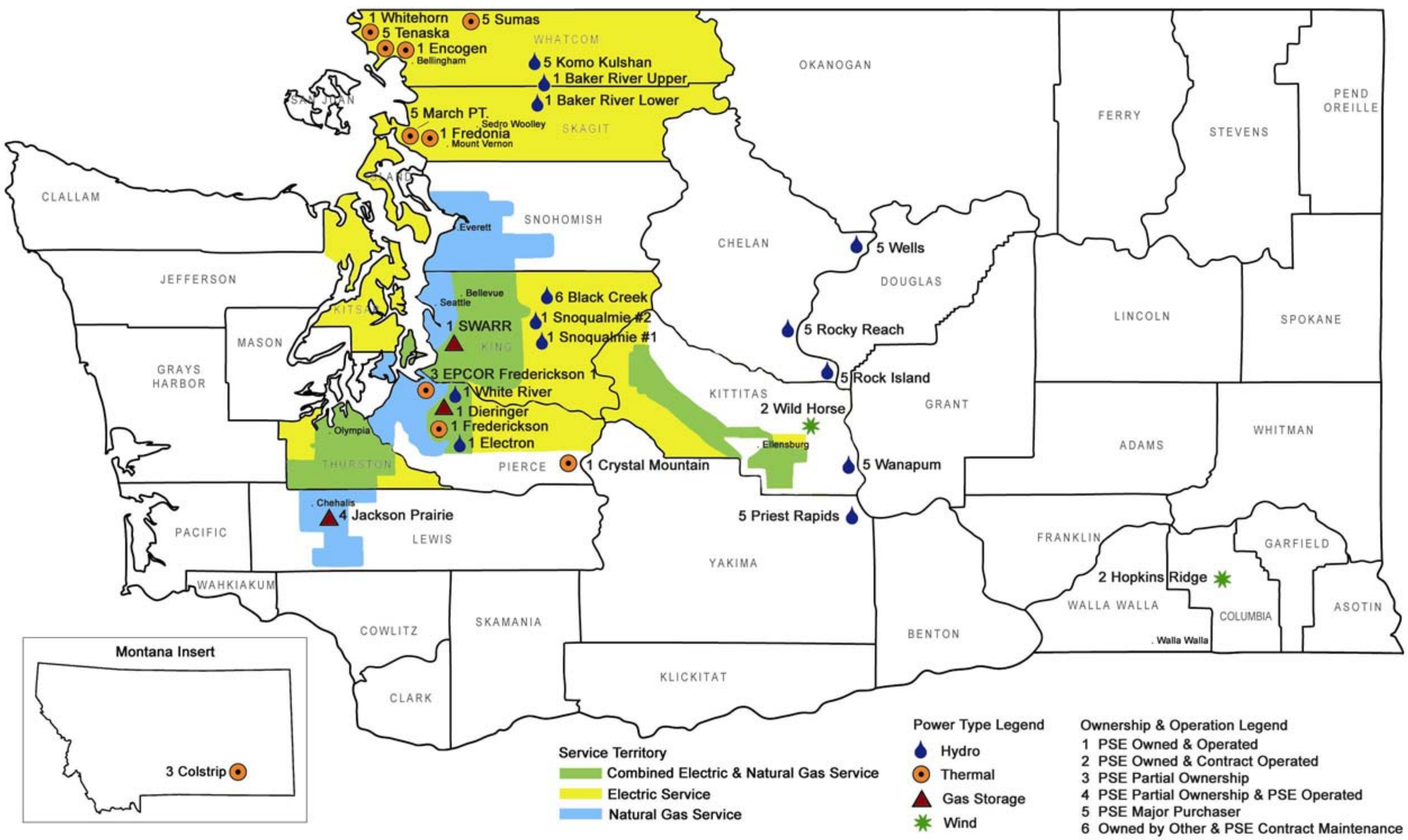


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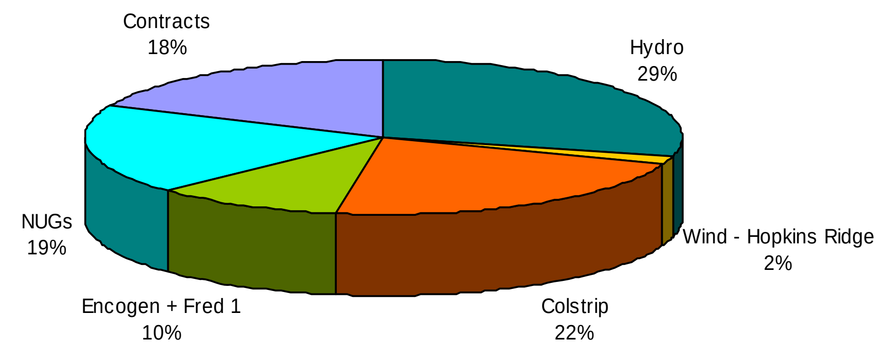
**Exhibit IX-2: December 2006 Supply Side Resources
Average Megawatts by Source**




*Hydro*

Hydroelectric plants cover approximately 33 percent of PSE's energy generation on an annual basis. Hydro resources consist of PSE-owned westside projects and long-term contracts with larger dams on the Columbia River. Other PSE hydro resources include the small dams named in the Contracts section as Qualifying Facilities. Hydro resources are very valuable as they can follow loads and are generally low-cost. High precipitation levels enable utilities to generate more power from hydro facilities. However, during low water years utilities must rely on other, more expensive sources in the market to meet load. PSE includes both the seasonality and year-to-year variation in hydro production in its Least Cost Plan analytics.

**Exhibit IX-3**
**PSE's Existing Hydro Resources (2006)**

| PLANT | OWNER | PSE SHARE % | ENERGY (aMW) | EXPIRATION DATE |
|---|---|---|---|---|
| Upper Baker River | PSE | 100 | 40 | |
| Lower Baker River | PSE | 100 | 44 | |
| Snoqualmie Falls and Electron | PSE | 100 | 48 | |
| **Total PSE-Owned** | | | **132** | |
| Wells | Douglas Co. PUD | 29.9 | 136 | 3/31/18 |
| Rocky Reach | Chelan Co. PUD | 38.9 | 269 | 11/1/11 |
| Rock Island I & II | Chelan Co. PUD | 55.0 | 182 | 6/7/12 |
| Wanapum and Priest Rapids | Grant Co. PUD | Mixed share and contract | 85 | Refer to **Wanapum and Priest Rapids** section below |
| **Mid-Columbia Total** | | | **672** | |
| **Total Hydro** | | | **804** | |

- **Baker River Hydroelectric Project**

  PSE initiated the relicense process for the Baker River Hydroelectric Project in March 2000, in anticipation of the expiration of its existing license on April 30, 2006. In 2004, 23 stakeholders, including all federal and state resource agencies, three Indian tribes, Skagit County, several nongovernmental organizations and PSE reached consensus to sign a Settlement Agreement. If the agreement is approved by the Federal Energy Regulatory Commission (FERC), the Company will be authorized to generate 707,600 MWh[1] for at least 30 years. While the current annual average output at Baker is actually slightly higher (716,320 MWh) and the cost lower than proposed in the new Settlement Agreement, the project will remain a very cost-effective resource. Furthermore, all parties to the Settlement Agreement have expressed support for a 45-year license rather than the more standard 30-year license, which, if granted, would provide 15 additional years of dependable generation at a stable and favorable cost.

[1] annual average output

- **White River Project**

  In January 2004, PSE stopped generating electricity at the White River Project because the environmental costs and other expenses required to license the Project would have resulted in a power cost well above available alternatives. Since production ceased, PSE has made post-retirement arrangements with third parties to cover most ongoing costs. In disposing of the Project assets, PSE is working with interested parties so that they may have the opportunity to preserve the Lake Tapps reservoir for regional recreation and municipal water supply.

- **Snoqualmie Falls Hydroelectric Project**

  FERC issued a license for the Snoqualmie Falls Hydroelectric Project on June 29, 2004. The terms and conditions of the 40-year license allow the Company to maintain the Project as a reliable and cost-effective resource. Over the 40-year term of the license, the Project will generate an estimated 300,000 MWh[2]. The license requires significant enhancements to a number of public amenities.[3]

- **Wanapum and Priest Rapids**

  On December 28, 2001, PSE signed new contracts to secure a share of the electricity produced at the Wanapum and Priest Rapids dams. The contract includes three agreements:

  1) The "Priest Rapids Product Sales Contract" – The terms of this contract begin November 1, 2005 for the Priest Rapids Development, and November 1, 2009 for the Wanapum Development. Contained within the contract are provisions for two products. The first is a "Surplus Product," which provides PSE with a percentage of project power at cost. The second is a "Displacement Product," which provides PSE with additional power resulting from Grant PUD's purchase of Bonneville Power Administration (BPA) power. The power from both products decreases over time as Grant PUD's loads increase.
  2) The "Additional Products Sales Agreement" – This agreement provides PSE with a portion of the non-firm generation available to Grant PUD from the Priest Rapids Project as and when such energy is available. The availability of this energy is determined by the District. The non-firm product is available for the life of the FERC license and the

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[2] annual average output
[3] e.g., parks and recreational resources, aesthetics resources, and historic resources

amount of power will increase gradually over time as Grant PUD withdraws more power from the Project.

3) The "Reasonable Portion Power Sales Contract" – This contract provides PSE with a percentage of the net revenue from the FERC's "Reasonable Portion." This is equivalent to 30 percent of the project output, which is to be marketed by Grant PUD according to "market-based principles."

The terms of these new agreements apply to the Priest Rapids Development beginning November 1, 2005 and to both developments beginning November 1, 2009. Until those dates, the previous agreement terms apply. After November 1, 2009, PSE will have a share of the combined Priest Rapids and Wanapum Developments instead of individual shares of each project.

*Colstrip*

PSE owns a 50 percent share in Colstrip 1 & 2, and a 25 percent share in Colstrip 3 & 4, a coal-fired plant located in Colstrip, Montana. The four units will be expanding their capacities by a total of 82 MW by installing higher efficiency turbine components in the years 2006-2008. PSE's share of this increase is 28 MW. Colstrip provides important baseload energy and about 23 percent of PSE's overall needs. PSE receives additional energy from Colstrip under a contract with NorthWestern Energy, described below. Exhibit IX-4 lists Colstrip's capacity and planned energy output.

**Exhibit IX-4: Colstrip (2006)**

| UNITS | PSE OWNERSHIP | NAMEPLATE CAPACITY (MW) | ENERGY (AMW) |
|---|---|---|---|
| Colstrip 1 & 2 | 50% | 614 | 251 |
| Colstrip 3 & 4 | 25% | 1,480 | 299 |
| **Total Colstrip** | | | **550** |

*Base-Load Gas-Fueled Resources*

Encogen, a former NUG which PSE purchased in 1999, is a natural gas-fired cogeneration facility located in Bellingham. The plant provides steam to the adjacent Georgia Pacific Mill. Frederickson 1 is a combined cycle plant operated by EPCOR, of which PSE owns 49.85 percent. The energy listed in Exhibit IX-5 represents the energy available for planning purposes. Actual output may be lower if market purchases displace production for economic reasons.

**Exhibit IX-5: Combined Cycle (2006)**

| UNITS | PSE OWNERSHIP | NAMEPLATE CAPACITY (MW) | ENERGY (AMW) |
|---|---|---|---|
| Encogen | 100% | 169 | 161 |
| Frederickson | 49.85% | 249.3 | 117 |
| **Total Gas CCs** | | | **278** |

*Combustion Turbines*

PSE operates four simple-cycle gas turbine facilities. These plants provide important capacity although they typically operate during only a few months each year. As discussed extensively in Appendix E of the April 2003 Least Cost Plan, these resources cannot be used for baseload energy. While the lease for the Whitehorn units originally expired in 2004, it has been extended to 2009. Fredonia 3 & 4 were installed in 2001 with financing arranged as a long-term lease expiring in 2011. Exhibit IX-6 provides additional detail on PSE's CTs.

**Exhibit IX-6: PSE's Combustion Turbines**

| NAME | PLANT CAPACITY (MW) |
|---|---|
| Fredonia 1 & 2 | 202 |
| Fredonia 3 & 4 | 118 |
| Whitehorn 2 & 3 | 134 |
| Frederickson | 141 |
| **Total** | **595** |

*Wind Energy*

PSE signed letters of intent with two wind resource developers in 2004. The first project, Hopkins Ridge, was developed by RES Inc. The site is located in Columbia County and will be PSE's first ownership of utility-scale renewable energy. The plant is scheduled to be online in late 2005 or early 2006. The second facility, Wild Horse, is located in Kittitas County, near Ellensburg and PSE's service territory. The plant could be online by the beginning of 2007. Further information on the RFP process was provided at the LCPAG meetings and in Appendix E.

**Exhibit IX-7: Wind Resources**

| UNITS | PSE OWNERSHIP | NAMEPLATE CAPACITY (MW) | ENERGY (aMW) |
|---|---|---|---|
| Hopkins Ridge | 100% | 149 | 52 |
| Wild Horse | 100% | 239 | 81 |
| **Total Wind** | | | **133** |

*Non-Utility Generators – NUGs*

The NUG supply consists of cogeneration plants that PSE contracted with in the early 1990s. The plants use natural gas, and supply steam to industrial "hosts" that use the steam energy in their production processes. All three of the plants are located in Skagit and Whatcom counties, in the northern part of PSE's service territory. Exhibit IX-8 lists PSE's NUG contracts.

**Exhibit IX-8: PSE NUG Contracts (2006)**

| NAME | CONTRACT EXPIRATION | ENERGY (aMW)[4] |
|---|---|---|
| March Point I | 12/31/2011 | 80 |
| March Point II | 12/31/2011 | 65 |
| Tenaska | 12/31/2011 | 224 |
| Sumas | 04/16/2013 | 133 |
| **Total** | | **502** |

- ***March Point Phase I & II (Gas-fired Cogeneration)* –** On June 29, 1989, PSE executed a long-term contract (through December 31, 2011) to purchase the full output of March Point Phase I, beginning October 11, 1991, from the March Point Cogeneration Company (March Point). March Point owns and operates the facility. On December 27, 1996, PSE executed a second contract (having a term co-extensive with the first contract) to purchase output of a second facility known as March Point Phase II. Both plants are located at the Texaco refinery in Anacortes.

- ***Tenaska Cogeneration (Gas-fired Cogeneration)*** – On March 20, 1991, PSE executed a long-term contract to purchase the output, beginning in April 1994, from Tenaska Washington Partners, L.P., which owns and operates the project near Ferndale. In December 1997 and January 1998, PSE bought out the project's existing long-term gas supply contracts, which contained fixed and escalating gas prices that were well above

[4] Energy (aMW) is expected annual average capability adjusted for forced outage rates and scheduled maintenance.

current and projected future market prices for natural gas. PSE became the principal natural gas supplier to the project, and power purchase prices under the Tenaska contract were revised to reflect market-based prices for the natural gas supply.

- ***Sumas Energy Cogeneration (Gas-fired Cogeneration)* –** On February 24, 1989, PSE executed a long-term contract to purchase from Sumas Cogeneration Company, L.P., which owns and operates the project located in Sumas, Wa.

*Other Long-Term Contracts*

The next portion of PSE's portfolio consists of long-term contracts that range in capacity from a few megawatts to three hundred megawatts. The group consists of a mix of contracts with independent producers and contracts with other utilities. The fuel sources include hydro, gas, waste products, and system purchases without designated supply resources. Most of the contracts will expire by 2011. Long-term contracts with independent producers provide approximately 39 aMW, and long-term utility contracts will contribute approximately 189 aMW in 2006. PSE's energy trading group procures short-term contracts (less than one year), which are not included as long-term resources. Exhibit IX-9 lists PSE's long-term contracts with independent producers, and Exhibit IX-10 lists PSE's long-term contracts with other utilities.

**Exhibit IX-9**
**PSE Long-Term Contracts with Independent Producers**

| CONTRACT | TYPE | EXPIRATION | CAPACITY (MW) | ENERGY (AMW) |
|---|---|---|---|---|
| Port Townsend Paper | Hydro-QF | 12/31/2008 | 0.4 | < 1 |
| Hutchison Creek | Hydro-QF | * | 0.9 | < 1 |
| Puyallup Energy Recovery Co.(PERC) | Biomass-QF | 4/18/2009 | 2.8 | 1 |
| Spokane Municipal Solid Waste | Biomass-QF | 11/15/2011 | 22.9 | 16 |
| North Wasco | Hydro-QF | 12/31/2012 | 5 | 4 |
| Kingdom Energy-Sygitowicz | Hydro-QF | 2/2/2014 | 0.4 | < 1 |
| Weeks Falls | Hydro | 12/1/2022 | 4.6 | 1 |
| Koma Kulshan | Hydro | 3/1/2037 | 14 | 5 |
| Twin Falls | Hydro | 3/8/2025 | 20 | 8 |
| Nooksack Hydro | Hydro | 11/30/2013 | 3 | 3 |
| **Total** | | | | **39** |

* Contract re-negotiation in progress.

**Exhibit IX-10**
**PSE Long-Term Contracts with other Utilities**

| CONTRACT | TYPE | EXPIRATION | CAPACITY (MW) | ENERGY (AMW) |
|---|---|---|---|---|
| Powerex/Pt.Roberts | Hydro | 9/30/2007 | 8 | 2 |
| Baker Replacement | Hydro | 10/1/2006 | 7 | 1 |
| PG&E Seasonal Exchange-PSE | Thermal | Ongoing* | 300 | 0 |
| Conservation Credit - SnoPUD | Hydro | 2/28/2010 | 12 | 11 |
| Northwestern Energy Company | Colstrip | 12/29/2010 | 97 | 80 |
| BPA- WNP-3 Exchange | Various | 6/30/2017 | 82 | 47 |
| Canadian EA | Hydro | 12/31/2025 | -60 | -37 |
| Arizona Public Service | Coal | 12/31/2006 | 85 | 85 |
| **Total** | | | | **189** |

*May be terminated with issuance of 5-year notice.

- ***BPA Baker Replacement.*** PSE and the U.S. Army Corps of Engineers signed a letter of intent to enter into a 20-year agreement which calls for PSE to provide flood control for the Skagit River Valley by reducing the level of the reservoir behind the Upper Baker hydro project between October 15 and March 1. During periods of high precipitation and run-off, the water can be stored in the Upper Baker reservoir and released in a controlled manner to reduce downstream flooding. In return for providing flood control, PSE receives power from BPA during the months of November through February to compensate for the lower generating capability caused by the reduced head at the plant.

- ***BPA Snohomish Conservation Contract*** (Term from March 1, 1990, to February 28, 2010). This agreement, the Conservation Transfer Agreement, is a system-delivery, not a unit-specific, purchased power contract. Snohomish PUD, together with Mason and Lewis County PUDs, installed conservation measures in their service areas. PSE receives an equivalent amount of power saved over the expected 20-year life of the measures. Under the contract, BPA delivered the power to PSE through the year 2001. PSE then continues to receive the power from Snohomish County PUD for the remaining life of the conservation measures.

- ***BPA – WNP-3 Bonneville Exchange Power (BEP)*** (Term from January 1, 1987, to June 30, 2017). This is a system-delivery, not a unit-specific, purchased power contract. PSE and the BPA entered into an agreement settling PSE's claims resulting from BPA's action in halting construction on nuclear project WNP-3, in which PSE had a 5 percent interest. Under the settlement agreement, for a period of 30.5 years beginning January 1, 1987, PSE receives a certain amount of power from BPA, as determined by a formula and depending on the equivalent annual availability factors of several surrogate nuclear plants similar in design to WNP-3.

- ***Canadian Entitlement Return****.* Pursuant to the 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 upon its participation percentage in the Columbia River projects. In 1997, PSE entered into agreements with the Mid-Columbia PUDs which specify PSE's share of the obligation to return one-half of the firm power benefits to Canada beginning in 1998 and continuing until the expiration of the PUD contracts or 2024, whichever occurs first. Note that the energy listed in the table is negative since this represents power PSE provides.

- ***NorthWestern Energy (formerly the Montana Power Company) 20-Year Contract*** (Term from October 1, 1989, to December 29, 2010.) This is a unit-specific purchased power contract tied to Colstrip Unit 4. The contract specifies capacity payments for each year, subject to reductions if specific performance is not achieved.

- ***Pacific Gas & Electric Company Seasonal Exchange.*** This is a system-delivery, not a unit-specific, purchased power contract. Under this agreement, 300 MW of capacity, together with 413,000 MWh of energy, is exchanged every calendar year on a one-for-one basis. PSE provides power to Pacific Gas & Electric (PG&E) during the months of June through September, and PG&E provides power to PSE during the months of November through February (PSE is a winter-peaking utility, while PG&E is a summer-peaking utility.).

- ***Powerex 5-Year Purchase for Point Roberts*** (Currently extended to September 30, 2007) Powerex delivers electric power to serve the retail customers of PSE within the boundaries of Point Roberts, Washington. The Point Roberts load, which is physically isolated from PSE's transmission system, connects to British Columbia Hydro's electric facilities. PSE pays a fixed price for the energy during the term of the contract.

## B. Green Power and Community Program

*Green Power Program*

Beginning in January 2001, Washington state law required the 16 largest of the state's electric utilities to provide customers with the opportunity to voluntarily purchase their retail electricity from qualified renewable energy resources; i.e., green power. PSE currently supplies the green power option for its customers primarily by purchasing renewable energy credits, called green tags, from the Bonneville Environmental Foundation (BEF), a nonprofit environmental organization located in Portland. Customers can purchase green power in 100 kWh blocks for $2 per block with a two-block minimum and the option to purchase multiple blocks.

The Company has recently broadened its efforts in relation to customer-focused renewable energy by setting goals for customer participation in the Green Power Program. In 2004, the Company added 4,619 new customers to the Green Power Program for a total of 14,074. Of these, 13,794 are residential and 280 are business customers. PSE's green power customers purchased just over 46,110 megawatt hours of green power in 2004.

PSE's Green Power Program efforts and outreach have received both local and national recognition. The Department of Energy, the Environmental Protection Agency and the Center for Resource Solutions presented PSE with the Beacon Award, and the Green Power Program was a contributing factor to PSE's receipt of NWEC's Eagle Award.

*Community and Small Scale Renewables Program*

PSE has initiated several processes to encourage development of small-scale renewable generation projects. These included implementation of a residential solar rebate program, increasing limits under our net-metering tariff, and an additional agreement with BEF to assist in the screening and development of projects utilizing a portion of PSE's conservation and renewable discount credits from the BPA.

Several proposed small-scale renewable projects were discussed and reviewed in 2004. PSE became directly involved with three projects that were constructed or partially constructed in PSE's service area in 2004. Two are solar "demonstration" projects, and one is an animal waste-to-energy project.

The first solar project is a 10-kilowatt system that was installed at the Puget Sound Electrician Joint Apprenticeship Training Center (PSEJATC) in Renton. The new solar electric system will allow PSEJATC to expand its program and improve curriculum by offering hands-on solar installation training. PSEJATC is committed to expanding the system by 5 kilowatts each year as part of its training program. The project also will substantially increase the number of electricians qualified to design and install solar power systems, relieving a critical bottleneck to regional expansion of this technology. PSE funded 50 percent of this project using conservation and renewable discount (C&RD) credit dollars.

The second solar project, located at the Washington State Legislative Building in Olympia, was installed in conjunction with the $118 million Legislative Building rehabilitation project. The 18.6-kilowatt system is only the second such project involving a state capital building in the United States and it is the largest. This project demonstrates solar system installation compatibility with historic preservation standards for this type of building. PSE made a monetary contribution using a portion of the Company's C&RD credits, and provided content for the project's informational kiosk. Other partners were BP Solar and Chelan County PUD.

The third small-scale renewable construction was the Vanderhaak dairy animal waste-to-energy project (anaerobic digester) in Lynden, Washington. This project is the first of its kind in the state. Anaerobic digesters have been called a "solution that leads to more solutions" for many of the environmental and economic problems facing the dairy industry today. Anaerobic digesters convert waste materials, such as dairy manure, into renewable energy and other value-added products. In addition, anaerobic digestion of dairy manure reduces odor problems, improves water quality and reduces methane emissions (a potent greenhouse gas linked to global climate change). This 350-kilowatt project uses dairy manure from approximately 1,500 cows and is anticipated to generate enough energy to serve 180 homes.

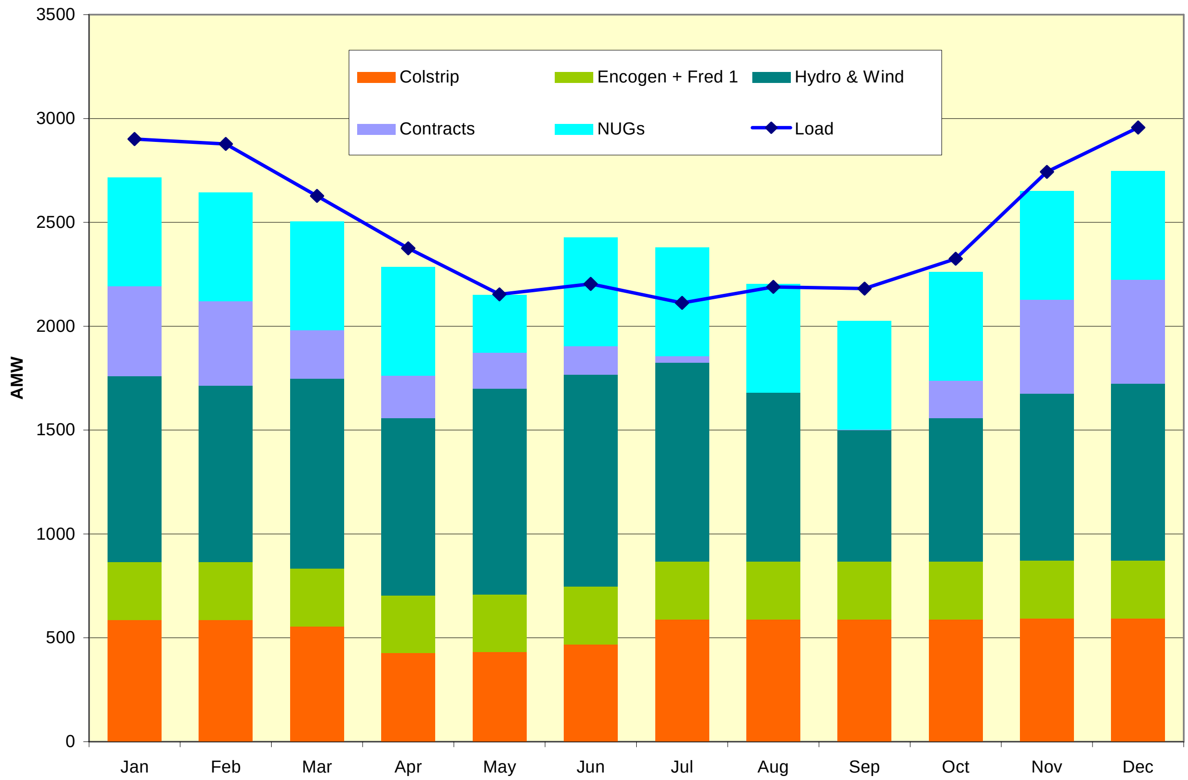
Also in 2004, PSE implemented a Solar Rebate Program, which provides residential electric customers up to $650 per installed kilowatt of Photovoltaic (PV) solar system installed. In 2004 this program provided rebates to 15 customers totaling over $16,000.

Finally, PSE increased the maximum project size allowable under its net-metering tariff, Schedule 150, from 25 to 50-kilowatts. As of December 2004, there were 47 customer generators connected to PSE's system under Schedule 150, for a total of 115.62 kW. Of the total, 44 are solar photovoltaic installations and 3 are micro hydro. Twenty of the 44 solar customer generators were connected in 2004.

## C. Load Resource Balance

Load resource balance shows the level of demand for power from PSE's customers, and the supply of available resources required to meet that demand. In this plan, PSE continues to use the standard developed in the previous Least Cost Plan, that of meeting energy needs for all months and planning for a peak load on a 16 degree day. Energy need is defined as the difference between the average monthly load and the average monthly expected or available energy. PSE's energy resources include both owned and contracted resources aggregated as Contracts, NUGs, Colstrip, Hydro & Wind, and Encogen & Fred 1. PSE's resources are currently shaped to provide more energy in the winter and less in the summer to better match the shape of the load. Nevertheless, as illustrated in Exhibit IX-11, the load shape is more varied than the resource shape. This results in a summer surplus and a winter shortage.

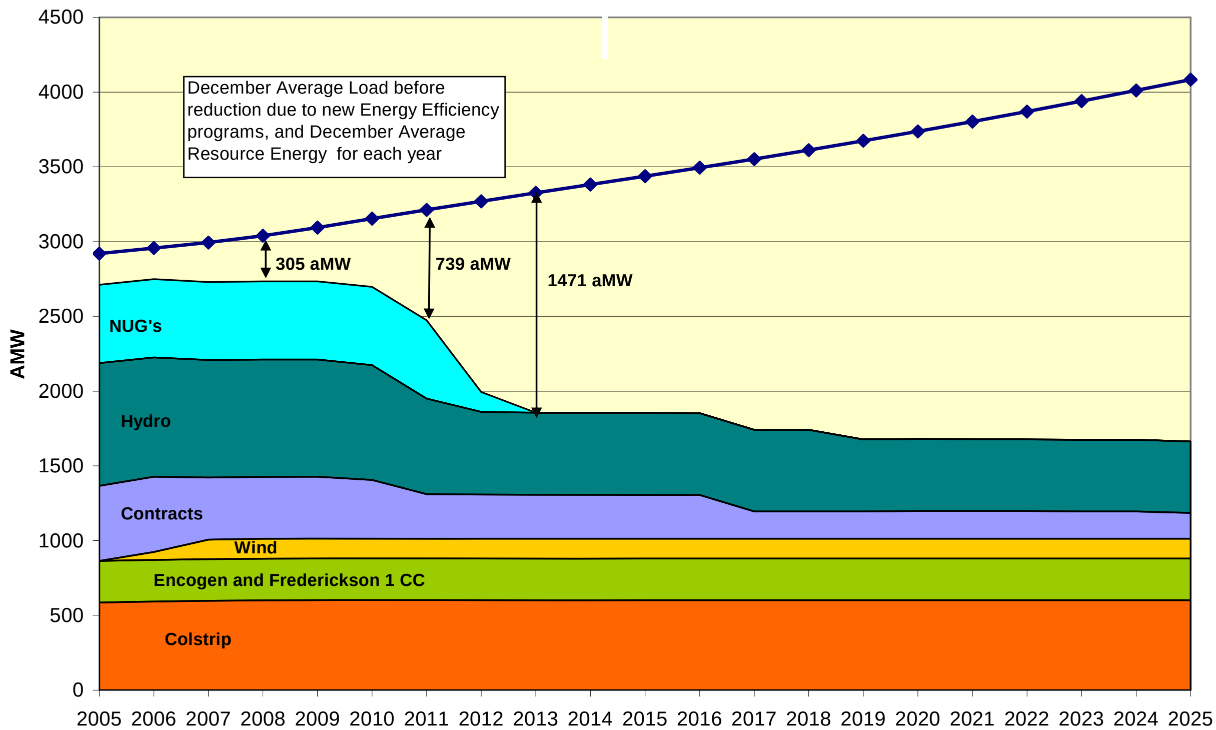
**Exhibit IX-11**
**2006 Monthly Average Energy Load Resource Balance**




Because the summer surplus offsets the winter shortage, PSE's annual average need is small in 2006. However, the summer surplus cannot realistically be stored for winter use. Meeting the need for all months is equivalent to meeting the need for the worst month, typically December of each year. Over time, the load-resource imbalance increases as the load grows and contracts expire.

Exhibit IX-12 shows the load resource balance from year-to-year based on the December average for each year. The gap between the load line and the stack of available resources portrays the "need" for new resources. As the chart clearly illustrates, the need comes from a combination of increasing load and contract terminations over time. The need is 305 aMW in 2008, increasing to 739 aMW in 2011, and 1,471 aMW in 2013. During this period, the load increases approximately 60 aMW per year without new energy efficiency programs.

**Exhibit IX-12: 2006-2025 Annual Load Resource Balance**
**Level B2 Standard, December Each Year**




*Energy from Resources*

Assumptions about the availability of energy from PSE's portfolio play an important role in the load-resource balance equation. Colstrip provides baseload energy with a known maintenance period. Hydro power assumes a 60-year average output from the Northwest Power Pool and is shaped to provide maximum peak energy. PSE's contract with the Chelan Public Utility District is set to expire in 2012. For modeling purposes only, PSE assumes that the contract with Chelan is extended, but at only one-half of the last year's contract portion of the resource. For the NUG contracts, generation technology has advanced, making these resources relatively inefficient compared to the market. Therefore, the Company has made no assumption about renewals upon their termination in 2011 and 2012. Prior to contract expiration they are modeled at their baseload capability and a 5 percent forced outage rate. Encogen and Frederickson 1, PSE's owned gas-fueled combined cycle plants, are modeled with their baseload capability and a 5 percent forced outage rate. The Company's simple cycle peakers are not included for energy, but are included in peak capacity planning. Lastly, most contracts have specific expiration dates with the exception of the PG&E Exchange, which continues year-to-year and has a 5-year notice of termination. Some of the larger contracts terminating in the study period include APS in 2006, Montana Power in 2011, and WNP-3 BPA Exchange in 2017.

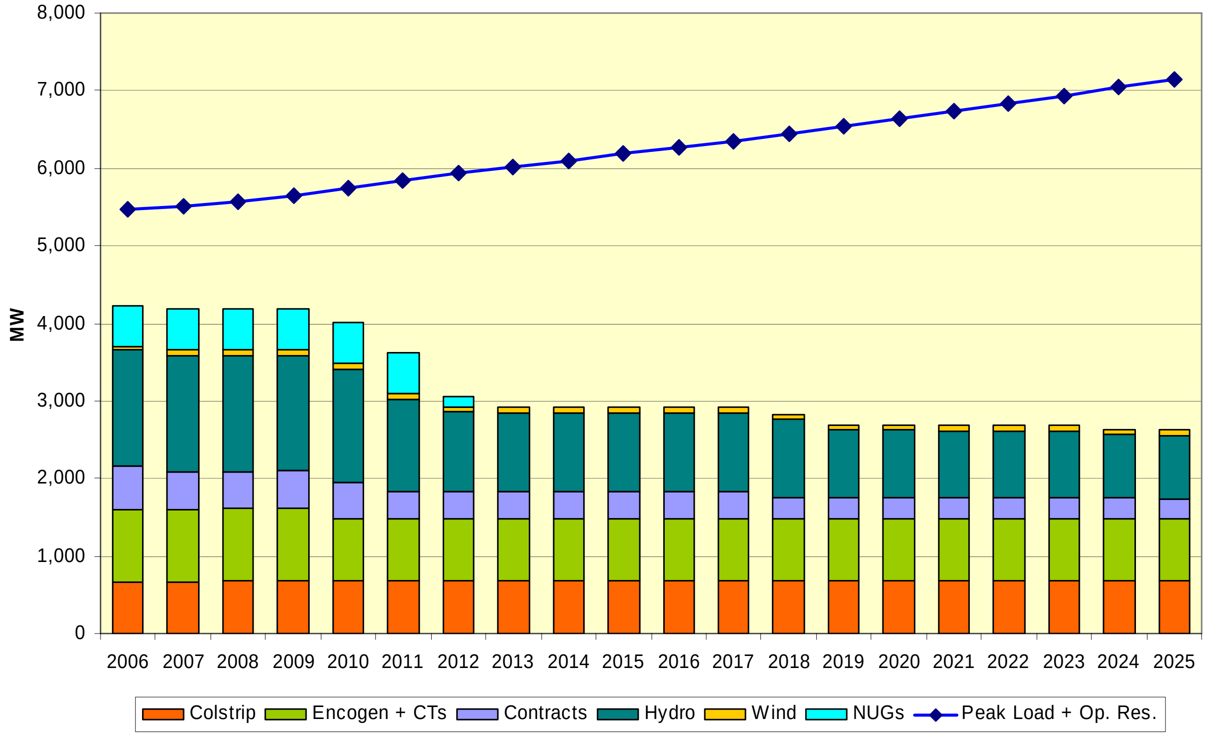
*Peak Capacity Needs*

The peak planning standard focuses on the highest demand hour of the year to compare load (in megawatts) to available resources. As with energy demand, peak load grows each year as the number of customers in PSE's service territory increases. PSE is winter peaking with peaks driven by temperature-dependent loads such as heating. The peak load forecast, therefore, includes both a forecast of the customer base, and an estimate of how much power would be used at a temperature of 16 degrees.

Resources are constrained by regional operating reserve requirements (from the Western Electricity Coordinating Council) of the greater of the largest single contingency or 7 percent for thermal units plus 5 percent for hydro units. Half of the reserve requirement must be provided as spinning (instantaneously available) reserves with the balance being carried as supplemental reserves. The reserve requirement in effect raises the peak resource requirement to take into account possible forced outages.

Resources available to meet peak capacity include hydro, contracts, NUGs, Colstrip, and PSE's gas-fueled turbines, including the simple cycle peaking units (These units are listed in section A.). Exhibit IX-13 illustrates the long-term gap between firm resources and peak demand. For peak modeling purposes new resources are assumed to need a 7 percent operating reserve, which is added into the peak load forecast.

**Exhibit IX-13**
**Peak Demand-Resource Balance**




Currently the region is long for winter peak capacity, (according to both the Northwest Power and Conservation Council and the Pacific Northwest Utilities Conference Committee) and PSE relies on its short-term Power Supply Operations to meet customer needs on an expected peak basis. In planning for winter peak needs, PSE uses a balanced approach including fixed and index-priced contracts for seasonal firm power; call options that cover the months of November, December, January and February; and leaving part of the possible load for market purchases.

# X. ELECTRIC ANALYSIS AND RESULTS

This chapter describes the analytical process and assumptions PSE used to develop its long-term electric resource strategy for the 20-year planning period. It begins with a discussion of the analytical methodology and planning standard used in the electric planning process. This is followed by an overview of generic new generation alternatives. Next, PSE presents the five power price forecasts created using the AURORA model, which correspond to each of six scenarios analyzed in this least cost planning process (two scenarios use the same power price forecast). Section D describes the benefits of scenario analysis, including brief summaries about each of the six scenarios and the use of probabilistic analysis. A summary table is provided to outline the key assumptions for each scenario. Section E offers a detailed discussion of electric generation and energy efficiency portfolios. The chapter concludes with quantitative findings and the identification of the theoretical "best" portfolio.

## A. Electric Methodology

The Least Cost Plan process establishes a methodology for evaluating resource portfolios. This methodology is used both in the generic least cost planning process and for evaluating specific resource acquisition opportunities. The following section describes the electric planning process.

*Analysis Process Objectives*

PSE strives to continually improve its least cost planning analytic process. The main analytic objectives of this Least Cost Plan are to:

- Reflect lessons and results of the 2004 resource acquisition process.
- Develop an analytical approach to properly assess the impacts of key uncertainties.
- Test major resource portfolio options.
- Facilitate open, well-documented decision-making that includes both quantitative and qualitative factors.
- Integrate energy supply resources and demand-side management in the analytic process.
- Identify the least-cost mix of supply resources and demand-side resources.

*Analytical Process Stages*

In order to achieve the Company's least cost planning objectives, PSE developed a deliberate and thorough analytical approach. In keeping with the overall goal to develop an executable plan, PSE's analytical approach addresses major industry uncertainties and key lessons from the 2004 resource acquisition process. The process followed these stages:

| | |
|---|---|
| 1. | Examine planning environment and identify key industry trends and drivers |
| 2. | Design analytical approach |
| 3. | Develop major input assumptions and forecasts |
| 4. | Determine PSE's need for new resources |
| 5. | Develop scenarios to evaluate key elements of uncertainty |
| 6. | Construct portfolios to analyze major resource options |
| 7. | Analyze supply resource portfolios |
| 8. | Analyze energy efficiency and fuel conversion potential |
| 9. | Identify final resource portfolio |

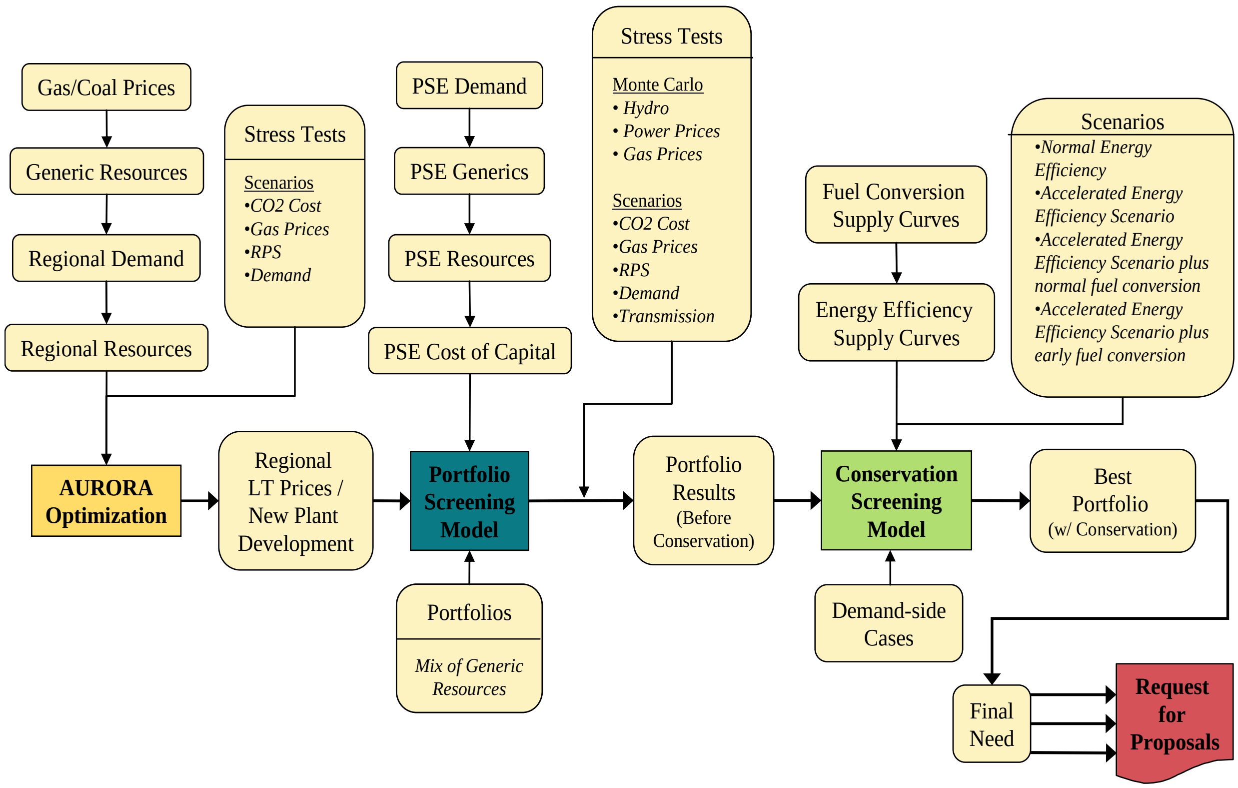
**Stage 1- Examine Planning Environment and Identify Key Industry Trends and Drivers.** Chapter VIII includes an expansive discussion of the planning environment and key issues. These key issues introduce uncertainty, and they impact the cost and availability of resources.

**Stage 2- Design Analytical Approach.** PSE elected to analyze the key issues using a scenario approach. This approach was selected because of the magnitude of the key issues and because many of the uncertainties are independent (i.e. availability of transmission is not dependent upon gas prices or greenhouse gas regulation). Since each of the scenarios represents a unique future, PSE developed a consistent set of input data for each.

Each scenario was analyzed using electric market simulation models. PSE uses three primary models for least cost planning. The AURORA model analyzes the western power market to produce hourly electricity price forecasts. The Portfolio Screening Model (PSM) tests portfolios to evaluate PSE's long-term incremental portfolio costs. Finally, the Conservation Screening Model (CSM) tests demand-side resource cases to determine the most cost effective level for a given generation portfolio. Appendix C provides more detail about the electric models.

Exhibit X-1 shows the integration of the major process stages and models.

**Exhibit X-1**
**Analytic Process for Least Cost Planning**




**Stage 3- Development of Major Input Assumptions and Forecasts.** The AURORA model and the PSM require inputs for demand, fuel prices, power prices (PSM only), existing and new resource costs, and operational characteristics. The input assumptions to the models are both regional and specific to PSE. PSE used Cambridge Energy Research Associates' (CERA) natural gas price forecasts from December 2004 for this Least Cost Plan. Chapter V discusses the gas price forecasts in detail. Generic plant costs and operational characteristics were developed from analysis of EIA data, resource acquisition bids, and other data sources. Chapter VI describes the methodology PSE uses for load forecasting.

**Stage 4- Determination of PSE's Need for New Resources.** For its 2003 Least Cost Plan, PSE performed extensive analyses on eight planning levels to meet energy and capacity need. The final result of the analyses was the selection of the level "B2" planning standard – energy resources to meet the average energy need for the highest winter month and peak resources to meet capacity needs at 16ºF. This planning standard was chosen as a result of cost and risk tradeoffs (see Chapters XI and XII of the 2003 Least Cost Plan). The definition of need determined in 2003 is still applicable and has, therefore, been used by PSE for the current Least Cost Plan.

Using this definition, PSE compared its forecast load requirements against existing resources to determine the need for acquisitions.

**Stage 5- Development of Scenarios to Evaluate Key Elements of Uncertainty.** Scenarios were developed with a consistent set of assumptions for transmission costs, carbon costs, renewable portfolio standards (RPS), gas prices, electric prices, and electric demand to evaluate key issues of uncertainty that affect PSE resource acquisition decisions. Scenarios were first run in AURORA to produce a scenario-specific forecast of regional electric market prices.

The use of scenarios allows PSE to quantify the uncertainty resulting from the key issues. Examining how portfolios perform across a range of scenarios provides insight into how resources perform under different conditions over 20 years.

**Stage 6- Construction of Portfolio to Analyze Major Resource Options.** A portfolio is a distinct set of generic resources over the planning period. For the Least Cost Plan, PSE creates a variety of portfolios with different mixes of coal, natural gas, renewables, and other resources. These portfolios include generic plants with known costs and operational characteristics. Each portfolio is analyzed against the scenarios, using the PSM.

**Stage 7- Analyze and Select Least Cost Portfolio of Supply Resources.** PSE employs the PSM to evaluate resource portfolios. PSM calculates the economic dispatch for existing and potential new PSE resources against hourly power prices from AURORA scenarios. The model derives a comparative incremental cost to customers for a particular resource portfolio by combining the variable cost of dispatch from the existing dispatchable fleet, the cost of net market purchases, and the revenue requirement for the new resource portfolio. The 20-year present value of these costs discounted at PSE's cost of capital is referred to as the portfolio cost (expressed in millions of dollars).

To compare scenario results, the portfolio cost is divided by the load to express values in dollars per megawatt hour. The unit cost makes relative comparisons of outcomes when scenario load levels vary. It is important to note that the portfolio cost does not equal total power costs because it does not include the capital or fixed operating costs for PSE's existing resources.

For each of the six scenarios, the developed generic resource portfolios are run through PSM. PSM supports Monte Carlo variation of hydro production, gas prices, and electric market prices. Model results without Monte Carlo variation (static mode) provide a point estimate of the incremental portfolio cost. From the static results, PSE can identify the best portfolio within a given scenario and compare portfolios across all scenarios. Model results with Monte Carlo variation (dynamic mode) provide an expected value and a range of outcomes. The Monte Carlo analysis identifies incremental portfolio cost estimates within a 90 percent confidence interval and creates a risk measure based upon the average of the 10 percent worst outcomes. The objective is to identify the least cost portfolio considering both cost and risk. PSE is most concerned with the risk of higher costs for its customers.

With uncertainty around many of the key variables, a single portfolio may not always be the lowest cost and lowest risk. The goal is to find a portfolio that performs well across the range of futures, and to identify areas of uncertainty that have the greatest impact on portfolio selection.

**Stage 8- Analyze Energy Efficiency and Fuel Conversion Potential.** After the generating resource portfolio is selected, the Conservation Screening Model (CSM) is used to determine the best level of demand-side resource. Thousands of demand resource portfolios with energy efficiency and fuel conversion are tested in the CSM. It builds on the PSM and integrates demand-side resource to find the level of conservation that produces the lowest portfolio cost.

**Stage 9- Identification of Final Resource Portfolio.** The integrated result of portfolio and conservation modeling is the theoretical best resource portfolio.

## B. New Generation Alternatives

*New Resource Choices*

There are numerous technically feasible generating technologies available to PSE as new resources. The resources modeled in the PSM represent generic resources that could reasonably be included in PSE's portfolio. Supply-side resources include combined cycle combustion turbines (CCCTs) fueled by gas; thermal plants fueled by coal; renewable energy, including wind and biomass; power bridging agreements and a winter call option contract to cover winter peak energy needs. Demand-side resources include numerous individual energy efficiency measures that were bundled into 17 supply curves; and residential fuel conversion where, for example, electric heaters are replaced with gas-fueled heaters.

One previously modeled resource was seasonally shared to provide PSE with winter energy without further increasing summer length. From the 2003-04 competitive resource acquisition process, it appears that the market potential for a shared resource is unlikely. Therefore, a seasonally shared resource is not considered in this plan as a generic resource. PSE recognizes that there is value in a seasonally shaped resource, and that one may be procured in a future acquisition process.

PSE has used information obtained from the request for proposal (RFP) and resource acquisition processes to inform the PSM. As a result, the Company was able to define a set of resources that included the relative cost of new resources. A primary source for information was the U.S. Department of Energy's Energy Information Agency's (EIA) table of "Cost and Performance Characteristics of New Central Station Electricity Generating Technologies" from the Annual Energy Outlook, 2004. The EIA provides basic information about plant characteristics at the national level, such as plant capacity, heat rates, capital costs, variable costs and fixed costs. This information was augmented with cost data gleaned from the recent resource acquisition process for capital costs, power transmission development and gas fuel transportation, among others.

Fuel prices for the gas turbines are based upon the CERA forecast and are discussed extensively in Chapter V. PSE considers a generic gas turbine to be located along the I-5 corridor, hence the CERA Sumas hub price needs to be increased to account for a pipeline commodity charge, fuel use, and tax. Coal prices were based upon an RFP response as well as PSE's knowledge of Powder River Basin coal where the company's Colstrip plant is located. The prices take into account market prices, heat content of the coal, and transportation costs.

*Gas-Fueled Combustion Turbines (CCCTs)*

The I-5 corridor of Puget Sound has numerous CCCTs in place along the Northwest Pipeline. PSE owns some CCCTs in this region and has contracts for the output of others. A new generic plant of 400 MW capacity could be an expansion of an existing simple-cycle combustion turbine site; the expansion, upgrade or development of a cogeneration facility; or a greenfield location.

For modeling, the site is assumed to be in PSE's service territory and includes costs that would be applicable to any new development. The gas fuel cost starts with the Sumas hub price from CERA, then adds a fixed cost for firm delivery on Northwest Pipeline and a commodity charge, fuel usage, and tax. Since the facility is local, the gas plant cost assumes no new transmission lines need to be built; however, there is a fixed electric transmission charge for connecting in the PSE control area, as well as a small variable charge. The capital cost for a plant built in Washington is slightly higher, taking into account the $CO_2$ charge (WAC 173-407) which is calculated as an upfront cost, not a pay-as-you-produce fee.

*Coal*

The generic coal plant for the model represents a new scrubbed mine-mouth facility in Montana with a capacity of 600 MW and a heat rate of 9,274 Btu/kWh. The coal comes from the Powder River Basin, which is the least expensive source area identified by the EIA. PSE's coal price reflects both the current market and some conveyance from mine to plant.

Unfortunately, there is currently no firm transmission available to bring power from Montana to the Puget Sound area. The cost of building new transmission facilities by generation participants to overcome constraints between Montana and PSE has been estimated by PSE to be over $1 billion. PSE anticipates that such facilities would not be available until 2016. Alternatively, there is the possibility of a regional transmission solution with system-wide rates, with availability in 2013 at the earliest. In all cases, the analysis assumes coal-fueled energy is not available until new transmission is constructed.

The low cost of coal makes it an attractive resource. The largest coal plant cost risks are potential carbon and greenhouse gas emissions restrictions and their associated costs, and the availability or construction of transmission. Two of the scenarios, Current Momentum and Green World, apply specific charges to $CO_2$ output.

*Wind*

Because PSE is directly involved with two wind projects in Washington state, the generic resource costs reflect recent direct experience. As discussed in the transmission section, PSE estimates that the Company may be able to double its wind generating capacity (from 5 percent to 10 percent of load) without further transmission upgrades. To get to 15 percent of load (under a renewable portfolio standard, for example) would require transmission upgrades with a large fixed cost. Because wind energy output is not dispatchable, day-ahead and hour-ahead integration costs are particularly important to wind power generation. As additional wind energy is added to a system, the integration cost increases. Currently the estimated integration cost is in the $4/MWh range (for more information, refer to Appendix D).

Before new transmission is completed, the fixed operations and maintenance (O&M) charge of $50/KW/yr is based on new developments and includes both fixed O&M as well as fixed transmission costs. When new transmission is considered, the fixed O&M is the sum of the new transmission fixed charge and the fixed O&M from EIA. EIA uses a plant capacity of 50 MW, while PSE uses 150 MW (which is large enough to provide economies of scale). PSE uses a capital cost 14 percent higher than EIA based on knowledge of costs for this region. One of the risks associated with wind plants involves obtaining an accurate estimate of the wind energy production, as there is little historical data. The second risk is that the federal tax credit is currently necessary to make these plants economic. In the model, the tax credit is reduced over the 20-year period to zero.

*Biomass*

A renewable energy alternative to wind is biomass using either wood waste or agriculture waste. PSE received some biomass energy bids in the all-source RFP, and is currently involved in a small biomass project at a dairy. The energy is created by burning methane gas in any of a number of turbine configurations. Collecting and producing methane gas from biomass is currently very expensive and an important area for improvement. For modeling, PSE includes biomass as an alternative because of the transmission limitations of wind projects. Although the capital cost is higher for biomass than for wind, it is offset by a much higher capacity factor (85 percent for biomass with a flat shape vs. 35 percent for wind with a highly variable shape). The risks involved in a biomass plant include the cost and continued availability of fuel.

*Power Bridging Agreements*

PSE is using the term “power bridging agreements” (PBAs) to designate power purchase agreements that bridge the period until long-lead resources or transmission can be developed. The load-resource balance shows that there is an immediate need for resources that continues to grow over time. The resources PSE models may not be immediately available or may require new transmission before becoming viable. The PBAs allow PSE to bridge the need before the resource is online. The PBAs also allow PSE to directly test delaying a resource. PBAs in the model are priced at a 5 percent premium for credit and liquidity costs over the market price forecast and include an appropriate transmission charge.

*Winter Call Options*

For modeling purposes, PSE has moved away from filling excess capacity need with simple-cycle peaker units, as this does not accurately reflect PSE operations. In planning for winter peak needs, PSE adopts a balanced approach that includes the use of existing simple-cycle gas peaking resources; contracts for seasonal firm power; call options that cover the months of November, December, January and February; and short-term market transactions. For modeling, PSE uses call options as a reasonable proxy for peak planning. The cost of the call option is a function of the spread between peak and off-peak prices using the AURORA Business as Usual (BAU) price forecast. In the model, the call premium is $14.60 per KW-season and escalates at 2.5 percent per year. The capacity option can be called when the market heat rate is greater than 12 MMBtu/MWh. The market heat rate and call premium were developed based on actual PSE purchases in previous peaking seasons.

*Resource Options Not Modeled*

For the purposes of testing generic portfolios in the Portfolio Screening Model, PSE only considered proven technologies with more certain costs and operational characteristics. PSE considered but did not analyze emerging technologies for which the costs are less certain because it would not provide an accurate cost tradeoff analysis.

PSE currently supports renewable energy including solar technology, wave technology and geothermal power with direct financial contributions or advice and regional participation. As of this time, all three of these technologies cannot cost-effectively be considered for utility-scale planning. PSE currently has contracts for energy generated from landfill gas and waste incineration. These resources have limited availability and site-specific costs making them less useful for generic modeling needs. Although nuclear energy is being considered for some new developments in other parts of the country, PSE has not considered it for the portfolio analysis this year. Some other gas-fueled technologies such as cogeneration plants and combined heat and power (CHP) were not judged as “generic” resources. These technologies capture waste heat and improve overall efficiency; however, the economics are very project specific because they require a steam host and negotiated terms.

PSE considered modeling in its portfolio analysis with two other generic coal technologies: integrated gasification combined cycle (IGCC) and IGCC with carbon sequestration. Currently, the IGCC technology owners can't provide generic cost estimates to PSE because the capital costs are specific to each fuel source, and development of a specific proposal requires significant preliminary engineering. As the industry gains more commercial experience with these plants, generic estimates will be more accurate. Until that time, model inputs and results would have an extreme range of uncertainty and would have only speculative value in choosing future resource portfolios. Similarly, carbon sequestration technology and costs have not been developed and tested on a commercially ready basis. PSE will continue to monitor and seek opportunities for these and other new supply resources as they become mature and cost-effective.

The following table lists the costs and operating characteristics of the generic resources used in the model.

## Exhibit X-2
## Summary of Generic Resources for PSM

| $2006 | Gas Turbine Periods 1 & 2 | Scrubbed Coal Period 2 Only | Wind Period 1 | Wind Period 2 | Biomass |
|---|---|---|---|---|---|
| **Capacity** | 400 MW | 600 MW | 150 MW | 150 MW | 80 MW |
| **Capital Cost** | $790/kW in WA | $1,672/kW | $1,438/kW | $1,438/kW | $1911/kW |
| **Heat Rate** | 6,711 Btu/kWh | 9,274 Btu/kWh | | | n/a |
| **Fuel** | CERA RVM | MT/WY $0.91/mmBtu | None | None | $10/MWh for fuel (waste) transportation |
| **FOR** | 5% | 10% | 68% | 68% | 15% |
| **Fixed Gas Transmission** | $25/kW-yr | | | | |
| **Fixed O&M** | $11.40/kW-yr | $27/kW-yr | $50.00/kW-yr includes transmission | $29.15/kW-yr | $51.30/kW-yr |
| **Fixed Electric Transmission** | $21.03 /kW-yr | | $0.00 / kW-yr Included in FOM | $0.00 / kW-yr Included in FOM | $15.00 / kW-yr |
| **Transmission Build [FOM]** | None | $99.60 / KW-yr[1] (2006 + 2.5% esc.) $31.81/KW-yr[2] (Regional) | None | $58.02 / kW-yr[1] (2006 + 2.5% esc.) $31.81/kW-yr[2] (Regional) | None |
| **Variable O&M** | $2.39/MWh | $3.42/MWh | $4.00/MWh Update for 400-450 total MW | $4.30/MWh Update for more than 450 total MW | $3.30 |
| **Fuel Basis Differential** | $0.359/mmBtu = $2.41/MWh | | | | $10/MWh for fuel transportation |
| **Emissions** | $CO_2$: 411 Tons/GWh | $CO_2$: 953Tons/GWh | None | None | None |

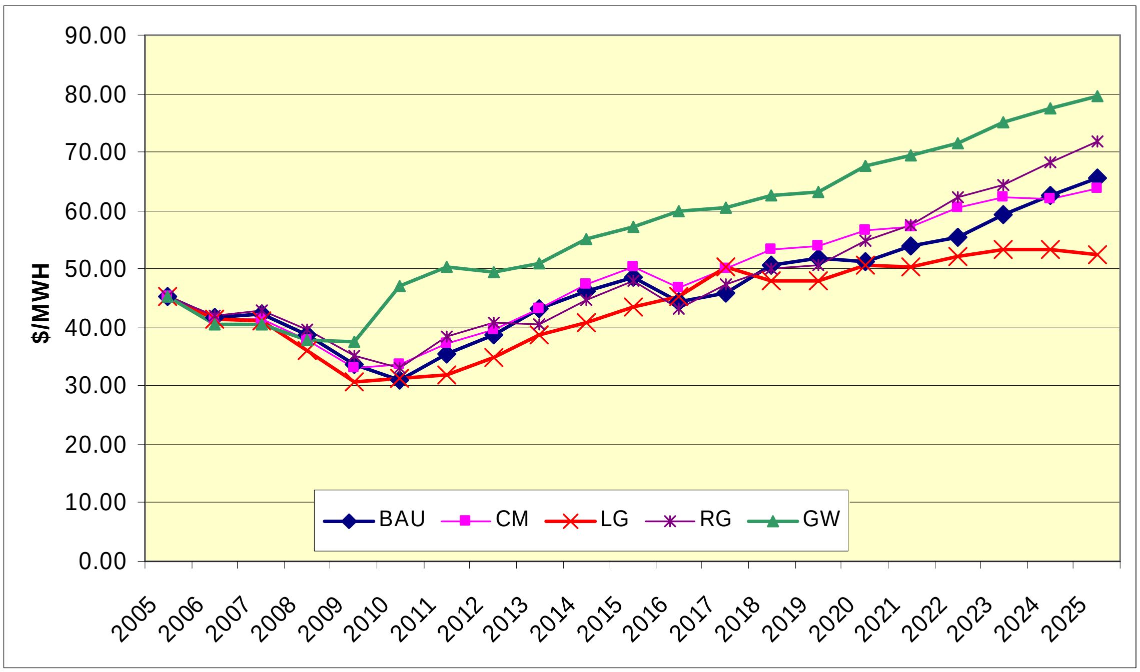
[1] Participant-funded transmission for BAU, CM, GW, LG and RG scenarios.
[2] System-wide rates for Transmission Solution scenario.

## C. Energy Price Forecasts

*Electricity*

Five power price forecasts were created using the AURORA model. One forecast was created for each of the scenarios except the Transmission Solution scenario, which uses the Business as Usual power price forecast. Each scenario is based on a set of assumptions that describe a possible future world (see the following section for more details about the scenarios). The prices represent the cost of dispatching the marginal resource in a Northwest market like the Mid-Columbia. Exhibit X-3 shows a comparison of the five AURORA price forecasts. Appendix C provides tables of monthly prices for all of the forecasts.

**Exhibit X-3**
**Electricity Price Forecasts by Scenario**




Demand for power in the Northwest and throughout the western United States is taken into account in the electricity price forecast. The database includes annual average growth rates for each area, which were compared to those used by the Northwest Power and Conservation Council and EIA. All growth rates are linear with no intertemporal changes (i.e. a growth rate could be 1.8 percent per year for 2005-2025 rather than reflecting a long-term pattern of slowing or increasing growth). For the Robust Growth and Low Growth scenarios, base growth rates were adjusted proportionately following PSE's high and low growth rate forecasts.

Demand for power is met with existing resources, planned new resources that are in the database with specific online dates, and future plants selected by the AURORA model using its optimizing algorithm. The AURORA database includes more than 3,000 existing plants in the WECC. Plants that are under construction and scheduled to be online in 2005 for gas plants, and in 2006 for coal and wind plants, are also included in the database.

Over time, energy demand grows beyond the capacity of PSE's existing plants, and the model brings new plants online using its optimizing process (further discussion of the optimizing process can be found in Appendix C). Also driving the development of new plants are renewable portfolio standards (RPS), which are mandated in many western states (Exhibit X-4). In total, these mandates require that thousands of megawatts of renewable energy capacity be added over the study period.

**Exhibit X-4**
**Renewable Portfolio Standards in WECC**

| State | RPS Standard |
|---|---|
| California | 20% by 2017 |
| Nevada | 15% by 2013 |
| Colorado | 10% by 2015 |
| New Mexico | 10% by 2011 |
| Arizona | 1.1% by 2007 |

An important input to an electric price forecast is a gas price forecast. As discussed in the gas price forecast (Chapter V), PSE relied on three CERA price forecasts created under different scenario assumptions. The CERA Rearview Mirror forecast is based on a scenario in which the future is much like the past. Rearview Mirror, therefore, was the basis for PSE's Business as Usual, Current Momentum and Transmission Solution scenarios. PSE's High Growth scenario also used CERA's Rearview Mirror forecast, while PSE's Low Growth scenario is based on CERA's low growth World in Turmoil forecast. Finally, PSE's Green World scenario used the Shades of Green forecast from CERA. Note that the forecasts are extrapolated beyond 2020.

Transmission between areas is another important factor in determining power prices. Transmission tends to equilibrate prices between areas as power moves from less expensive to more expensive areas. For example, the Northwest is a winter-peaking area. Yet prices are higher in the summer as more expensive resources are brought online to send power south to meet the greater demand in summer-peaking California. While the AURORA model will “build” new power plants to meet increasing demand, it does not have an algorithm for increasing transmission over time. The model includes “physical” transmission between areas, which is often greater than the “available” transmission on a contract basis. AURORA is not a transmission model and does not reflect contractual constraints. Hence, the Transmission scenario uses the Business as Usual AURORA price forecast and transmission builds are considered in the portfolio analysis.

AURORA hourly prices are capped at the $250/MWh level based on the FERC-mandated level from 2001. Since prices fall below $250/MWh for most hours, price caps don’t have much impact on average prices. Nevertheless, PSE uses an hourly dispatch model where a few hours of very high prices can make some resource decisions appear overly beneficial. Most of the highest priced hours occur in September, when hydro availability is low and summer demand is still high. Note that the $250 price cap is also used by the Northwest Power and Conservation Council.

## D. Uncertainty Analysis

*Electric Planning Scenarios*

One of the most important improvements for the quantitative analysis, compared to the previous Least Cost Plan, is the inclusion of scenarios. The shift to scenarios reflects current uncertainty about energy policy, environmental issues and the macro economy. In the 2003 Least Cost Plan, PSE analyzed uncertainty using Monte Carlo analyses that covered a range of possible prices, shaped around a mean or expected level. Monte Carlo uncertainty is based on quantifiable variability found in historical statistics for which a distribution can be derived. The 2005 Least Cost Plan continues the Monte Carlo analysis and adds an additional level of analysis with scenarios.

Benefits of scenarios are seen when changing events can drive costs and, therefore, the decision process and when probability distributions cannot be statistically defined and defended. Scenarios represent a fundamental change between the important issues that are observed today. For example, scenario analysis is appropriate for considering a renewable portfolio standard, where the passage of such legislation is possible but uncertain. On the other hand, Monte Carlo is appropriate for power prices where there is an expected level and a historical distribution.

One important aspect to scenario analysis is that it takes a holistic approach to the important variables. For example, rather than looking only at the impact of an exogenous $CO_2$ charge on portfolio resource selection, the process includes a long-term analysis for power prices based on optimal regional new resource construction which takes the charge into account. An important starting place for the scenarios is the three CERA gas price forecasts.

Exhibit X-5 at the end of this section provides a summary of the six scenarios PSE included in the analysis.

*Business as Usual*

The Business as Usual (BAU) scenario best represents current reality for gas and power prices, and for policy direction. This scenario is considered the least speculative about the future. It relies on the CERA Rearview Mirror gas price forecast as its foundation. The growth in demand for PSE and the western United States is "normal." The scenario considers only proven technologies for generation.

For renewables, it takes into account various renewable portfolio standards (RPS) that have been implemented in some western states by adding new renewable resources to the database over time. However, it follows the CERA assumption that some of these laws may be too ambitious in the long run, thus they are relaxed after 2011. Nevertheless, the RPS resources total 8,677 megawatts of renewable energy in the WECC. The PSE portfolio sets renewable capacity targets at 10 percent of load by 2013.

There is currently no carbon tax at the federal level to include in this scenario. It does take into account the Washington state carbon charge (P.L. 3141) and assumes this same level for Oregon's public service charge.

Transmission in the region is currently constrained in many places, making increased development of resources far from the load implausible. Hence, if more coal is to be included in the portfolio, this scenario adds the cost for new transmission facilities to the cost of the resource without regard to any benefits to the regional transmission system. The transmission constraint keeps coal out of the portfolio until 2015, at which point new coal is introduced with a transmission cost of over $99/kW/yr. Wind also requires more transmission if the portfolio is to go above the 10 percent renewable target.

*Current Momentum*

The Current Momentum (CM) scenario takes into account some of the possible or likely changes in policy toward renewable resources and carbon charges. In recent years there has been increased interest and support for a renewable portfolio standard for Washington state and Oregon, although opposition remains. This scenario includes a Washington state renewable portfolio standard of 10 percent of load by 2013. For federal carbon policy, PSE adopted the recommendation from the National Commission on Energy Policy of $5/ton of $CO_2$ starting in 2010 and increasing by 5 percent per year.[1] The CM scenario keeps the current fuel price forecasts and the current demand forecast unchanged from the BAU scenario. Transmission is funded by participants only, unchanged from the BAU scenario above.

*Green World*

The Green World (GW) scenario is significantly different from the BAU and CM scenarios. First, it starts with the CERA Green World natural gas price forecast, which assumes that pipelines from Alaska are not built, resulting in a much higher gas price. In this scenario, all WECC states meet their renewable portfolio standards. Washington and Oregon have an RPS of 10 percent by 2013, rising to 15 percent by 2020, for a total of 22,790 MW of renewable energy. Those renewable resource levels are also implemented by PSE.

At the federal level, the $CO_2$ charge is based on the Pew Center for Climate Change's summary of the MIT analysis of the McCain-Lieberman cap-and-trade bill. The Pew Center focuses on the MIT scenario which allows for the most market-oriented flexibility. This scenario assumes a $CO_2$ cost of $11/ton starting in 2010 and stepping up to $16/ton in 2015 and to $23/ton in 2020.

Note that the mandated RPS (in all areas) would have a cost that would be passed through to either taxpayers or ratepayers depending on the state's policy. Those costs, however, are not included in the market price, which is based on the marginal cost of the last resource. The RPS costs, along with all other new resource costs, are included in the PSE portfolio.

[1] Table 2-1, page 26, "Ending the Energy Stalemate," NCEP, December 2004

Exhibit X-3, “Electricity Price Forecasts by Scenario,” shows the GW scenario to have much higher energy prices than the other scenarios. This is a function of the higher gas prices and the carbon charge. Like the BAU scenario, transmission costs are participant-funded.

*Low Growth*

The Low Growth (LG) scenario, as the name implies, takes a less bullish view of electricity demand growth for PSE and the WECC. The electric demand growth rate for PSE is the Company’s forecasted low growth rate, which has an annual average growth rate of 1.2 percent compared to the base growth rate of 1.8 percent. In the AURORA model, each area has its own growth rates, which were reduced proportionately with the growth rates of PSE (e.g. a region with 1.5 percent growth rate was reduced to 1 percent.). The CERA forecast used in this scenario was The World in Turmoil. This forecast involves an economy in recession with low demand and therefore low gas prices. As with the BAU scenario, there is no new renewable portfolio standard in the Northwest and only the existing emissions charge is included. The transmission constraint keeps coal out of the portfolio until transmission is completed in 2015, at which point new coal is introduced at a cost of over $99/kW/yr. Exhibit X-3 shows that power prices under this scenario are lowest, reflecting low demand and low gas prices.

*Robust Growth*

The Robust Growth (RG) scenario was created to provide symmetry with the LG scenario. The annual average growth rate for PSE was increased from 1.8 percent to 2.3 percent and the growth rates for all areas within the WECC were also increased proportionately. As in the BAU and CM scenarios, the gas price forecast used in the RG scenario was the CERA Rearview Mirror. Again, as in the BAU scenario, there is no new renewable portfolio standard in the Northwest and only the existing emissions charge is included. The transmission constraint keeps coal out of the portfolio until transmission is completed in 2015, at which point new coal is introduced at a cost of over $99/kW/yr. Exhibit X-3 shows that the power prices under this scenario are similar to those in BAU and CM for the first 15 years, reflecting the gas price forecast.

*Transmission Solution*

The Transmission Solution (TS) scenario was created to analyze the limitations placed on development of new resources because of the region’s significant transmission constraints. Given the uncertainty regarding the ultimate form of a regional transmission solution and the cost recovery for transmission investments, PSE created two transmission cost estimates for the analysis. The previous scenarios assume direct participant funding wherein the costs of necessary transmission upgrades are added to the cost of the resource, without regard to the regional benefits to the transmission system. The TS scenario assumes regional pricing where upgrades are recovered through rolled-in-rates charged to all system users in recognition of the regional benefits.

The portfolio results of this scenario can be directly compared to the BAU scenario because the only difference is the cost and availability of transmission and because the TS uses the BAU power price forecast. A regional transmission solution with the cost spread over all electric power entities is much less expensive than the participant (PSE)-funded process in the BAU and CM scenarios. For example, the cost of new transmission facilities to relieve constraints from Montana to Sammamish has been estimated at over $1 billion. If funded by PSE, without credit for any regional transmission benefit, the fixed cost of the transmission would be $99/kW/yr in 2006 dollars. A regional transmission solution where system expansions are funded by system-wide wheeling rates would cost $31.81/kW/yr. In 2006 dollars, transmission for increased wind energy capacity from Columbia County to Sammamish would have fixed costs of $58/kW/yr if participant-funded, whereas a regional transmission solution is assumed to cost $31.81/kW/yr.

**Exhibit X-5**
**PSE 2005 Least Cost Plan**
**Scenario Input Assumptions**

| | **Business as Usual** | **Current Momentum** | **Green World** | **Transmission Solution**[4] | **Low Growth** | **Robust Growth** |
|---|---|---|---|---|---|---|
| **Scenario Theme: An energy future assuming...** | Existing environmental and regulatory environment | Current environmental regulatory and policy momentum is enacted | Strong state and federal policy supporting environmental issues | Regional transmission solution and system-wide rates | Low economic growth | High economic Growth |
| **Electric Demand** | Base Region and PSE | Base Region and PSE | Base Region and PSE | Base Region and PSE | Low Growth Region and PSE | High Growth Region and PSE |
| **Gas Prices** | CERA Rear view mirror | CERA Rear view mirror | CERA Shades of Green | CERA Rear view mirror | CERA World in Turmoil | CERA Rear view mirror |
| **Coal-Fired Generation** | Scrubbed pulverized coal plants available except CA | Scrubbed pulverized coal plants available except CA | Mitigated coal plants become available in 2010. | Scrubbed pulverized coal plants available except CA | Scrubbed pulverized coal plants available except CA | Scrubbed pulverized coal plants available except CA |
| **Renewables**[5] | No WA/OR RPS. WECC States meet goal in 2011 then economics decide. PTC decline linearly over planning period. | WA/OR passes RPS at 10% by 2013. WECC States meet goal in 2011 then economics decide. PTC decline linearly over planning period. | WA/OR passes RPS at 10% by 2013 going to 15% by 2020. WECC States meet RPS goals for entire planning horizon. PTC decline linearly over planning period | No WA/OR RPS. WECC States meet goal in 2011 then economics decide. PTC decline linearly over planning period. | No WA/OR RPS. WECC States meet goal in 2011 then economics decide. PTC decline linearly over planning period. | No WA/OR RPS. WECC States meet goal in 2011 then economics decide. PTC decline linearly over planning period. |
| **Environmental / Carbon** | $1.60 per ton WA applied to 20% of expected output at 60% cap factor. | National cap and trade system established. Carbon costs start at 5$/ton in 2010 and escalate at 5% thereafter. National Com. on Energy Policy | Carbon costs are 11$/ton in 2010, 16$/ton in 2015, 23$/ton in 2020. Pew Center on Global Climate Change. | $1.60 per ton WA applied to 20% of expected output at 60% cap factor. | $1.60 per ton WA applied to 20% of expected output at 60% cap factor. | $1.60 per ton WA applied to 20% of expected output at 60% cap factor. |
| **Transmission** | No regional solutions. Transmission additions are participant funded by 2015 | No regional solutions. Transmission additions are participant funded by 2015 | No regional solutions. Transmission additions are participant funded by 2015 | Regional transmission solution reached to support resource diversity with system-wide rates by 2012 | No regional solutions. Transmission additions are participant funded by 2015 | No regional solutions. Transmission additions are participant funded by 2015 |

[4] Analysis done in Portfolio Model only
[5] PSE meets 10 percent renewables target by 2013 in all scenarios

*Probabilistic Analysis of Risk Factors*

In addition to using scenarios to assess risk, this 2005 Least Cost Plan continues to assess portfolio uncertainty through probabilistic Monte Carlo modeling. As in the 2003 version, the 2005 plan relies on Monte Carlo analysis to consider three uncertainty factors: market prices for natural gas, market prices for power, and hydroelectric generation availability. The annual variability of power and gas prices, as well as the correlation between these variables, was updated. The variability of hydroelectric generation and correlation with power prices was held at the same values used in the 2003 Least Cost Plan. The following table (Exhibit X-6) shows the Monte Carlo input assumptions. Annual variability is calculated as the standard deviation divided by the mean, expressed as percent.

**Exhibit X-6**
**Monte Carlo Input Assumptions**

| | **Variability and Distribution** | **Correlations** | | |
|---|---|---|---|---|
| | | **Gas Price** | **Power Price** | **Hydro** |
| Gas Price | 53% Log normal | 1.0 | .95 | |
| Power Price | 36% Log normal | .95 | 1.0 | -.54 |
| Mid-C Hydro | 8% Normal | | -.54 | 1.0 |
| West Side Hydro | 12% Normal | | -.54 | 1.0 |

## E. Electric Planning Portfolios

The Portfolio Screening Model tests generic resource portfolios against the scenarios described previously in Section D. Modeling generic resource portfolios allows PSE to determine which mix of resources is likely to be competitive for given gas prices, power prices, and other costs. Based upon PSE's recent RFP and acquisition experience, PSE is considering near-term (Period 1) resource mixes and long-term (Period 2) resource mixes. This section describes the portfolio timing considerations, the four portfolios that are tested in this Least Cost Plan, the steps involved in constructing portfolios for the model, and a summary of portfolio and scenario combinations.

*Portfolio Time Period Considerations*

An important consideration in this Least Cost Plan analysis is the limited resource alternatives available to PSE today because of constraints on the transmission system for firm resources. Until transmission congestion is relieved, energy resource choices may be limited to natural gas plants, power bridging agreements, and biomass and wind plants in western Washington. Increased transmission availability will create opportunities to access other resources, namely, coal and additional wind capacity. To represent the transmission problem in the model, PSE divided the planning horizon into two periods. Period 1 includes the planning years that will occur prior to a transmission solution, while Period 2 includes the planning years that will occur subsequent to a transmission solution.

In the TS scenario, a regional solution is achieved by 2012, and period 2 begins in 2013. In the other scenarios, transmission is delayed and period 2 doesn't become available until 2016.

Exhibit X-7 shows the generic resource considerations for the two time periods. Before transmission solutions (Period 1), the supply-side resource options available to PSE are expected to be gas plants, PBAs, and limited renewables. A transmission solution (Period 2) provides access to additional wind and coal plants in addition to gas plants. In Exhibit X-7, 10 percent renewables refers to meeting 10 percent of PSE's load needs with renewable resources by 2013 and continuing to meet 10 percent of the load with renewables into the future. The 15 percent renewables indicates a requirement to meet load in 2020 with 15 percent renewables and to continue at that level. PSE's two wind plants currently being developed are included as resources to meet these requirements. Exhibit X-8 shows the schedule of renewable generation additions to meet the 10 percent and 15 percent levels under the base electric load forecast.

**Exhibit X-7**
**Future Energy Needs with Two Time Periods**

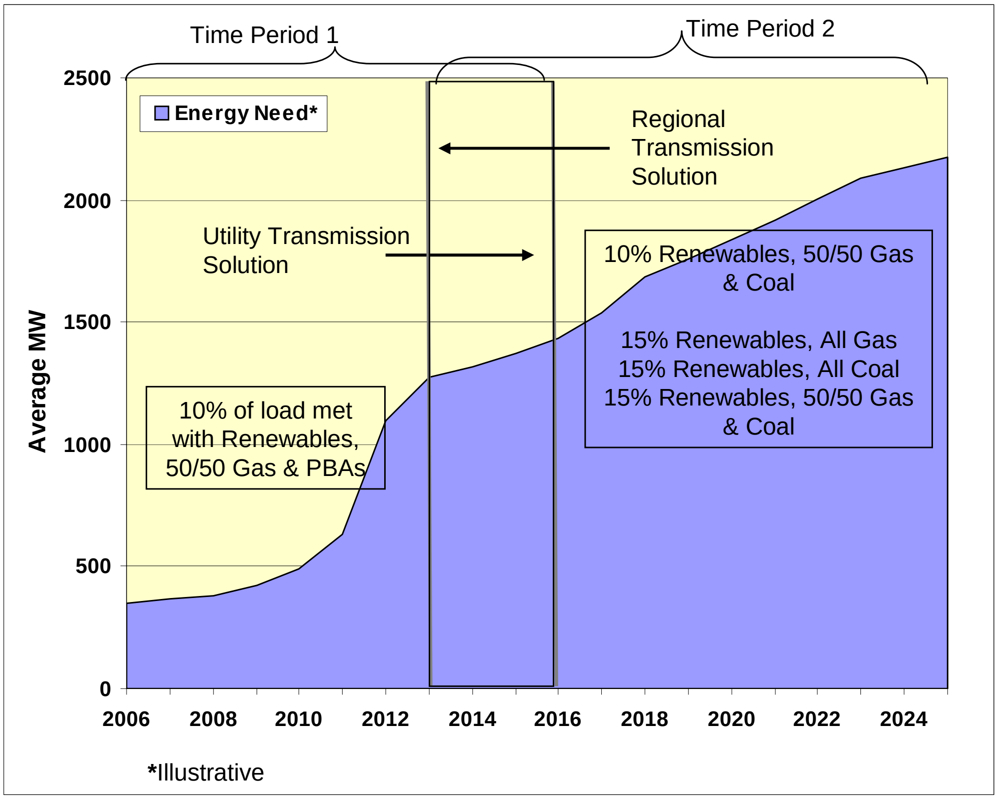



**Exhibit X-8**
**Renewable Generation Necessary to Meet Load Requirements**

| AMW | 2013 | 2020 | 2025 |
|---|---|---|---|
| 10% of Load | 279 | 314 | 344 |
| 15% of Load | 279 | 471 | 516 |

*Four Supply Portfolios*

The four supply portfolios and corresponding descriptors, which are used throughout the document, are summarized in Exhibit X-9. Additionally, when CCCTs are added, additional duct firing capacity is added. Any remaining peak capacity needs are met with winter call options for every portfolio and time period.

**Exhibit X-9**
**Portfolio Descriptions**

| Portfolio Descriptor | Period 1 Generation Mix | Period 2 Generation Mix |
|---|---|---|
| **10% Renewable and 50/50 Coal & Gas** | 10 percent of load is met with renewable generation by 2013 and the balance of the energy need is met with an equal portion of CCCTs and PBAs. | 10 percent of load is met with renewable generation and the balance of the energy need is met with an equal portion of scrubbed coal and CCCTs. |
| **15% Renewable and 50/50 Coal & Gas** | 10 percent of load is met with renewable generation by 2013 and the balance of the energy need is met with an equal portion of CCCTs and PBAs. | By 2020, 15 percent of load is met with renewable generation and the balance of the energy need is met with an equal portion of scrubbed coal and CCCTs. |
| **15% Renewable and Coal** | 10 percent of load is met with renewable generation by 2013 and the balance of the energy need is met with an equal portion of CCCTs and PBAs. | By 2020, 15 percent of load is met with renewable generation and the balance of the energy need is met scrubbed coal. |
| **15% Renewable and Gas** | 10 percent of load is met with renewable generation by 2013 and the balance of the energy need is met with an equal portion of CCCTs and PBAs. | By 2020, 15 percent of load is met with renewable generation and the balance of the energy need is met CCCTs. |

*General Portfolio Construction Rules*

PSE employed several “rules” to guide the construction of meaningful theoretical portfolios. The portfolios are generic in nature to provide a guide for the resource selection process. This process entails three primary steps, each with a number of special considerations.

1) *Add renewables*—The portfolio construction process begins by adding renewable resources to meet the requirements of the renewable portfolio standard (10 percent, 15 percent of load) or PSE’s target from the 2003 Least Cost Plan for a given scenario. It is likely that highest capacity factor wind sites will be developed in the near term. Therefore, it is assumed that PSE would add Wind first to secure as many of these desirable sites as possible relatively early. Next, Biomass is added as needed in order to meet renewable targets. If the transmission solution occurs in 2013, 300 aMW of

wind and 50 aMW of biomass are added in Period 1. If the transmission solution is 2016, 300 aMW of wind and 75 aMW of biomass are added in Period 1.

2) *Add other resources in 25 MW increments*—In Period 1, new combined cycle gas plants and PBAs are added in equal proportion (subject to the 25 MW increment constraint) to meet the remaining energy need. In Period 2, resources are added to all portfolios discussed above in 25 MW increments, until the minimum monthly aMW deficit is 13 aMW or less in each year. In some portfolio/scenario combinations, small temporary surpluses exist in certain years. This is a mathematical consequence of the 13 aMW or less deficit requirement combined with the 25 MW increment rule. Generally, in the 50/50 Gas & Coal and the 50/50 Gas & PBA portfolios, resources are added in as close to a 50/50 proportion as possible.

3) *Add Capacity to meet peak demand*—Duct firing is always added to CCCTs. Whenever PSE adds a CCCT resource, duct firing is added at a rate of 13.5 percent of the capacity of the CCCT. PSE bases its 13.5 percent assumption on the average of the projects Tenaska reviewed in its study supporting the 2003 Least Cost Plan. Additional peak demand needs are met with winter (November-December) call options. In most years, winter call options are purchased in order to meet monthly on-peak capacity demands so that PSE is never in a capacity deficit situation.

Exhibits X-10.1 through X-10.4 illustrate total incremental energy resource additions by 2025 for the four portfolio alternatives evaluated in the scenarios in which increased transmission capacity is available in 2016 and load growth is normal (BAU, CM, GW). These charts do not include the existing portfolio resources. In Exhibit X-10.1 and X-10.2, the figures do not show an equal portion of gas and coal because of the addition of gas plants in Period 1. Therefore, this portfolio actually has a higher proportion of gas plants since the equal mix only refers to Period 2 additions. In all portfolios, PBAs are replaced in Period 2 with gas and/or coal plants.

Additionally, the new biomass and wind additions shown plus the two wind projects currently being developed equal the renewable requirements by 2025. Please note that the renewable targets established are based upon meeting a percentage of load, and not upon meeting a percent of resource additions.

**Exhibit X-10.1**

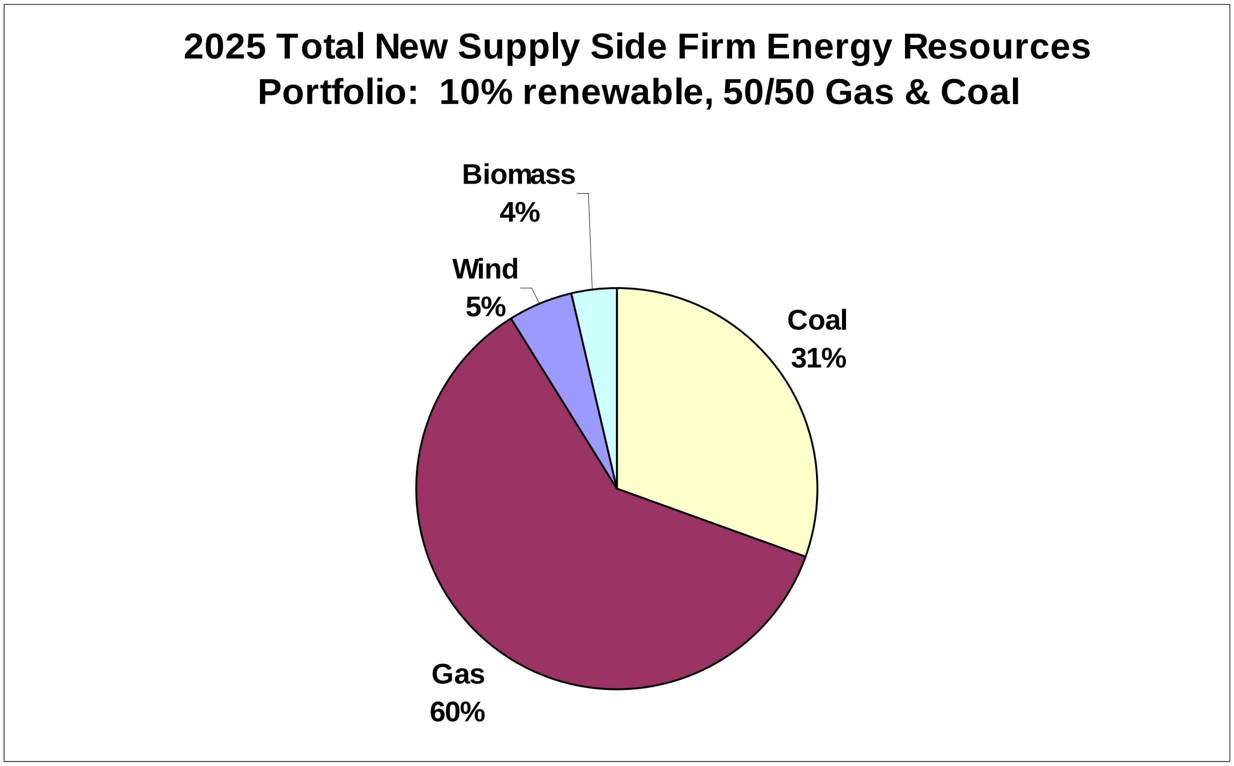



**Exhibit X-10.2**

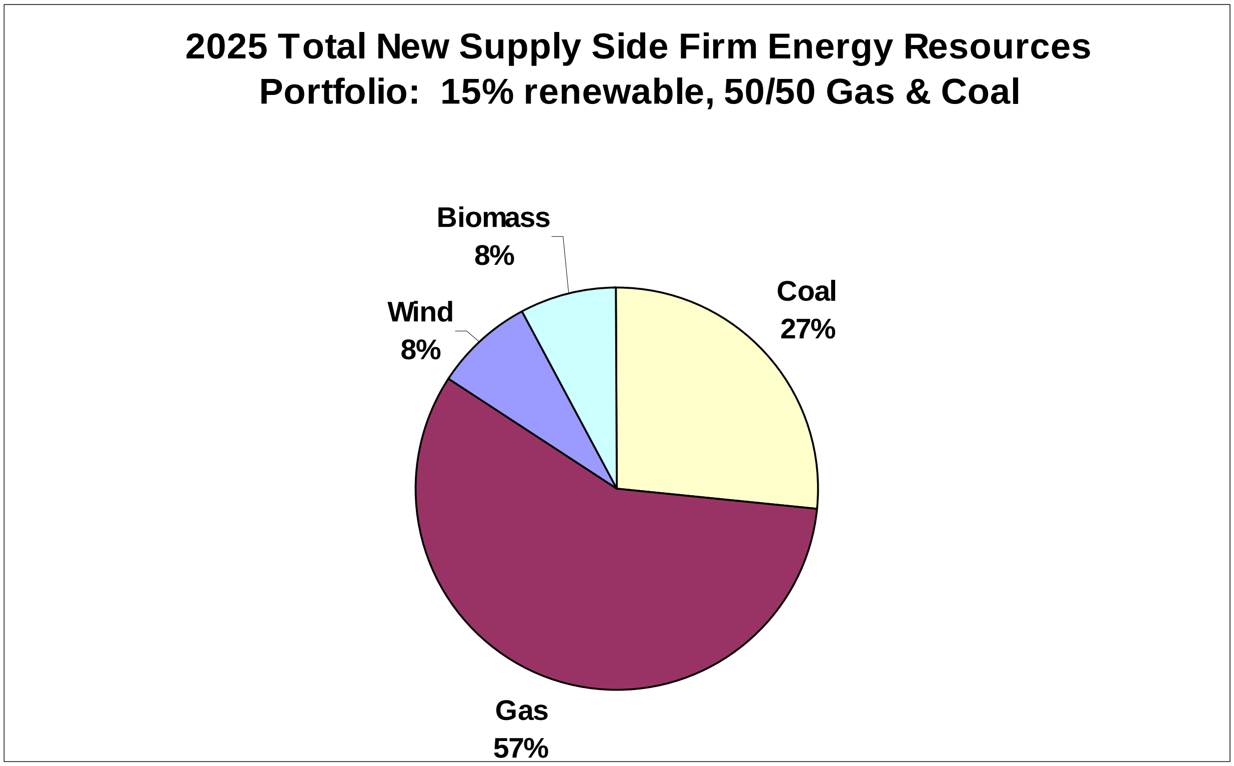


**Exhibit X-10.3**

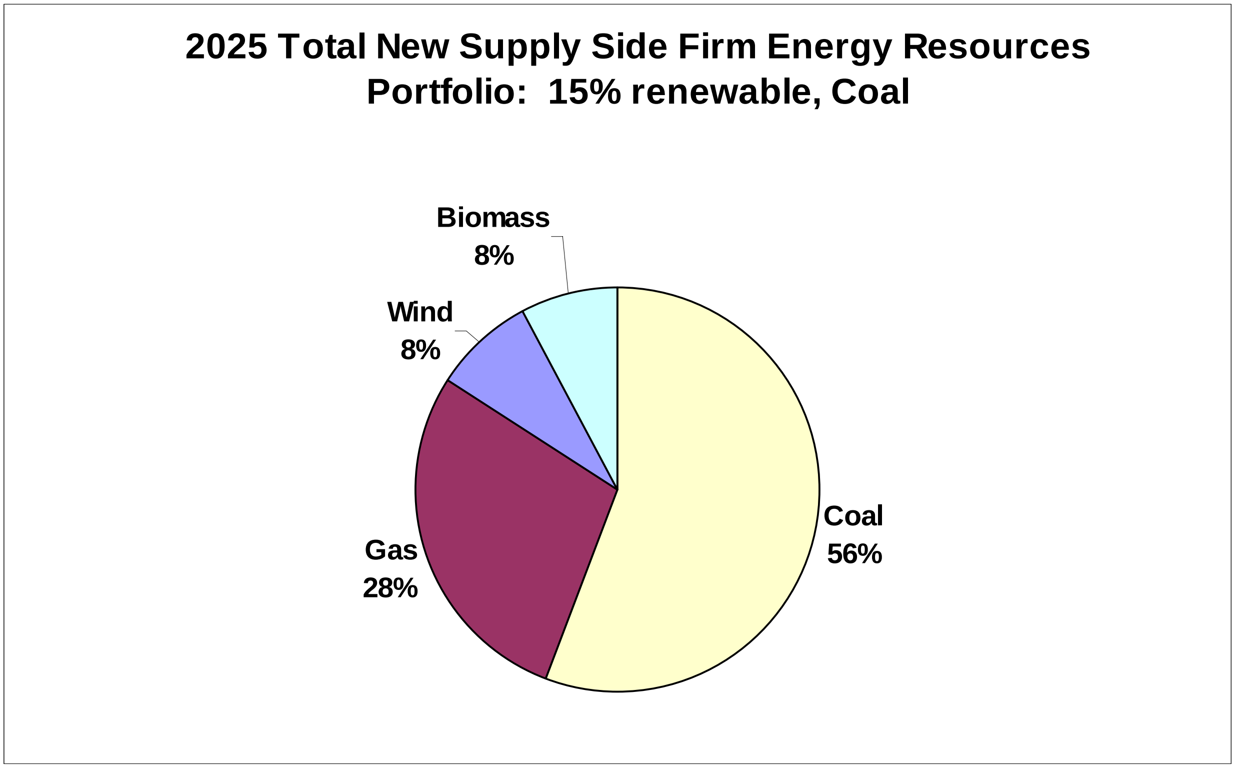
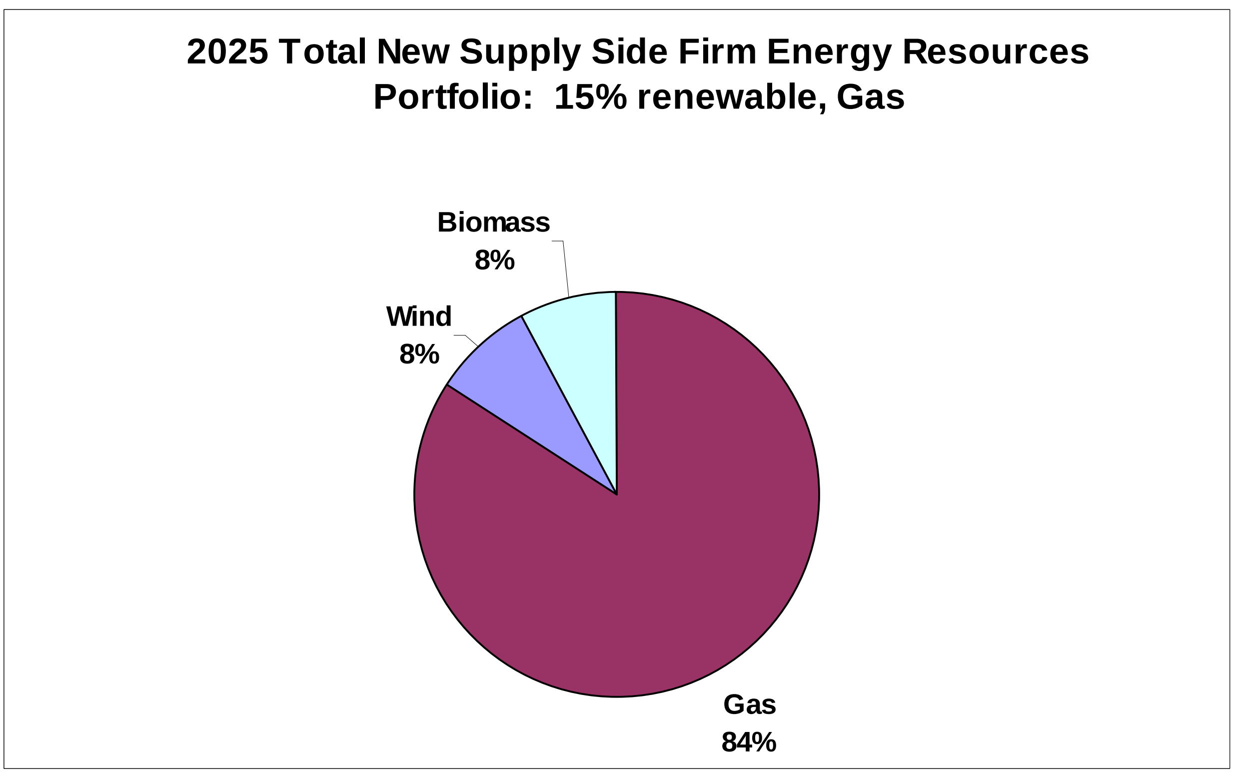



**Exhibit X-10.4**



*Summary of Portfolio and Scenario Combinations*

The four portfolios are analyzed across five of the scenarios: BAU, CM, TS, RG, and LG. Two of the portfolios are not applicable for the GW scenario. An inherent assumption in the GW is that significant amounts of renewable generation are built. For that reason, the 10 percent Renewable and 50/50 Coal & Gas portfolio is not applicable. Additionally, the GW scenario assumes less reliance on conventional coal technology. Therefore, the 15 percent Renewable and Coal portfolio was also not analyzed in the GW scenario. Ultimately, the testing of portfolios and scenarios resulted in 22 PSM runs with Monte Carlo analysis.

## F. Supply-side Analytical Results and Conclusions

The analysis of the 2003 Least Cost Plan focused on defining a planning standard for determining new supply needs and finding the theoretical best mix of resources to meet the growing need. The 2005 analysis is meant to go a step beyond and identify areas of risk, then recommend actions for acquiring appropriate resources given the key uncertainties.

The main emphasis of this analysis is to explore the key uncertainties described throughout this Least Cost Plan. As an enhancement to the 2003 Least Cost Plan, PSE has incorporated scenarios into this Least Cost Plan analysis. While there is a great deal of uncertainty around future gas prices, power prices, transmission costs, and environmental regulation, the scenarios allow analysis of portfolios under varying assumptions.

*Reference Case Findings (Business as Usual Scenario)*

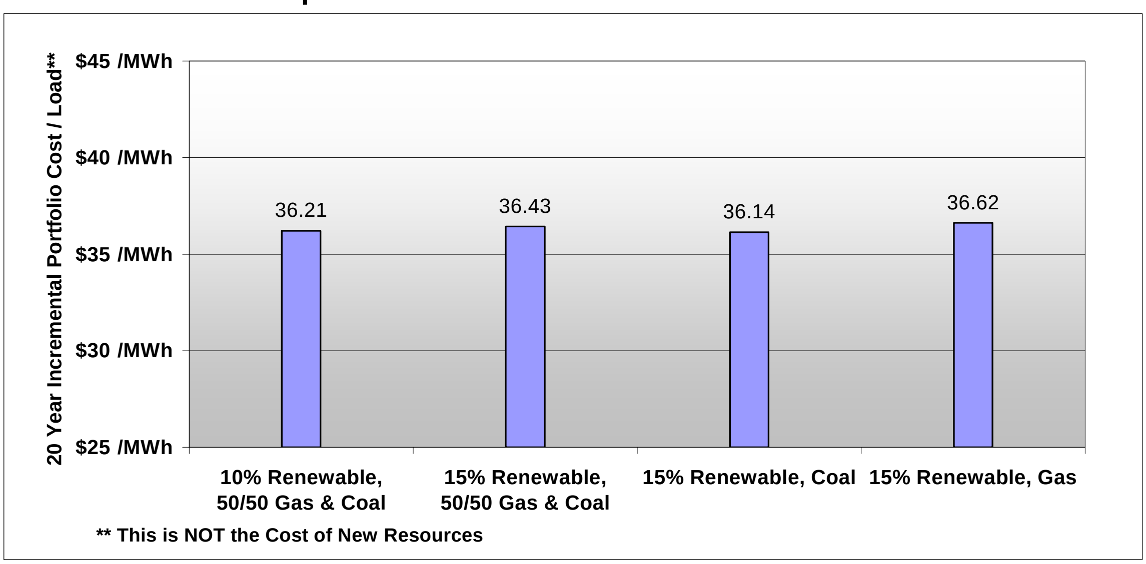
For analytical comparisons, it is useful to establish a reference case. The BAU scenario serves as the reference case. Compared with other scenarios, the BAU scenario makes fewer changes in assumptions from the current regulatory and market environment. Each subsequent scenario starts with the assumptions of the BAU scenario to build potential futures. To better understand the results presented below, the primary scenario differences from BAU are summarized as follows:

- Current Momentum Scenario (CM) includes incremental assumptions about possible or likely changes in policy favoring renewable resources, and implements carbon emission charges.
- Green World Scenario (GW) contains significant assumption changes about higher gas prices, renewable portfolio standards, as well as carbon emission charges.

- Transmission Solution Scenario (TS) includes assumptions about regional transmission improvements completed by the end of 2012 with costs recovered through system rolled-in rates.
- Low Growth Scenario (LG) assumes a smaller rate of load growth as compared with BAU, and LG also assumes lower prices for natural gas.
- Robust Growth Scenario (RG) assumes a rate of load growth higher than BAU.

Exhibit X-11 shows the expected 20-year incremental portfolio cost in dollars per MWh for the BAU scenario. There is little difference in the expected incremental portfolio cost across the four portfolios. The 15 percent Renewable and Coal portfolio is slightly lower cost than the other three portfolios. The range of costs is less than $0.50 per MWh or within 1.5 percent. Appendix G includes the detailed results of the portfolio analysis. Each $1 per MWh is equivalent to about $225 million of present value revenue requirements for all except the LG and RG scenarios. It is important to remember that the portfolio cost does not equal total power costs because it does not include the capital or fixed operating costs for PSE's existing resources.

**Exhibit X-11**
**Expected Cost Result for Business as Usual**

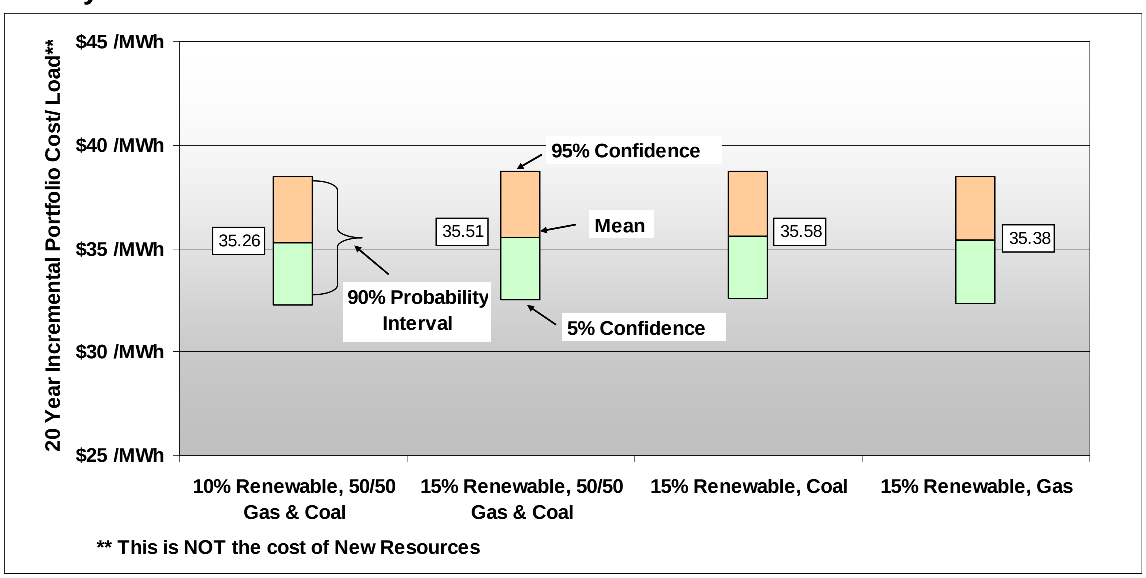



The Portfolio Screening Model (described in Appendix C) uses hourly power prices from AURORA, monthly gas prices from CERA and hourly average hydro generation as forecast by

AURORA. Using these inputs and running the PSM model in static mode produces the results shown in Exhibit X-11.

When PSM runs with Monte Carlo variability, the model produces a range of portfolio costs based upon the historical variability of power prices, gas prices and hydro generation. The stochastic results from this Monte Carlo analysis indicate that the portfolio with 10 percent renewable generation and 50/50 Coal & Gas is the lowest cost portfolio. Once again, the difference between the portfolio mean values is relatively small, less than 1 percent. The stochastic results also show little difference in risk among portfolios. Exhibit X-12 provides the range of results within a 90 percent probability interval as well as the mean of the 100 iterations. In general, when historical volatility of gas prices, power prices, and hydro generation is considered, portfolios become less costly than the static case outcomes. This reduction in portfolio cost is due to the potential option value of both existing and new natural gas generation plants. Option value is created by the flexibility of gas plants to respond to favorable market conditions that occur when the power price is higher than the variable cost of operations including fuel. In the PSM, option value occurs when the Monte Carlo simulated power prices are much higher, in relative terms, than simulated gas prices.

**Exhibit X-12**
**Dynamic 20-Year Incremental Unit Costs for Business as Usual Portfolios**



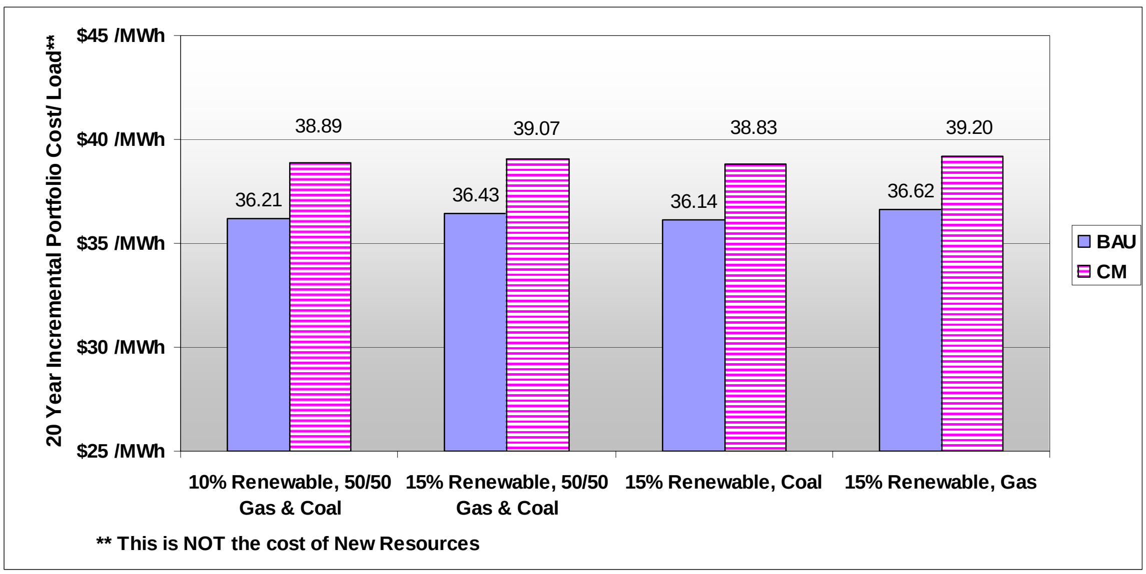

*Scenario Approach to Evaluating Risk*

As discussed earlier in this chapter, several scenarios were developed to help evaluate the effect of risk on the resource portfolios. The scenarios CM and GW address environmental risk associated with carbon costs and the addition of Renewable Portfolio Standards (RPS) in the WECC. The TS scenario primarily addresses the impact to portfolio costs of a regional transmission solution that shares the cost of transmission expansion through system-wide rates. Scenarios LG and RG show the impact of lower demand and higher demand for electricity. The LG case also incorporates a lower gas price forecast to reflect overall lower demand for natural gas.

*Current Momentum*

A comparison of the expected incremental portfolio costs for the BAU and CM scenarios is displayed in Exhibit X-13.

**Exhibit X-13**
**Expected Portfolio Costs - Current Momentum vs. Business as Usual**

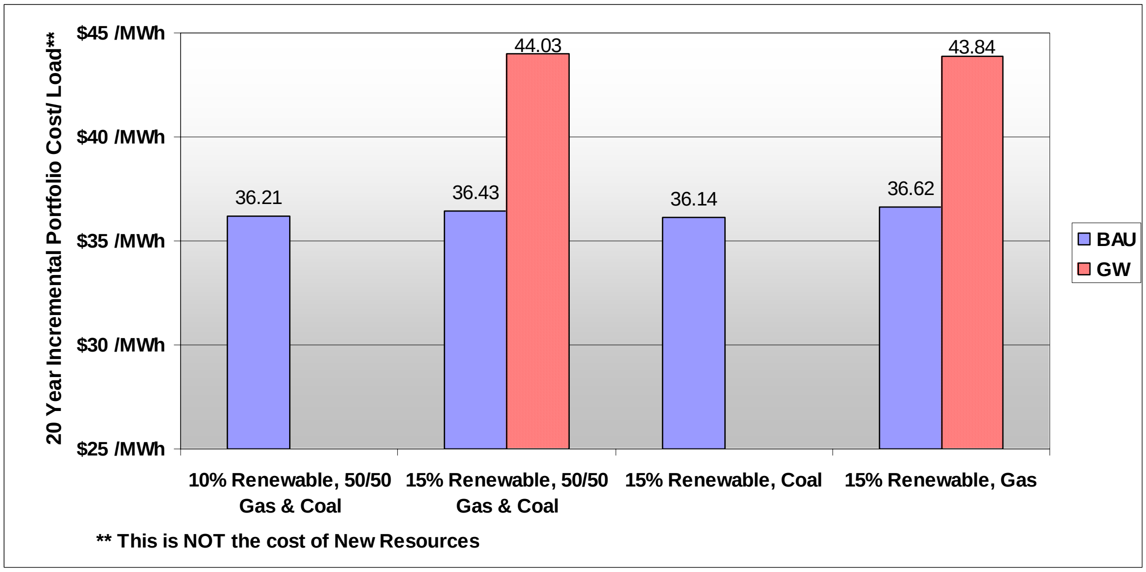



Increases in carbon costs and power prices in the CM scenario indicate an overall increase in portfolio costs from $2.58 to $2.70 per MWh. This equates to a cost increase of approximately $600 million in PV of expected portfolio costs. The lowest cost portfolio is still the 15 percent Renewable and 100 Coal. However, the 10 percent Renewable with 50/50 Coal/Gas portfolio is only $12.5 million more costly over the 20 years.

*Green World*

A comparison of the expected incremental portfolio costs for BAU and GW scenarios is displayed in Exhibit X-14.

**Exhibit X-14**
**Expected Portfolio Costs – Green World vs. Business as Usual**

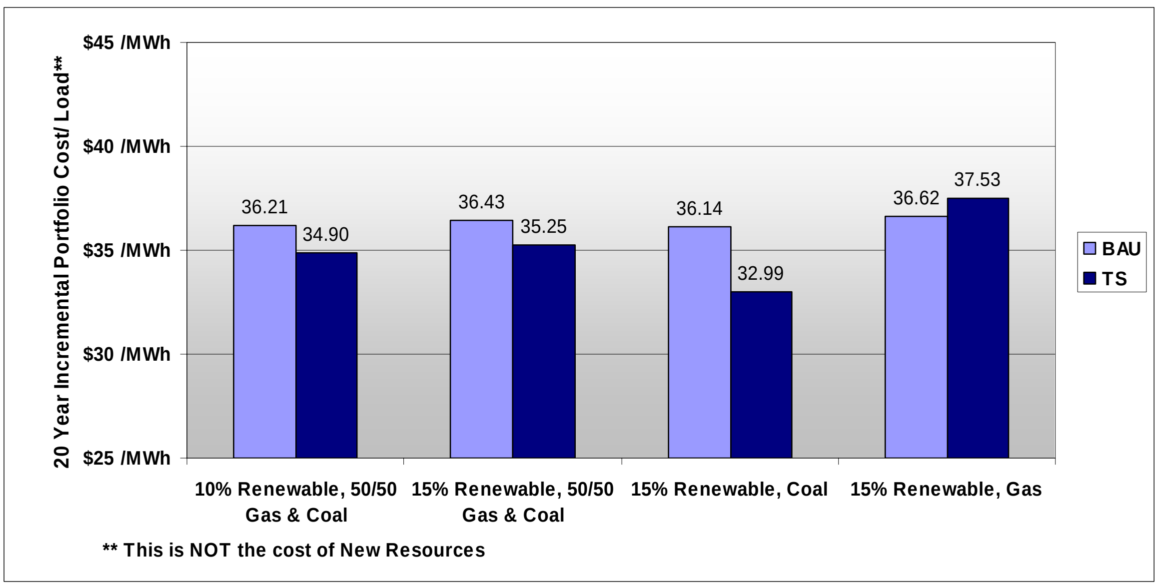



This analysis included only two portfolios in the GW scenario. The portfolio with only 10 percent renewable resources and the portfolio with 100 percent coal were deemed not feasible in a GW. Portfolio costs in the GW increased by a total of $7.23 to $7.60 per MWh compared with BAU. This significant increase in costs results from a combination of higher fuel costs (see Chapter V), higher power prices (see Chapter X, section C), and greater costs associated with $CO_2$ production. The majority of the cost increase of the GW scenario is due to emissions costs.

*Transmission Solution*

A comparison of the expected incremental portfolio costs for the BAU and TS scenarios is displayed in Exhibit X-15. In general, a regional transmission solution leads to lower portfolio costs when coal plants are part of the mix. The only portfolio to increase in cost with the transmission solution is the portfolio with 100 percent gas. In the 100 percent gas portfolio, PSE's existing wheeling costs increase with the regional sharing of incremental transmission costs, but the portfolio does not benefit from the lower cost wind or coal that would be made available from the increased transmission to those resources located in eastern Washington, Idaho, or Montana. Conversely, the coal and wind plants located in those areas, which are currently transmission-constrained, see the largest benefit of a regional transmission solution. Transmission availability and cost is a significant driver of PSE's overall portfolio cost.

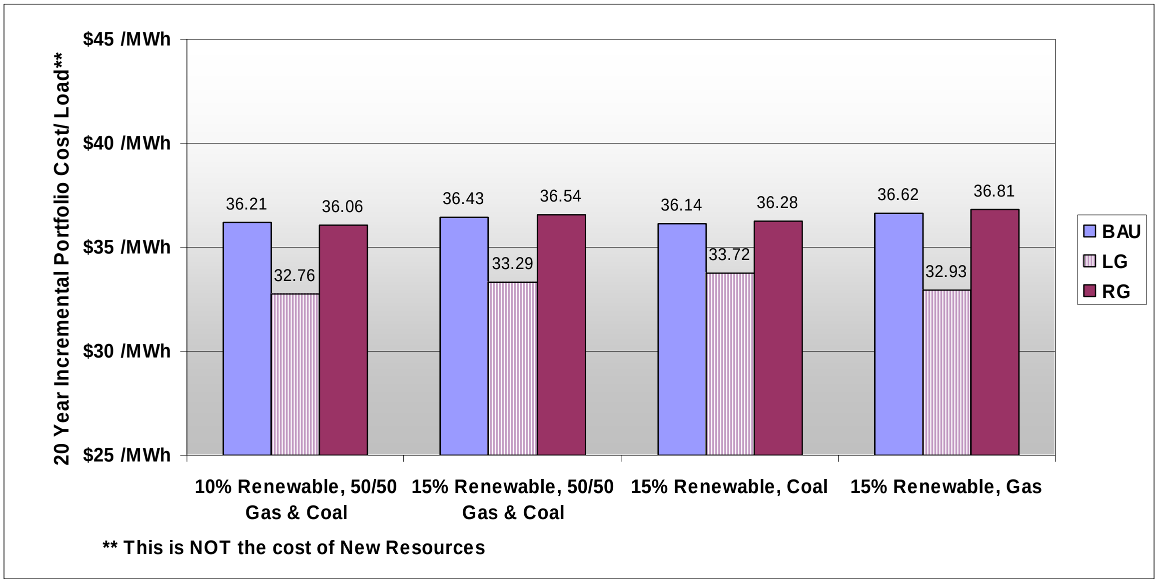
**Exhibit X-15**
**Expected Portfolio Costs – Transmission Solution vs. Business as Usual**



*Low Growth and Robust Growth*

A comparison of the expected incremental portfolio costs for BAU and the LG and RG scenarios is displayed in Exhibit X-16

**Exhibit X-16**
**Expected Portfolio Costs – Growth Scenarios vs. Business as Usual**

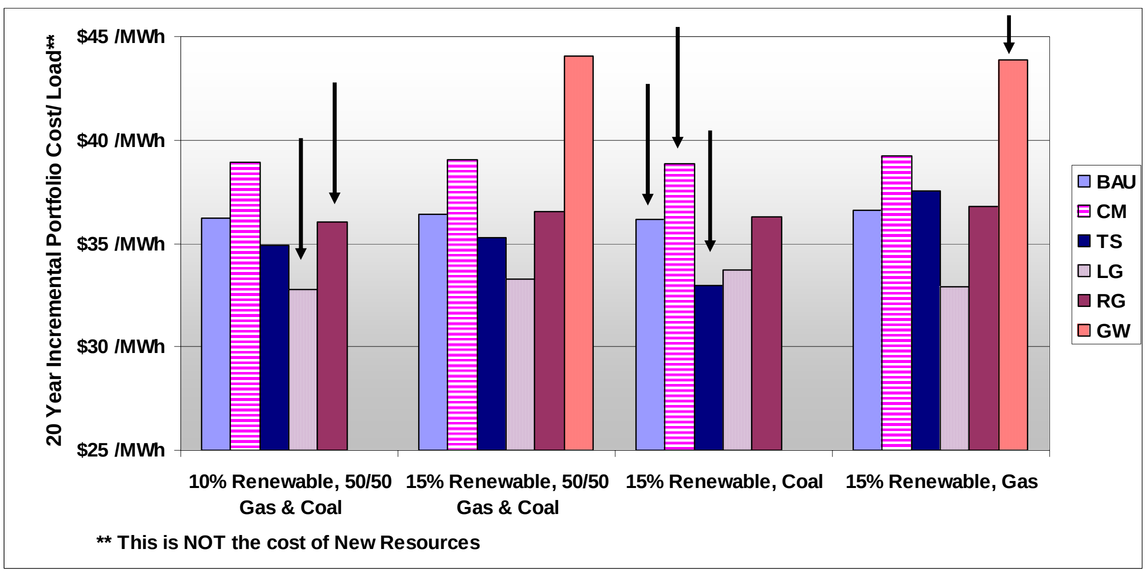



Decreases in regional demand and PSE demand, along with the lower gas prices assumed in the LG scenario, significantly reduce the expected portfolio costs. Some of the decrease, about 1$/MWh, is attributable to lower gas prices. The balance of the decrease, about 2$/MWh, is driven by lower PSE demand. Lower PSE demand reduces the need for new supply by 400 aMW. In the RG scenario, increases in regional and PSE demand cause slight increases in expected portfolio costs because incremental plants cost more than embedded average cost. With a significant proportion of generation expiring in the 2011 time period, any change in demand is directly offset by new resources. The RG scenario requires the addition of another 460 aMW of new supply.

*Static Results - All Scenarios*

A comparison of the expected incremental portfolio costs for all scenarios and portfolios is displayed in Exhibit X-17. The arrows point to the low cost portfolio for each scenario. Most arrows point to the 15 percent Renewable and Coal portfolio. However, when looking across portfolios for a single scenario, it is observed that the differences between portfolio costs are very slight under most scenarios except the TS scenario. It appears that a transmission solution with system-wide rates would have the biggest impact when choosing between portfolios. Additionally, the LG scenario shows that strategies to reduce electric demand could have a significant impact on portfolio cost. Based upon the static results alone, PSE should work toward finding a transmission solution and continue to pursue a diversified portfolio of natural gas plants, coal plants, and renewable plants. It appears that going to a 15 percent renewable target is slightly more costly, but PSE should continue to evaluate renewable costs on a case-by-case basis. These conclusions do not yet consider risk.

**Exhibit X-17**
**Static Portfolio Costs – All Scenarios**




*Dynamic Results – All Scenarios*

The next figure (Exhibit X-18) superimposes the static results of all scenarios on the BAU dynamic result. The BAU expected cost is greater than the BAU dynamic mean. This is a result of the option value of gas plants. Exhibit X-18 also shows that the dynamic result of the BAU scenario does not bound the outcomes of the scenarios. Looking at the expected results from the dynamic analysis in Exhibit X-19, the 10 percent Renewable and 50/50 Gas and Coal portfolio is lowest cost for most scenarios. Comparing Exhibits 17 and 19, it is apparent that the dynamic results shift the selection of portfolios toward those with a higher proportion of natural gas plants.

**Exhibit X-18**
**Dynamic BAU Result and Static Scenario Results**

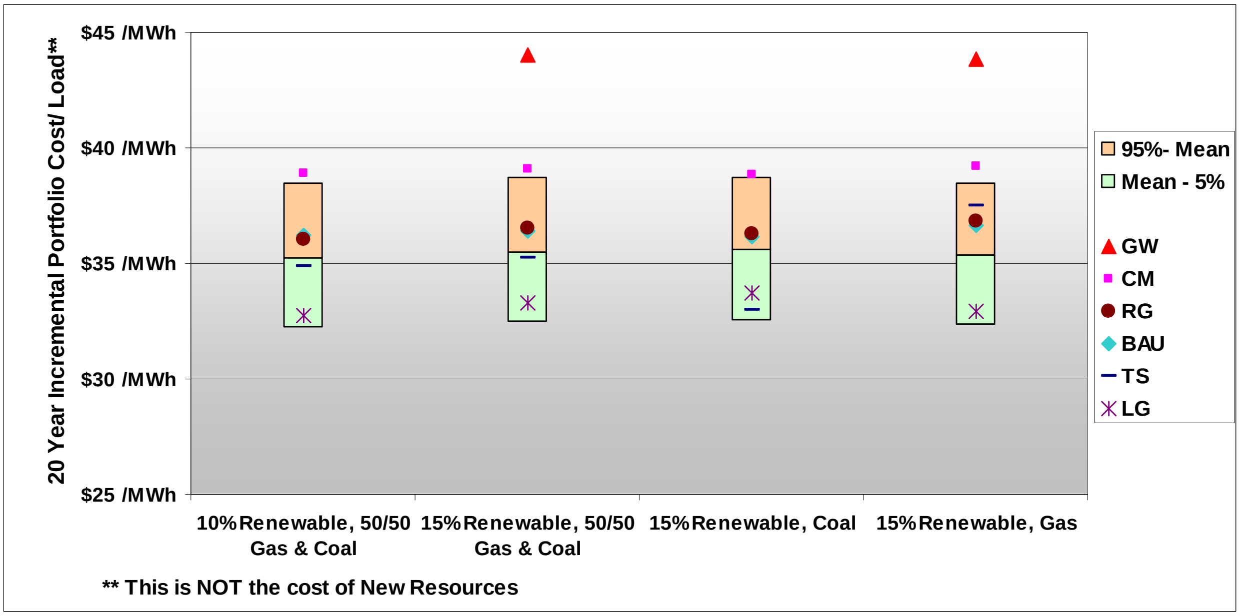
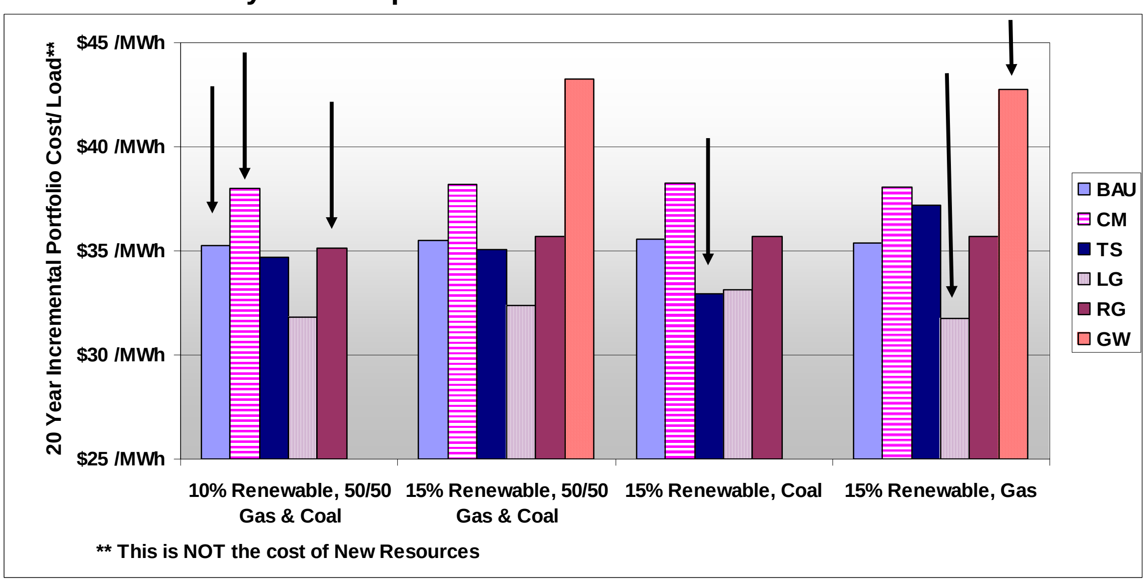


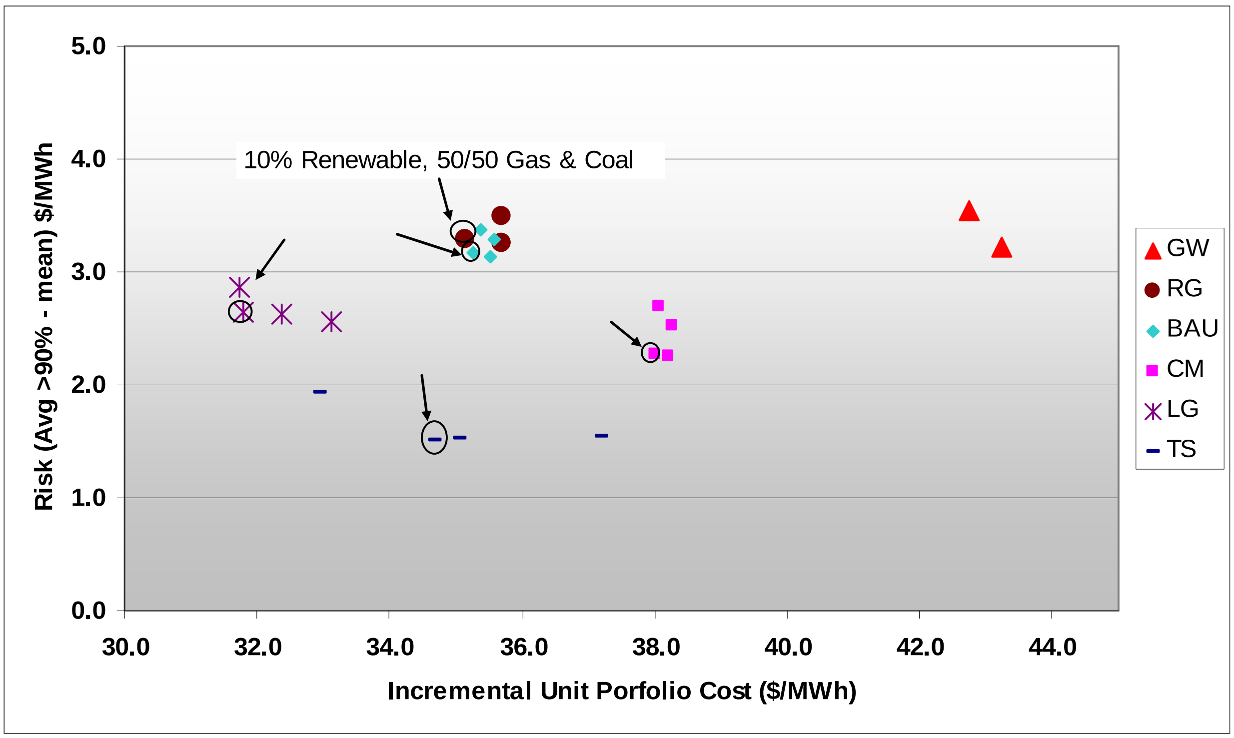

**Exhibit X-19**
**Dynamic Expected Value Results for all Scenarios**



*Risk for all Scenarios*

Similar to the Northwest Power and Conservation Council in their 5th Power Plan, PSE measures risk by examining the bad outcomes, the average value for the 10 percent worst outcomes (Avg > 90 percent). The risk measure used is the difference between the Avg > 90 percent and the mean result. Exhibit X-20 plots this risk vs. incremental unit portfolio cost. The chart shows that the portfolios are clustered together for each scenario. The best portfolio for any scenario cluster is located toward the bottom left corner reflecting lower costs and lower risk.

**Exhibit X-20**
**Dynamic Cost and Risk Tradeoff Results for all Scenarios**




As shown, the portfolio with 10 percent renewables and 50/50 gas and coal (circled points in Exhibit X-20) performs best across most scenarios. For three of these scenarios (BAU, CM, and RG), the 10 percent renewables and 50/50 gas and coal portfolio is lowest cost. In the TS case, the 15 percent renewables and all coal portfolio is lower cost but higher risk. Similarly, in the LG case, the 15 percent renewables and all gas portfolio has a slight cost advantage but is higher risk than the 10 percent renewables and 50/50 gas and coal portfolio. For the GW scenario, the 10 percent renewables and 50/50 gas and coal did not meet the scenario parameters and was not modeled. However, of the two portfolios modeled in GW, the diversified portfolio (15 percent Renewable and 50/50 Coal & Gas) was higher cost but lower risk than the all gas portfolio (15 percent Renewable and Gas).

*Portfolio Conclusion*

Overall, considering both cost and risk together, this analysis supports the selection of the 10 percent Renewables and 50/50 Coal and Gas portfolio since it does well across many different scenarios. (Appendix G shows the detailed results for each symbol in the Exhibit X-20). This analysis also helps determine which uncertainties have the greatest cost impact. It appears that the biggest cost drivers for the PSE portfolio are possible carbon costs based on GW and CM. The LG scenario shows that a reduction in demand can lower costs. Transmission cost and availability is also an important driver of cost and risk. Although the dynamic results show a wide range of cost differences associated with volatility in gas prices, power prices, and hydro generation, the impact across portfolios doesn't favor one portfolio over another.

*Summary of Supply-side Key Quantitative Findings*

- A regional transmission solution generally reduces portfolio cost when coal resources are in the mix.
- The 15 percent Renewable and Coal portfolio with a transmission solution is the lowest cost portfolio compared to all other portfolios and scenarios with normal growth.
- For many scenarios, portfolios with coal resources lower portfolio costs; however, there is uncertainty regarding environmental costs.
- Scenarios with increasing environmental constraints, that are quantified in the scenario, have 20-year portfolio costs that are about 8 percent higher (CM) and 20 percent higher (GW) than the BAU scenario.
- Volatility in hydro generation, gas prices and power prices generate a 20-year downside risk in portfolio cost that is about 5 percent of the mean in the TS scenario and about 9 percent of the mean in the BAU scenario.
- Over all scenarios, the lowest risk portfolio is the 15 percent Renewable and 50/50 Coal & Gas.
- Slower growth in demand reduces 20-year portfolio cost by reducing additions of newer, incrementally more expensive resources.
- The theoretical least cost portfolio across all scenarios evaluated is diversified with coal, gas, and renewable resources.

*Additional Analysis and Conclusions*

Aside from the main analysis, a few additional model sensitivity analyses were performed. These analyses were conducted to examine the value of summer sales revenue, the imputed debt costs of PBAs and the benefits of PBAs as a deferral mechanism, and the impact of potential emissions costs on resource selection.

*Summer Sales Revenue* – PSE is a winter peaking utility and average load is greater in the winter than in the summer. The 2003 Least Cost Plan demonstrated that, to the extent possible, PSE should seek shaped resources to meet its growing winter need. PSE will continue to seek resources shaped to the seasonal load profile. However, because shaped resources are specific proposals, they were not tested in the generic portfolios. Since the coal and gas resources examined in the portfolio analysis are available year round and may increase with summer energy surpluses, PSE decided to analyze the impact of summer sales revenues on the portfolio.

To evaluate whether high-priced summer surplus sales were a significant driver of outcomes from portfolio analysis, PSE developed an alternate BAU scenario, “BAU $125”. In BAU $125, power prices were capped at $125/MWh from April through October and had no cap in the winter months. The original BAU scenario assumes that $250 price caps apply all year. The following table (Exhibit X-21) compares the results of the portfolios in the BAU scenario with the same portfolios in the BAU $125 scenario.

**Exhibit X-21**
**Impact of Seasonal Price Cap on BAU Scenario**

| | 10% Renewable, 50/50 Gas & Coal | 15% Renewable, 50/50 Gas & Coal | 15% Renewable, Coal | 15% Renewable, Gas |
|---|---|---|---|---|
| **Expected (Static) Results** | | | | |
| BAU (assumes $250 cap) | $36.21 | $36.43 | $36.14 | $36.62 |
| BAU w/ $125/MWh Price Cap | $36.63 | $36.84 | $36.53 | $37.05 |
| April-October; No Winter Cap | | | | |
| Impact of Seasonal Price Cap | $0.42 | $0.41 | $0.39 | $0.43 |
| **Dynamic Results** | | | | |
| BAU (assumes $250 cap) | $35.26 | $35.51 | $35.58 | $35.38 |
| BAU w/ $125/MWh Price Cap | $35.70 | $35.94 | $35.95 | $35.86 |
| April-October; No Winter Cap | | | | |
| Impact of Seasonal Price Cap | $0.44 | $0.43 | $0.37 | $0.49 |

Several conclusions can be drawn. First, lowering the price cap to $125/MWh and applying the cap only in April through October increases portfolio costs in all scenarios by $0.37 to $0.49/MWh that is equivalent to a PV cost increase of $83 to $109 million over 20 years. Second, there is no change in portfolio ranking. The portfolio with 15 percent renewable with the balance of coal is the least cost portfolio regardless of whether the price cap is $250 for all months or $125 for April through October. And third, as expected, the 15 percent renewable with balance of gas portfolio shows more impact than the other portfolios. In general, the impact of summer surplus sales is not significantly influencing the portfolio outcomes.

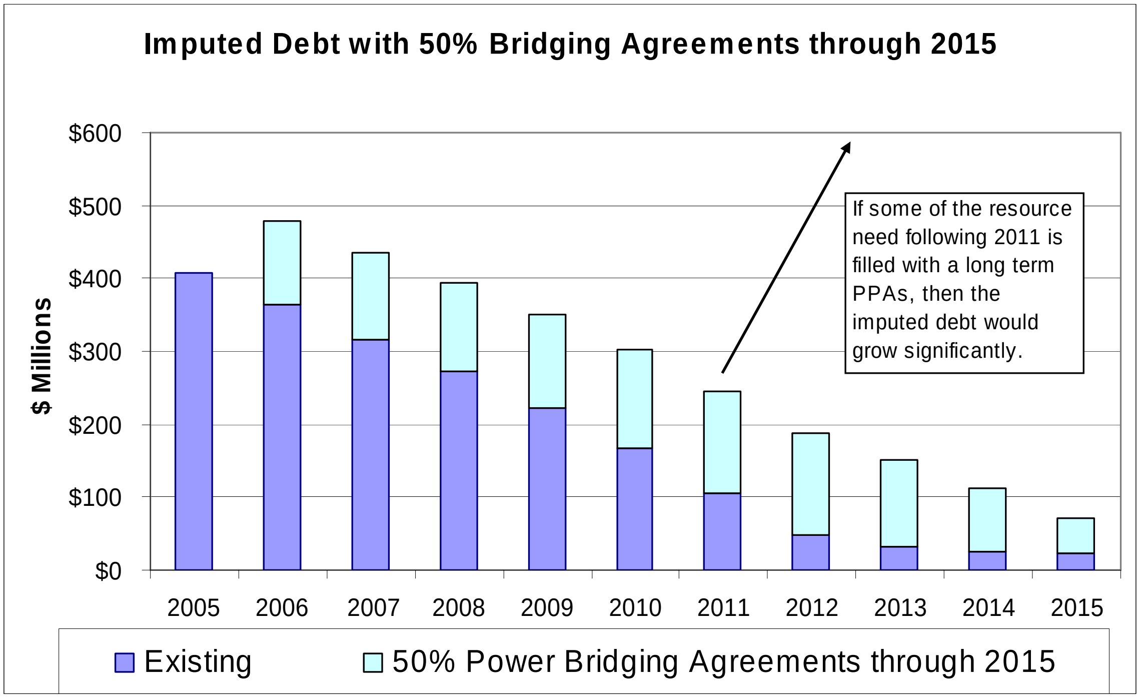
*Power Bridging Agreements (PBAs) and Imputed Debt* – All portfolios, except TS, in the near term through 2015 contain an equal mix of PBAs and gas generation to meet the resource need that remains after 10 percent renewable supply. Without some mechanism to offset imputed debt costs, the modeled PBAs would increase the imputed debt for PSE and thus put downward pressure on its credit rating (see Chapter IV for a more complete discussion of imputed debt). Using the BAU scenario for illustrative purposes, Exhibit X-22 shows that the accumulated volume of PBA purchases is 750 MW by 2015. Exhibit X-23 shows an annual forecast of imputed debt for the 750 MW of PBAs.

**Exhibit X-22**
**Volume of PBA Purchases**

| | PBA MW | Accumulated PBA MW |
|---|---|---|
| 2006 | 125 | 125 |
| 2007 | | 125 |
| 2008 | | 125 |
| 2009 | | 125 |
| 2010 | 25 | 150 |
| 2011 | 175 | 325 |
| 2012 | 275 | 600 |
| 2013 | 100 | 700 |
| 2014 | 25 | 725 |
| 2015 | 25 | 750 |

As described in Chapter X, Section B, "New Generation Alternatives," the PBA is priced using the average of the AURORA market forecast plus a 5 percent premium used to estimate a combination of credit and liquidity risk. The fixed price of the PBA helps to reduce the variability of portfolio costs, but also increases the imputed debt. The imputed debt shown in Exhibit X-23 is based upon the Standard & Poor's calculation, assuming that PSE makes the commitment in 2006 for all of the purchases through 2015. In the actual acquisition process, PSE would weigh the pros and cons of shorter-term vs. longer-term PBAs, and may elect not to enter into a contract years before necessary.

**Exhibit X-23**




<u>*Cost Impacts of No PBAs*</u> – A sensitivity study was run to evaluate the portfolio cost impact of PBAs. For this analysis, PBAs were replaced with an equal volume of new gas generation plants in the near term through 2015. The study results can be used to quantify the cost reduction and variability benefits provided by the PBAs priced at AURORA forecast plus 5 percent. The impact of the additional gas generation supply to replace PBAs could have the result of increasing costs by $1.70/MWh, which is equivalent to a present value of $380 million in additional portfolio costs over 20 years.

If PBAs are not available from system purchases at market prices, then the likely source for PBAs will be from tolling arrangements with gas plants. A tolling agreement commits PSE to pay a fixed monthly amount to purchase power from a specific power plant. Typically, under such an agreement, PSE would also be responsible to supply the gas to the plant. Under tolling agreements, the PBA pricing would be more similar to gas plant pricing than to system purchases at market prices. In this case, replacing market priced PBAs with tolling PBAs could be expected to have the same cost impact, $1.70/MWh, as replacing the market priced PBAs with new gas generation. Additionally, tolling PBAs would create imputed debt impacts. Exhibit X-24 compares the No PBA portfolio with the Generic Portfolio. Removing PBAs would increase cost and portfolio variability (Exhibit X-25). While these results indicate PBAs provide value, the terms studied are not standard products and their price and availability will need to be confirmed in the market.

**Exhibit X-24**

| | 2006 – 2015 | 2016 - 2025 |
|---|---|---|
| Generic Portfolio | 10% Renewables, 50/50 PBA & Gas | 10% Renewables, 50/50 Gas & Coal |
| No PBA Portfolio | 10% Renewables, Balance Gas | 10% Renewables, 50/50 Gas & Coal |

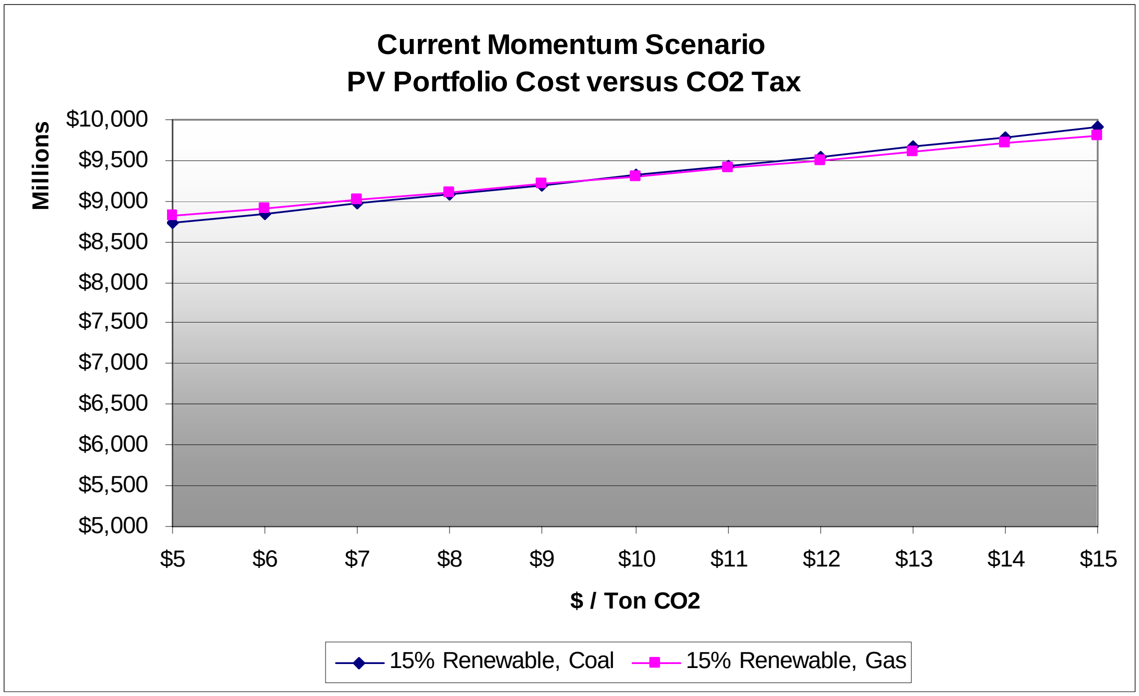
**Exhibit X-25**

| | No PBA Portfolio | Generic Portfolio | Change |
|---|---|---|---|
| Expected Cost $/MWh | $37.91 | $36.21 | $1.70 |
| Dynamic Mean $/MWh | $36.68 | $35.26 | $1.42 |
| Risk = 95% less Mean | $3.98 | $3.20 | $0.78 |

*Carbon Dioxide Cost Sensitivity Analysis* – Two scenarios were developed to integrate the impacts of $CO_2$ costs into the analysis of portfolios. These scenarios were the CM and GW cases. Although these scenarios provide an indication of whether $CO_2$ costs impact PSE's decision to build coal in the future, they don't establish the costs that might lead to the decision not to build coal. Therefore, sensitivity analyses were performed to help provide some guidance on this issue.

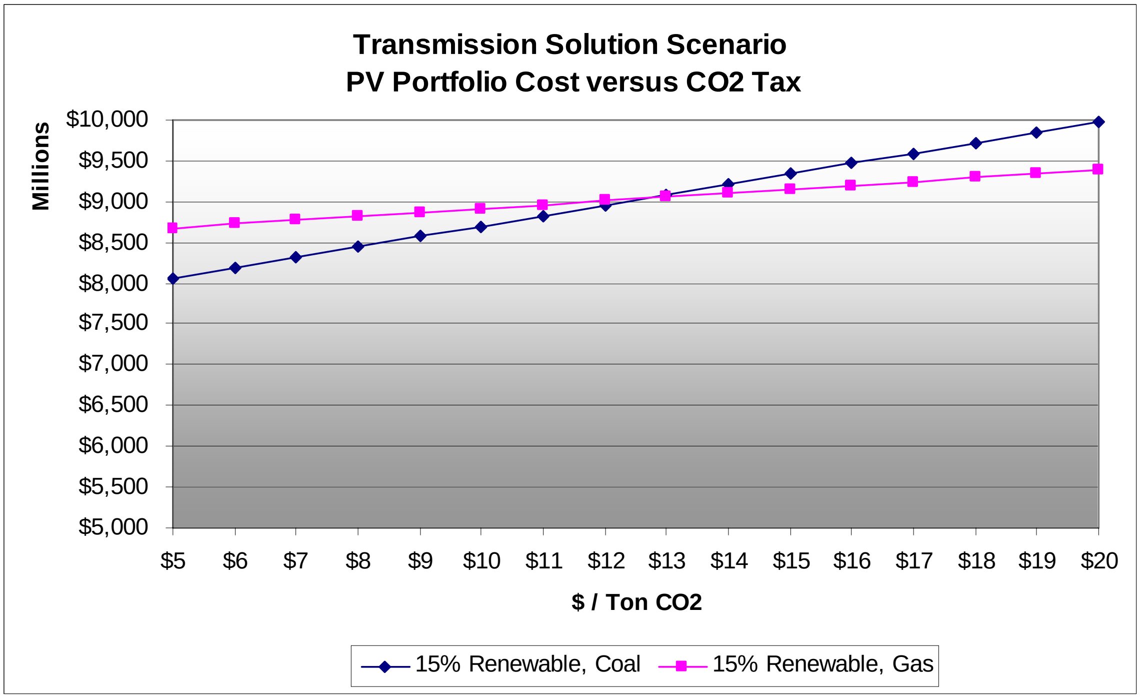
For the analysis, PSE examined what level of $CO_2$ would lead to the selection of the 15 percent Renewable and All Gas portfolio over the 15 percent Renewable and All Coal portfolio in the CM and TS scenarios. These model runs assumed a $CO_2$ cost starting in 2010 with a 2.5 percent escalation per year. The value of looking at the CM scenario is that it was a scenario designed to examine $CO_2$ costs, but did not lead to the selection of an all gas scenario. For CM, the portfolio selection changes to gas from coal between $9 and $10, as shown in Exhibit X-26. The figure also shows that the differences in portfolio costs and $CO_2$ costs between $5 and $15 per ton are very close.

**Exhibit X-26**




The other scenario examined was the TS scenario (Exhibit X-27), which includes a regional transmission solution. In this scenario, the cost of coal plants including transmission costs are less than natural gas plants. The analysis shows that the tipping point occurs between $12 and $13 per ton.

**Exhibit X-27**




The analysis and conclusions regarding potential carbon regulation are problematic, as there is so much uncertainty about future policies on $CO_2$ taxes or "cap and trade" regimes. There are numerous policy assumptions that impact the analysis of carbon charges. These include the size of a carbon charge and its escalation rate, the online date and level of grandfathering for existing resources or distribution of credits, the future fuel prices associated with coal and gas in the future, and the development cost of different control or sequestration technologies in the future.

*Summary of Additional Quantitative Findings*

- Summer surplus sales do not significantly influence portfolio outcomes.
- Power bridging agreements reduce portfolio cost variability, but increase imputed debt.
- Under current market price assumptions, near-term power bridging agreements are less expensive than gas resources.
- The tipping point analysis indicates that a $CO_2$ charge, which equates the cost of coal and gas portfolios, would be $9 to $10 in the CM scenario and $12 to $13 in the TS scenario.

## G. Demand-side Analytical Results and Conclusions

*Demand-Side Analytic Approach*

PSE uses the Conservation Screening Model (CSM) (described in Appendix C) for analyzing energy efficiency and fuel conversion programs. CSM integrates demand-side resource potential estimates, which are based upon the achievable cost categories for each end-use, and hourly load shapes for program bundles to reduce PSE customer electricity demand. This reduction in demand offsets the addition of the generation supply resources to meet the energy need. The CSM analyzes thousands of energy efficiency and fuel conversion (demand-side) cases to find the most cost effective combination of supply resource, and energy efficiency and fuel conversion programs. Similar to the electric planning analysis, the primary metric is the 20-year NPV of the incremental portfolio cost in millions of dollars. The goal is to minimize the incremental portfolio cost.

Analysis of demand-side portfolios was a multi-step process because of CSM model limitations. A demand-side portfolio is defined as any combination of the bundle/price points (As described in Chapter VII, there are 17 electric end-use bundles: eight residential bundles, eight commercial bundles, and one industrial bundle. There are up to eight cost categories for the residential and commercial end-uses, and a single cost category for the industrial bundle). Because not every end-use has eight cost categories, there are 95 unique bundle/price points to be considered. Input data to CSM is limited to 65 combinations of bundle/price points for any single model run.

To address the model constraint of 65 bundle/price points, the cost categories were aggregated at the low ends, with most granularities retained in the middle and upper cost categories. The cost aggregations were made initially by reviewing results from the energy efficiency and fuel conversion portfolio analysis of cost levels A to D and combining the cost categories where all bundles at a particular cost level were either accepted or rejected. For reference, cost categories are lettered A to H from lowest to highest cost. The four price points (levelized cost per MWh saved) ultimately utilized in this analysis are:

- Less than $75 per MWh (cost categories A-D)
- $75 - $85 per MWh (cost category E)
- $85 - $95 per MWh (cost category F)
- $95 - $105 per MWh (cost category G)

Cost category G bundles were never selected by CSM; therefore, there was no need to test category H.

Demand-Side scenarios were designed to test the timing of acquiring demand-side resources. Two timing scenarios are represented for both energy efficiency and fuel conversion—a constant rate of acquisition over the entire 20-year planning horizon (normal) and an accelerated rate of acquisition to achieve as much savings as possible over the first 10 years (accelerated). The following are scenario descriptions and show the maximum achievable potential energy savings inputs before testing for cost-effectiveness.

- *Constant energy efficiency acquisition (Normal EE)* – 14.8 aMW/year for 2006 – 2025 from energy efficiency resources only, no fuel conversion.
- *Accelerated energy efficiency acquisition (Accelerated EE)* – 24.3 aMW/year for 2006 – 2015 and 5.4 aMW/year for 2016 – 2025 from energy efficiency resources only, no fuel conversion.
- *Normal replacement fuel conversion plus accelerated energy efficiency* (Accel EE std eff Normal FC) – 26.9 aMW/year for 2006 – 2015 and 8.1 aMW/year for 2016 – 2025 from a combination of accelerated energy efficiency and fuel conversion acquired as equipment is normally replaced at the end of its useful life.
- *Early replacement fuel conversion plus accelerated energy efficiency* (Accel EE std eff Early FC) –34.3 aMW/year for 2006 – 2015 and 4.5 aMW/year for 2016 – 2025 from a combination of accelerated energy efficiency and fuel conversion at an accelerated pace of equipment replacement.

Fuel conversion was analyzed in combination with energy efficiency in order to address interactions between the two. The impacts of fuel conversion can be derived as the difference between a portfolio that includes both energy efficiency and fuel conversion and a portfolio that consists of energy efficiency only. The portfolio screening analysis only examined fuel conversion in combination with accelerated energy efficiency because accelerated energy efficiency was found to be preferable to a constant rate of acquisition at the first stage in the analysis.

**Modeling Approach for Simultaneous Assessment of Demand and Supply Resources Steps**

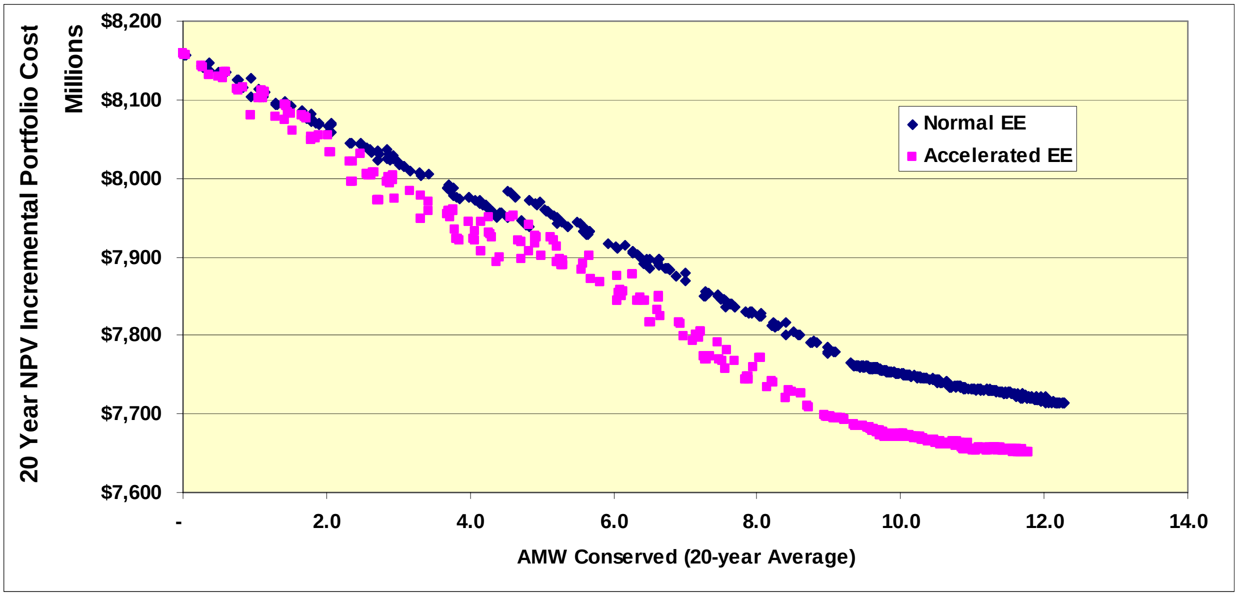
1. Selection of Energy Supply Portfolio
2. Analysis of Energy Efficiency supply curves under normal implementation schedule
3. Analysis of Energy Efficiency supply curves under accelerated schedule
4. Selection of normal vs. accelerated schedule for energy efficiency
5. Analysis of normal level of fuel conversion (normal) with selection from step 4
6. Analysis of accelerated level of fuel conversion (early) with selection from step 4
7. Selection of demand-side case with lowest incremental portfolio cost

*Analytic Results*

The ultimate goal of running CSM is to determine the level of energy efficiency and fuel conversion that is cost effective in combination with the least cost energy supply portfolio. As determined from the PSM analysis, the supply portfolio used for the demand-side analysis is 10 percent Renewable and 50/50 Coal and Gas resources.

Exhibit X-28 shows demand-side cases (unique combinations of 65 bundles/price points) tested in CSM for the constant rate of acquisition energy efficiency scenario and the accelerated energy efficiency scenario. Over 1,000 cases were tested. The lowest incremental portfolio cost achieved in this sample of cases included all end-use bundles up to the cost category D. Therefore, it can be concluded that all programs up to this cost level are cost effective compared to the selected supply resource portfolio. Additionally, the exhibit shows that accelerated energy efficiency reduces portfolio cost more than a constant rate of acceleration.

**Exhibit X-28**
**Constant Rate vs. Accelerated Rate of Energy Efficiency testing cases up to Cost Point D**




Since accelerated EE is more cost effective, the analysis focused on fuel conversion programs combined with accelerated energy efficiency. Again, Exhibit X-29 confirms the acceptance of all demand-side bundles/price points through cost category D because portfolio costs continue to decline as energy efficiency and fuel conversion cost levels increase.

**Exhibit X-29**
**Scenario Results- Cost Points testing cases up to Cost Point D**

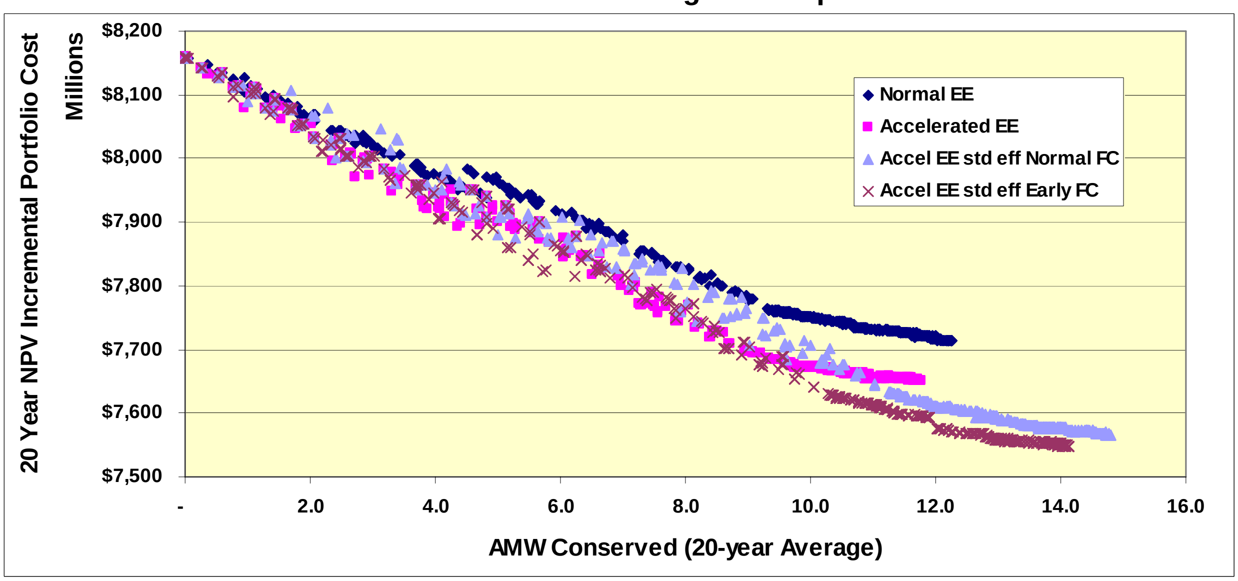


Exhibit X -30 tests energy efficiency and fuel conversion cases through cost level G. The result shows that accelerated energy efficiency plus early fuel conversion is lowest cost. Identifying the minimum point on these curves indicates the optimal level of savings that can be achieved through demand-side programs. The result shows that average energy per year saved through energy efficiency and demand response is approximately 15.5 aMW over the 20-year planning period.

**Exhibit X-30**
**Scenario Results- Cost Points A to G with A to D Combined**

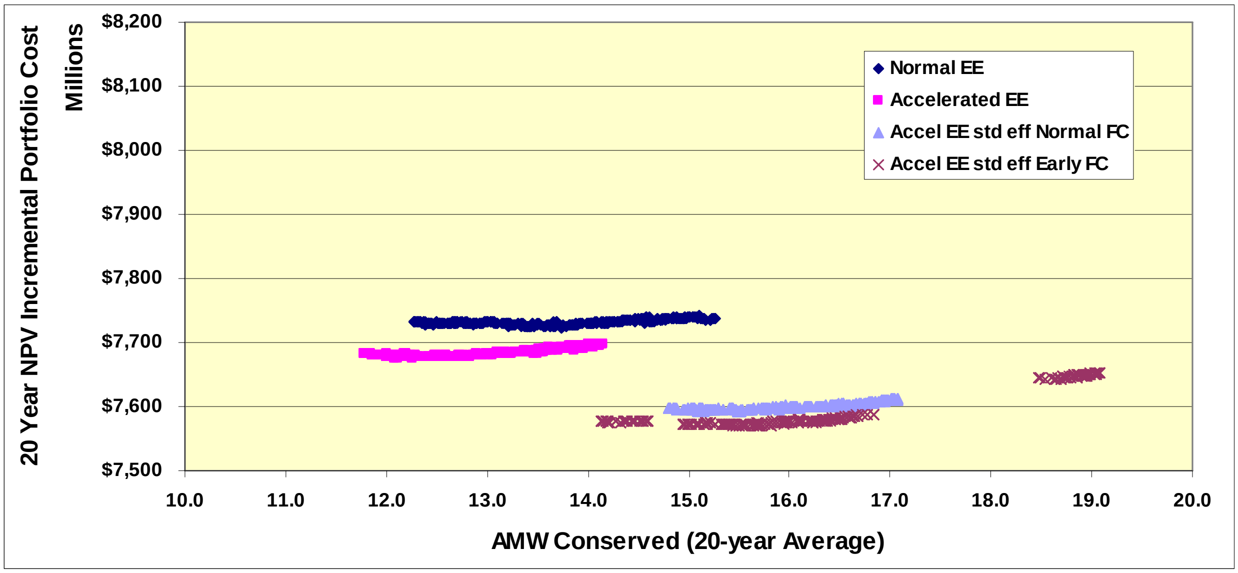



Exhibit X-31 compares the annual energy savings for the accelerated energy efficiency scenario, and the early replacement fuel conversion plus accelerated energy efficiency scenario. Overall, the results show that early replacement fuel conversion plus accelerated energy efficiency will save the PSE portfolio over 300 aMW. Early replacement fuel conversion contributes nearly 90 aMW of energy savings. Exhibit X-32 shows that the addition of demand-side resources not only lowers cost, but also lowers risk. The risk measure is cut by more than half with demand-side programs. This analysis demonstrates that a balanced portfolio with coal, gas, renewable, and demand-side resources is least cost.

**Exhibit X-31**
**Incremental and Cumulative Conservation**

| | Accelerated Energy Efficiency No Fuel Conversion | |
|---|---|---|
| Years | Average (AMW) | Cumulative (AMW) |
| 2006-2015 | 20 | 199 |
| 2016-2025 | 5 | 47 |
| 20-Year | 12 | 245 |

| | Accelerated Energy Efficiency Standard Efficiency Early Fuel Conversion | |
|---|---|---|
| Years | Average (AMW) | Cumulative (AMW) |
| 2006-2015 | 28 | 279 |
| 2016-2025 | 3 | 34 |
| 20-Year | 16 | 313 |

**Exhibit X-32**
**Comparison of Dynamic Results for 10% Renewable and 50/50 Gas & Coal with and without Demand-Side Programs**

| Dynamic Results- 100 Trials $ Millions | With Demand-Side Programs | Without Demand-Side Programs |
|---|---|---|
| Mean | 7,497 | 7,929 |
| Avg. > 90% | 7,804 | 8,642 |
| Risk (Avg. > 90% - Mean) | 307 | 713 |

*Summary of Demand-side Key Quantitative Findings*

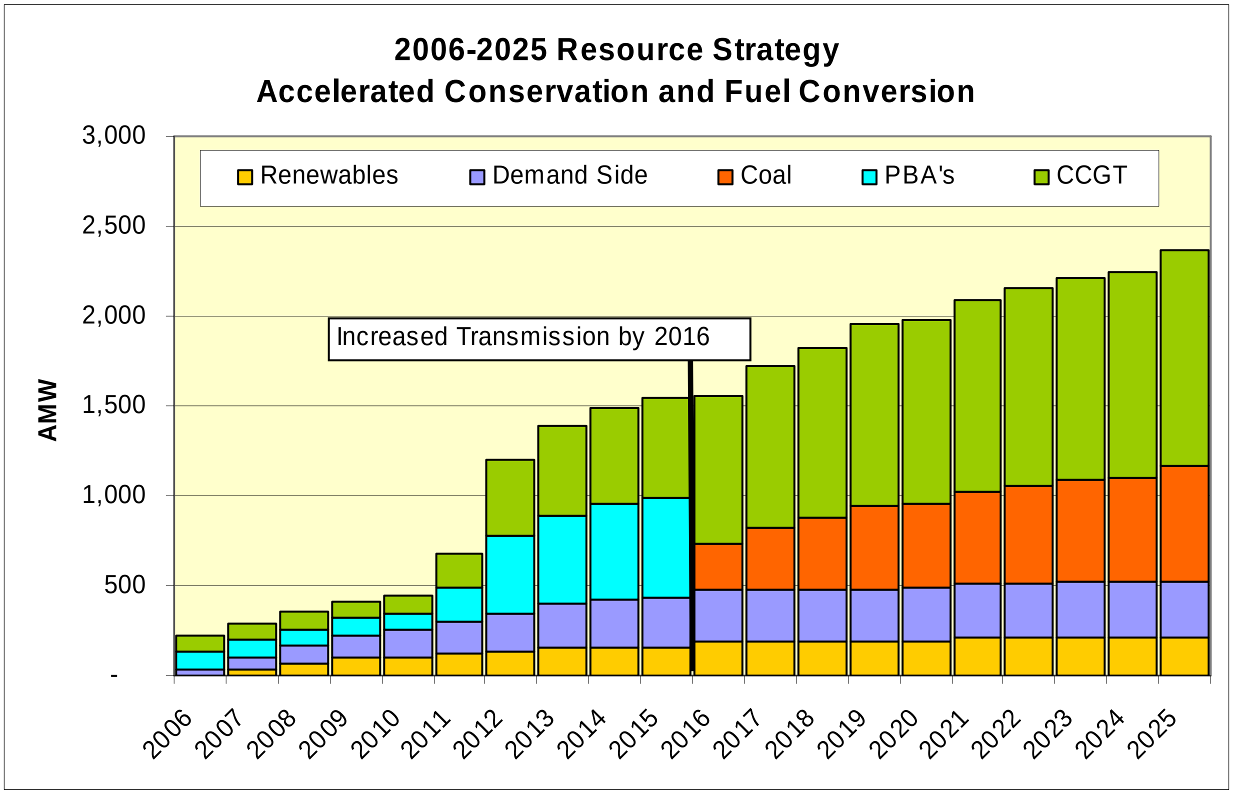
- Accelerated energy efficiency provides more benefit to the portfolio than a constant rate of energy efficiency.
- Early fuel conversion benefits the portfolio more the normal fuel conversion.
- After 20 years, the implementation of demand-side resources will result in over 300 aMW of energy savings.
- The least cost portfolio evaluated is diversified with coal, gas, renewable, and demand-side resources.

### H. Final Resource Portfolio

Exhibit X-33 shows how the long-term need for resources (2006-2025) could be filled under the constraints and assumptions described throughout this Least Cost Plan. The chart shows the least cost mix of additional resources to fill the planning standard need. The portfolio includes additional renewables such that 10 percent of load is met with renewables by 2013.

Accelerated energy efficiency can provide about 20 average megawatts for each of the first 10 years, then slows down to five average megawatts for the next 10 years. The chart shows the level with both accelerated energy efficiency and early fuel conversion, which increases the potential savings to 28 average megawatts for each of the first 10 years. During Period 1, before more transmission is built, PSE will depend on a mix of power PBAs and gas-fueled turbines. Only after transmission is built can coal be added.

**Exhibit X-33**



# XI. ELECTRIC RESOURCE STRATEGY AND ACTION PLAN

## A. Overview

This Least Cost Plan reinforces PSE's commitment to developing an executable electric resource acquisition strategy. As discussed throughout the document, long-term resource planning is conducted in an environment of increasing uncertainty. The challenge in developing the long-term resource strategy is to convert analytical results, key issues, and a consideration of risks and uncertainties into an actionable strategy.

An essential consideration in developing the resource strategy is recognition of the least cost planning cycle. While the Least Cost Plan develops a strategy for the 20-year planning horizon, the action plan covers the two years until the next Least Cost Plan is issued. Therefore, for some long-term resources, the action plan may call for feasibility work in this plan, while the final acquisition decision may not occur until after the next plan is issued.

The least cost planning cycle also requires a competitive acquisition process following the Least Cost Plan. Since PSE has identified a resource need (see Exhibit II-1), a draft resource acquisition request for proposals (RFP) is due to the Washington Utilities and Transportation Commission (WUTC) 90 days after this plan is filed. The Company does not presume to know the cost and availability of potential resources before the bid. Thus PSE's resource acquisition strategy acknowledges the competitive acquisition requirement and that actual resource cost will vary from the generic assumptions of this plan.

This chapter discusses how qualitative considerations and quantitative modeling results are combined to develop the electric resource acquisition strategy.

## B. Quantitative Results

As detailed in Chapter X, PSE's analyses produced varying results depending on the scenario assumptions. PSE chose a scenario approach to explore a range of uncertainties and to test the sensitivity of results to changes in key assumptions. The six scenarios analyzed examine changes related to regional transmission availability, gas price forecasts, greenhouse gas regulation, and load growth. PSE acknowledges that there are innumerable other scenarios that could be created by varying input assumptions on key issues. The number of scenarios and the scenario assumptions were chosen to address the key electric industry and PSE-specific challenges identified in this least cost planning process.

PSE did not assign likelihoods or weights to the various scenarios. Assigning weights is a subjective process and, given the large independent uncertainties, would provide combined results with little certainty or value. Without assigning weights, PSE was able to examine the results of all scenarios to assess which risk factors had the greatest impact upon portfolio performance across scenarios. Thus PSE concluded that assigning weights to the scenarios was not required to develop an executable resource acquisition strategy. The portfolio model results showed that, considering costs and risks across all scenarios, a resource portfolio with a diversified mix of renewable, natural gas, and coal resources is preferred.

## C. Non-Quantified Factors

The summary quantitative result is the starting point for PSE's resource strategy. As discussed above, the use of scenarios allowed PSE to explore important areas of uncertainty. However, the quantitative analysis did not fully capture all factors that impact the resource strategy. The resource strategy is also informed by the non-quantified considerations discussed throughout this Least Cost Plan. This section considers some of the key non-quantified considerations.

*Key Issues*

Chapter VIII provides a detailed discussion of the key electric planning issues considered for this Least Cost Plan. These issues impact resource availability and costs. Proper consideration of these issues can determine whether PSE's resource strategy can be successfully implemented. The key issues not integrated into the quantitative analysis are as follows:

- Corporate Financial Considerations: Corporate financial considerations generally favor owned resources over long-term power purchase agreements (PPAs). Other financial considerations include the timing for regulatory recovery and the potential for placing "construction work in progress" costs for long-lead time resources into rate base.

- Development Process and Status of the Independent Power Producer Industry: The availability of suspended Independent Power Producer (IPP) plants that were in development during the energy crisis is diminishing. The new "development for hire" model discussed in Chapter VIII means that utilities are involved earlier in project development and are required to take on more development risk. The development process for an IPP coal project is especially difficult, given the higher up-front costs, higher development risk, and long-lead time to carry costs.

- Existing Resources and Contract Renewals: Expiring contracts will cause a rapid increase in need from 2011-2013. PSE will explore contract renewal alternatives but the results of such discussions are unknown.

- Regulatory Environment: This Least Cost Plan assumes the current state regulatory model is maintained.

- New Technologies: Wind power is no longer considered a new or experimental technology. Today, technologies that appear to have commercial potential include wave technology and Integrated Coal-Gasification Combined Cycle (IGCC).

Although transmission costs, gas prices, and greenhouse gas regulation were considered in the quantitative analysis, it is important to recognize that PSE had to make assumptions about the timing and cost levels of these key variables in order to perform the analysis. Other non-quantified costs related to these challenges are stranded asset costs for transmission, and possible gas supply policy issues raised by the American Gas Federation that recommend restrictions on the use of natural gas for power generation

## D. Key Analytical Findings and Strategy Conclusions

Chapter X describes PSE's key analytical findings. These findings, considered in the context of the planning environment and along with the non-quantified uncertainties, are the basis for the Company's resource strategy. Set forth below is the strategy discussion for each key analytical finding.

*Findings and Discussion*

**Transmission availability is a key driver:** PSE used publicly available data and the Company's own experience to develop representative transmission cost estimates for the analyses. However, these estimates are more uncertain than other data. The development process for new transmission is also unknown and subject to substantial risk. The resource acquisition strategy needs to focus on developing better cost and availability estimates for transmission. Additionally, PSE needs to participate in regional efforts to clarify the transmission planning and development process.

**Coal is cost-competitive with natural gas in all of the scenarios:** Absent transmission considerations, coal would be the lowest direct-cost, long-term resource primarily because of the dramatic increase in forecast natural gas prices. However, the high transmission costs and high carbon risk could offset coal's low-cost advantage. PSE's resource strategy should explore electric transmission and coal transportation alternatives. PSE should also track and support new technology that may partially address environmental concerns, such as IGCC.

**Accelerated energy efficiency is selected in all of the scenarios:** PSE is already pursuing an accelerated conservation strategy based on the 2003 Least Cost Plan. The resource acquisition strategy will continue to include aggressive conservation acquisition.

**Scenarios with quantified carbon dioxide costs cause portfolios that include natural gas resources to be cost-competitive with portfolios that include coal resources**: Potential future greenhouse gas costs favor natural gas generation vs. coal generation. To partially mitigate future carbon emissions risk, PSE is maintaining its 10 percent renewable goal and continuing its accelerated conservation strategy. PSE will continue to track and participate in greenhouse gas initiatives as discussed in Chapter VIII.

**Fuel conversion is selected in all of the scenarios:** The model results indicate that PSE should acquire fuel conversion based upon the input assumptions. PSE will be working with regulators and stakeholders to address open issues associated with fuel conversion including: value to customers, free-riders, regulatory cost recovery mechanisms, and the capability of the gas delivery system.

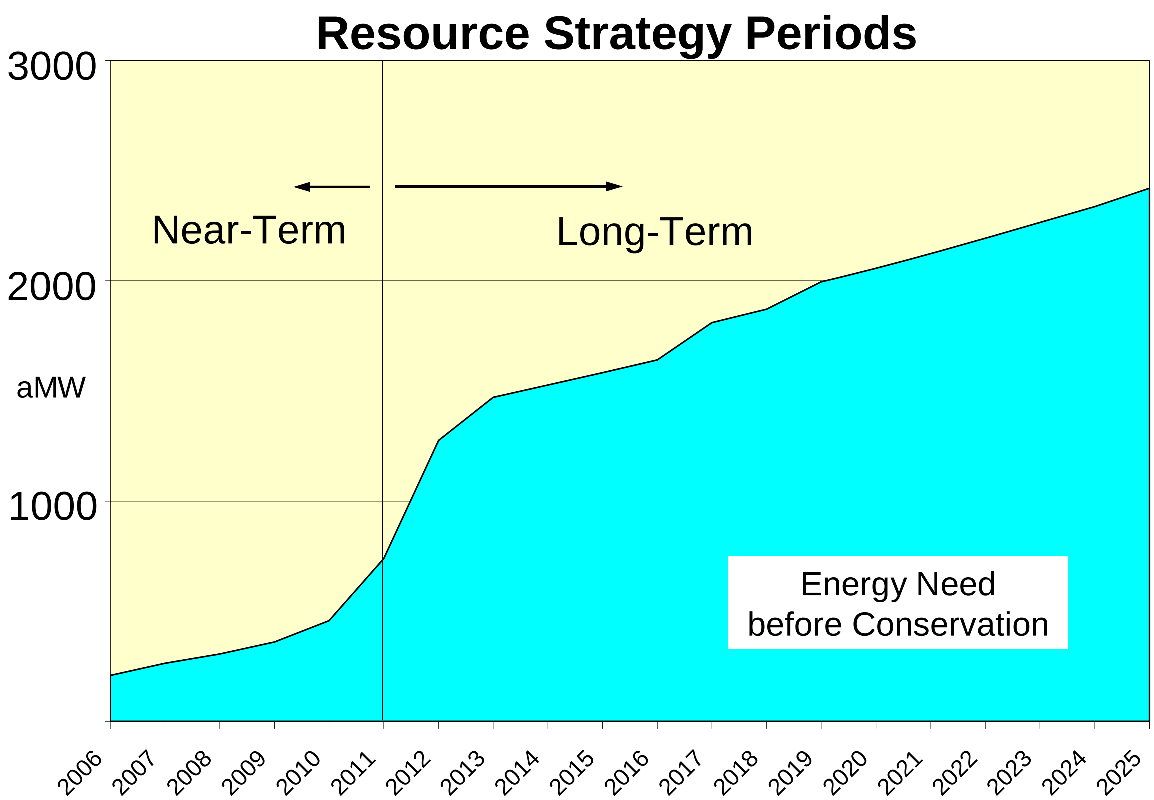
**Power bridging agreements (PBAs) appear cost-competitive given the assumptions used for the Least Cost Plan:** PBA price and market depth are unknown. PSE's resource strategy will need to include actions to confirm market purchase opportunities.

**Overall, considering both cost and risk, the analysis supports the selection of a diversified portfolio including accelerated energy efficiency, early fuel conversion, renewables to meet the 10 percent target, and 50/50 gas and coal :** The favored portfolio performed well across all scenarios (see Chapter X). The diversity of this portfolio also limits PSE's exposure to fuel-specific cost risks. Natural gas plants are subject to high fuel price risk and volatility. Coal plants face permitting, transmission, and environmental cost uncertainties.

### E. Resource Strategy and Actions

As noted earlier, over the planning period PSE has identified a pronounced time of rapidly increasing resource need from 2011-2013. This results from the expiration of several long-term PPAs as previously delineated. This distinct non-linearity also approximately coincides with PSE's estimates of when regional transmission solutions and long-lead resources may become available. Exhibit XI-1 illustrates PSE's energy need forecast and splits the planning period at the start of the rapid increase in 2011.

**Exhibit XI-1**



Prior to 2011, PSE anticipates a moderate resource need. Resource alternatives and constraints are relatively known. However, beyond 2011, PSE will have a much larger resource need, and resource cost and availability will be subject to high uncertainty. For these reasons, PSE has organized its resource strategy discussion into two periods. Near-term includes resources expected to come online between 2006 and approximately 2011. Long-term includes resources expected to come online between 2012 and the end of the planning period.

### E.1 Near-Term (2006-2011)

*Characteristics of the Near-Term*

The primary constraint of the near-term is transmission. Access to prime wind and coal generation areas is restricted. Time constraints may also limit availability of long-lead time resources and green-field developments. PSE is expecting a decreasing pool of natural gas plants that were suspended in development during the Western energy crisis. FERC's market power tests (sections 203 and 206 rules) may also limit PSE's acquisition of existing IPP projects.

*Strategic Objectives for the Near-Term*

- Confirm costs and availability of specific generating resources.
- Test energy market for purchase opportunities.
- Convert demand-side supply estimates into specific programs.
- Resolve remaining issues with fuel conversion.
- Acquire diverse mix of available demand and supply resources.

*Expected Resource Alternatives*

| **Near-Term – Potential Resource Alternatives** |
| --- |
| • Energy efficiency<br>• Small to medium renewables<br>• Wind expansion (transmission limited)<br>• Gas generation power bridging agreements<br>• Remaining gas plants in development<br>• Utility and marketer power bridging agreements |

*Acquisition Activities for the Near-Term*

Energy Efficiency – Develop new electric and gas energy efficiency savings targets for 2006-2007 that are informed by Least Cost Plan analyses and file new program tariffs with the WUTC by the end of 2005.

Initiate an energy efficiency resource acquisition RFP process that complies with regulatory requirements. This RFP will address: 1) long lead times due to 2006-2007 targets and program commitments needing to be made before the RFP process can be completed; and 2) development of a "targeted" RFP, focused on specific markets and/or technologies that complement PSE's programs.

Fuel Conversion – Complete evaluation of single-family and multifamily fuel choice pilots and explore the feasibility of further developing fuel conversion programs.

Demand Management – Explore the feasibility of implementing one or more demand-response pilots, with input from regulators and stakeholders.

Green Power Program and Community Renewable Generation – By the end of 2005, develop a two-year goal for the Green Power program covering 2006-2007. Continue to encourage small-scale solar or other renewable energy demonstration projects.

New Electric Generating Resources – Initiate a competitive solicitation process for new electric energy resources by filing a draft RFP and accompanying materials with the WUTC within 90 days of the submittal of this Least Cost Plan.

### E.2 Long-Term (2012-2025)

*Characteristics of the Long-Term*

- Potential regional transmission solution.
- Potential long-lead resource availability, such as coal and new combined heat and power with a capacity large enough to replace expiring contracts.
- Potential for new technologies or innovative mix of fuel transportation and energy transmission with new resource locations.

*Strategic Objectives for the Long-Term*

- Confirm the costs and availability of long-term resources evaluated in the Least Cost Plan.
- Identify and manage long-term risks.
- Maintain and establish access to a diverse mix of future resources.
- Read the “signposts” to identify likely future scenarios.

*Expected Resource Options*

| **Long-Term – Potential Resource Options** |
|---|
| • Energy efficiency<br>• Additional renewables (with transmission solution)<br>• New gas plant development<br>• New coal plant development (with transmission solution)<br>• IGCC or new technology |

*Acquisition Activities for Resources Coming Online in Long-Term (2012-2025)*

Note that PSE plans to perform the following activities over the next two years, for resources planned for 2012 and beyond.

New Electric Resources – Explore contract renewal discussions with expiring cogeneration projects to maintain resource availability.

Explore feasibility, partnering opportunities, and transmission alternatives for remote-located, coal-fueled and renewable generation.

Seek opportunities for emergent technologies including biomass, geothermal, and IGCC.

# XII. EXISTING GAS SUPPLY-SIDE PORTFOLIO RESOURCES

Chapter XII provides an overview of PSE's existing gas supply-side resource portfolio. The chapter details PSE's pipeline capacity, storage capacity, other capacity resources and gas supplies. The chapter continues with an assessment of PSE's existing gas supply/demand balance for PSE's gas customers. Finally, the chapter concludes with a summary of PSE's gas resources related to its electric generation portfolio.

In the natural gas industry, long-term resource planning has traditionally focused on company-owned or contracted transportation and storage services. With the maturation of liquid supply trading points and unbundled pipeline services, planners have presumed that if a company were to hold firm transportation capacity from the supply point to the city-gate, one could always access supplies on a short- or long-term basis. This fundamental principle is still true. However, as the overall supply-demand balance has come into an equilibrium status, occasional supply imbalances can create extremely volatile pricing. PSE's policies have long acknowledged the potential for this situation. Those policies provide for maintaining long-term firm contracts from reliable suppliers for both pipeline capacity and gas supply from geographically diverse locations.

## A. Pipeline Capacity Resources

PSE holds two categories of pipeline capacity: "direct connect" pipeline capacity, which moves supplies from production areas, storage or interconnections with other pipelines, and delivers directly into PSE's distribution system; and "upstream" capacity, which accesses production, storage and market centers further upstream from the direct connect capacity.

*Direct-Connect Pipeline Capacity*

As PSE's only direct connect pipeline, all gas delivered to PSE's gas distribution system is handled last by Northwest Pipeline ("NWP"). PSE holds 465,053 Dth/day and 413,557 Dth/day of firm TF-1 and TF-2 transportation capacity, respectively, on NWP. Receipt points on the NWP contracts allow access to supplies from British Columbia, Alberta and the Rocky Mountain producing regions. The structure of some of the contracts allows for significant flexibility in sourcing gas from the various production regions on a day to day basis. Furthermore, it provides valuable zonal delivery point flexibility.

Given such exclusive reliance, PSE was understandably concerned when in 2003, NWP experienced two pipeline failures on its 26-inch mainline in Washington. On Dec. 17, following the second failure, NWP notified customers that it was taking steps to idle a 268-mile segment of the 26-inch pipeline between Sumas and Washougal, near Portland.

As a result of this action, pipeline capacity south from Sumas was temporarily reduced by about 360,000 Dth/d, from 1,310,000 to approximately 950,000 Dth/d. To date, no customers have been affected as a result of this reduction, nor has there been any decrease in transportation volumes. Even during the cold snaps in January of 2004 and 2005, NWP was able to meet the firm service requirements of its customers. NWP worked with the Office of Pipeline Safety (OPS) to restore 131,000 Dth/d of capacity by the end of June 2004. This effort is expected to allow NWP to satisfy customers' firm nominations between the summer of 2004 and fall of 2006.

NWP has recently filed an application with the Federal Energy Regulatory Commission (FERC) to replace the contractual capacity of the 26-inch pipeline with a new, larger diameter pipe and additional compression by November 2006. This "Capacity Replacement Project" is not a mile-for-mile replacement of the 26-inch pipeline, but is expected to restore all of the capacity flexibility and reliability of the original facilities. The Capacity Replacement Project is expected to cost approximately $334 million. When it is incorporated into rates in January 2007, it will have a significant impact on gas costs in the region. The current 31-cent per Dth 100 percent load factor rate for vintage system capacity is expected to increase to about 39 cents, and capacity from the Evergreen Expansion in 2003 is expected to rise from a levelized 100 percent load factor rate of 43 cents per Dth to 44 cents.

PSE reviewed the NWP Capacity Replacement Project proposal, compared it to other proposals to transport gas to western Washington, and concluded that it is the most cost-effective solution for the region to retain access to gas supplies. As a result, PSE has pronounced its support for the timely completion of the Capacity Replacement Project.

*Upstream Pipeline Capacity*

In order to transport gas supply from production basins or trading hubs to the NWP system, PSE holds capacity on several upstream pipelines. To transport supplies from the AECO trading hub in Alberta to the interconnect with NWP in eastern Washington, PSE holds the following: approximately 80,000 Dth/day of capacity on each of TransCanada's Alberta systems—TCPL-Alberta (formerly known as the “Nova” or NGTL system) and TransCanada’s BC system (TCPL-BC, formerly known as the Alberta Natural Gas or “ANG” system), and 90,392 Dth/day on TransCanada’s Gas Transmission Northwest (“GTN,” formerly known as PG&E Gas Transmission or PGT).

To transport supplies from the producing area in northern British Columbia, PSE holds approximately 40,000 Dth/day of capacity on Duke Energy Gas Transmission’s Westcoast Pipeline (“Westcoast”) from Station 2 to the interconnect with NWP at Huntingdon, B.C. / Sumas, WA. Further discussion of trends in the gas supply market and the growing need for upstream pipeline capacity appears in the next chapter, which discusses new gas supply-side resource opportunities.

Exhibit XII-1 provides a summary of PSE’s pipeline capacity position.

**Exhibit XII-1.1**
**PSE Pipeline Direct Connect Capacity Position (Dth/Day)**

| **Pipeline / Receipt Point** | | **TOTAL** | **Year of Expiration** | | | |
|---|---|---|---|---|---|---|
| | **Notes** | | **2006** | **2008** | **2009** | **Other** |
| **Direct Connect Pipeline / Receipt Point** | | | | | | |
| NWP / Westcoast Interconnect (Sumas) | 1 | 204,761 | - | 58,000 | 128,705 | 18,056 (in 2016) |
| NWP / GTN Interconnect (Spokane) | 1 | 75,936 | - | - | 75,936 | - |
| NWP / various Rockies | 1 | 184,356 | 616 | 43,848 | 131,836 | 8,056 (in 2016) |
| ***Total TF-1*** | | ***465,053*** | **616** | ***101,848*** | ***336,477*** | ***26,112*** |
| NWP / Jackson Prairie | 1,2 | 343,057 | 343,057 | - | - | - |
| NWP / Plymouth LNG | 1,2 | 70,500 | 70,500 | - | - | - |
| ***Total TF-2*** | | ***413,557*** | ***413,557*** | **-** | **-** | **-** |
| ***Total Capacity to City-Gate*** | | ***878,610*** | ***414,173*** | ***101,848*** | ***336,477*** | ***26,112*** |

**Exhibit XII-1.2**
**PSE Pipeline Upstream Capacity Position (Dth/Day)**

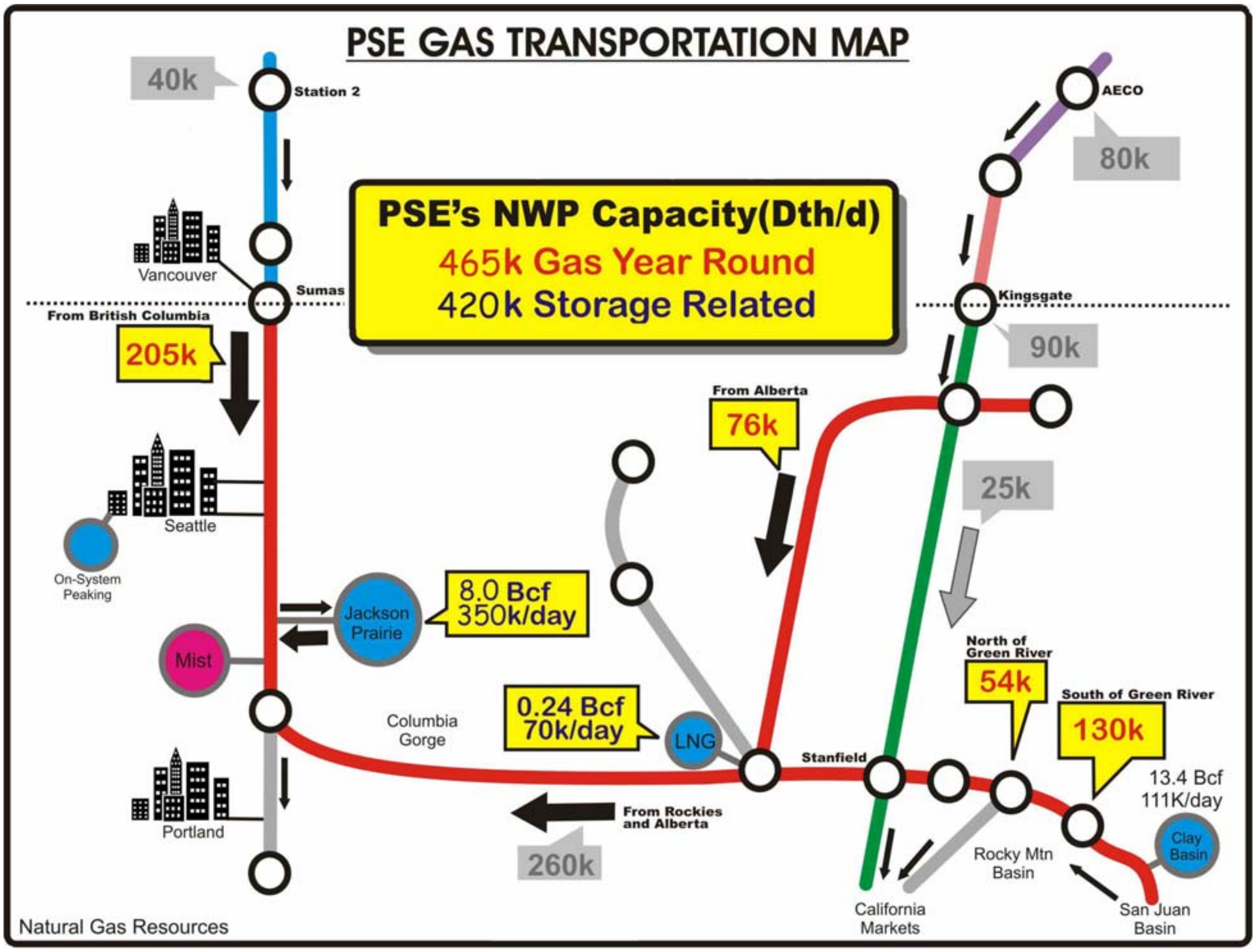
| Pipeline / Receipt Point | Notes | TOTAL | Year of Expiration | | | |
|---|---|---|---|---|---|---|
| | | | 2006 | 2008 | 2009 | Other |
| **Upstream Pipeline / Corridor** | | | | | | |
| TCPL-Alberta / from AECO to TCPL-BC Interconnect (A-BC Border) | 3 | 80,000 | | | | |
| TCPL-BC / from TCPL-Alberta to TCPL-GTN Interconnect (Kingsgate) | 4 | 80,000 | | | | |
| TCPL-GTN / from TCPL-BC Interconnect to NWP Interconnect (Spokane) | 5 | 65,392 | - | - | - | 65,392 (in 2023) |
| TCPL-GTN / fromTCPL-BC Interconnect to NWP Interconnect (Stanfield) | 5,6 | 25,000 | - | - | - | 25,000 (in 2023) |
| Westcoast / from Station 2 to NWP Interconnect (Sumas) | 4,7 | 40,000 | - | - | - | 25,000 (in 2014)<br>15,000 (in 2019) |
| ***Total Upstream Capacity*** | 8 | ***290,392*** | | | | |

***Notes to Tables XII-1A and XII-1B:***

1) *NWP contracts have automatic annual renewal provisions, but can be canceled by PSE upon one year's prior notice.*
2) *TF-2 service is intended only for redelivery of storage volumes during the winter heating season, and as such has significantly lower annual costs than the year-round service provided under TF-1.*
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 prior 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 supplies acquired at interconnects in the Rockies and for some of the supplies available at Sumas.*

Exhibit XII-2 graphically displays PSE's direct connect and upstream pipeline capacity:

**Exhibit XII-2**




Firm pipeline transportation capacity carries the right, but not the obligation, to transport up to a maximum daily quantity (MDQ) of gas from one or more receipt points to one or more delivery points.[1] This transportation activity is conducted in accordance with the pipeline's published tariff, as approved by FERC for U.S. pipelines or by the National Energy Board (NEB) or provincial regulators for Canadian pipelines. The tariff defines the scope of service, which includes the number of days that the transportation service is available, along with the rates, rate adjustment procedures and other operating terms and conditions.

[1] From a risk management perspective, pipeline capacity can be viewed as an option that provides the contract holder with the right, but not the obligation, to buy gas at one location and deliver or sell it at another.

All of the transportation contracts are firm contracts, available for use 365 days each year. The NWP TF-2 firm transportation contracts have annual contract quantities (ACQ) that generally correspond to the storage capacity held by the shipper at the receipt point and are intended for use only during the heating season. While the annual contract term limits TF-2 service to a quantity equal to the storage ACQ, the cost of this service proves to be significantly lower than holding firm pipeline capacity for the entire year.

PSE may also use interruptible transportation, sometimes referred to as "best-efforts" agreements, from NWP under rate schedule TI-1. This service allows NWP to provide a transportation service that is subordinate to the rights of the shippers holding and using firm transportation capacity. To the extent that the firm shippers do not use their pipeline capacity, they may receive interruptible capacity. Since TI-1 transportation service can be interrupted, PSE does not rely upon it to meet peak demand; thus it serves a limited role in PSE's gas resource portfolio.

Additionally, firm transportation capacity on NWP and GTN may be "released" and remarketed to third parties under the FERC-approved pipeline tariffs. Firm capacity on Westcoast can also be remarketed under recently instituted "streamlined capacity assignment" provisions. PSE aggressively releases capacity during time periods when it has identified surplus capacity and where market conditions provide value back to customers. The capacity release market can also provide PSE with access to additional firm capacity, when available.

Consistent with the pipeline's service obligations, the rate for firm transportation capacity requires a fixed payment, regardless of whether PSE uses the capacity. The rate for interruptible capacity is negotiable, and is typically billed as a variable charge.

## B. Storage Resources

PSE's natural gas storage represents an important and cost-effective component of the Company's capacity portfolio because of the many advantages it offers. Primarily, storage offers an immediate and controllable source of firm gas supply. Storage also proves advantageous as it can be used as a pooling point for the quantities of gas purchased, but not consumed during off-peak seasons, or times of the year when gas prices tend to be less expensive. PSE can achieve significant commodity price savings by buying gas during the relatively low demand period of the summer. In addition, coupling the market area storage and peaking facility located near PSE's system (Jackson Prairie and Plymouth LNG) with the TF-2 transportation service, allows PSE to purchase significantly less year-round pipeline capacity than it would otherwise need.

Further, storage allows PSE to use its annual transportation and gas supply contracts at a higher load factor, minimizing the average cost of gas to its customers. In addition, PSE uses underground storage for daily balancing of its distribution system loads and its volumes flowing on the interstate pipeline. If PSE's loads run higher or lower than the forecasted amount, PSE will use its storage to handle operational imbalances throughout the day, and minimize any pipeline balancing or scheduling penalties.

PSE also uses storage to balance the city-gate gas receipts with the actual loads of its Gas Transportation customers. The industrial and commercial customers who elect gas transportation service (as an alternative to gas sales service) make nominations directly or through marketer-agents to move city-gate gas deliveries to their respective meters. Customers, or marketers providing services to customers, often have daily imbalances since their scheduled gas deliveries do not match their actual gas consumption. On a daily basis, PSE provides balancing services in connection with its transportation tariff, and relies upon storage to manage these imbalances.

PSE has contractual access to two underground storage projects, each of which serves a different purpose in the Company's resource portfolio. Jackson Prairie storage, located in Lewis County, Wa., is an aquifer-driven storage field that has been designed to deliver large quantities of gas over a relatively short period of time. Clay Basin—a depleted reservoir storage field located in northeast Utah—provides supply area storage and a winter gas supply. PSE has 343,057 Dth/day of TF-2 transport capacity to deliver gas from Jackson Prairie and can use its Rockies-originated TF-1 transportation capacity from Clay Basin. Exhibit XII-3 provides more detail about PSE's storage capacity.

**Exhibit XII-3**
**PSE Gas Storage Position**

| | STORAGE CAPACITY (DTH) | INJECTION CAPACITY (DTH/DAY) | WITHDRAWAL CAPACITY (DTH/DAY) | EXPIRATION DATE |
|---|---|---|---|---|
| Jackson Prairie – Owned (1) | 6,854,879 | 147,334 | 294,667 | N/A |
| Jackson Prairie – NWP SGS-2F (2) | 1,181,021 | 24,195 | 48,390 | 2006 |
| Jackson Prairie – NWP SGS-2F (3) | 140,622 | 3,352 | 6,704 | 2006 |
| Clay Basin | 13,419,000 | 55,900 | 111,825 | 2013/19 |
| **Total** | **21,454,900** | | **454,882** | |

***Notes to Exhibit XII-3:***
*1 Storage Capacity at 12/31/2004. Storage Capacity will continue to grow due to current expansion of the process.*
*2 NWP contracts have automatic annual renewal provisions, but can be canceled by PSE upon one year's prior notice.*
*3 Obtained through capacity release market*.

Located in PSE's market area in Chehalis, Wa., the Company uses Jackson Prairie and the associated NWP TF-2 transportation capacity to meet seasonal load requirements, for daily load balancing, and to eliminate the need to contract for year-round pipeline capacity to meet winter-only demand. PSE primarily uses Jackson Prairie to meet the intermediate peaking requirements of core customers.

PSE, NWP and Avista Utilities each own an undivided 1/3 interest in the Jackson Prairie Gas Storage Project. PSE operates the project under FERC authorizations. Included in Exhibit XII-4 is PSE's share of the firm daily deliverability and firm seasonal capacity from the project. PSE has access to additional deliverability and seasonal capacity through a contract for SGS-2F storage service from NWP and from a third party through the capacity release market. The storage contract with NWP allows for automatic annual renewal from the October 31, 2004 termination date, but PSE holds the unilateral right to terminate the agreement on one-year notice. PSE has access to best efforts withdrawal rights of up to 58,000 Dth/day, and interruptible transportation service from Jackson Prairie, which we believe would be quite reliable.

Questar Pipeline owns and operates the Clay Basin storage facility in Daggett County, Utah. This depleted gas reservoir was developed to allow gas to be stored during the summer and withdrawn all winter. PSE holds the right, under two contracts, to store up to 13,419,000 Dth, and withdraw up to 111,825 Dth/day. FERC regulates the terms and conditions, including rates, of this agreement.

PSE also uses Clay Basin as a pooling point for purchasing gas, and as a partial supply backup in the case of well freeze-offs, or other supply disruptions in the Rocky Mountains during the winter.[2] As such, gas stored at Clay Basin provides a reliable source of available gas throughout the winter, including on-peak days. Gas withdrawn from Clay Basin is delivered to PSE's system, and to other markets directly or indirectly, using firm, TF-1 transportation.

Similar to firm pipeline capacity, firm storage arrangements require that a fixed charge be paid regardless of whether the storage service is used. 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 the Company's PGA, while the cost of service associated with the PSE-owned portion of Jackson Prairie is recovered from customers through base rates. PSE pays a variable charge for gas injected or withdrawn from storage at Clay Basin.

### C. Peaking Supply and Capacity Resources

PSE has firm access to other resources that provide capacity and gas supplies to meet peaking requirements or short-term operational needs. Liquefied natural gas (LNG) storage, LNG satellite storage, vaporized propane-air (LP-Air) and a Peak Gas Supply Service (PGSS) provide firm gas supplies on short notice for relatively short periods of time. PSE typically uses these sources to meet extreme peak demand during the coldest few hours or days, and generally only as the supply of last resort due to their relatively higher variable cost. LNG, PGSS, and LP-Air do not afford all of the flexibility of other supply sources. Exhibit XII-4 provides an overview of PSE's peaking gas resources.

[2] From a risk management perspective, Clay Basin provides value as an arbitrage tool, and serves as a partial hedge to price spikes in the Rockies supply basins.

**Exhibit XII-4**
**PSE Peaking Gas Resources**

| | STORAGE CAPACITY (DTH) | INJECTION CAPACITY (DTH/DAY) | WITHDRAWAL CAPACITY (DTH/DAY) | TRANSPORT TARIFF |
|---|---|---|---|---|
| Plymouth LNG | 241,700 | 1,208 | 70,500 | TF-2 |
| Gig Harbor LNG (1) | 5,250<br>10,500 ('06-07)<br>15,750 ('10-11) | 1,500<br>3,000 ('06-07) | 2,000<br>3,000 ('06-07)<br>4,000 ('08-09)<br>5,250 ('10-11) | On-system |
| Swarr LP-Air | 128,440 | 16,680 (2) | 10,000 | On-system |
| PGSS | NA | NA | 48,000 | City-gate delivered, via TF-1 or commercial arrangement |
| Total | 375,390 | 19,388 | 131,500 | |

***Notes to Exhibit XII-4:***

*1 Withdrawal capacity will grow as the load on the distribution system grows thus allowing more supply to be absorbed.*

*2 Swarr holds 1.24 million gallons. At a refill rate of 111 gallons/minute, it takes 7.7 days to refill Swarr. This equates to 16,680 Dth/day*

NWP owns and operates an LNG storage facility located at Plymouth, Wa., and provides a gas liquefaction, storage, and vaporization service under its LS-1 and LS-2F tariffs. PSE holds a long-term contract that provides for seasonal storage with an ACQ of 241,700 Dth, liquefaction with an MDQ of 1,208 Dth/day, and a withdrawal MDQ of 70,500 Dth/day. The ratio of injection and withdrawal rates to the storage capacity means that it can take PSE over 200 days to fill to capacity, but only three and one-half days to empty. Due to these operating characteristics, PSE uses the LS-1 service to meet its needle-peak demands, with LS-1 gas delivered to PSE's city-gate using firm TF-2 transportation.

PSE supplements its gas-distribution system in the Gig Harbor area with a new, satellite liquid natural gas (LNG) facility. The facility has been constructed to ensure that a remote but rapidly growing region of the distribution system has sufficient gas supply during peak weather events.

The LNG facility is referred to as a “satellite” because it is designed to receive, store, and vaporize LNG that has been liquefied at other LNG facilities.  PSE transports the LNG by tanker truck from third-party providers.  Because the source of the LNG is outside the PSE distribution system, the Gig Harbor LNG facility represents an incremental supply source and is therefore included in the Peak Day resource stack, even though the plant was justified based on the distribution capacity need.  The hourly deliverability, total storage capacity, and the ability of the distribution system to absorb the supply limit the daily deliverability of the plant.  The deliverability rating increases over time as loads on the distribution system increase.  Although this LNG facility can benefit only that portion of the distribution system adjacent to the Gig Harbor plant, its operation allows gas supply from pipeline interconnects or other storage to be diverted elsewhere.  By fall of 2006, an additional tank will be installed at the site. This will double the on-site storage capacity and increase the operational flexibility of the plant, as one tank can be filled while the other is used.   PSE anticipates that a third tank may be installed by 2010.  However, that decision will be based on distribution capacity need rather than supply need.

PSE maintains the Swarr LP-Air facility with a net storage capacity of 128,440 Dth equivalent, and has the ability to vaporize approximately 30,000 Dth per day.  At the maximum vaporization capacity, this provides a little over four days of supply.  Since the propane air facilities connect to PSE’s distribution system, PSE requires no upstream pipeline capacity.  PSE typically uses this LP-Air facility to meet extreme hourly or daily peak demand, or to supplement distribution pressures in the event of a pressure decline on NWP.  Given the operational flow characteristics of its system, PSE has determined that it is highly unlikely to operate the LP-Air facility for more than 8 hours per day, to meet the early morning and evening peak demand periods on the distribution system.  Therefore, for peak-day planning purposes this facility will be considered to supply only 10,000 Dth per day.

Under its PGSS agreements, PSE has the contractual right to call on third party gas supplies for a limited duration during peak periods.  Currently, PSE has the right to purchase up to 48,000 Dth/day at a price tied to the replacement cost of distillate oil for up to twelve days during the winter season.[3]   This supply is available at Sumas and would be delivered to PSE distribution city gates on a firm basis through dedication of TF-1 capacity (when such capacity is not needed for other supplies) or by way of a commercial exchange agreement with a third party.

The PGSS agreement expires after the 2011-2012 heating season, and renewal options are uncertain at this time.

Some of PSE's peak shaving resources require that a fixed charge be paid regardless of whether the resource is used. The LNG service is billed to PSE pursuant to a FERC-approved tariff, and recovered from customers through the company's PGA. The cost of the PGSS contract is also recovered through the PGA. The cost of service associated with the on-system LP-Air plant and Gig Harbor LNG plant is recovered from customers through base rates. PSE pays a variable charge on gas injected or withdrawn from LNG storage.

### D. Gas Supplies

By maintaining pipeline capacity to various supply basins or trading hubs, PSE gains access to sources of natural gas. The price and delivery terms across supply basins tend to be very similar, although the price levels from one day to the next can vary significantly. Longer term, prices at a given supply hub may "separate" from other regional supply locations due to shortages of pipeline capacity. This separation cycle typically lasts one to three years and is alleviated with the construction of additional pipeline infrastructure. Over the 20 year planning horizon, PSE would expect the regional supply basins to have generally comparable pricing, with differentials primarily driven by differences in the cost of transportation.

Gas supply contracts tend to have a shorter duration than transportation contracts. While the terms outlined in gas supply contracts ensure that the gas supplier will perform, PSE's firm transportation capacity grants access to supply basins and trading hubs that offer a greater likelihood of availability and liquidity. In the event of supplier default, PSE can always use its pipeline capacity to buy gas from other suppliers or marketers at market locations along the pipeline. PSE's long-term planning has primarily focused on the reliability of its pipeline delivery capacity and the long-term outlook for natural gas supply.

In recent times, current and long-term views for natural gas availability suggest slower rates of growth in gas supply, and increased rates of growth in demand. This leads many experts to believe that significant imports of LNG into North America will be required to maintain a supply/demand balance. Like many LDCs, PSE is somewhat disadvantaged in the buying arena because of its very low load-factor market relative to industrial and power-generation

[3] In essence, this is a call option with a variable strike price equal to the then current, delivered price of distillate oil.

markets, meaning access to additional gas supply may be more difficult over time. PSE has therefore developed a policy to maintain supply under long-term contracts at a level sufficient to serve at least 50 percent of its annual sales volumes.

PSE has a mix of long-term gas supply contracts (more than 2 years) and short-term gas supply contracts (2 years or less) to meet average loads during different months. Long-term contracts and medium-term contracts are typically baseload supplies delivered at a constant daily rate over the contract period. Additionally, PSE can contract for seasonal baseload firm supply, typically for the winter months. The Company enters into forward-month transactions to supplement the baseload transactions, particularly for the months of November through March. During “bid week”—the week prior to the beginning of the upcoming delivery month—PSE estimates the average load requirements for the upcoming month and enters into month-long transactions to balance load. On a daily basis, the company does not plan to be long or short going into any day, but instead balances the position using storage and day-ahead purchases and off-system sales transactions. During the gas day, the company uses its Jackson Prairie storage for balancing.

Exhibit XII-5 provides an example of the weighting between different contract terms in 2004-2005. It summarizes the long-term gas contracts in PSE’s portfolio as of the beginning of 2005. As can be seen in the table, the contracts have primary-term termination dates that are spread out over a number of years. The volumes under contract today, taken at their contractual 100 percent load factor, represent approximately 66 percent of PSE’s forecasted 2005 annual sales volumes. As contracts expire, PSE will renew, extend or replace the contracts with similar long-term contracts.

**Exhibit XII-5**
**Long-term Gas Supply Contracts at Jan.2005**

| Contract | Basin | Winter Volume (Dth/d) | Summer Volume (Dth/d) | Primary Term Start Date | Primary Term Termination Date |
|---|---|---|---|---|---|
| Contract 1 | **System** | **500** | **500** | 05/15/85 | 05/15/05 |
| Contract 2 | BC/Sumas | 20,000 | 20,000 | 11/01/90 | 10/31/06 |
| Contract 3 | BC/Sumas | 10,000 | 10,000 | 11/01/04 | 10/31/08 |
| Contract 4 | BC/Sumas | 20,000 | 20,000 | 11/01/04 | 10/31/09 |
| Contract 5 | BC/Sumas | 10,000 | 10,000 | 11/01/04 | 10/31/09 |
| Contract 6 | BC/Stn 2 | 10,000 | 10,000 | 11/01/04 | 10/31/09 |
| Subtotal | **BC** | **70,000** | **70,000** | | |
| Contract 7 | Alberta | 20,000 | 20,000 | 11/01/04 | 10/31/08 |
| Contract 8 | Alberta | 10,000 | 10,000 | 11/01/04 | 10/31/09 |
| Subtotal | **Alberta** | **30,000** | **30,000** | | |
| Contract 9 | Rockies | 9,000 | 9,000 | 05/01/03 | 04/30/06 |
| Contract 10 | Rockies | 10,000 | 10,000 | 04/01/05 | 10/31/09 |
| Contract 11 | Rockies | 10,000 | 10,000 | 04/01/05 | 10/31/09 |
| Contract 12 | Rockies | 30,000 | 20,000 | 11/01/04 | 10/31/14 |
| Subtotal | **Rockies** | **59,000** | **49,000** | | |
| TOTAL | | 159,500 | 149,500 | | |

PSE will continue to monitor and evaluate the gas markets to identify trends and opportunities to fine-tune its policy for contracting gas supply on a long-term vs. short-term basis. Because of the liquidity of the markets in which PSE participates, there does not appear to be a significant advantage (other than reliability) to holding long-term contracts. PSE will continue to model and analyze varying levels of long-term contracts, seeking to identify costs and benefits to develop a more clearly delineated policy guideline.

*PSE Participation in the Gas Futures Market*

PSE began hedging its core gas portfolio as of September 2002. The Company utilizes hedge instruments, such as fixed-price physical transactions and fixed-price financial swap transactions. These were determined to be the most effective means of hedging at the time.

The New York Mercantile Exchange (NYMEX) futures market has a delivery point at Henry Hub in Louisiana. However, there can be a significant price variance between Henry Hub and the physical locations from which PSE sources its supply (the Rockies, British Columbia and Alberta). In order for a futures hedge to be fully effective, PSE would need to enter into an Exchange for Physical (EFP) transaction with another party to execute local delivery. In this way, PSE could enter into a fixed price hedge that transpires into physical delivery.

Having a futures account requires opening an account with a clearing firm, and establishing commercial relationships with floor brokers who can execute transactions with the NYMEX on behalf of customers. The clearing firm would require PSE to post a margin call, and there would be a daily settlement into and out of the PSE account, depending upon the size of PSE's futures position and the daily direction of futures prices. Then, PSE would enter into an EFP transaction with a counterparty, who would agree to physical delivery at the agreed upon location. The two parties would exchange futures at the NYMEX as part of the EFP transaction. The level at which the futures are exchanged, combined with the basis price of the EFP contract, sets the price for the physical delivered gas.

While the EFP mechanism provides a viable means to hedge, PSE has been able to negotiate much more simple, fixed-price physical agreements directly with regional suppliers. Not only are these transactions far simpler, they remove the need for both opening and managing a futures account with a clearing firm, and entering into EFPs with regional suppliers.

In addition, a liquid market has developed for the over-the-counter financial derivatives for fixed-price and basis transactions. From a pricing perspective, these transactions are similar to futures trades and EFPs, but they involve a simpler process, as transactions do not require intermediary clearing firms, floor brokers and the NYMEX. A master agreement, or an ISDA agreement, governs these transactions, and the parties negotiate a range of contractual items including credit, netting and cross-collateral terms. These transactions have worked well for PSE, as they can be combined with physical index purchases. Moreover, many of PSE's long-term and short-term contracts are index-based contracts, thus the financial derivatives work well within the company's portfolio.

On a going-forward basis, the company will continue to evaluate the hedging mechanisms available in the market to weigh the benefits of each device to determine its applicability in

PSE's portfolio. PSE will consider the values afforded to price stability by its customers (market research underway) in developing further internal policies and procedures for determining the appropriate mix of market price vs. fixed price gas supply. Please refer to the discussion of portfolio management and optimization in Chapter XV.

## E. PSE Gas Resource / Demand Balance

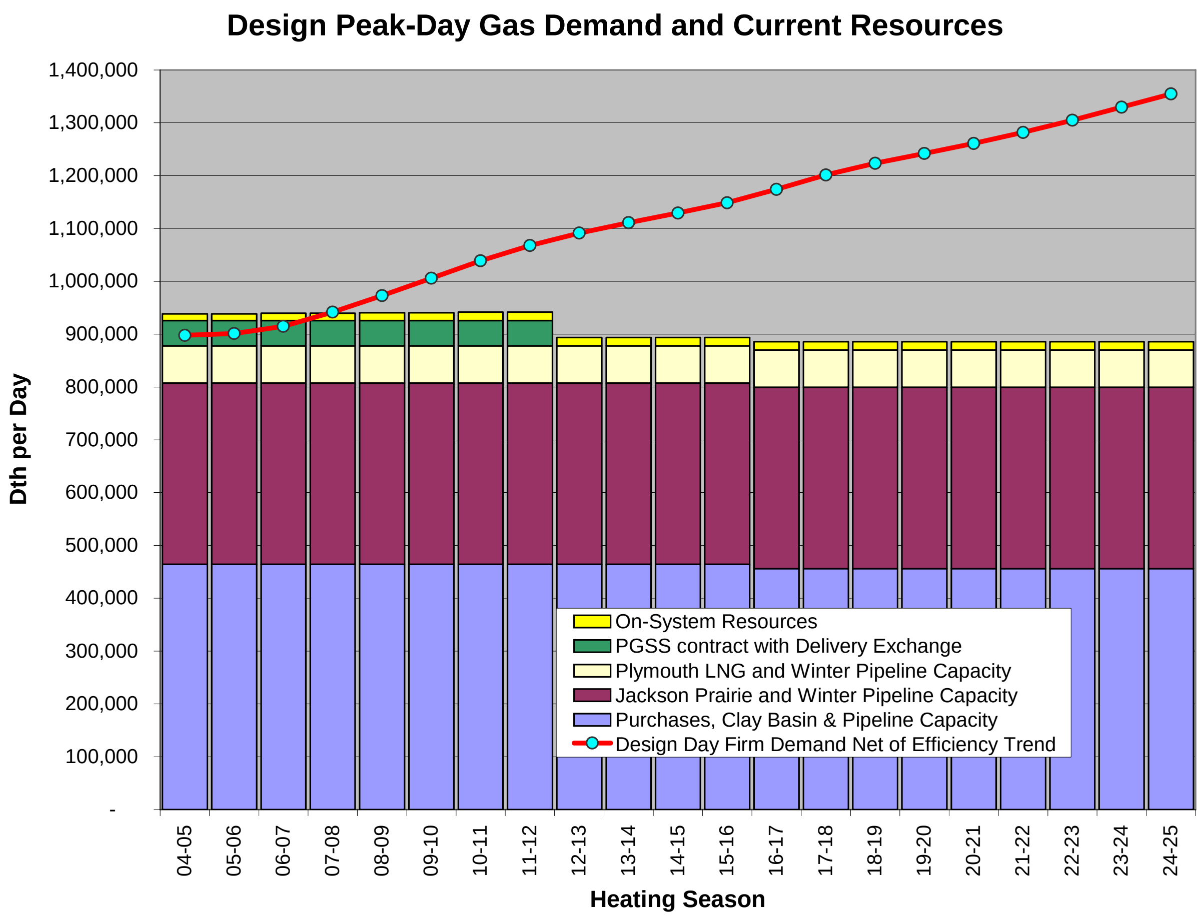
PSE holds firm pipeline transportation and peaking capacity that allows the Company to transport or otherwise deliver gas, on a firm basis, from points of receipt to customers. This capacity ensures that PSE can provide its customers with reliable and cost-effective gas supplies during the coldest expected weather, and over a range of expected scenarios. In addition, PSE maintains upstream pipeline capacity to ensure direct access to gas production areas and the inherent reliability that this brings. PSE also maintains a mix of on-system resources that assist in meeting peak demands and contribute to the reliability of the distribution system.

Based on the current base case forecast, and assuming no increase or decrease in energy efficiency measures identified in PSE's 2003 Least Cost Plan, the Company does not anticipate requiring additional firm capacity until the winter of 2008-2009. Until that time, PSE has adequate capacity to meet the expected requirements of its firm customers.

In the 2003 Least Cost Plan PSE anticipated it would not require additional delivery resources until the 2010-2011 heating season. The adoption of a slightly higher peak-day design standard (1 degree colder), and substantially higher load growth in the past three years have eroded the future adequacy of PSE's gas resources.

Exhibit XII-6 summarizes PSE's direct resource/demand balance position.

**Exhibit XII-6**
**Summary of PSE's Gas Capacity Position**
**(Dth/Day)**




## F. PSE Gas Resource for Power Generation Portfolio

PSE holds firm pipeline transportation capacity to supply fuel to its various gas-fired generation plants for the benefit of its electric customers.  The following table summarizes the capacity held by the Power Generation Portfolio:

**Exhibit XII-7**
**Summary of PSE- Power Generation Gas Capacity Position**
**(Dth/Day)**

## Direct Connect Capacity

| Plant | Transporter | Service | CD | Primary Path | Primary Term End | Renewal Right |
|---|---|---|---|---|---|---|
| Whitehorn | Cascade Natural Gas | Firm | (Note 1) | Westcoast/CNG Interconnect (Sumas) to plant | 12/31/2000 | Yr to Yr |
| Tenaska | Cascade Natural Gas | Firm | (Note 1) | Westcoast/CNG Interconnect (Sumas) to plant | 12/31/2000 | Yr to Yr |
| Encogen | Cascade Natural Gas | Firm | (Note 1) | NWP-Bellingham to plant | 6/30/2008 | Yr to Yr |
| Fredonia | Cascade Natural Gas | Firm | (Note 1) | NWP-Sedro-Wooley to plant | 7/31/2021 | Yr to Yr |
| Freddy 1 | NWP | Firm | 21,747 | Westcoast/NWP Interconnect (Sumas) to plant | 9/30/2018 | Yr to Yr |

## Upstream Capacity

| Plant | Transporter | Service | CD | Primary Path | Primary Term End | Renewal Right |
|---|---|---|---|---|---|---|
| Freddy 1 | Westcoast | Firm | 22,000 (Note 2) | Station 2 to Westcoast/NWP Interconnect (Sumas) | 10/31/2019 | Yes |
| Encogen | NWP | Firm (Note 3) | 9,300 | Westcoast/NWP Interconnect (Sumas) to Bellingham | 10/31/2009 | No |
| Encogen | NWP | Firm (Note 3) | 27,700 | Rockies to Bellingham | 10/31/2009 | No |

Note 1: Plant requirements
Note 2: Converted to approximate Dth per day from contract stated in cubic meters per day,.
Note 3: Capacity held by a third party, controlled by PSE via a grandfathered Buy/Sell agreement

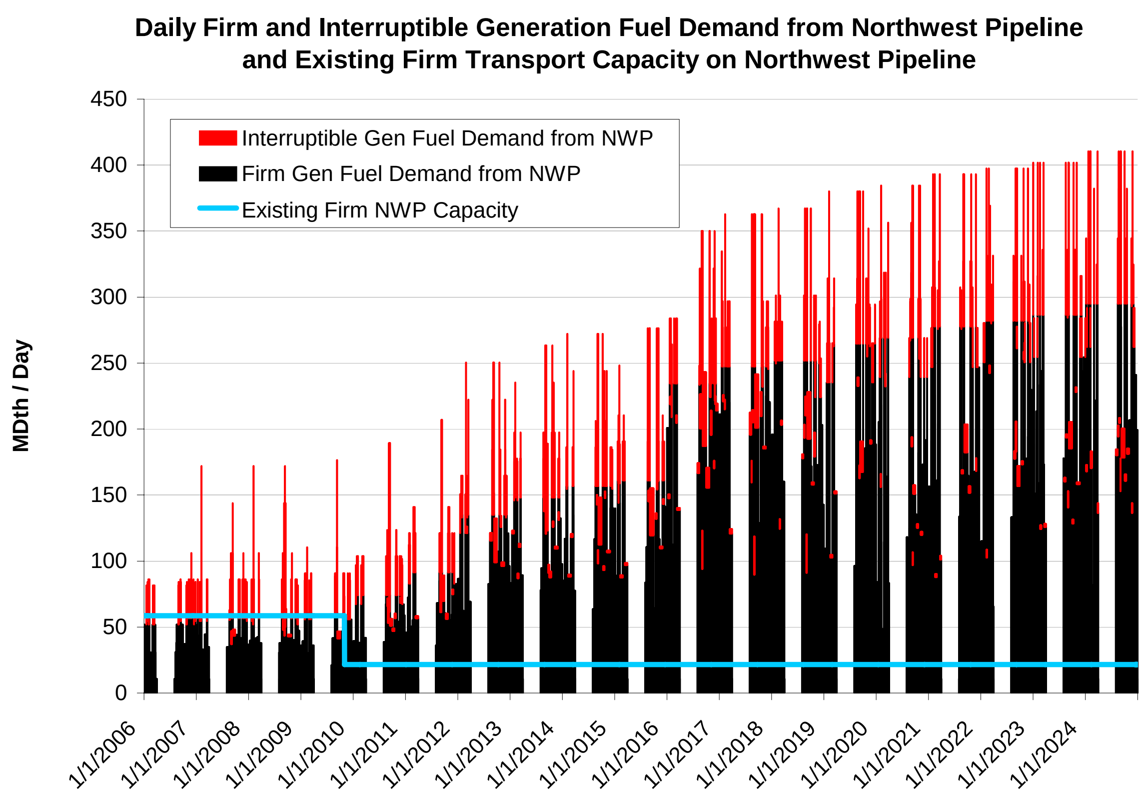
Several of the gas-fired generation units for which PSE is obligated to provide gas fuel, specifically Whitehorn, Tenaska, Fredonia and Frederickson have fuel-oil firing capability and thus do not require firm capacity. [The planning standard for gas fuel for generation is far less stringent than for core gas customers, therefore, firm transportation capacity upstream all the way to a gas supply source is not necessarily required to support even the “firm” generation plants.]

For modeling purposes PSE has grouped the current PSE generation plants into 4 categories:

- Firm via NWP: Encogen “must run” and Freddy 1
- Interruptible via NWP: Frederickson, Fredonia, Encogen dispatchable
- Firm via Westcoast: Tenaska- winter only, to support PGSS Agreement
- Interruptible via Westcoast: Whitehorn

Incremental gas-fired generation resources (generic CCCT) as selected in the Electric Planning scenario “Business As Usual” are assumed to be located in the I-5 Corridor and require firm transportation on NWP. Thus the current load-resource balance for Power Generation Gas transportation capacity is shown in Exhibit XII-8.

**Exhibit XII-8**
**Summary of PSE’s Gas for Generation Capacity Position**
**(MDth/Day)**



# XIII. NEW GAS SUPPLY-SIDE RESOURCE OPPORTUNITIES

Chapter XII provided an overview of PSE's existing natural gas supply-side resources. This chapter examines potential new gas resource opportunities for PSE. Gas resource portfolio opportunities exist when PSE can vary the structure of its existing capacity resource portfolio. These opportunities arise either when capacity contracts expire or additional capacity opportunities become available. Under some situations, it might also be desirable for PSE to buy out of an existing capacity contract in order to meet PSE's least cost objectives. Over the forecast period, PSE has a number of opportunities to modify the structure of its gas resource portfolio.[1] Although the Northwest Pipeline (NWP) transportation contracts expire over the next 10 years, sponsors are considering new pipeline projects, underground storage expansions are proceeding, conservation continues, and peak shaving resource options could be expanded.

## A. Pipeline Capacity

PSE has a number of opportunities to modify its capacity position on interstate pipelines. As detailed in Chapter XII, portions of the NWP contracts expire in 2008, 2009 and 2016. PSE retains the unilateral right to cancel these contracts upon one year's notice. Otherwise, the contracts renew automatically. In essence, the pending expirations, coupled with PSE's renewal rights, create opportunities for PSE to make alternative resource decisions.

*Direct-Connect Pipeline Capacity*

NWP is the only pipeline connecting directly to PSE's city gates. However, other pipeline projects have developed initial plans to offer transportation alternatives, some of which might connect directly with PSE. To date, those pipeline projects have not generated enough interest to make a project feasible, which leads PSE to believe that a new pipeline delivering into the Company's service area is not likely to happen for some time. However, PSE continues to monitor their progress toward aggregating load, as PSE has some flexibility with respect to the expiration of transportation contracts with NWP and the roll-over terms of those contracts.

[1] These opportunities are permanent capacity changes, as opposed to capacity optimization techniques such as capacity release, interruptible sales, off-system sales, and other portfolio management activities used by PSE to minimize the average cost of gas to its customers.

New pipeline capacity tends to be more expensive than existing capacity. Even expansions of existing pipeline systems tend to be more expensive than the vintage capacity. For example, NWP's recent incrementally-priced Evergreen expansion had a 15-year levelized cost of approximately $0.42 per dth/day, vs. NWP's vintage rate of $0.31. The Federal Energy Regulatory Commission (FERC) has instituted a policy of pricing pipeline expansions incrementally, unless benefits to existing shippers can be demonstrated, with only minor rate impacts.

Even with the higher rates resulting from the completion of the Capacity Replacement Project, PSE expects that NWP will remain the most cost-effective solution for reliable firm service to western Washington. Future expansions of NWP, even though they will be incrementally priced, will also likely be the most cost-effective alternative, until such time as incremental demand aggregates into a single location to justify a new pipeline alternative.

PSE's exclusive reliance on NWP for connection to all supplies of natural gas is a matter of geography, not preference. Understandably, it is difficult for a new pipeline sponsor to compete with the inherently lower cost of expanding or rebuilding infrastructure in an existing right of way. It is especially difficult when the new pipeline must build around or over such hurdles as the Cascade Range or the Columbia River Gorge to access anything but BC-sourced gas.

PSE will evaluate the cost of incremental capacity, weighing other transportation alternatives from a cost and reliability perspective, with economic diversity benefits from access to other supply basins. PSE will be especially mindful of the "reliability in diversity" benefits to be enjoyed by sourcing gas that can get to its system along multiple alternate routes. For threshold economic reasons, PSE may need to rely on NWP to move incremental gas supplies from Sumas to the city gate, but perhaps there can be diversity in how the gas gets to Sumas. To the extent that core loads and/or incremental capacity costs change, PSE believes it is important to maintain this analytical perspective in order to structure its gas resource portfolio on a least cost basis.

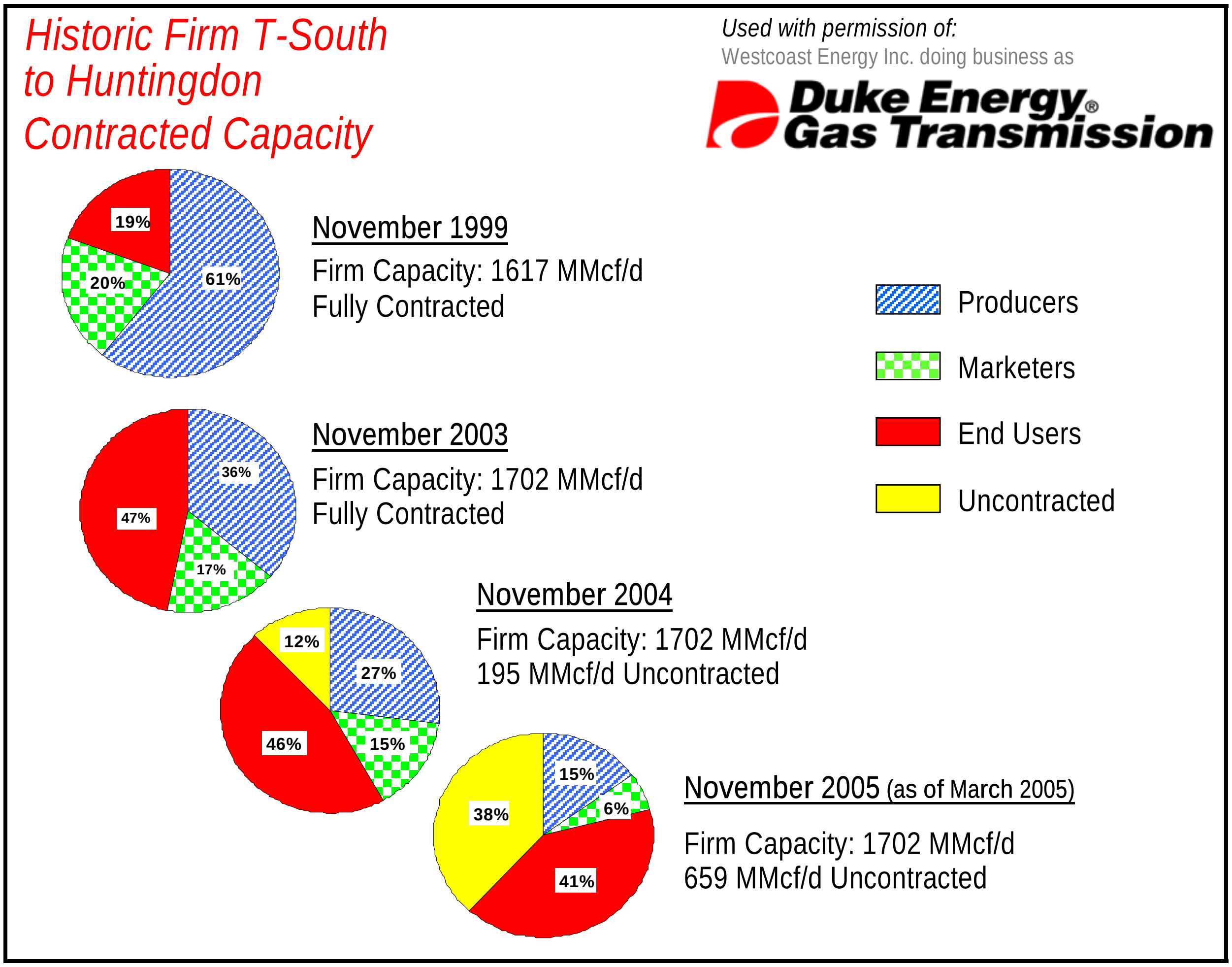
*Upstream Pipeline Capacity*

In some cases, a trade-off exists between buying gas at one point and buying capacity to enable the purchase of gas at another upstream point closer to the supply basin. PSE has faced this situation with its traditional purchases of gas at the Canadian import points of Sumas and Kingsgate.

PSE holds Gas Transmission Northwest (GTN) capacity from Kingsgate (Canadian border) south to NWP. The Company has had a long-term supply arrangement, through aggregators, with the Alberta Pool at Kingsgate. Transportation costs for upstream pipelines Alaska Natural Gas (ANG) and Nova had been included in the pricing formula. That supply contract terminated in late 2004. In anticipation of the aggregator's decision against renewing or extending the agreement, PSE explored acquiring a) firm supply arrangements at Kingsgate or b) firm supplies at the Alberta Energy Trading Company (AECO), and the acquisition of upstream transportation capacity on ANG and NGTL, if available, or c) some combination of options a and b. In making those decisions, the Company considered a host of factors including price risk, currency risk, pricing and other contract conditions, fixed cost exposure, market liquidity, security of supply issues, other transaction costs, and counterparty creditworthiness. Ultimately, PSE found a very illiquid market at Kingsgate and little or no interest by suppliers in providing firm supply commitments at that point. PSE found that capacity on ANG and Nova was available such that PSE could transport gas from AECO to its city gates. The analysis ultimately led to PSE's acquisition of upstream capacity on both ANG and Nova to allow the Company to acquire gas directly from suppliers at the very liquid trading hub at AECO.

PSE's experience in viewing the Kingsgate market is similar to recent trends on the Westcoast Pipeline system and the probable impact on the Sumas market. In the past two years of annual contract renewals on the Westcoast system, capacity holders (primarily suppliers—Producers/ Marketers of supply) have increasingly allowed their contracts for T-South capacity to expire. It is expected that, as of Nov. 1, 2006, as much as 659,000 Mcf/day or 38 percent of T-South capacity will be uncontracted. See Exhibit XIII-1 below.

**Exhibit XIII-1**




The producers and marketers of gas supply at Sumas have concluded that it is not in their economic interest to hold T-South capacity, as the cost of such capacity is rarely recouped in the selling price at Sumas. In other words, the spread between Station 2 market price and Sumas price is smaller than the cost of transporting from Station 2 to Sumas. While PSE believes that some producers/marketers will ultimately recontract for T-South capacity, they are only likely to do so if parties commit to new firm supply agreements with pricing terms that remove the risk in holding T-South capacity. As a result, PSE expects that the new pricing norm for long-term firm gas at Sumas will be "Station 2 Index plus the cost of T-South." Short-term gas will likely still be sold at Sumas Index, but that index is likely to be quite volatile due to a much more thinly traded market. During cold spells, selling prices are likely to capture value far greater than the cost of T-South capacity. If this becomes the norm, we would expect that

LDCs—including PSE—would be driven to acquire the unsold T-South capacity and contract for supplies at Station 2 to ensure the continued reliability of access to firm supply.

PSE initiated its response to this market development by acquiring 40,000 Dth/d of capacity on Westcoast Pipeline from Station 2 to Huntingdon, BC (Sumas), starting November 2003. PSE can take advantage of a growing supply market at Station 2 with this transportation capacity, minimizing its cost and risk by contracting for a portion of this upstream transportation, and serving as a hedge against potential price spikes at the Sumas market.

As the availability of gas at Sumas declines, PSE expects it will acquire additional T-South capacity to access firm supplies at Station 2. In addition, PSE will explore other opportunities to access firm gas supply that can be delivered to the city gate through the Sumas interconnect.

Terasen Gas, formerly known as BC Gas, is offering firm bundled capacity from the interconnection point of their facilities in south-eastern BC to the ANG/Nova system through the southernmost portion of the Westcoast system to the Sumas interconnect with NWP. This route, along with additional ANG and Nova capacity, could be used to move incremental supply from the liquid trading hub at AECO to the PSE system. While not inexpensive, such an alternative would increase geographic diversity of supply and reduce reliance on BC-sourced supply from what it would otherwise be.

PSE will continue to evaluate its upstream transportation requirements and opportunities, and evaluate its position to ensure a balance of market diversity, liquidity, volatility and least cost.

## B. Storage Capacity

PSE has a number of opportunities to modify its storage capacity positions over the next eight years. As detailed in Chapter XIII, the Jackson Prairie leased capacity expires in 2006. The Clay Basin contract continues through 2013 and 2020.

A capacity expansion is currently underway at Jackson Prairie, anticipated to add an additional 900,000 Dth of storage capacity to the facility each of the next eight years, eventually expanding the total capacity by 10,500,000 Dth by the summer of 2012. Of this capacity, 40 percent will be cushion gas—gas that is injected and used to maintain reservoir pressure. The remaining 60 percent—or 540,000 Dth each year for a grand total of 6,300,000 Dth—will be used to provide working storage capacity. PSE holds the right to use one-third of this working capacity or 2,100,000 Dth when complete.

While the exact timeframe for the expansion of the Jackson Prairie deliverability has not yet been determined, PSE anticipates the owners will expand the deliverability of the project by as much as 300,000 dth/day (100,000 dth/day for PSE) before the winter of 2012-2013. PSE is also analyzing the benefits of expanding deliverability as early as 2008. Jackson Prairie deliverability is likely to be the least cost way of meeting PSE's firm load growth.

### C. Peaking Resources

PSE's recent experience with the development of its Gig Harbor Liquified Natural Gas (LNG) peaking facility has provided insight into the new technology, operational efficiency and cost effectiveness of satellite LNG peaking. LNG is easier to blend into the natural gas stream than propane-air mix.

PSE will study the potential to incorporate satellite (using trucked-in LNG) LNG technology and conventional (using LNG liquefied on-site from pipeline gas) LNG peaking into the long-term resource mix.

PSE will also consider contracting for conventional LNG peaking service from a third-party provider, which recently received preliminary authorization to construct a plant in the region. LNG peaking and a cost-effective firm redelivery/exchange service will be available for an interim period beginning in 2007 (or 2008 depending on the timing of final authorizations) to serve as a bridge to other long-term resources.

### D. Gas Supplies

The Company manages its supply portfolio to maintain supply diversity, and the pricing terms reflect at least three regional markets: the U.S. Rockies, British Columbia, and Alberta. Over long periods of time, a tendency exists toward equilibrium pricing among the three regions. Over shorter timeframes, however, one basin will be lower in cost than the others—a difference that can be more pronounced on a daily basis. PSE's capacity rights on NWP provide some flexibility in buying from the lowest cost basin. This arbitrage opportunity can mitigate price volatility, and serves to mediate prices between the various supply basins.

PSE has always purchased its supply at market hubs or pooling points. In the Rockies, the transportation receipt point is Opal, but alternate points, such as gathering system interconnects with NWP, allow for some purchases directly from producers as well as from gathering and processing firms. In fact, PSE has a number of supply arrangements with major producers in the Rockies, giving the Company the ability to purchase supply at or close "to the wellhead," or point of production.

The addition of capacity on Westcoast and ANG/Nova to the PSE portfolio have increased PSE's ability to access supply "at the wellhead" in Canada as well.

From a supply-planning perspective, continued diversification of its natural gas purchases among the three supply basins provides some measure of reliability and price protection for PSE by avoiding a concentration in any single market. For this reason, PSE expects to maintain this approach to contracting for gas supplies in the Rockies, British Columbia and Alberta.

Pipeline projects add capacity in a stepwise fashion, while load growth and supply production increases tend to happen more gradually. New pipeline projects can suddenly increase the take-away capacity from one supply basin, shifting the supply-demand dynamic across the network. As a result, large price shifts can result from a pipeline expansion project. While the pricing data illustrates the relative equilibrium among the western basins, the imbalance lies between these basins and the market areas. When that differential becomes large enough and persists over time, market participants contract for new capacity, and the new pipeline capacity is built. This tends to re-balance the market.

*Commercial Relationships, Market Trends and New Resources*

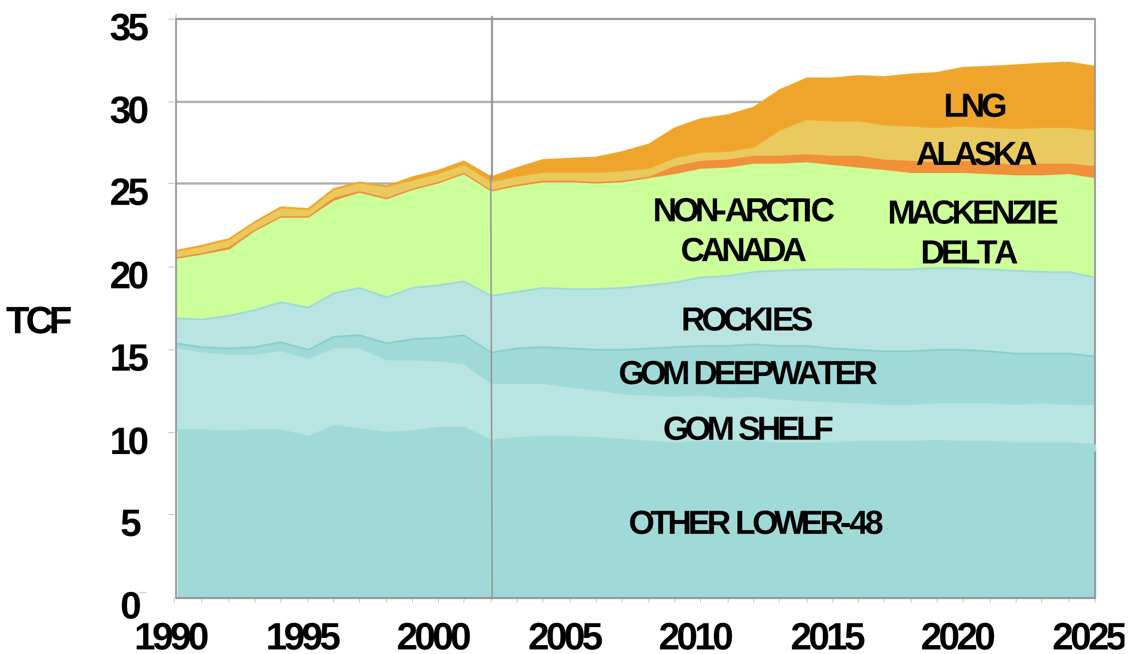
The variables associated with managing PSE's natural gas supply portfolios include physical supply security, commodity pricing (including volatility), and commercial relationships. Historically, PSE has sought to diversify its overall supply portfolios by dividing its supplies among its three primary supply regions – Rockies, Alberta, and British Columbia – and further dividing its commercial relationships among as many creditworthy counterparties as possible. The growing economy (demand for natural gas) and the fear of flat to declining year-on-year domestic and Canadian natural gas production creates significant concern for both supply security and pricing certainty. It is generally believed that the current supply scarcity in the

North American market will continue and possibly become worse before new sources of natural gas can be developed. It is generally believed that this shortfall—absent contributions from Arctic or Alaskan gas, or from LNG imports—will reach between 8 and 10 Bcf per day by 2010. Therefore, it is very likely that the price of natural gas will remain high and be subject to significant market volatility.

*Supply Overview*

From a supply standpoint, the major oil and gas companies have moved their exploration activities offshore. These companies, along with others, have developed large, "stranded" gas reserves for which they are seeking markets. The United States is the largest market, where the addition of new gas-fired electrical generation, along with other load growth has created a projected 2010 natural gas shortfall of 8 to 10 Bcf/d.

**Exhibit XIII-2**
**AGA's Forecast of New Resources**




Whether real or perceived, an anticipated supply shortage has driven natural gas prices to high levels, created a great deal of pricing volatility in the market, and prompted conservative market pricing practices. Further, it must be remembered that costs do not establish market prices until there is an oversupply. Major suppliers and producers are moving their planning prices upward, but not above $4.00/MMBtu.  Instead, they are improving their balance sheets by reducing debt and buying back stock.

*Marketplace Trends*

In response to increases in demand and supply uncertainty, the natural gas marketplace has experienced high prices coupled with pricing volatility.  Combined with the increased counterparty credit requirements (an outcome of the energy crisis), the majority of suppliers and producers have consistently avoided long-term fixed price supply arrangements in favor of short-term sales arrangements.  For the most part, only producers with secure sources of production have been willing to consider agreements of up to 5 years, but only if sales agreements have “market mean reverting” price structures, and any term beyond 3-4 years must have corporate approvals.  The most prevalent of these pricing mechanisms incorporate indexing to published monthly market indices.

Until recently, only a handful of suppliers and financial institutions, wanting to “lock in” the current high gas prices, were willing to discuss the development of long-term, “fixed price” contracts.  Even tentative discussions about fixed pricing mechanisms were very infrequent.  No supplier was willing to sell its gas at below its forward-market price curves, and even then a healthy risk premium was required.  Only recently have a handful of the largest producers been willing to explore long-term fixed price contracts.

In the past 12 months, two potential counterparties have expressed a willingness to enter into discussions of long-term fixed priced supply arrangements on an exploratory basis.  Both counterparties suggested that their willingness to discuss long-term arrangements was a manifestation of a desire to “hedge” their LNG and/or their Alaskan or Frontier pipeline projects. A concern that they and others have is that the introduction of new supplies of natural gas into the currently constrained North American marketplace may drive the current market price downward and they are anxious to lock-in today’s prices.

Along with the willingness to explore longer-term contracts came an implicit willingness to modify current industry credit requirements.  To date, PSE has seen no relaxation or modification of industry credit requirements.  Without this, our long-term, fixed-price natural gas discussions will remain only “exploratory” in nature and the natural gas marketplace will remain focused on relatively short-term natural gas transactions.

*New and Alternate Supply Resources*

Recognizing that the current high and volatile pricing is largely a function of the supply scarcity, PSE has and continues to carefully monitor projects and resources that will provide for gas supply surplus. To this end, the two areas of major focus include new Alaskan and frontier gas pipelines and the importation of LNG.

Two major pipelines have been proposed to transport gas from the Arctic to the North American markets. The Alaska Natural Gas Transmission System is intended to transport natural gas 3,500 miles from the North Slope through Canada and on to Chicago. This $20 billion project is designed to provide 4.5 Bcf/d of natural gas between 2013 and 2015. The second major pipeline, the Mackenzie Valley Pipeline is intended to transport natural gas 1,300 kilometers from the Tablus, Parsons Lake and Niglintgak fields to the northern border of Alberta. This $3.6 billion project is designed to deliver 800 million cubic feet per day as early as 2010. Unfortunately, both of these attractive projects are too far out into the future to provide relief to the current supply-scarce marketplace.

The most promising of the identified supply scenarios is the utilization of existing and the development of incremental LNG regasification terminals. At today's prevailing gas prices, LNG can be competitively transported, stored, and marketed. There are four major existing LNG regasification terminals operating in the United States (Everett, Trunkline LNG, Elba Island, and Cove Point). Throughout 2004 these terminals averaged a throughput of approximately 2.5 Bcf/d. They have the ability to provide approximately 4Bcf/d, and are capable of providing between 3 and 4 percent of the current natural gas requirement.

Major oil and gas companies recognize that LNG can provide a significant contribution to alleviating the current supply scarcity, and they see an opportunity to market their "stranded" reserves. In response, these companies are pursuing the development of additional regasification terminals. To date, over 50 terminals have been proposed, with at least seven to be located in Oregon, Washington and British Columbia. However, given the existing anticipated 8 to 10 Bcf/d shortfall, it is likely that only 4 to 6 additional regasification terminals will be needed in the near future.

The LNG Value Chain is made up of four discreet parts: Exploration and Production (feedstock), Liquefaction, Transportation, and Regasification. An approximate breakdown of the capital and production costs for a 1 Bcf/d LNG Value Chain is shown in Exhibit XIII-3.

**Exhibit XIII-3**
**LNG Value Chain**

| Value Chain Component | Capital Cost/Bcf/d ($Billions)[2] | Market Cost Required ($/MMBtu)[3,4] |
|---|---|---|
| E & P (Feedstock) | 1.5 | $0.5 to $1.0 |
| Liquefaction | 2.0 | $0.8 to $1.2 |
| Transportation | 2.0 | $0.3 to $1.8 |
| Regasification | 0.5 | $0.3 to $0.65 |
| Total | $6.0 | $2.10 to $4.65/Mcf |

The estimated cost of LNG production is well within the current and anticipated market price range of natural gas. The development of individual trains is typified by low exploration and technology risks, and by high capital cost. These projects are best described as financial transactions that will require the following:

- An experienced sponsor with a strong balance sheet
- A secure source of natural gas
- A large immediate market or an extensive infrastructure that is capable of consuming the entire output of an LNG regasification plant
- Long-term off-take agreements that will support the project financing costs

The siting of domestic regasification terminals will be challenging. To capture the economies of scale, the terminals must be large. These large "supply building blocks" will require bigger markets that can swallow the design output "whole." Ideal sites include the Gulf of Mexico (with its takeaway transportation hub), Southern California, and parts of the Eastern Seaboard. Fundamentals models of the North American gas market all indicate that the introduction of incremental imported LNG at any location will tend to lower or at least stabilize prices

[2] Turkelson, Don. "LNG to North America's Gulf Coast" (SRI).
[3] Foss, Michelle Michot. "LNG Development in a Post 9/11 World" (SRI 2004). Ms. Michot is the Executive Director of the Institute for Energy, law & Enterprise at the University of Houston Law Center.
[4] Second set of numbers came from a Ziff Presentation "North American Gas Strategies 1st Quarter 2005" made in PSE's offices on 3 March, 2005. The Ziff numbers are expressed in US $/Mcf

throughout the market as the supply growth rebalances the market. Additionally, depending on location, imported LNG could have the effect of displacing some of the current supply for a given region—freeing up that supply to serve other markets. For example, it is generally assumed that LNG imports into the southern California market would displace some supplies from Alberta, thus causing a relative decline in pricing of Alberta supplies as they attempt to find a home in other markets. Irrespective of location, import LNG regasification projects hold the greatest potential for providing supply scarcity and price volatility relief in the near term.

For analysis purposes, PSE has considered two hypothetical regional LNG import regasification terminals: "South LNG Import"—connected to the NWP system south of PSE's service territory and assumed to require incremental NWP capacity construction north to PSE's service territory, and "North LNG Import"—connected to the Westcoast system in BC and requiring utilization of Westcoast T-South capacity and NWP capacity to provide delivery to the PSE system. In each case it has been assumed, absent more definitive information from project developers, that the LNG supply itself would be priced at the AECO index plus a small demand charge (at the regasification plant outlet/pipeline interconnect).

With respect to planning future gas purchases from the various supply basins, PSE will diversify its portfolio to match the transportation take-way capacity it holds at the primary receipt points in its long-term pipeline transportation contracts. Over time, as the market differentials spur pipeline capacity expansions, PSE could have an opportunity to diversify to other supply basins. However, the expansions might also serve to bring prices closer together.

In summary, the pipeline transportation contracts held by PSE position it well to maintain access to adequate gas supplies in producing areas well-positioned for further development. These supplies will likely remain price competitive due to the focus on development of these reserves. PSE finds itself in a strong position to seek additional pipeline capacity when needed to meet incremental load requirements with reliable and economical gas supplies.

Therefore, PSE's long-term natural gas acquisition strategy is as follows:

- Establish master enabling agreements with as many creditworthy entities as possible.
- Improve supply security by entering into long-term, index-based contracts across multiple supply regions and with a diversity of index-based pricing structures.

- Explore the potential development of long-term “fixed price” contracts and incorporate them into PSE’s portfolio as appropriate.
- Monitor the development of new or alternative natural gas resources (e.g., coal bed methane, LNG importation, landfill gas, new pipelines, etc.).

# XIV. NATURAL GAS ANALYSIS AND RESULTS

*Overview*

This section will provide a high-level summary of the primary analysis performed to support the gas resource plan. PSE's plan goes beyond the typical examination of how different load growth and gas price scenarios affect the optimal future resources needed to serve the Company's gas sales customers. Rather, this plan includes a benefit-cost analysis to determine the optimal peak-day planning standard. Additionally, this plan includes PSE's first application of its long-term gas planning analytical framework (traditionally used to optimize the long-term gas sales or "LDC" portfolio) to its long-term gas for generation fuel portfolio. Also, PSE used this same framework to investigate possible economies of scale and scope to joint planning for gas sales load and generation fuel, relative to planning for them separately. Finally, PSE examined the impact of price and weather uncertainty by applying a Monte Carlo approach using the Company's new resource planning models.

*Summary of Key Analytical Results—LDC Analysis*

- Higher gas prices relative to the last Least Cost Plan indicate PSE should consider expanding its level of natural gas energy efficiency programs.
- PSE should work with Jackson Prairie co-owners to expand deliverability and work with Northwest Pipeline to obtain seasonal delivery rights similar to today's TF-2 service.
- PSE should consider acquiring additional upstream capacity on Westcoast from Station 2, although maintaining diversity of supply from AECO is an important qualitative factor for consideration.
- Additional load from a fuel conversion program does not appear to put upward pressure on average gas costs to existing customers.
- Monte Carlo analysis to examine physical supply risk indicates that a portfolio designed to meet PSE's design-day peak forecast, in an otherwise normal temperature winter, is sufficient to meet its obligations under a variety of possible winter conditions.
- With regard to cost risk, the 20-Year Monte Carlo analysis demonstrates that viewing risk over a 20-year horizon tends to mute the effects of price and volumetric

variability. Shorter time periods, such as annual variability, should be considered when examining the impact of different resources on cost variability.

- Monte Carlo analysis on optimal portfolio construction highlights that the timing of certain resource additions is highly sensitive to Base Case assumptions.

*Key Results from Generation Fuel Analysis*

- Based on electric Business as Usual gas-fired generation resources, PSE's gas portfolio for power generation appears to have sufficient firm Northwest Pipeline capacity through 2009.
- Like the sales portfolio, additional upstream transportation capacity to Station 2 may need to be acquired as gas producers and marketers hold less capacity on Westcoast to move gas south to Sumas.

*Key Result from Joint LDC and Generation Fuel Analysis*

- Analysis showed potential savings of approximately 1 percent per year on an annualized basis relative to the combined stand-alone portfolio costs, a large portion of which would be achievable through short-term optimization without significant changes in long-term planning.

*Roadmap for Chapter XIV*

Section A describes the benefit-cost analysis PSE performed to determine its primary planning standard—the design peak day planning standard. This analysis provides the basis for the 20-year gas sales load forecast peak-day demand that the Company will plan to meet. Section B presents the Company's estimated need for resources over the next 20 years for gas sales load, based on comparing the design peak day demand forecast with the Company's current resources. Section C presents an overview of PSE's new planning tools. Section D describes the various optimization analyses and scenarios the Company considered for gas resource planning. Section E provides an overview of the input assumptions and the potential resources that were modeled. In addition, this section describes the various gas resource planning and uncertainty analyses performed. Finally, Section F provides an overview of analytical results, and section G summarizes the conclusions of the analysis.

### A. Planning Standard

In its 2003 Least Cost Plan, PSE changed its gas supply peak-day planning standard from 55 heating degree days (HDD)[1], 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 Least Cost Plan.

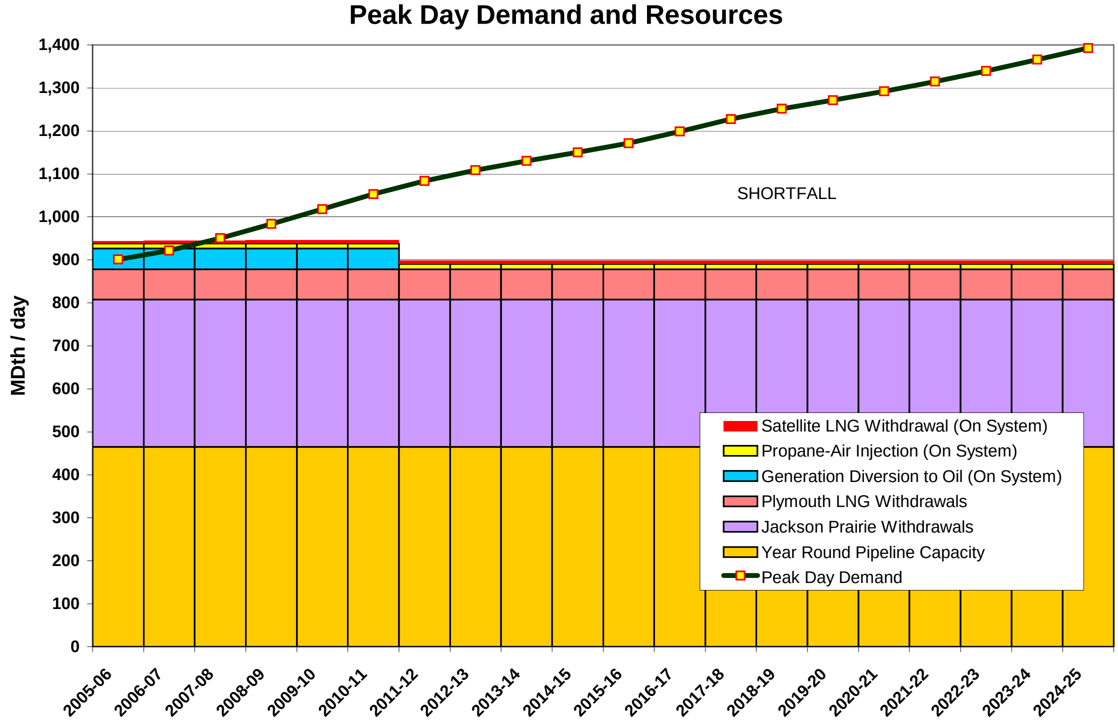
PSE has completed a detailed, stochastic cost-benefit analysis that considers both the value customers place on reliability of service and the incremental costs of the resources necessary to provide that reliability at various temperatures. Based on the analysis, described in more detail in Appendix I, PSE has determined that it would be appropriate to increase its planning standard from 51 HDD (14 F) to 52 HDD (13 F). PSE's Gas Planning standard is based on a detailed cost/benefit analysis that relies on the value attributed to reliability by PSE's natural gas customers. As such, it is unique to that customer base, service territory and the chosen form of energy.

### B. Resource Need

As described more completely in Chapter XII, PSE currently has adequate resources to meet its design standard for the next two winters. Additional "deliverability" in the form of energy efficiency and supply-side resources will be needed to accommodate forecasted customer demand growth and the loss of certain resources over the planning horizon.

[1] The concept of heating degree days (HDD) was developed by engineers as an index of heating fuel requirements. They found that when the daily mean temperature is lower than 65 degrees, most buildings require heat to maintain an inside temperature of 70 degrees. Thus, an HDD number represents the following equation: 65 – the average daily temperature = HDD.

**Exhibit XIV-1**




## C. Optimization Analysis Tools

PSE has enhanced its ability to model gas resources for long-term planning and long-term gas resource acquisition activities since the 2003 Least Cost Plan and Update were filed. The Company acquired SENDOUT® and VectorGas™ from New Energy Associates in August of 2004. SENDOUT® is a widely used model that helps identify the long-term least cost combination of resources to meet stated loads using a linear programming model. The model determines the portfolio of resources that will minimize costs over the planning horizon, based on a set of assumptions regarding resource alternatives, resource costs, demand growth, and gas prices. SENDOUT® has the capability to integrate demand side resources alongside supply-side resources in determining the optimal resource portfolio. The linear programming approach is a helpful analytical tool to help guide decisions, but it is important to acknowledge this technique provides the model with "perfect foresight," meaning the theoretical results would 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 would not be possible in the real world. Real world decisions must be made where numerous critical factors about the future will always be uncertain. Linear programming analysis provides helpful but not perfect information to guide decisions.

Because decisions must be made in the context of uncertainty about the future, PSE acquired VectorGas™ along with SENDOUT®. VectorGas™ is an add-in product that facilitates the ability to model gas price and load (driven by weather) uncertainty into the future. VectorGas uses a Monte Carlo approach in combination with the linear programming approach in SENDOUT®. This additional modeling capability will provide additional information to decision-makers under conditions of uncertainty. These new tools provide valuable enhancements to the robustness of the Company's long-term resource planning and acquisition activities. See Appendix H for a more complete description of SENDOUT® and VectorGas™, as well as details of the various modeling inputs.

## D. Scenarios and Cases

Scenario analysis is a useful method to examine the implications of uncertainty, especially in long-term resource planning. Gas planning scenarios are summarized in Exhibit XIV-2 and discussed further in the sections below.

The goal in developing scenarios was to explore the impact of possible alternative futures on PSE's optimal gas resource portfolio. The gas planning scenarios differ from those used in the electric planning process only in that PSE did not include a gas case comparable to the electric Current Momentum scenario. The gas scenario Base Case should be viewed as the companion to both the Business As Usual and Current Momentum electric scenarios. The gas Green World is based on the same gas price forecast as the electric Green World. Gas price assumptions between electric Robust Growth and the gas Strong Economy are the same, as are gas price assumptions for the electric Low Growth and gas Weak Economy. Additionally, alternative demand forecasts include high load growth for Strong Economy (like electric Robust Growth) and a low load growth scenario in Weak Economy (like electric Low Growth). These alternative gas demand forecasts reflect differences in the growth in customer counts over time. Additionally, the alternative demand forecasts reflect different patterns in use per customer. Additional information on demand forecasts can be found in Chapter VI. An additional gas demand scenario was examined in the fuel conversion case, which adds gas load results from the electric to gas fuel conversion to the Base Case to determine whether a fuel conversion program could have an adverse affect on average gas costs.

The alternative gas price forecasts used in the gas planning scenarios represent a wide range of potential future price paths. As mentioned in the gas price forecast (Chapter V), PSE cannot disclose the specific gas prices used in its Least Cost Plan analysis. However, the spread between the high gas price forecast (CERA's Shades of Green scenario) and the low gas price forecast (CERA's World in Turmoil scenario) is more than three times greater than the range in the EIA-based AECO price scenarios shown in Exhibit V-2 (see Chapter V).

**Exhibit XIV-2**
**Gas Resource Planning Scenarios**

| | | Theme | Gas Demand | Gas Prices |
|---|---|---|---|---|
| Gas LDC | **Base Case** | Current trends continue. | Base case customer growth and use/customer. | Mid-Prices: CERA Rearview Mirror scenario |
| Gas LDC | **Fuel Conversion** | Current trends continue. | Base case customer growth and use/customer + Fuel Conversion loads. | Mid-Prices: CERA Rearview Mirror scenario |
| Gas LDC | **Green World** | National gas demand driven up, driving up prices. | Base case customer growth and use/customer. | High Prices: CERA Shades of Green scenario |
| Gas LDC | **Strong Economy** | Local economy grows faster than expected. | High customer growth rate and higher use/customer. | Mid-Prices: CERA Rearview Mirror scenario |
| Gas LDC | **Weak Economy** | Low regional and national economy. | Low customer growth rate and lower use/customer. | Low Prices: CERA World in Turmoil scenario |
| Joint Gas Planning | **Gas for Generation Fuel** | Electric Business as Usual. | Generation demand from Electric Business as Usual | Mid Prices: CERARearview Mirror scenario |
| Joint Gas Planning | **Joint LDC + Generation Fuel** | Gas: Base Case Electric: Business as Usual. | Gas: Base Case Electric: Business as Usual. | Mid Prices: CERA Rearview Mirror scenario |
| Joint Gas Planning | **Economies of Scale/Scope** | Compare results of gas LDC Base Case plus Gas for Generation Fuel with Joint LDC + Generation Fuel analysis. | | |

### D.1. Gas Sales (LDC) Scenarios

*Static Optimization Analysis*

As noted above, five gas sales scenarios were considered to examine the impact of different future demand and gas price scenarios on resource planning. The key to using scenario analysis is to understand how different resources will perform across a variety of conditions. Scenario analysis clarifies the robustness of the optimality of a particular strategy. That is, scenario analysis will help identify if a particular strategy is reasonable only under a unique set of future circumstances.

*Monte Carlo Analysis on Base Case Portfolio*

This is the first Least Cost Plan in which PSE has used Monte Carlo analysis in conjunction with gas resource planning. Two kinds of Monte Carlo analysis were performed to test different dimensions of uncertainty. The first Monte Carlo analysis was performed to test how a specific portfolio will perform under uncertain price- and temperature-induced demand uncertainty. The portfolio used in this analysis was the resulting optimal portfolio derived from the static Base Case analysis. Analysis of this kind, examining the performance of a specific scenario is helpful to examine financial and physical risk. First, the analysis provides an estimate of cost variability. This can be particularly helpful when comparing two portfolios with similar expected costs, but different resulting cost risk profiles, which would not be evident in the traditional static analysis.

Performing Monte Carlo analysis on the optimal Base Case portfolio to examine physical risk is also helpful. The static optimal portfolio is determined by minimizing the cost of meeting the Company's design-day planning standard. Monte Carlo analysis can help examine the robustness of this optimal portfolio in meeting a variety of loads driven by possible different winter temperature patterns. Thus, Monte Carlo analysis will be helpful in determining whether PSE should consider adding additional dimensions to its gas planning standard in addition to design peak day and otherwise normal weather.

Monte Carlo analysis on the Base Case portfolio was performed using 200 different daily price and temperature scenarios—or draws—for the 20-year planning horizon. The starting point for each price draw was the CERA Rearview Mirror prices. Prices and weather are related in the underlying analysis that generates the scenario for each draw. Details of SENDOUT and VectorGas are included in the technical appendix.

*Monte Carlo Analysis Including Resource Optimization*

The Monte Carlo analysis described above locked in the optimal resources from the static Base Case analysis to examine how that portfolio will perform physically and financially. The other way PSE used Monte Carlo analysis was to examine the robustness of the optimal portfolio resulting from the static Base Case optimization analysis. Analysis to examine sensitivity of the optimal portfolio was performed by creating 100 scenarios of daily prices and demands for 20 years, then calculating the optimal portfolio to meet each of the 100 scenarios. CERA's Rearview Mirror gas prices were again the starting point for prices underlying this analysis. This analysis generates probability distributions for each of the potential resource additions. Using just the static analysis, it is easy to over-emphasize the importance of determining the "optimal" portfolio. Results of the resource optimization Monte Carlo analysis will provide useful information about how sensitive resource additions in the Base Case optimal portfolio are to the specific price and demand assumptions underlying the Base Case scenario.

### D.2. Generation Fuel Planning

Analysis for long-term generation fuel planning was performed using Sendout, in a manner similar to planning for LDC sales load. Gas fuel requirements of the Business as Usual electric scenario were used to run the long-term optimization analysis. These requirements were taken from the Company's Portfolio Screening model. As the portfolio screening model reports monthly gas volumes, the volumes were spread to a daily basis by dividing the gas consumed each month by the total gas consumed if the unit operated 24 hours, to determine the number of full-run days. Those full-run days were assigned to days with the highest imputed market-clearing heat rate. This analysis was the first step in applying the same analytical rigor to optimizing resources to meet generation fuel needs, as is applied to the sales portfolio. Note this is not a financial risk management exercise, but a way to identify the least-cost method to get gas to the generating plants. Static analysis was performed using Sendout. Stochastic analysis using Vector Gas is an ideal application and one the Company plans to pursue. PSE will work to develop modeling techniques that can simulate uncertainty in the daily gas fuel-for-generation demand that are compatible with Vector Gas.

### D.3. Joint LDC-Generation Fuel Planning

A joint LDC and Generation Fuel planning analysis was conducted for this Least Cost Plan. To perform this analysis, the gas LDC and generation fuel portfolios were combined, and future demand projections for LDC sales and generation fuel were combined. Sendout was then used to identify the optimal set of long-term resources to meet the combined gas demands. The existence of potential economies of scale and/or scope that could potentially reduce costs for both gas and electric customers were investigated by comparing the 20-year net present value cost of the combined portfolio with the summation of the 20-year net present value costs of the optimal gas Base Case and optimal generation fuel results.

## E. Resource Alternatives

Sendout was used to identify the optimal portfolio in each scenario. Supply-side and energy efficiency resource alternatives were generally consistent across the scenarios. Energy efficiency programs were consolidated slightly differently across scenarios, to focus the optimal efficiency analysis on the most relevant programs. For example, in the Green World scenario, PSE tested higher-cost efficiency programs than were rejected in the Base Case, as the higher Green World gas prices may have justified higher-cost efficiency programs. The gas planning process differs from the electric process in that there are no competing alternate portfolio approaches to consider. After energy efficiency programs, there is only one choice of supply—purchased natural gas. The gas planning analysis thus necessarily focuses on where to buy it, how to transport it to customers and whether or not to store some along the way. The following tables summarize the supply- and demand-side alternatives considered in the analyses.

### E.1. Resource Alternatives—Gas Supply

**Exhibit XIV-3**
**Gas Supply Alternatives**

| Resource | Scenario Considered | Notes |
|---|---|---|
| Northern LNG Import interconnected with Westcoast Pipeline | All | Flows over Westcoast T-South transport to Sumas and then on existing or incremental NWP capacity to PSE. |
| Southern LNG Import interconnected with NWP, south of PSE service territory | All | Flows over NWP, North to PSE on incremental transport capacity. |
| Conventional Gas Supply purchase contracts | All | Current contracts modeled for term then to monthly spot market. Sumas spot supplies assumed shrinking. Supply at Station 2 growing. AECO and Rockies supplies assumed to be sufficient. |

### E.2. Resource Alternatives—Transportation

**Exhibit XIV-4**
**Transportation Alternatives**

| Resource | Scenario Considered | Notes |
|---|---|---|
| **Direct Connect Pipeline** | | |
| Northwest Pipeline- Sumas to PSE | All | Several potential dates for capacity offered. New expansion capacity and existing surplus capacity were considered. |
| Seasonal storage related transport to JP similar to TF-2. | All | Northwest has indicated it does not plan to offer additional TF-2 service, but a displacement-reliant service with similar pricing may be available. |
| Northwest Pipeline incrementally priced new capacity from LNG import facility south of PSE service territory | All | To match up with assumed LNG import terminal south of PSE service territory |
| **Upstream Pipeline** | | |
| Station 2 to Sumas | All | Several potential dates for capacity offered. |
| AECO via Southern Crossing + ANG & NOVA | Initial Base Case analysis. | Analysis showed higher transport cost and gas prices such that Sendout would not select this resource unless Station 2 supply availability was constrained. |

### E.3. Resource Alternatives—Storage

**Exhibit XIV-5**
**Storage Alternatives**

| Resource | Scenario Considered | Notes |
|---|---|---|
| Jackson Prairie Storage Project deliverability expansion. | All | (along with the ongoing expansion of inventory) |
| 1-3-year LNG peaking storage service contract. | All | Includes firm exchange delivery to PSE. |
| On-system LNG storage with liquefaction. | All | Injections and withdrawals from and to PSE distribution. |
| On-system satellite LNG with trucked in supply. | Initial Base Case analysis | Analysis showed higher costs and clearly indicates this is not a good generic resource. Requires local benefits. |

### E.4. Resource Alternatives—Gas Energy Efficiency Program Bundles

The following program categories from Quantec were examined for cost effectiveness using Sendout. It should be noted that the Sendout optimization model is able to directly compare the costs and benefits of energy efficiency programs with the costs and benefits of supply-side resources simultaneously. This means that in calculating the optimal portfolio, Sendout treats demand-side resources the same as supply-side resources and thus no “screening” step is required.

**Exhibit XIV-6**
**Commercial and Industrial Gas Efficiency Program Bundles**

| Efficiency Program | Scenario Considered | Levelized Cost |
|---|---|---|
| Commercial Programs A-C Baseload + Heat | Resource considered in all scenarios. | $3.20/Dth |
| Commercial Program Baseload D1 - New Construction. | Base Case, Green World, and Strong Economy. Not considered in Weak Economy because programs rejected in Base Case. | $6.98/Dth |
| Commercial Program Baseload D2 - Existing Construction. | Base Case, Green World, and Strong Economy. Not considered in Weak Economy because programs rejected in Base Case. | $7.16/Dth |
| Commercial Heat Program D3 – New Construction. | Resource considered in all scenarios. | $6.69/Dth |
| Commercial Heat Program D4 – Existing Construction. | Resource considered in all scenarios. | $6.71/Dth |
| Commercial Heat Program E1 – New Construction | Resource considered in all scenarios. | $7.94/Dth |
| Commercial Heat Program E2 – Existing Construction | Resource considered in all scenarios. | $8.00/Dth |
| Commercial Heat Program F1 – New Construction | Resource considered in all scenarios. | $8.67/Dth |
| Commercial Heat Program G1 + G2 – New and Existing Construction. | Resource considered in all scenarios. | $9.96/Dth |
| | | |
| Industrial | Resource considered in all scenarios. | |

**Exhibit XIV-7**
**Residential Gas Efficiency Program Bundles**

| Efficiency Program | Scenario Considered | Levelized Cost |
|---|---|---|
| Residential Programs A-C Baseload + Heat | Resource considered in all scenarios. | $3.55/Dth |
| Residential Baseload program D1 – New Construction | Resource considered in all scenarios. | $6.58/Dth |
| Residential Baseload Program E1 – Existing Construction | Considered in Base Case, Green World and Strong Economy, not in Weak Economy, as rejected in Base Case. | $8.18/Dth |
| Residential Heat Program D1 – New Construction | Resource considered in all scenarios. | $6.58/Dth |
| Residential Heat Program E1 – Existing Construction | Resource considered in all scenarios. | $8.38/Dth |
| Residential Heat Program F1 – Existing Construction | Resource considered in all scenarios. | $8.87/Dth |
| Residential Heat Program G1 – Existing Construction | Considered in Base Case, Green World, and Strong Economy, not in Weak Economy, as rejected in Base Case. | $9.83/Dth |
| Residential Heat Program G2 – New Construction | Considered in Base Case, Green World, and Strong Economy, not in Weak Economy, as rejected in Base Case. | $10.06/Dth |

## F. Results of Natural Gas Analysis

As described in the scenario section, PSE performed analysis on seven different scenarios. The results are summarized below, followed by more discussion of each scenario. Additional details are provided in Appendix J.

*Cautionary Note*

Conclusions from this analysis must be considered broadly. Like all analysis, results of the resource optimization models are dependent on input assumptions. Scenario and Monte Carlo analysis help by providing information on ranges of input assumptions. A key input assumption underlying all the analysis in this plan, however, is the ability to add very small units of capacity resources each year. In reality, capacity resources are more incremental than marginal; i.e., resource additions are “lumpy”. For example, PSE’s analysis assumed that small increments of Jackson Prairie storage deliverability could be added each year up to 2012. In reality, the expansion would likely be completed in one full increment. This approach establishes a theoretically optimal schedule of resource additions that will be useful in guiding future resource acquisition activities, and provides results that can be publicly disclosed without unduly disadvantaging the Company's ability to negotiate the lowest-cost arrangements on behalf of customers. However, given the theoretical nature of the optimal portfolio, specific resource acquisitions must be backed up and supported by specific resource acquisition analysis. The Least Cost Plan analysis should be used to guide resource strategies, not justify specific acquisitions.

One specific area to note is how the marginal nature of future capacity resources affects the determination of cost effectiveness for gas efficiency programs. This theoretical analysis assumes that capacity can be added in small, marginal increments. This means that energy efficiency programs are credited with more capacity cost savings in this analysis than would accrue with more realistic lumpy resource additions. Based on preliminary Base Case analysis, the impact on optimal energy efficiency programs could be a result of the difference between an increase in programmatic savings of 40 percent, shown in the marginal analysis, vs. 20 percent, shown in the more realistic case wherein capacity additions are assumed to be more lumpy. Therefore, the proper conclusion from the Least Cost Plan analysis is that the Company should consider significantly increasing its gas efficiency programs, as opposed to increasing its programs by 40 percent. The actual targeted amount of energy efficiency programs should be based on specific analysis, as is the acquisition of other resources.

*Key Analytical Results from LDC Scenarios*

Results of the four scenarios that focus exclusively on planning for gas local distribution system loads (LDC) are generally consistent and reveal the following general trends:

- More energy efficiency programs appear cost effective given the new higher gas price forecasts. PSE should consider expanding its level of natural gas energy efficiency programs.
- PSE should work with Jackson Prairie co-owners to expand deliverability and work with Northwest Pipeline to obtain seasonal delivery rights similar to today's TF-2 service.
- Given the trend that suppliers will no longer hold as much transportation capacity on Westcoast to deliver gas to Sumas, PSE should consider acquiring upstream capacity. Generally, capacity from Station 2 on Westcoast appears more cost

effective than capacity from AECO on Nova, ANG and Southern Crossing, though diversity of supply concerns are a qualitative factor that should be considered.

- A medium-term peaking resource may be cost effective as a bridge to the full expansion of Jackson Prairie assumed by 2012.
- Additional transportation on Northwest Pipeline from Sumas, along with additional T-South or other upstream capacity will be required over the planning period. PSE should continue to monitor other proposals to bring gas to its market area.
- PSE should monitor developments of regional LNG import facilities. A long-term supply contract with a supplier from this type of facility may be cost effective, dependent on transport costs from a specific location and the basis of the commodity pricing.
- Local LNG storage, LNG satellite and LNG with liquefaction, do not appear to be cost effective generic resources. Like distributed generation on the power side, localized LNG storage may be a cost-effective solution to a specific situation. Cost estimates should be refined and cost effectiveness considered on a case-by-case basis.
- Additional load from fuel conversions does not appear to put upward pressure on average gas costs to existing customers.
- Monte Carlo analysis to examine physical supply risk indicates that a portfolio designed to meet PSE's design-day peak forecast in an otherwise normal temperature winter is sufficient to meet its obligations under a variety of possible winter conditions.
- With regard to cost risk, the 20-Year Monte Carlo analysis demonstrates that viewing risk over a 20-year horizon tends to mute the effects of price and volumetric variability. Shorter time periods, such as annual variability, should be considered when examining the impact of different resources on cost variability.
- Monte Carlo analysis on optimal portfolio construction highlights the fact that timing of certain resource additions are highly sensitive to Base Case assumptions.

*Key Results from Generation Fuel Analysis*

Two primary results are observed in the gas for generation fuel analysis:

- Based on the electric Business as Usual gas-fired generation resources, PSE's gas portfolio for power generation appears to have sufficient firm Northwest Pipeline capacity through 2009.

- Like the sales portfolio, additional upstream transportation capacity to Station 2 may need to be acquired as gas producers and marketers hold less capacity on Westcoast to move gas south to Sumas.

*Summary of Joint LDC and Generation Fuel Analysis*

Results of the analysis to test for potential economies of scale and scope to joint planning did not show significant savings opportunity. The analysis showed a potential savings of approximately 1 percent per year on an annualized basis relative to the combined stand-alone portfolio costs, a portion of which would be achievable through short-term optimization without significant changes in long-term planning.

### F.1. Results across LDC Scenarios

This section will include a comparison of resulting annual average gas costs and a comparison of the relevant differences between resource additions, including energy efficiency programs. Additional details are available in Appendix J.

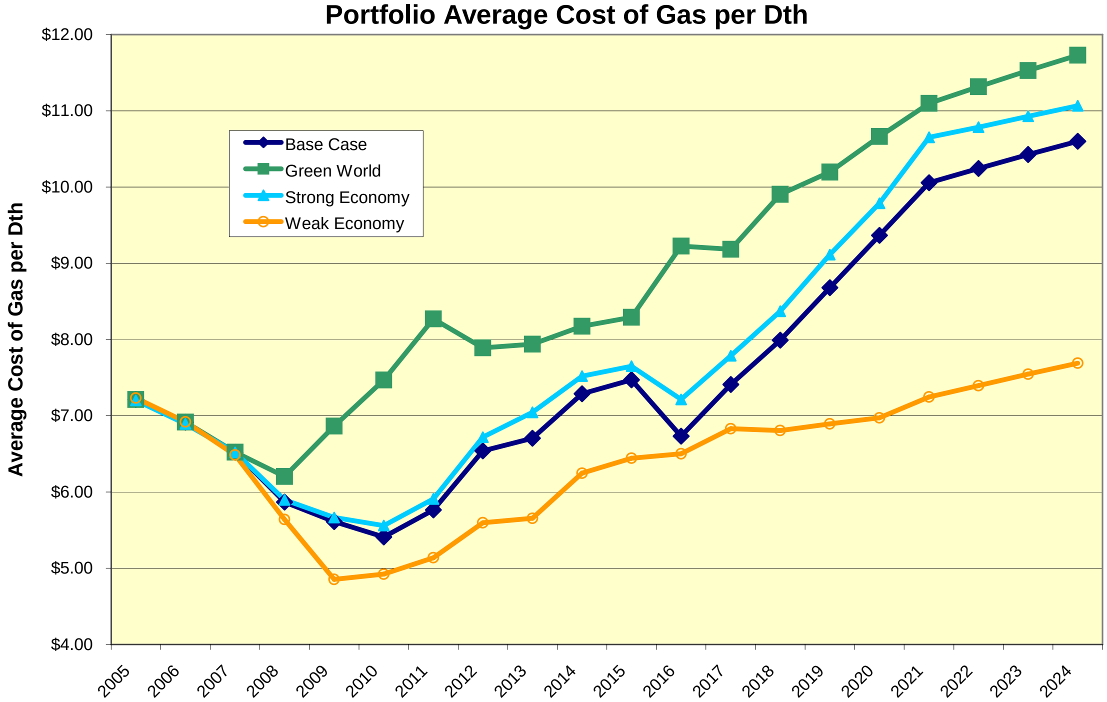
*Comparison of Resulting Average Annual Portfolio Costs*

Please note this chart is not a projection of average PGA rates. Costs included here are based on the assumption of highly incrementalized resource availability, which is a theoretical construct. Additionally, costs included in the average portfolio costs include items that are not included in the PGA. These include rate-base related Jackson Prairie storage and costs for energy efficiency programs, which are included on an average levelized basis, not on a projected cash flow basis. Also, please note comments previously expressed in this chapter, which state that the perfect foresight of a linear programming model creates theoretical results that cannot be achieved in the real world.

Exhibit XIV-8 shows that average optimized portfolio costs follow expectations. Average Green World portfolio costs are higher than the other scenarios, driven by higher projected commodity costs. Weak Economy prices drive lower average portfolio costs. Strong Economy average portfolio costs are slightly higher than the Base Case, as the increase in fixed gas supply costs to meet the higher load growth is greater than the corresponding increase in volumes. Thus, average fixed costs are slightly higher in that case.

**Exhibit XIV-8**

**Gas Scenario Comparison:
Portfolio Average Cost of Gas per Dth**




### F.2. Comparison of Resource Additions

Differences in resource additions are generally driven by load growth. The exception is for energy efficiency resources, which are influenced more directly by the gas price forecast than supply resources because efficiency programs avoid commodity costs. However, the absolute level of efficiency programs is also affected by load growth assumptions. The following information summarizes the optimal resource additions across the scenarios by resource type.

*Energy Efficiency Resources*

As noted above, Sendout optimizes energy efficiency programs as part of the resource optimization analysis. Exhibit XIV-9 summarizes the levelized cost of the energy efficiency bundles analyzed using Sendout, along with the results by scenario. This format reveals how various program bundles were accepted (taken) or rejected across the scenarios as part of the optimization analysis.

Sets of increasingly expensive efficiency programs were added to the optimization analysis until SENDOUT rejected programs at a similar cost level. For example, ComA2C, ComHeatD3, ComD1-Bload, ComdD2-Bload, Indust, ResA2C, Res D1-Bload, and Res Heat D1, were run through a SENDOUT optimization run, along with all of the supply-side alternatives to determine if these efficiency bundles would be part of the optimal portfolio. The optimal portfolio included all of these programs except for ComD1-Bload and ComdD2-Bload (Note: This optimization analysis took over 24 hours to run.). In the next SENDOUT run, the low-cost demand resources found to be cost effective were accepted (or "baselined" in the portfolio) and the next set of higher-cost efficiency programs were offered, along with the same supply-side resources, to check whether that next set of higher-cost efficiency programs would be included in the optimal resource portfolio. For programs that were rejected, i.e., ComD1-Bload and ComdD2-Bload, there was no need to test higher-cost commercial base load programs. This approach was used in each category until the model either rejected an efficiency bundle or all the categories from Quantec had been analyzed. For example, in the Base Case SENDOUT selected the highest-cost commercial heat bundle from Quantec ($9.96/Dth) but rejected more expensive residential heat programs.

Alternative scenarios used the Base Case analysis as the starting point for examining energy efficiency programs. In Green World, gas prices are significantly higher than the Base Case forecast. This indicates all the efficiency programs from the Base Case would be part of the optimal portfolio in Green World. Therefore, all efficiency resources accepted in the Base Case analysis were not offered as resource alternatives in Green World, but were assumed to be selected as resources in the optimal portfolio. However, resources that were rejected in the Base Case were offered as resource alternatives in Green World. For example, ResG1-Heat was rejected in the Base Case but accepted in the Green World scenario. Efficiency programs in the Strong Economy scenario were treated in the same manner as Green World. For Weak Economy, since the gas price forecast is significantly lower than the Base Case forecast, the Company did not offer efficiency programs that were rejected in the Base Case, as it was clear these would not be selected in the Weak Economy scenario.

**Exhibit XIV-9**

| Efficiency Program | Levelized Cost | Base Case | Green World | Strong Economy | Weak Economy | Joint Planning |
|---|---|---|---|---|---|---|
| ComA2C | $ 3.20 | taken | taken | taken | taken | taken |
| ComHeatD3 | $ 6.69 | taken | taken | taken | taken | taken |
| ComHeatD4 | $ 6.71 | taken | taken | taken | taken | taken |
| ComD1-BLoad | $ 6.98 | rejected | taken | taken | na | rejected |
| ComD2-BLoad | $ 7.16 | rejected | taken | taken | na | na |
| ComHeatE1 | $ 7.94 | taken | taken | taken | taken | taken |
| ComHeatE2 | $ 8.00 | taken | taken | taken | taken | taken |
| Com Heat F1 | $ 8.76 | taken | taken | taken | taken | taken |
| ComHeat G1+2 | $ 9.96 | taken | taken | taken | rejected | taken |
| **Indust** | **$** 2.01 | taken | taken | taken | taken | taken |
| ResA2C | $ 3.55 | taken | taken | taken | taken | taken |
| Res D1-BLoad | $ 7.21 | taken | taken | taken | rejected | rejected |
| Res Heat D1 | $ 6.58 | taken | taken | taken | taken | taken |
| Res E1-BLoad | $ 8.18 | rejected | rejected | rejected | na | rejected |
| Res Heat E1 | $ 8.38 | taken | taken | taken | rejected | taken |
| Res Heat F1 | $ 8.87 | taken | taken | taken | rejected | taken |
| ResG1-Heat | $ 9.83 | rejected | taken | taken | na | rejected |
| ResG2-Heat | $ 10.06 | rejected | taken | taken | na | na |

Exhibit XIV-9 shows that for the Base Case, commercial base load programs with a levelized cost greater than or equal to $6.98 were rejected, but those programs were taken in Green World and Strong Economy. All commercial heat programs were taken in scenarios other than Weak Economy. For residential programs, baseload programs greater than $7.21 were rejected, as were heat programs with a levelized cost at or greater than $9.83. Notice that the efficiency programs for the Green World and Strong Economy scenarios are identical. In both of these scenarios, residential base load program bundles with costs greater than or equal to the $8.18 level were rejected, but all heat program bundles that were offered were taken. Overall, the primary conclusion from this analysis is that gas conservation programs should emphasize heating programs, given current gas price forecasts and the higher future cost of capacity additions.

Exhibit XIV-9 provides a quick way to identify how different program bundles performed across scenarios. Exhibit XIV-10 illustrates the overall impact on load from the optimized programs. Results are intuitive; i.e., the low price Weak Economy scenario has the lowest efficiency savings at 84 percent of the Base Case by 2024, while Green

World and Strong Economy exhibit higher savings, at 114 percent of the Base Case by 2024.

**Exhibit XIV-10**
**Annual Energy Efficiency Savings (MDth)**

| | Base Case | Green World | Strong Economy | Weak Economy | Joint |
|---|---|---|---|---|---|
| 2005 | - | - | - | - | |
| 2006 | 389 | 409 | 409 | 361 | 388 |
| 2007 | 826 | 884 | 884 | 740 | 825 |
| 2008 | 1,316 | 1,434 | 1,434 | 1,139 | 1,314 |
| 2009 | 1,833 | 2,027 | 2,027 | 1,552 | 1,831 |
| 2010 | 2,347 | 2,622 | 2,622 | 1,968 | 2,344 |
| 2011 | 2,853 | 3,211 | 3,211 | 2,380 | 2,849 |
| 2012 | 3,328 | 3,764 | 3,764 | 2,770 | 3,323 |
| 2013 | 3,783 | 4,291 | 4,291 | 3,145 | 3,778 |
| 2014 | 4,215 | 4,788 | 4,788 | 3,503 | 4,209 |
| 2015 | 4,633 | 5,268 | 5,268 | 3,854 | 4,627 |
| 2016 | 5,061 | 5,760 | 5,760 | 4,214 | 5,055 |
| 2017 | 5,508 | 6,274 | 6,274 | 4,593 | 5,501 |
| 2018 | 5,924 | 6,753 | 6,753 | 4,948 | 5,917 |
| 2019 | 6,309 | 7,194 | 7,194 | 5,277 | 6,301 |
| 2020 | 6,681 | 7,620 | 7,620 | 5,598 | 6,674 |
| 2021 | 7,055 | 8,047 | 8,047 | 5,921 | 7,047 |
| 2022 | 7,434 | 8,478 | 8,478 | 6,249 | 7,426 |
| 2023 | 7,816 | 8,913 | 8,913 | 6,580 | 7,807 |
| 2024 | 8,197 | 9,345 | 9,345 | 6,910 | 8,188 |

The Base Case efficiency savings are significantly higher than those shown in the August 2003 Least Cost Plan Update. Exhibit XIV-11 compares the Base Case results to the same planning period results from the August 2003 Least Cost Plan Update. Overall, the optimal level of conservation programs from the Base Case analysis is 40 percent higher by year 20 than the August 2003 Update.

**Exhibit XIV-11**
**Comparison of Optimal Energy Efficiency – Current vs. Prior Plan**

| Period # | Current Planning Period | Base Case Optimal Efficiency Savings (MDth) | August 2003 LCP Update Optimal Efficiency Savings (MDth) | Aug 2003 LCPUpdate Planning Period | % Change |
|---|---|---|---|---|---|
| 1 | 2006 | 388.6 | 306.4 | 2004 | 27% |
| 2 | 2007 | 825.8 | 612.9 | 2005 | 35% |
| 3 | 2008 | 1,316.0 | 919.3 | 2006 | 43% |
| 4 | 2009 | 1,833.5 | 1,225.7 | 2007 | 50% |
| 5 | 2010 | 2,347.1 | 1,532.2 | 2008 | 53% |
| 6 | 2011 | 2,853.1 | 1,838.6 | 2009 | 55% |
| 7 | 2012 | 3,327.9 | 2,145.1 | 2010 | 55% |
| 8 | 2013 | 3,783.0 | 2,451.5 | 2011 | 54% |
| 9 | 2014 | 4,214.6 | 2,757.9 | 2012 | 53% |
| 10 | 2015 | 4,633.2 | 3,064.4 | 2013 | 51% |
| 11 | 2016 | 5,061.3 | 3,370.8 | 2014 | 50% |
| 12 | 2017 | 5,508.3 | 3,677.2 | 2015 | 50% |
| 13 | 2018 | 5,924.5 | 3,983.7 | 2016 | 49% |
| 14 | 2019 | 6,308.5 | 4,290.1 | 2017 | 47% |
| 15 | 2020 | 6,681.3 | 4,596.6 | 2018 | 45% |
| 16 | 2021 | 7,054.9 | 4,903.0 | 2019 | 44% |
| 17 | 2022 | 7,433.8 | 5,209.4 | 2020 | 43% |
| 18 | 2023 | 7,815.8 | 5,515.9 | 2021 | 42% |
| 19 | 2024 | 8,197.3 | 5,822.3 | 2022 | 41% |
| 20 | 2025 | 8,576.6 | 6,128.7 | 2023 | 40% |

It is important to view these results from the proper perspective. As noted above, the Least Cost Plan analysis is not designed to support specific resource acquisitions. It would be an inappropriate use of the analysis to conclude that the Company should increase its conservation programs by 40 percent in the program bundles noted on Exhibit XIV-9. However, the proper conclusion to be drawn from this analysis is that the Company should begin to prepare for a significant increase in its gas efficiency programs, and that such programs should primarily target heating loads. Actual programs and targets must be developed based on more specific program information.

*Gas Supply Resources*

As discussed in Chapters XII and XIII, there is no substitute fuel for PSE's natural gas customers. PSE will continue to rely on acquisition of natural gas from creditworthy and reliable suppliers at major market hubs or production areas. In the Sendout model, PSE has assumed that its existing geographically diverse, long-term contracts for supply (which currently represent approximately two-thirds of annual requirements) would continue through the planning horizon. Additional gas supply is selected by the model, as needed, from various supply basins or trading locations along with the optimal utilization of existing and new capacity options to create the optimal portfolio. The majority of this additional supply would likely be acquired under short-term contracts (from one month to two years in duration) at market price, as is the standard in the industry. In this Least Cost Plan, PSE has not attempted to determine the appropriate quantity of gas that might be purchased under *Fixed Price* contracts (of short or long term). PSE will be investigating that topic, guided by additional customer value research, at a later date.

A new category of gas supply resources was examined for the purposes of this Least Cost Plan. Imported LNG supply was modeled as being available at two different locations. This is described more fully in the section on new gas supply resource alternatives. The first location was in British Columbia. This project connected to the pipeline system at or south of Station 2, requiring transportation down the Westcoast system to Sumas, then on Northwest Pipeline to PSE's city gates. An alternative location was modeled South of PSE's service territory, connecting to the pipeline system south of PSE's city gates but hydraulically north (or west) of the Columbia Gorge. Transportation costs for the South LNG option were assumed to be identical to Northwest Pipeline expansion capacity costs from PSE's load center to Sumas. It was assumed that South LNG would require incremental new pipeline capacity, as existing capacity from points south are dedicated to accessing supply from AECO and the Rockies. Commodity prices for both North and South LNG were assumed to be AECO index plus $0.05/Dth as a physical premium or to reflect other possible fixed gas supply charges. The contract was assumed to be a 100 percent load factor take agreement. A maximum of 50 MDth/day contract from each of the North and South options was considered across all scenarios.

Exhibit XIV-12 summarizes the results of the LNG projects. North LNG imports were rejected across all Scenarios. This is not surprising, given Station 2 spot market prices are expected to be at a slight discount to AECO prices, rather than at a slight premium. Further, in the long-run North LNG supplies would likely require transportation on two pipelines (rate stacking). South LNG, however, was selected in all scenarios except the

Weak Economy Case. The generation fuel analysis took 11,000 Dth/day of imported South LNG. For the joint planning analysis, a maximum of 62 MDth/day was made available, all of which was taken.

**Exhibit XIV-12**
**Results of LNG Import Analysis**

| | Base Case | Green World | Strong Economy | Weak Economy | Generation Fuel | Joint Analysis |
|---|---|---|---|---|---|---|
| North LNG | 0 | 0 | 0 | 0 | 0 | 0 |
| South LNG | 50 MDth/d | 50 MDth/d | 50 MDth/d | 0 | 11 MDth/d | 62 MDth/d |

Assumptions about commodity cost pricing and transportation costs have a significant impact on the cost effectiveness of LNG imports. This analysis indicates that the Company should continue to monitor development of regional LNG import facilities, as specific location details will considerably impact the cost effectiveness of imported LNG supplies. Imported LNG is also impacted by public policy and other considerations. These factors were not modeled in an optimization model, but will need to be considered.

*Storage Resources*

Four different storage resources were considered for this Least Cost Plan. Jackson Prairie storage capacity/deliverability expansions were modeled for all but the Generation Fuel analysis, and made available to the model from 2008-2012. The Jackson Prairie deliverability expansion was not modeled in the Generation Fuel analysis because it was selected in each of the LDC scenarios. Thus, as a stand-alone portfolio, the same Jackson Prairie expansion would not be available to both portfolios. LNG storage that has the ability to liquefy natural gas on-site was considered in all scenarios. Satellite LNG, which requires LNG to be trucked to the storage facility (like the Company's facility at Gig Harbor), was considered in the Base Case analysis but clearly would not be selected as a generic supply resource without consideration of localized benefit. As a result, it was not modeled for other scenarios as a generic supply resource. Finally, a shorter-term LNG bridging service was considered in all of the LDC scenarios. This option was based on leasing capacity in a new LNG storage system in British Columbia on an annual basis through 2010. Delivery of the stored LNG would be accomplished through a commercial exchange agreement. Like the Jackson Prairie storage, this LNG bridging service was not made available in the generation fuel study, as it was selected in the Base Case LDC scenario.

- *Jackson Prairie Storage Capacity Expansion*

  As explained earlier, resources for this analysis were assumed to be available in small increments. Jackson Prairie storage capacity/deliverability expansions were assumed to be available in optimally sized increments each year from 2008 through 2012. Exhibit XIV-13 lists the capacity/deliverability expansions by year for each of the scenarios. Storage capacity is shown in thousands of Dth and deliverability is shown in thousands of Dth/day.

**Exhibit XIV-13**
**Jackson Prairie Storage Capacity/Deliverability**

| | **Base Case** | **Green World** | **Strong Economy** | **Weak Economy** | **Joint Plan** |
|---|---|---|---|---|---|
| 2008 | 383 MDth<br>27 MDth/day | 375 MDth<br>27 MDth/day | 573 MDth<br>41 MDth/day | 213 MDth<br>15 MDth/day | 651.4 MDth<br>46.5 MDth/day |
| 2009 | 621 MDth<br>44 MDth/day | 594 MDth<br>42 MDth/day | 1056 MDth<br>75 MDth/day | 213 MDth<br>15 MDth/day | 1354 MDth<br>98 MDth/Day |
| 2010 | 635 MDth<br>45 MDth/day | 597 MDth<br>43 MDth/day | 1,254 MDth<br>90 MDth/day | 464 MDth<br>33 MDth/day | 1429 MDth<br>102 MDth/Day |
| 2011 | 1456 MDth<br>104 MDth/day | 1,456 MDth<br>104 MDth/day | 1,456 MDth<br>104 MDth/day | 1,308 MDth<br>93 MDth/day | 1456 MDth<br>104 MDth/day |
| 2012 | 1456 MDth<br>104 MDth/day | 1,456 MDth<br>104 MDth/day | 1,456 MDth<br>104 MDth/day | 1,456 Mdth<br>104 MDth/day | 1456 MDth<br>104 MDth/day |

The key resource strategy conclusion from this analysis is that under all scenarios, a Jackson Prairie expansion is desirable and least cost, beginning in 2008 with full expansion in place by 2011 (except in the Weak Economy scenario, which completes the expansion in 2012.) Note that in the Joint Planning scenario, Jackson Prairie developments are approximately twice the level in the Base Case, up until 2011 when Jackson Prairie is fully developed. This suggests that, if the project expansion is developed early, it may be worthwhile until the sales portfolio grows into the capacity to investigate a cost allocation or other state regulatory policy to provide the generation portfolio with access to a portion of Jackson Prairie storage and related deliverability.

- *LNG Bridging Service*

  The shorter-term LNG bridging service was available in all scenarios. Exhibit XIV-14 summarizes the optimal addition across the scenarios. Across all scenarios, the full LNG bridging service is selected, except for the last year of the Weak Economy scenario. Investigating the availability and cost of an LNG bridging service should be part of the Company's gas resource strategy.

**Exhibit XIV-14**
**LNG Bridging Capacity/Deliverability**

| | Base Case | Green World | Strong Economy | Weak Economy | Joint Plan |
|---|---|---|---|---|---|
| 2007 | 50 MDth | 50 MDth | 50 MDth | 50 MDth | 50 MDth |
| | 10 MDth/day | 10 MDth/day | 10 MDth/day | 10 MDth/day | 10 MDth/day |
| 2008 | 100 MDth | 100 MDth | 100 MDth | 100 MDth | 100 MDth |
| | 20 MDth/day | 20 MDth/day | 20 MDth/day | 20 MDth/day | 20 MDth/day |
| 2009 | 100 MDth | 100 MDth | 100 MDth | 7.8 MDth | 100 MDth |
| | 20 MDth/day | 20 MDth/day | 20 MDth/day | 1.6 MDth/day | 20 MDth/day |

- *LNG Storage*

  LNG storage, as a generic resource, does not appear to be as clear a part of the Company's resource strategy as Jackson Prairie or LNG bridging. LNG storage is selected as a resource only in the Strong Economy case, and then with a storage capacity level of 14 MDth and daily deliverability of 2 MDth/day. As a generic resource, LNG storage does not appear to be cost effective. In terms of its resource strategy, the Company should only consider LNG storage in locations that also provide additional local distribution system benefits, as with PSE's satellite LNG facility in Gig Harbor.

*Transportation Capacity Additions*

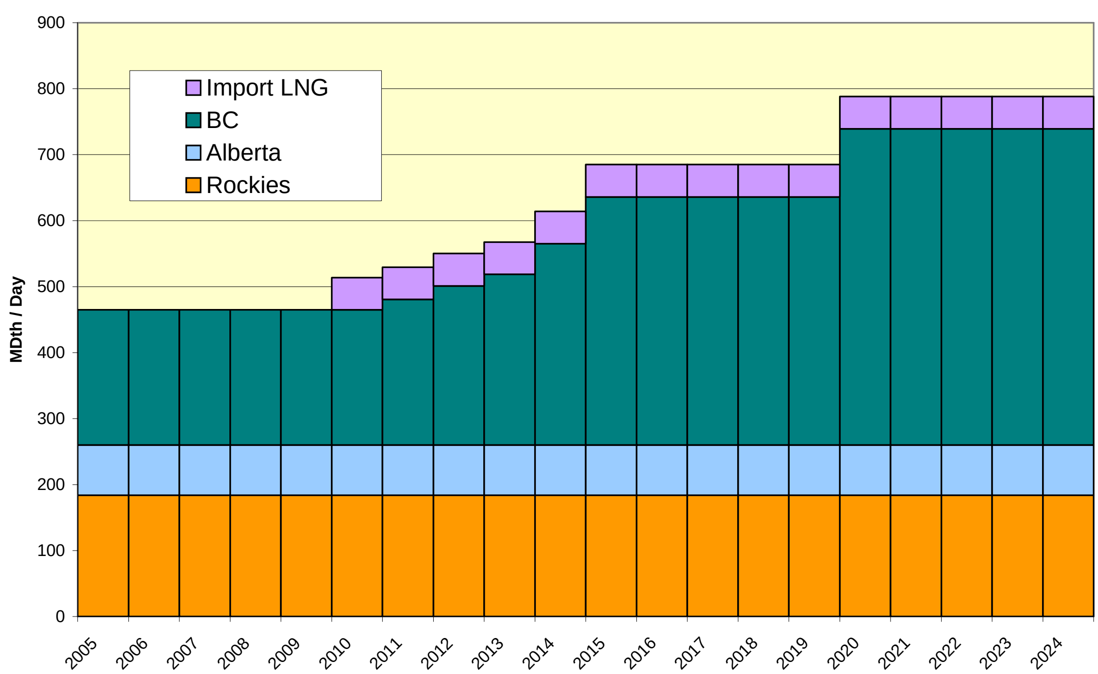
Transportation capacity additions are considered in two primary categories: upstream pipelines to transport gas to Sumas, and Northwest Pipeline capacity to deliver gas to PSE's city gates.

- *Upstream Pipeline*

  A significant amount of Westcoast pipeline capacity is added based on the assumption that decreasing supply will be available at Sumas. The significant upstream analysis was performed in the preliminary Base Case analysis to consider if the capacity to move gas on Terasen Gas's Southern Crossing pipeline (with ANG and Nova capacity upstream) from AECO (rather than Station 2) to Sumas would be the least cost option. The analysis indicated that this is not the case. This is not surprising, considering that gas at Station 2 is expected to sell at a discount to AECO, and that transport on Southern Crossing, ANG, and Nova is more costly than transport on Westcoast from Station 2. There may, however, be substantial benefits to maintaining a degree of supply diversity. The Base Case optimal resource solution indicates that without Southern Crossing capacity, PSE's pipeline capacity portfolio relies increasingly on British Columbia-sourced supply (see Exhibit XIV-15). The Company may wish to consider diversity and other qualitative reasons for increasing capacity from other sources.

**Exhibit XIV-15**

**Base Case- Cumulative Pipeline Capacity by Source**



- *Direct Connect Pipeline Capacity*

  Transportation capacity on Northwest Pipeline can be separated into two major categories. First is seasonal transportation service, such as the existing TF-2 service, which is priced to reflect the seasonal availability tied to Jackson Prairie storage. The following discussion will not highlight seasonal transportation, since this kind of transport is essentially the same as daily deliverability, which was included in the storage discussion above. Year-round transportation capacity is the other primary category. PSE modeled up to 100 MDth/day of existing surplus capacity referred to as "secondary capacity" which might be obtained from different counterparties; the second category is capacity obtained as a result of new construction subsequent to an open season offering by Northwest Pipeline, referred to as "expansion capacity."

  Secondary capacity was selected as part of the least cost portfolio in all but the Weak Economy Case. The Base Case and Green World scenarios do not take any secondary capacity until 2011, but Strong Economy begins taking secondary capacity in 2007. The Generation Fuel analysis assumed that the secondary capacity which was not taken in the gas Base Case analysis was available on that schedule, to avoid double counting availability. Please see Exhibit XIV-16.

**Exhibit XIV-16**
**Optimal Secondary Market Capacity Additions**

| | Base Case MDth/day | Green World MDth/day | Strong Economy MDth/day | Weak Economy MDth/day | Generation Fuel MDth/day | Joint Plan MDth/day |
|---|---|---|---|---|---|---|
| 2006 | 0 | 0 | 0 | 0 | 12 | 0 |
| 2007 | 0 | 0 | 24 | 0 | 12 | 0 |
| 2008 | 0 | 0 | 24 | 0 | 12 | 0 |
| 2009 | 0 | 0 | 24 | 0 | 81 | 0 |
| 2010 | 0 | 0 | 24 | 0 | 81 | 0 |
| 2011 | 16 | 12 | 100 | 0 | 76 | 46 |
| 2012 | 36 | 32 | 100 | 0 | 63 | 80 |
| 2013 | 54 | 49 | 100 | 0 | 0 | 100 |
| 2014 | 100 | 100 | 100 | 0 | 0 | 100 |

The implication of this analysis for resource strategies is that the Company should investigate whether a commitment for future access to this secondary market capacity could be obtained, or whether the capacity can be obtained now at appropriate pricing, even though it is not needed for several years.

Expansion capacity is ultimately required in all cases. Exhibit XIV-17 shows the cumulative addition of expansion capacity across the scenarios. Please note that this includes additional Northwest Pipeline capacity required to transport gas from the South LNG import facility to PSE's load.

**Table XIV-17**
**Optimal Direct-Connect Pipeline Capacity Additions from Expansions**

| | Base Case MDth/day | Green World MDth/day | Strong Economy MDth/day | Weak Economy MDth/day | Generation Fuel MDth/day | Joint Plan MDth/day |
|---|---|---|---|---|---|---|
| 2006 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2007 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2008 | 0 | 23 | 23 | 0 | 0 | 0 |
| 2009 | 0 | 38 | 38 | 0 | 0 | 0 |
| 2010 | 49 | 38 | 38 | 49 | 11 | 0 |
| 2011 | 49 | 100 | 100 | 49 | 63 | 70 |
| 2012 | 49 | 100 | 100 | 159 | 63 | 70 |
| 2013 | 49 | 100 | 100 | 159 | 139 | 96 |
| 2014 | 49 | 100 | 100 | 159 | 139 | 96 |
| 2015 | 120 | 162 | 162 | 379 | 247 | 285 |
| 2016 | 120 | 162 | 162 | 379 | 247 | 285 |
| 2017 | 120 | 162 | 162 | 379 | 247 | 285 |
| 2018 | 120 | 162 | 162 | 379 | 247 | 285 |
| 2019 | 120 | 162 | 162 | 379 | 247 | 285 |
| 2020 | 223 | 262 | 262 | 618 | 282 | 411 |

The primary take-away from this analysis for the gas resource strategy is that PSE will need to monitor and optimize the timing of transportation capacity expansions in conjunction with Northwest Pipeline and other shippers.

### F.3. Complete Picture—Base Case

The Base Case Optimal Resource Portfolio is shown below in Exhibit XIV-18. Additional Scenario results are included in Appendix J.

**Exhibit XIV-18.1**

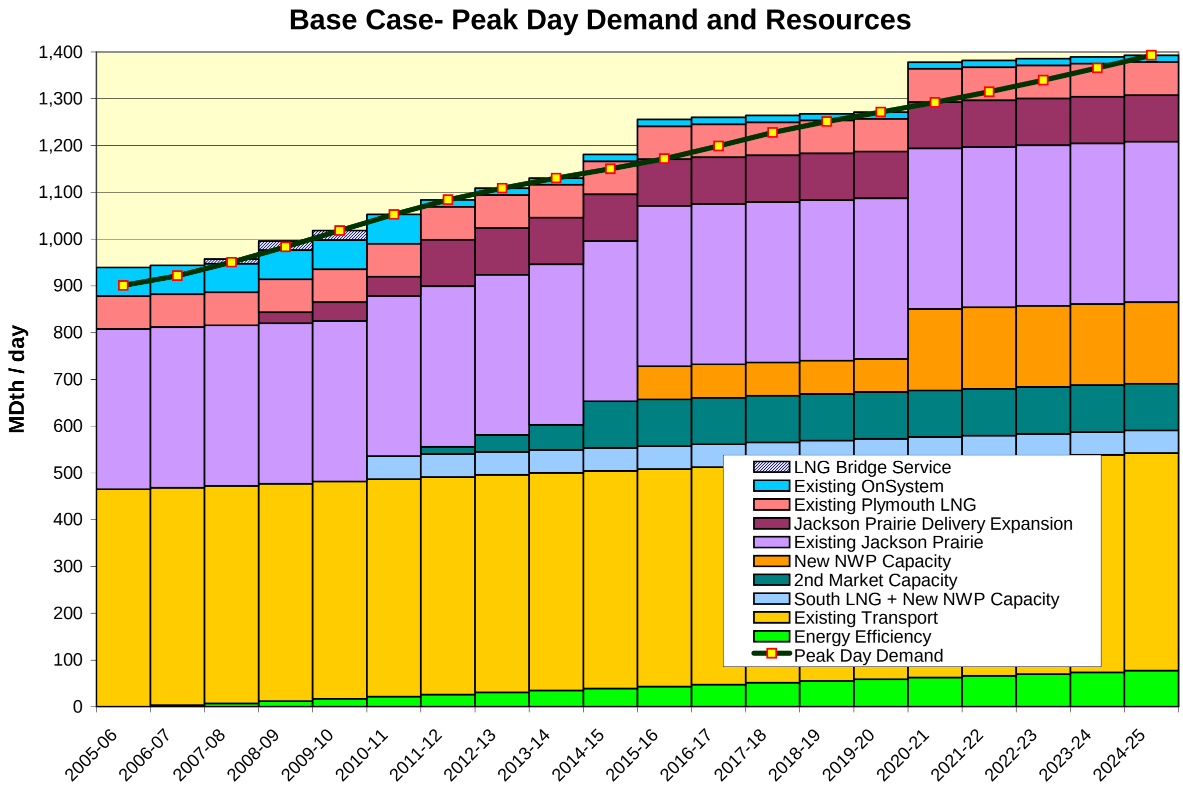
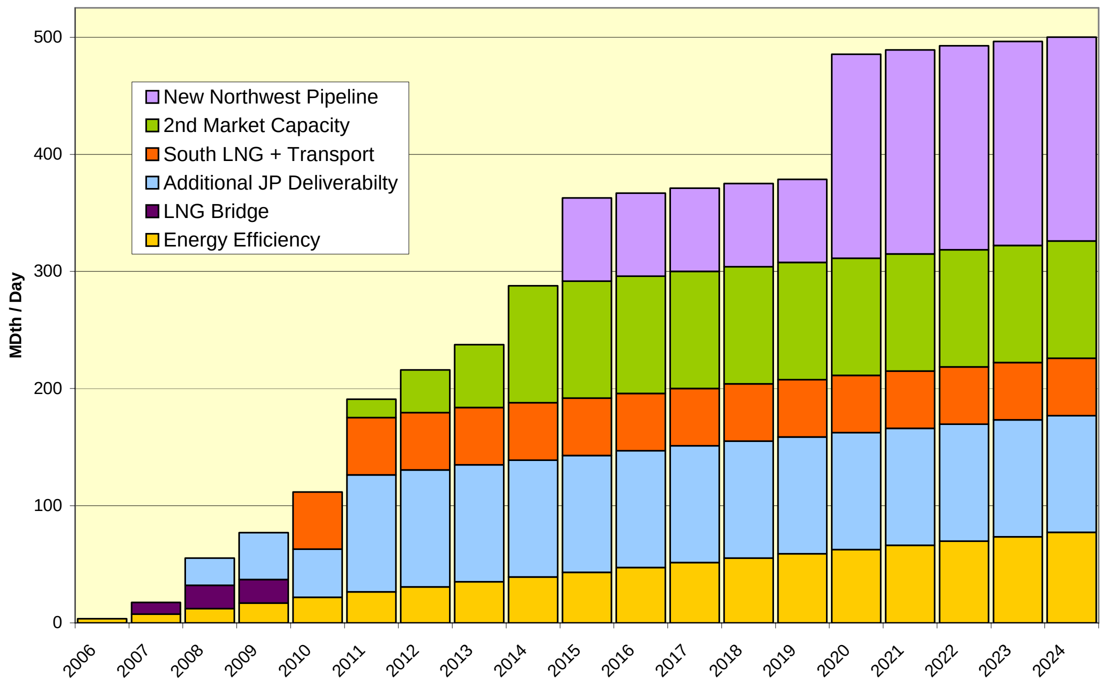


**Exhibit XIV-18.2**

**2006-2024 LDC Gas Resource Strategy (Additions)**

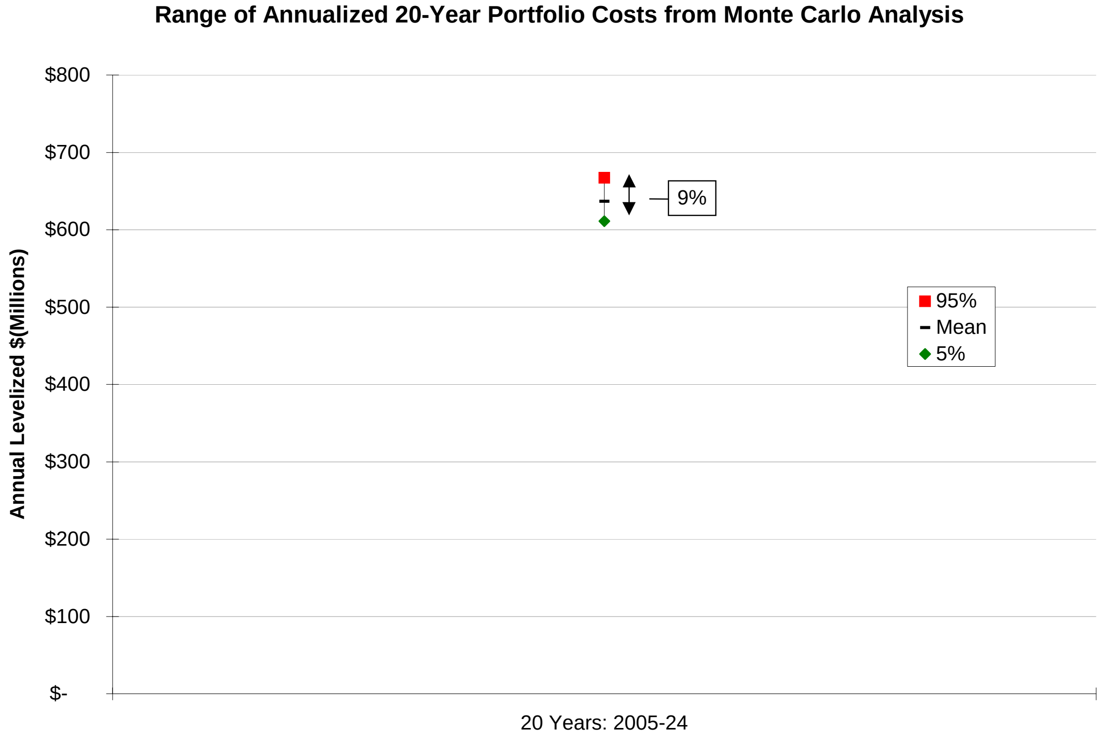



*Base Case—Results of Monte Carlo Analysis on Base Case Portfolio*

As noted above, the Company used the Monte Carlo capabilities of Vector Gas to examine the effects of temperature-induced load uncertainty and price uncertainty on the Optimal Base Case portfolio. The portfolio PSE examined was the resulting optimal portfolio from the Company's Base Case analysis. In this analysis, daily temperatures affect both load and daily gas prices. The Monte Carlo analysis was performed using 200 draws. Each of the 200 draws results in 20 years worth of daily prices and loads.

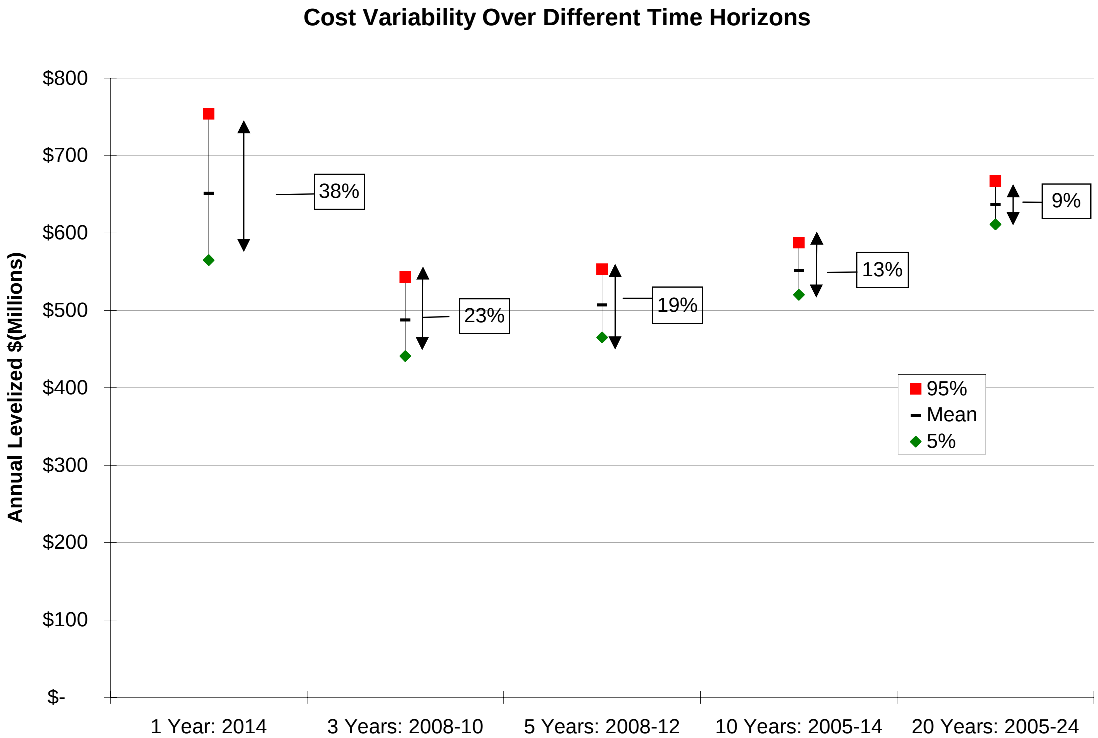
Exhibit XIV-19 shows the mean, and the 5$^{th}$ and 95$^{th}$ percentiles of the 20-year annual levelized portfolio costs.

**Exhibit XIV-19**
**Annual 20-Year Levelized Monte Carlo Results**



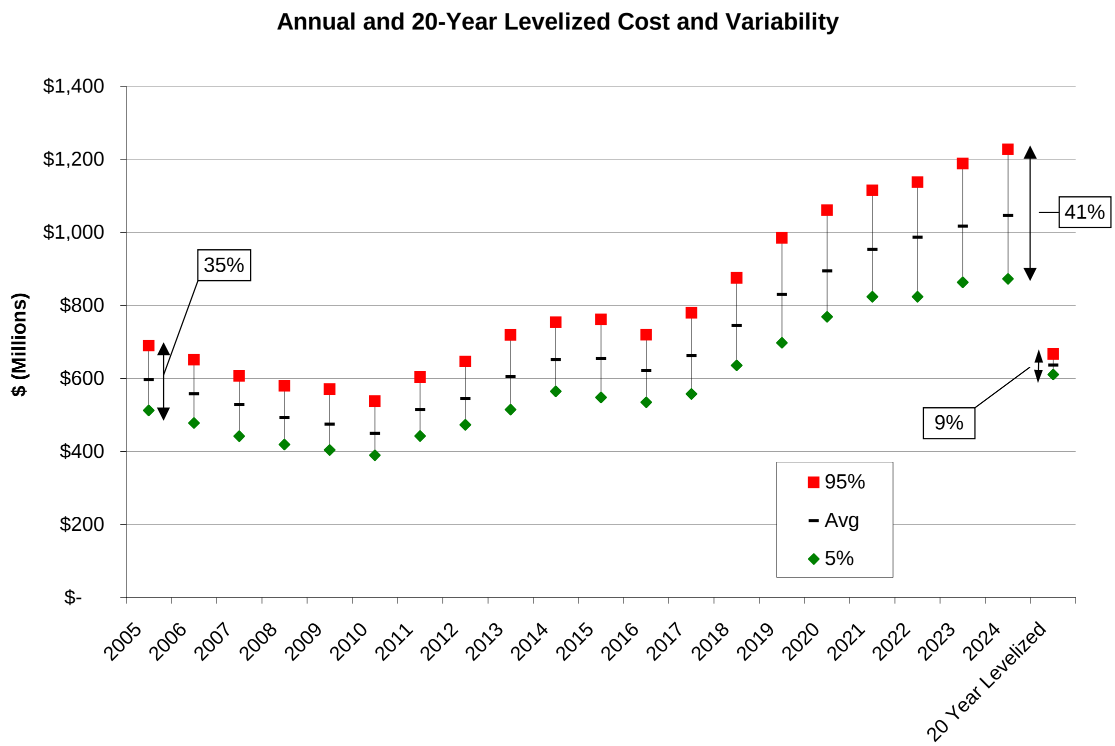

Results of the 20-Year Monte Carlo analysis shown in Exhibit XIV-19 do not portray the kind of variability one might initially expect. The range in annualized cost from the 5th to the 95th percentiles is only a 9 percent spread—given the significant volatility in gas prices, one might expect much more variability. However, as one stretches out the time horizon over which the Monte Carlo analysis is performed, variability within each draw is reduced. This is because extreme high and low draws have a greater probability of canceling each other out. For example, in a 20 year analysis, the effect of a December 2014 gas price of $12/Dth could be offset by a January 2018 gas price of $3.80/Dth, whereas if the analysis were just done on 2014, the effect of the $12/Dth would not be as muted. Exhibit XIV-20 illustrates how variability changes as the period considered increases from 1 to 20 years. Note, 2014 was chosen as the annual period for this exhibit because the mean is quite close to the mean of the 20-year levelized annual result, but shows a significant difference in variability. This exhibit supports the notion that results will appear less variable as the time frame under consideration is increased, because highs and lows tend to average out over time.

**Exhibit XIV-20**
**Comparison of Variability across Different Time Horizons**




This analysis suggests that while the 20-year view of risk is accurate, it may not be particularly helpful in making long-term resource decisions. Were the Company comparing the impact of different resources, such as Jackson Prairie deliverability expansion in 2008, or adding a large block of secondary capacity, the 20-year picture of cost volatility would most likely show very little difference in variability because highs and lows average out. It may be more informative to consider the annual variability resulting from the portfolio alternatives. An annual perspective is quite reasonable, because gas cost rates charged to customers are generally calculated on an annual basis; i.e., the 20-year horizon is comprised of 20 annual periods for which customers will pay bills. Exhibit XIV-21 illustrates the nominal mean, and the 5$^{th}$ and 95$^{th}$ percentiles of total portfolio costs on an annual basis, along with the 20-year levelized results.

**Exhibit XIV-21**
**Annual and 20-Year Levelized Cost and Variability**




The key take-away from a review of the Monte Carlo portfolio cost analysis is that measuring risk in the long term tends to dampen the effects of variability, thus short-term measures of risk in the context of the long-term analysis should also be considered.

Monte Carlo analysis on the Base Case optimal portfolio also provided information on the physical robustness of the optimal portfolio. This provides a reasonable test of whether the Company's planning standard of using normal weather with one design peak day per year creates a portfolio that will meet firm demands under a wide range of different temperature conditions. Results indicate that the Base Case portfolio, based on PSE's planning standard, will meet firm demands in 98 percent of the draws. This result is consistent with the Company's estimate that its peak day planning standard of 52 HDD will meet or exceed 98 percent of peak day temperatures based on temperature data from 1950-2003. This standard was selected as the result of a stochastic benefit cost analysis (for more information, refer to Appendix I). Therefore, PSE's planning approach of relying on a design peak day temperature in an otherwise normal weather winter provides reasonable results.

*Base Case—Results of Base Case Monte Carlo Analysis with Resource Optimization*

Monte Carlo analysis to test the sensitivity of resource additions in the static Base Case scenario, to assumptions in the Base Case, was described in section D.1. Three specific resources will be examined in the following discussion: timing of the Jackson Prairie storage deliverability expansion, results of the Southern LNG import supply, and addition of secondary Northwest Pipeline capacity. The following tables will compare results from the static Base Case with the mean results from the resource optimization Monte Carlo analysis along with probability distributions for each of the resources, which is informative.

*Monte Carlo Optimization Results—Jackson Prairie's Storage Expansion*

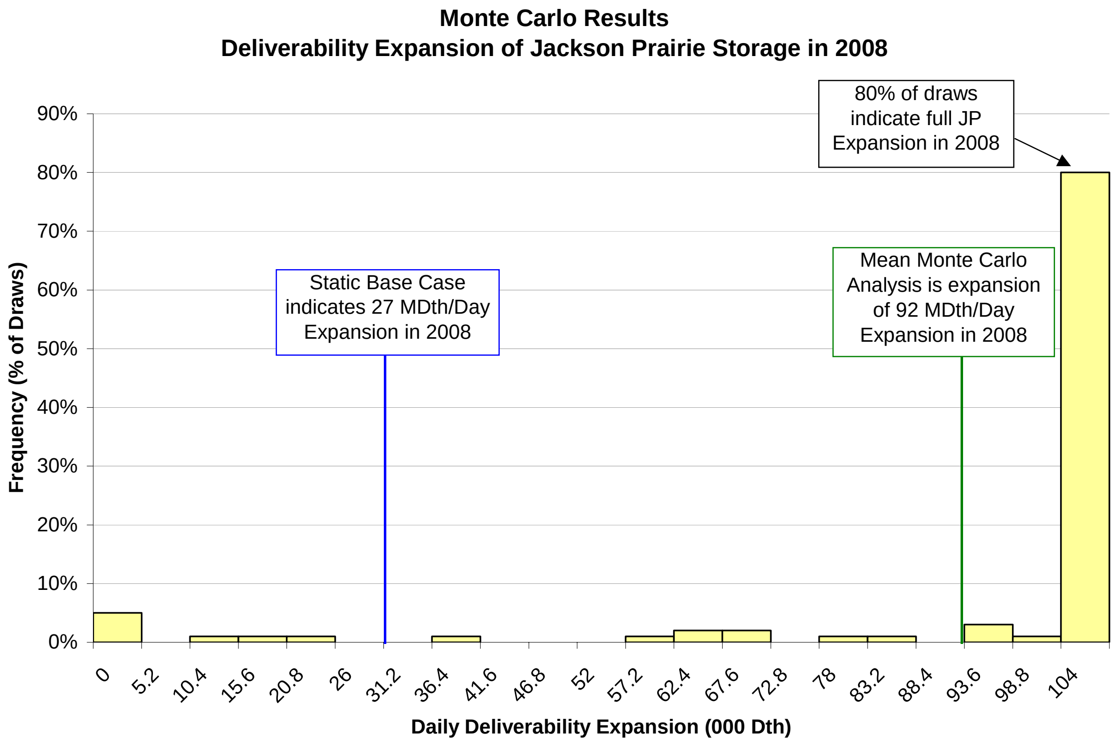
Jackson Prairie storage expansion in the optimal static Base Case analysis appears to be sensitive to the specific underlying assumptions. Exhibit XIV-22 shows results from the optimal static Base Case analysis (presented above) with the mean capacity expansions from the 100 Monte Carlo scenarios. Notice that the mean of Monte Carlo analysis indicates Jackson Prairie would be expanded at a faster rate than the static case.

**Exhibit XIV-22**
**Jackson Prairie Expansion Results—Static and Stochastic Results**

| | **Static Base Case Optimal Cumulative Expansion** | **Mean Cumulative Expansion from Monte Carlo Analysis** |
|---|---|---|
| 2008 | 383 MDth<br>27 MDth/day | 1288 MDth<br>92 MDth/day |
| 2009 | 621 MDth<br>44 MDth/day | 1428 MDth<br>102 MDth/day |
| 2010 | 635 MDth<br>45 MDth/day | 1456 MDth<br>104 MDth/day |
| 2011 | 1456 MDth<br>104 MDth/day | 1,456 MDth<br>104 MDth/day |
| 2012 | 1456 MDth<br>104 MDth/day | 1,456 MDth<br>104 MDth/day |

The frequency distribution of how Jackson Prairie expansion is selected across the 100 scenarios for 2008 is shown in Exhibit XIV-23. This exhibit focuses on daily deliverability component of the storage. The Monte Carlo analysis demonstrates that in 80 percent of the 100 draws, the full Jackson Prairie expansion is selected in 2008.

**Exhibit XIV-23**
**Frequency Distribution of JP Deliverability Expansion**




The Monte Carlo analysis indicates it would be reasonable for the Company to consider expanding Jackson Prairie fully in 2008.

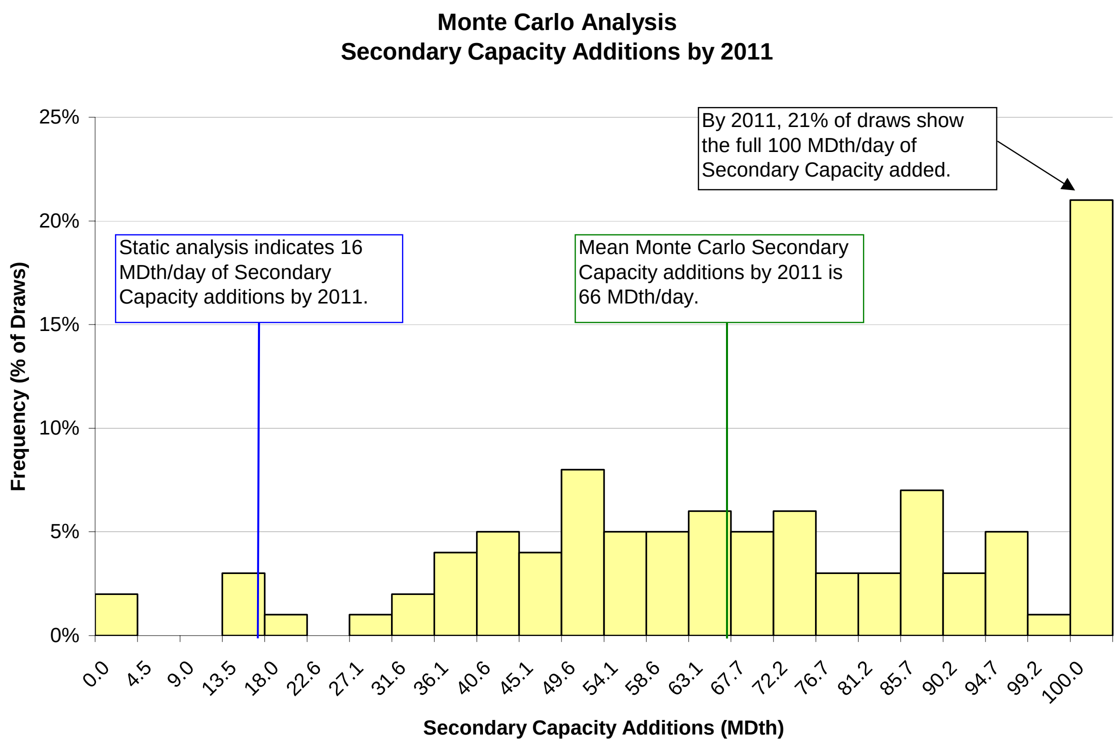
Monte Carlo Optimization Results—Secondary Capacity on Northwest Pipeline

Addition of Secondary Capacity in the Monte Carlo analysis generally shows a similar trend as in the static analysis, though the stochastic results indicate a faster rate of acquisition. Exhibit XIV-24 provides a table comparing the static and mean stochastic results. Exhibit XIV-25 provides the frequency distribution for secondary capacity additions in year 2011, the first year in which the static Base Case adds capacity. Exhibit XIV-25 illustrates that the static analysis addition in 2011 is in the bottom 5 percent of the stochastic analysis, which suggests the Base Case analysis may somewhat understate consideration of timing for adding secondary capacity relative to the stochastic analysis.

**Exhibit XIV-24**
**Static and Mean Stochastic Results for Secondary Capacity**

| | Base Case MDth/day | Mean Cumulative Secondary Capacity Acquisition from Monte Carlo Analysis |
|---|---|---|
| 2006 | 0 | 0 |
| 2007 | 0 | 11 |
| 2008 | 0 | 19 |
| 2009 | 0 | 47 |
| 2010 | 0 | 47 |
| 2011 | 16 | 66 |
| 2012 | 36 | 78 |
| 2013 | 54 | 89 |
| 2014 | 100 | 100 |

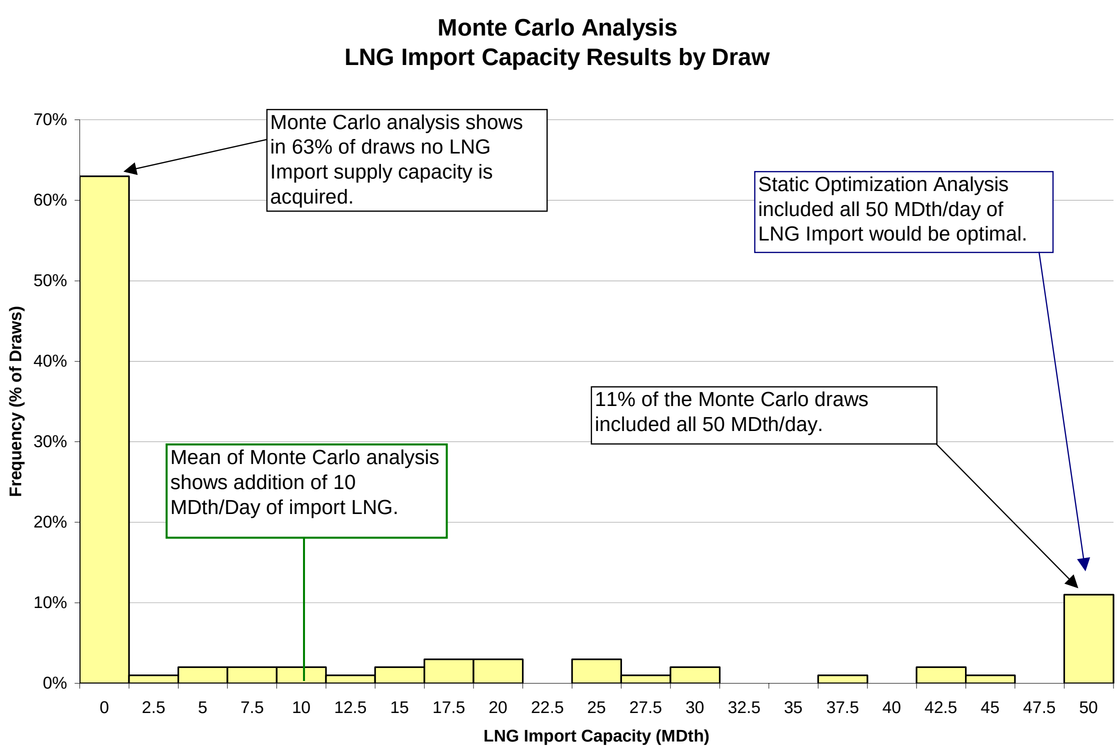
**Exhibit XIV-25**
**Frequency Distribution for Secondary Capacity Additions in 2011**



*Monte Carlo Optimization Analysis—LNG Import Supply*

Import LNG results appear to be highly sensitive to Base Case assumptions. Exhibit XIV-26 illustrates the frequency distribution for the Southern LNG Import Supply and shows results of the static Base Case analysis. The Exhibit illustrates that in 63 percent of the Monte Carlo scenarios, Import LNG was not selected as part of the optimal resource portfolio. Only 11 percent of the Monte Carlo results include the full 50 MDth/day of LNG import supply would be optimal. These results support the prior conclusion that PSE should carefully consider the specific terms and conditions of a long-term LNG import supply contract, should one become available.

**Exhibit XIV-26**
**Frequency Distribution for Southern LNG Import Supply**




*Monte Carlo Optimization Analysis—Summary Conclusion*

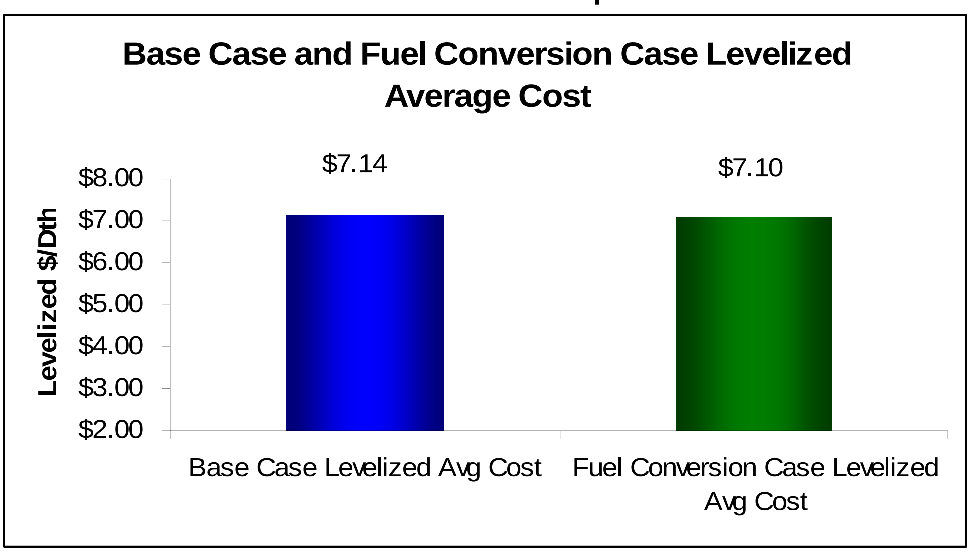
Monte Carlo analysis in the resource optimization approach provides information about the sensitivity of the optimality of resource additions to underlying assumptions of price and demand variability. As with the static optimization analysis, results of the Monte Carlo analysis will not provide the answer as to what kind of resources should be added to the portfolio at different times. Rather, this analysis will provide additional information to help support the Company's efforts to make informed resource acquisition decisions.

### F.4. Impact of Fuel Conversion

The Company performed an optimization analysis using the same sets of resource availability and gas price assumptions as in the Base Case, but adding in the base and heat loads that were estimated to result from the electric to gas fuel conversion program. Generally, these were not large volumetric additions. Fuel conversion load would increase residential load by approximately 1 percent to 5 percent relative to Base Case volumes. An important aspect of the fuel conversion load is that roughly 60 percent of the projected increase in sales is related to water heat load, while the other 40 percent comes from heat load.

The purpose of this analysis was to study whether an electric to gas fuel conversion program would adversely affect gas costs to existing customers. Exhibit XIV-27 below shows the 20-Year levelized average cost of gas from the Base Case and the Fuel Conversion Case. The 20-year levelized average cost in the Fuel Conversion case is half a percent lower than the Base Case, so the conclusion here is that the fuel conversion program modeled is not expected to adversely affect gas costs to existing sales customers. These results are intuitive, given that most of the fuel conversion load is expected to be base load thus lowering resource requirements year-round.

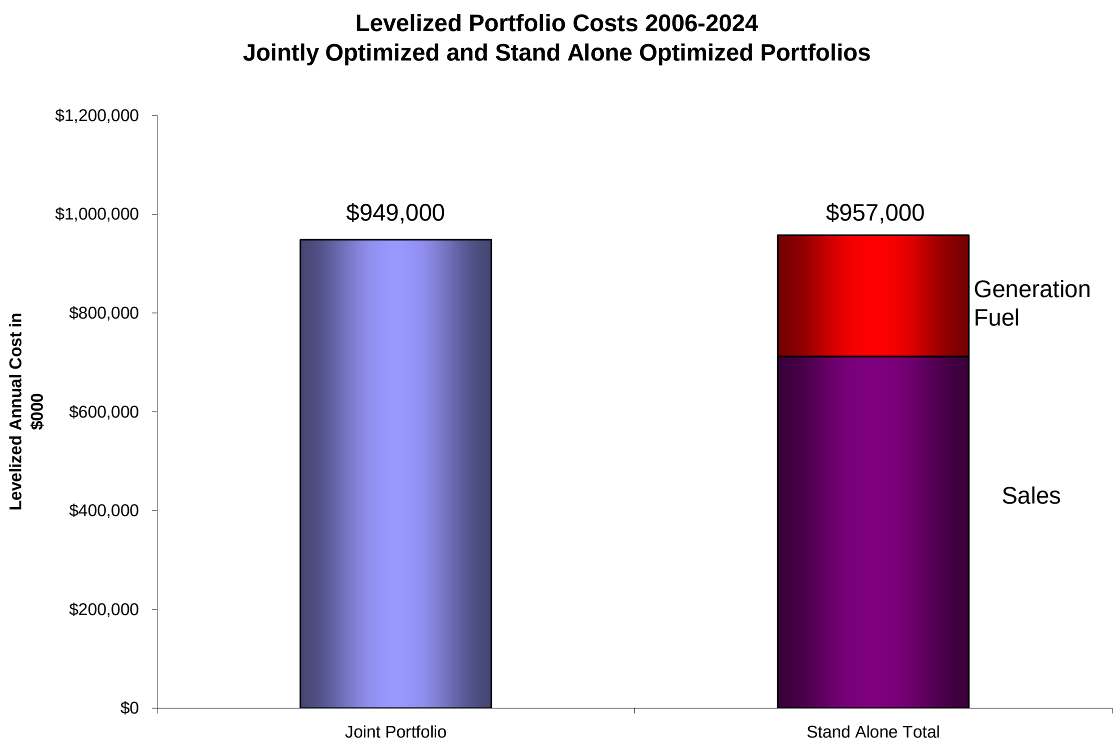
**Exhibit XIV-27**
**Fuel Conversion Impact**



### F.5. Results of Joint Planning Analysis

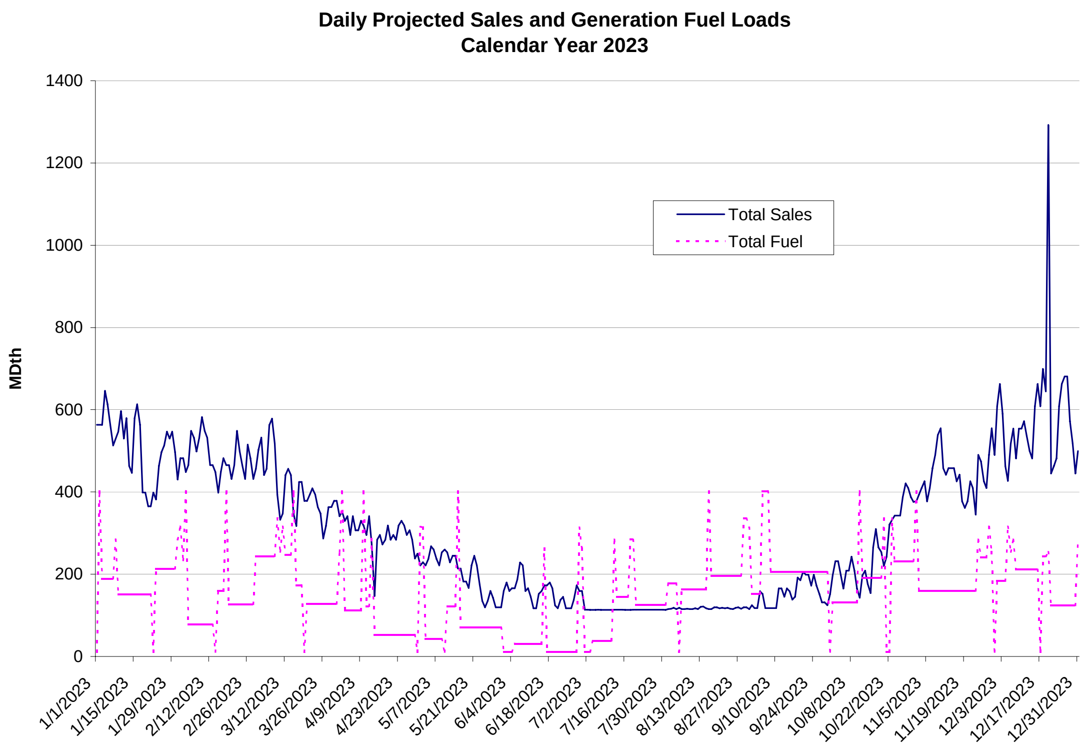
The Joint Planning analysis was performed by combining the loads for the gas sales Base Case and the gas for Generation Fuel case and optimizing across what are generally the same resources as those available in the stand-alone optimization cases. (Please refer to section D.3 for an explanation of how daily generation fuel loads were determined). Comparison of the jointly optimized portfolio cost with summation of costs of the stand alone optimal portfolio costs did not identify significant levels of savings. Exhibit XIV-28 shows the annual levelized costs from the Joint Plan study and the summation of the Sales and Generation Fuel studies. The results show an approximate $8 million/year savings, which is only a 1 percent cost savings from the Stand Alone results. This is a very modest level, especially given that some short-term optimization details were not present in the model. Some of the savings result from simplifying assumptions pertaining to short-term optimization opportunities, so even the $8 million is on the high side of what would be available in reality.

**Exhibit XIV-28**
**Joint Planning Analysis**



The primary reason larger savings are not seen in this analysis is the lack of the kind of load diversity that would drive capacity saving/sharing opportunities. Exhibit XIV-29 illustrates the daily forecast gas sales load and the daily forecast gas fuel for generation load during calendar year 2023. The relatively high generation load levels in the winter periods means capacity must be acquired to meet these generation loads and gas sales loads. The Company did not perform Monte Carlo analysis to support these results, as the gas for generation fuel demand is a completely different kind of function than gas for the sales portfolio. Such analysis would require a significant amount of effort to develop uncertainty factors for VectorGas, but such analysis would not really provide any additional information. That is, because the generation portfolio is expected to have significant capacity needs to meet winter fuel requirements, there is little opportunity to capture joint planning benefits.

**Exhibit XIV-29**
**Comparison of Sales and Generation Demand**



## G. Conclusions

The natural gas resource planning analysis suggests that the following key items should be considered as PSE moves forward with a gas resource strategy:

1. PSE should investigate the ability to expand its gas energy efficiency programs, especially space heat programs.
2. PSE should monitor developments in regional LNG import terminals to determine if any specific location can favorably influence transportation costs.
3. Feasibility and timing of Jackson Prairie storage expansion should be investigated with the co-owners.
4. PSE should investigate the availability and pricing of an LNG bridging service.
5. LNG storage or satellite LNG should not be pursued as a generic supply resource without local system benefits.
6. In acquiring upstream transportation capacity, PSE should continue monitoring the Sumas market, but primarily plan on acquiring transport to Station 2. PSE should also weigh the benefit of supply diversity against the additional cost of obtaining supplies from AECO.
7. Possibilities for acquiring existing secondary transportation capacity, possibly at a discount, should be considered.
8. In examining long-term cost variability, the risk analysis should include consideration of how different portfolios perform in shorter-term increments during a long-term period.
9. In acquiring long-term resources, the Company should consider sensitivity to key underlying assumptions.

# XV. ENERGY PORTFOLIO MANAGEMENT

## A. PSE's Risk Management Approach

The Least Cost Plan is a depiction of the Company's overall load-resource balance, at a given point in time. It is based upon current projections of load and assumptions about the future availability of existing resources. The structure of the portfolio depicted in the Least Cost Plan remains essentially fixed until the next opportunity to modify one or more resources. The structure of the portfolio also defines the fixed costs that PSE will incur until the next portfolio modification.

In contrast, everyday management of PSE's power and gas portfolios is a dynamic process. The effort to minimize costs and manage cost volatility is known as "risk management." Risk management is the process by which PSE manages its wholesale energy portfolio in a dynamic environment to mitigate the impacts of risk factors upon power and gas costs.

Commodity price volatility in energy markets, combined with operational risks, can have a meaningful impact on overall power and gas costs. Energy risk management focuses on managing costs and reducing potential exposure. This entails balancing long- and short-term resource commitments with load requirements, and understanding risk exposures within the regulated power and natural gas portfolios.

The following principles guide PSE's energy risk management practices: 1) identify risk exposure in the energy portfolio, 2) measure the degree of the risk exposure, 3) develop and test risk management strategies designed to reduce risk exposure, 4) implement risk management strategies that minimize energy cost volatility, and 5) implement approved risk management strategies. PSE's energy risk management focuses on risk mitigation and value protection within the regulated energy portfolios for electric and gas customers.

## B. Portfolio Management

Risk management activities include hedging the portfolio against many of the risks inherent in a load-serving entity's regulated portfolio, arising from the imbalances that can occur between loads and resources. PSE's electric and gas portfolios contain a diverse mix of resources with widely differing operating and cost characteristics. Risk management focuses on risk impacts to the overall portfolio, in order to view the aggregated results of correlated and interconnected elements of the power and gas portfolios. Similarly, PSE considers risk mitigation strategies for the overall portfolios.

Although there are many complex variables embedded in the portfolio, the major volume and price drivers of power and gas cost volatility are: (1) streamflow variation affecting the supply of hydroelectric generation, (2) risk of forced outages of thermal plants, (3) weather uncertainty affecting power and gas usage, (4) variations in market conditions such as wholesale power and gas prices, (5) transmission and pipeline transportation constraints, (6) storage inventory levels, and (7) North American and global energy prices, including crude oil. All of these create energy cost volatility that PSE seeks to mitigate through its energy risk management activities.

PSE manages its energy supply portfolio to achieve three primary objectives:

- Ensure that physical energy supplies are available to reliably serve retail customer requirements.
- Manage portfolio risks to reliably serve retail load at overall least cost while limiting undesired volatility on customer bills and PSE financial results.
- Optimize the value of PSE energy supply assets.

The risk types associated with PSE's power supply portfolio are both financial and operational in nature:

- **Volumetric Risk** – Volumetric risks arise due to the potential variability of loads and resources within the portfolio. For example, customer loads will fluctuate with weather, and production from specific plants may vary depending upon rainfall. This potential variability in demand and supply creates imbalances that the Company must consider and manage.
- **Commodity Risk** – Future power and gas prices are unknown and potentially volatile. Uncontrollable factors, including local and national weather, economic conditions, hydro supply, plant availability in the Pacific Northwest region, regional reserve margins, and oil prices drive this price uncertainty. Thus, PSE and its customers are at risk for potential commodity price changes if PSE purchases products in the short-term power market.

- **Counterparty Risk**– Counterparty risk is the risk of default by PSE's counterparties. A strategy to mitigate price volatility can go awry if the counterparty fails to perform its contractual obligations, and causes PSE to be at risk for liquidated damages.
- **Operational Risk** – Changes in generation or transmission operating conditions and availability that affect PSE's portfolio (such as plant outages and transmission curtailments) are examples of operational risk.
- **Estimation Risk** – There are estimation risks associated with using models to measure real world events – especially in the complex energy industry. Different assumptions or inputs can all cause changes to the model results.

The Company's primary objective is to develop and implement effective risk management strategies that will reduce overall costs and operational risks when buying energy from the markets (in times of need) and selling energy into the markets (in times of surplus). PSE manages the major portion of its electric portfolio risks with a diverse supply portfolio of resources that includes hydro, coal-based generation, combustion turbines, non-utility generation contracts, long-term purchase and exchange contracts, gas supply contracts, gas transportation and electric transmission. Imbalances in the resource-load equation are then managed with short-term physical and financial wholesale energy hedging instruments.

PSE uses hedging transactions to mitigate risk exposures. A hedge is an offsetting position designed to protect against fluctuations in a commodity price. For example, if a company is deficit energy, then an important hedge would be to purchase energy. By extension, a hedge instrument is a transaction that can be used to hedge risk exposures. Specifically, in order to balance the supply portfolio and to achieve net cost reductions, PSE may purchase and sell energy in the wholesale commodity markets, acquire options that allow the Company to buy or sell at a pre-determined price, enter into third party contracts that mirror the dispatch-displacement capacity of generation units, and use storage contracts.

PSE assesses how a given hedging strategy will mitigate risk exposure in the portfolio, then evaluates the costs to effectuate the hedge. There are many factors to consider and many uncertainties. Therefore, there is no single formula for weighing the cost/benefit analysis of a hedge strategy. There has to be a balance between risk reduction, the opportunity costs associated with certain hedges, and the outright costs of some hedges (such as options). Also, counterparty risks and credit availability need to be determined in connection with hedging strategies. In order to help determine a hedge strategy, PSE measures the incremental benefit of the next hedging opportunity. This approach is important when there are constraints to the availability of credit with which to engage in hedging transactions or when there are market liquidity concerns.

PSE's hedge strategies for the gas and electric portfolios incorporate risk analysis, operational factors, the professional judgment of its employees, as well as fundamental analysis. Programmatic hedge plans are developed to insure disciplined hedging, and discretion is used within specific guidelines of the programmatic hedge plans approved by the risk management committee. Most hedges can be implemented in ways that retain the Company's ability to use its energy supply optimization opportunities. Programmatic hedging provides a framework with specific guidelines. PSE employs programmatic risk reduction, with defined volumes and time periods, to methodically reduce risk exposures in its power and gas portfolios. Additionally, PSE employs market analysis and fundamental analysis to determine the best time to execute hedge transactions and the appropriate amount to hedge, within the specified guidelines.

## C. Integration of Energy Risk Management within Energy Supply

PSE's energy risk management tools, systems and models are integrated with those employed in longer range planning, such as long-term risk management, resource planning and least cost planning. By example, in the area of long-term risk management, the Company integrates model output from the short- and long-term models to create a seamless outlook of future load, supply, and portfolio exposure to market volatility. This integration is used as the foundation for resource and financial analysis, and it enhances the Company's ability to evaluate various hedging and resource acquisition strategies.

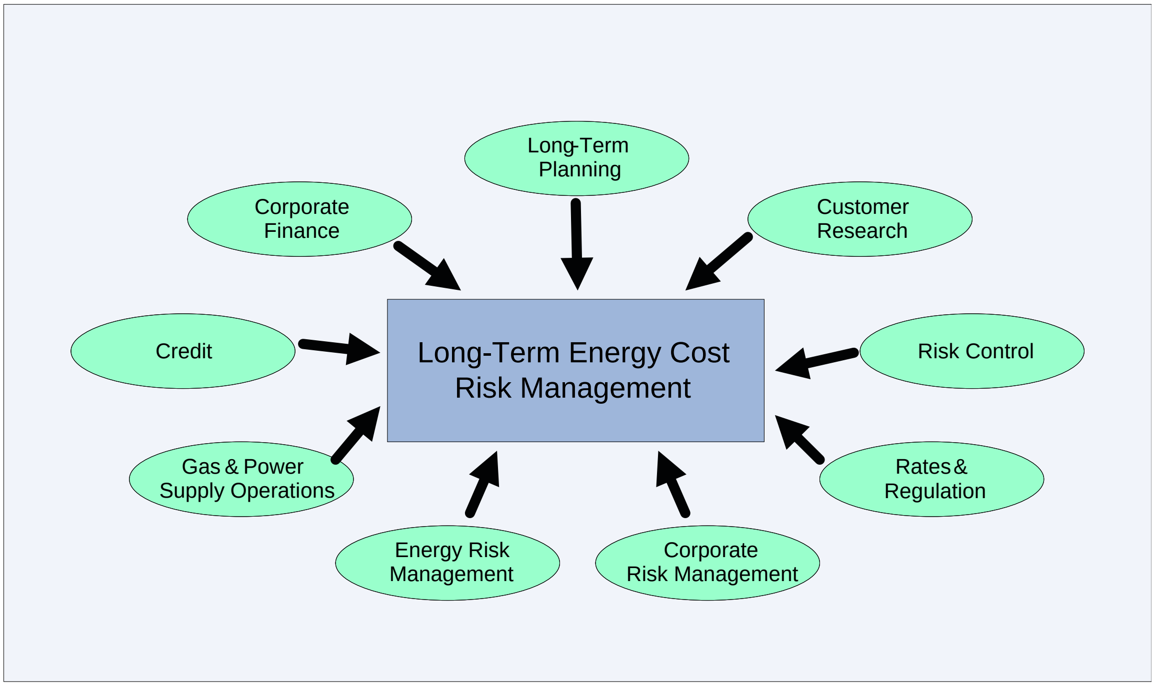
**Exhibit XV-1**
**Energy Supply Synergies**


## D. Long-term Energy Risk Management

The following provides an overview of the Company's long-term risk management. The long-term energy risk management strategy expands the focus of short-term risk management by addressing the longer-term risks identified in resource planning and resource acquisition, as well as other key considerations.

The diagram below represents the Company's organizations that contribute to or influence long-term energy risk management:

**Exhibit XV-2**




Long-term energy cost risk management supports the following goals.

- *Manage potential energy cost variability in context of total cost of service*. This is addressed by estimating the expected cost and benefits of long-term alternatives in addition to performing fundamental analysis that supports the execution of various hedge strategies.
- *Minimize buying at "high" market.* This is addressed by systematically reducing energy exposure. All strategies achieving this must balance the potential impacts of customer costs, financial impacts, and market realities.
- *Actively manage the Company's energy portfolios*. This is addressed by ongoing analysis of hedging needs and by continually assessing all alternative strategies.

As part of this effort to develop a comprehensive strategy and balanced approach to energy cost risk management, the Company considers hedging opportunities in the short-term, intermediate-term, and long-term energy markets. Energy cost risk is borne by customers; therefore, it follows that the strong management of long-term energy costs should be based on the risk preferences of customers.[1] Accordingly, one aspect of the evaluation of hedging opportunities is to identify the value, as perceived by PSE customers, of removing some portion

[1] Notwithstanding the form of the regulatory cost recovery mechanism, the Company faces a risk of disallowance if it is unable to demonstrate prudent management of energy costs.

of the price volatility from retail customers' power and gas bills for a specific length of time. To examine their risk preferences, the Company has engaged in market research to assess retail consumers' preferences regarding the importance (value) of decreasing the retail rate volatility that is introduced through volatile commodity markets. The results from this market research will be utilized in developing hedging structures for both the power and PGA gas portfolios.

The Company generates a long-term physical and financial base position for its power portfolio (power as well as gas-for-power generation) and gas portfolio using the base case of a distribution of alternative scenarios. From this, PSE can estimate risk by calculating the monetary exposure of the energy position as a percent of energy cost exposed to spot market purchases. This metric is critical to managing the energy portfolio with respect to total power costs or total PGA gas costs, as it establishes an indicator that is used to develop hedging objectives for the planning horizon. Hedging strategies strive to provide the optimal outcome, minimizing downside and maximizing upside. But it is important to note that in order to mitigate hedging costs, some upside opportunity usually has to be relinquished to minimize negative risk exposure.

### E. Risk Control

The Company is not engaged in the business of assuming risk for the purpose of speculative trading revenues. Therefore, wholesale market transactions are focused on balancing the Company's energy portfolio, reducing costs and risks where feasible, and reducing volatility in wholesale costs and margin in the portfolio. In order to manage risks effectively, PSE enters into physical and financial transactions, which are appropriate for the service territory of the Company and are relevant to its regulated electric and gas portfolios.

An important aspect to portfolio management includes strong internal risk controls. PSE's portfolio exposure is managed in accordance with Company polices and procedures. There is an oversight executive group, the risk management committee, that provides policy-level and strategic direction for management of the energy portfolio. The audit committee of the Company's board of directors has oversight of the risk management committee.

PSE employs an energy risk management system that models elements of the Company's load and resources, and can report risk exposures. There is centralized data input for transaction information, and the database holds information critical for credit risk management as well as energy risk management analysis. The risk system interfaces with physical scheduling systems as well as the Company's corporate accounting model for billing, accounting, and data records management.

The risk metrics the Company employs are aimed at assessing exposure for the purposes of developing strategies to reduce the potential exposure on a cost-effective basis in regulated utility portfolios. Specifically, the amount of risk exposure is defined by time period and by portfolio. It is measured through statistical methods aimed at forecasting risk. PSE monitors exposures on a regular basis; analyzes volumetric, commodity price, counterparty, and operational risks; and monitors transactions against approved strategies. Strong system controls are key to providing internal control checks within the risk management framework. To document decisions, the Company develops strong documentation of analysis and strategy, and maintains detailed files and minutes in a secure location.

# XVI. DELIVERY SYSTEM PLANNING

This chapter addresses delivery system planning, a key component of the Least Cost Plan process. Delivery system planning employs processes that ensure the gas and electric energy delivery systems are integrated to provide safe and reliable service at the lowest cost. Within this integrated view, delivery system planning establishes the guidelines for installation, maintenance and operation of the Company's physical plant while balancing cost, safety, and operational requirements. The delivery system planning process also considers environmental management, regulatory requirements and changing customer demands as it reviews cost-effective alternatives and develops contingency plans. The chapter concludes with a discussion of PSE's involvement in the Bonneville Power Administration's (BPA's) Non-Wires Solutions Round Table.

This chapter specifically discusses the following:

- How the gas and electric energy delivery systems work,
- Industry challenges,
- System performance criteria,
- Planning process including methods for evaluating system alterations, planning tools and modeling techniques,
- Decision process for optimizing the improvement plan based on estimated benefits and constraints,
- Types of adjustments that can be made within the energy system to lessen the need for additional facilities, and
- Overview of distributed resource technologies that could impact the landscape of the electric delivery system.

## A. Delivery System Mechanics

*Gas Delivery System*

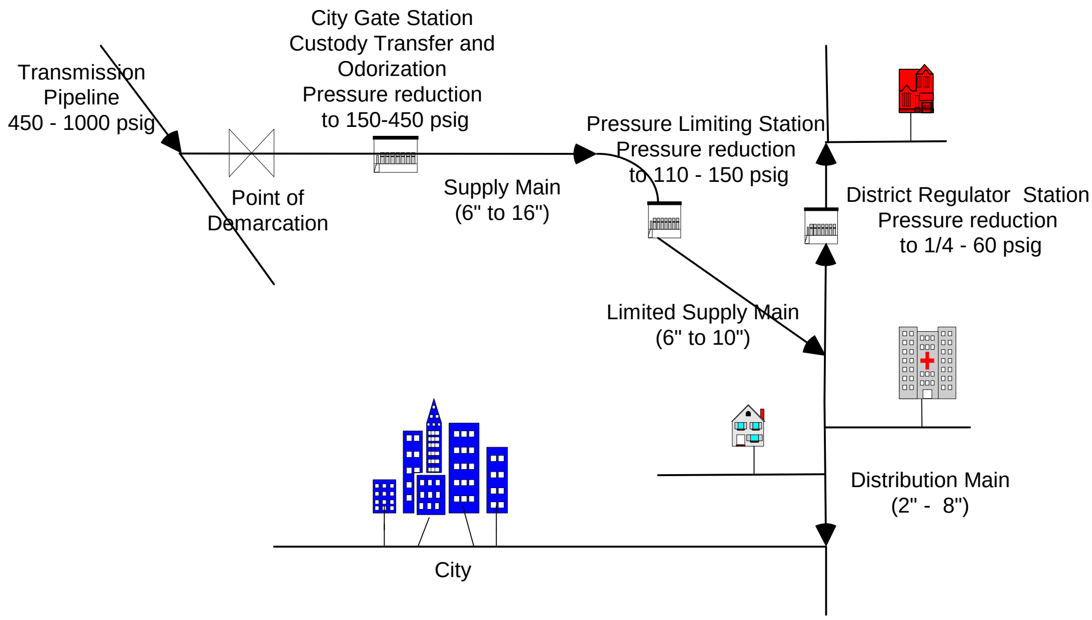
A properly sized and designed pipe system will have the capacity and reliability to deliver gas at sufficient pressure to all customers at all times. System sizing and design are driven by gas system mechanics. When gas is compressed, energy is stored in it. As gas flows through the delivery infrastructure, its pressure decreases due to friction, and the energy is converted to heat. If the delivery system is too small, high velocities and turbulent flow behavior result in an excessive pressure drop. The consequence is pressures that are too low to supply customers with the energy necessary to operate their appliances. Pipe diameter, material, roughness, efficiency, length and the fitting type, along with flow characteristics, all influence the system's pressure.

The delivery system infrastructure is comprised primarily of pipes, valves, regulation equipment (pressure reduction), and measurement equipment (meters). Transmission pipelines typically operate at pressures between 450 and 1,000 pounds per square inch gauge (psig). Pressure regulating stations reduce the operating pressure for local distribution. Distribution pipelines within residential neighborhoods typically operate at pressures between 45 and 60 psig. Pressure regulation at the customer's meter reduces the pressure for appliance operation. The pressure for a stove or space heater to operate effectively is typically ¼ psig. Exhibit XVI-1 provides a schematic view of the gas delivery system.

PSE operates and maintains an extensive gas system consisting of 46 city gate stations, 10,990 miles of high, intermediate, and low pressure gas distribution pipelines, and 980 district regulator stations. This infrastructure serves approximately 669,190 natural gas customers in six counties that lie within approximately 2,800 square miles of service territory. Approximately 326,320 customers receive both gas and electric service from PSE. In areas where PSE provides both electric and gas service, additional efficiencies and lower costs can be realized by coordinating plans for energy need, and considering alternatives such as fuel switching and distributed generation.

**Exhibit XVI-1**

**Gas Delivery System**

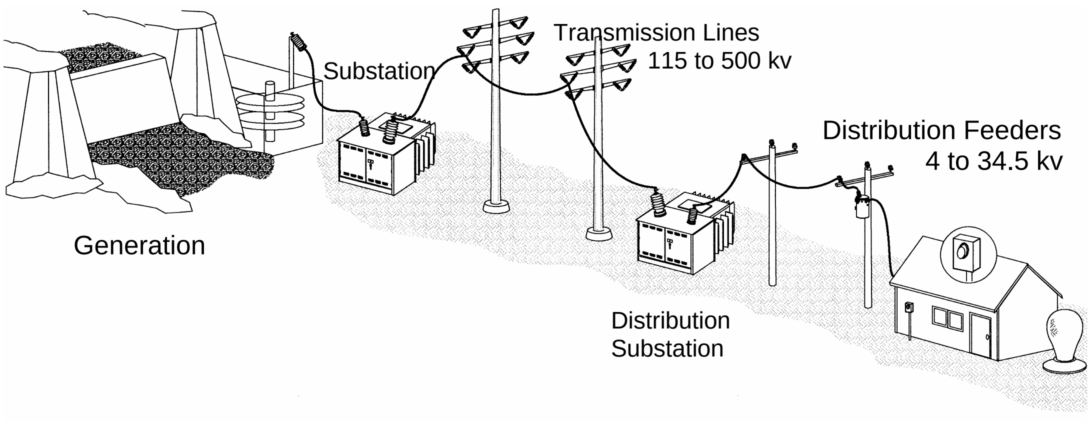



*Electric Delivery System*

Delivering electricity to customers requires an intricate system of generation, transmission, and distribution infrastructure. A unique product, energy moves from electric generators to the consumers over wires and cables, using a wide range of voltages and capacities. Unlike other forms of energy, electrical energy cannot be stored in quantities sufficient for widespread use. It must be continuously generated using other forms of energy, such as falling water and steam. The electrical generators and electrical network are designed to automatically regulate the flow of electricity through the system to quickly accommodate instantaneous changes in consumer demand.

The delivery system infrastructure is composed primarily of wires, circuit breakers, transformers, and measurement equipment (meters). The voltage at the generation site must be stepped up to a high voltage for efficient transmission over long distances. Generally, transmission lines operate at voltages between 115 and 500 kilovolts (kV). Substations reduce the voltage for local distribution. Distribution lines typically operate at voltages between 4 and 34.5 kV. Finally, transformers at the customer site reduce the voltage to under 600 volts (V) for effective operation of appliances. Exhibit XVI-2 provides a schematic view of the electric delivery system.

**Exhibit XVI-2**
**Electric Delivery System**




PSE operates and maintains an extensive electric system consisting of 303 substations, 2,671 miles of transmission line, 10,512 miles of overhead distribution line, and 8,418 miles of underground distribution line. This infrastructure serves approximately 999,375 electric customers in nine counties within approximately 4,500 square miles of service territory.

PSE's complex electric and gas networks must be flexible enough to meet changing operating conditions as well as future service needs. Significant investment in this infrastructure means that it is important that PSE make additions and improvements as cost-effectively as possible.

## B. Challenges

Planning these infrastructure networks is an evolving and complicated process due to changes in the industry. For example, planning processes and investments are subject to increasing scrutiny in the wake of recent events and drivers including the Northeast and upper Midwest blackout in 2003, pipeline safety regulation implementation, aging infrastructure, and continued customer sensitivity to electric reliability. For several years, the industry has been on a path towards deregulation. This caused utilities to defer investments because future ownership and operation have been unknown. More recently, electric transmission investments have been on the rise, due to the cascading event experienced in the northeast in August, 2003 and the resulting loss of power to 50 million customers. Regulations mandating the reliable operation of that particular system are being finalized. PSE will continue to emphasize the development of plans to ensure its transmission infrastructure meets these regulations.

As a result of the Olympic pipeline rupture in 2003, the Pipeline Safety Law has been enacted and the industry is actively working to comply with the law's greater pipeline integrity requirements. PSE is on track to implement its own program resulting from the safety law. As a result, there will be more focus on transmission pipelines to ensure continued system integrity.

On an ongoing basis, PSE reviews the reliability of its gas and electric infrastructure. PSE's gas system has been operating since 1890, and its electric system since 1917. The Company continually reviews the performance of these systems and the impact their condition has on reliability. Programs to replace aging cast iron mains, bare steel mains, power poles, and underground cables are in place to minimize leaks and outages, and to ensure continued safe operation.

In the future, active coordination and collaboration with other utilities and municipalities will be increasingly important to minimize conflicting objectives, issues, concerns, and the costs of operating within rights-of-way. Because customer concerns and environmental regulations are making installation in new rights-of-way increasingly difficult and lengthy, proper planning is essential.

Higher performance standards pose additional challenges that need to be reflected in an evolving delivery system plan. For example, computers and other highly sophisticated voltage-sensitive equipment drive the need for more stringent power quality than was previously required.

If PSE is to remain prepared to address these ever-changing challenges, the Company must actively review and participate in emerging electric and gas technology. A key example is distributed resources (DR) technology, which will eventually alter the historic demand on both the gas and electric systems, and change electricity usage as power is generated at the customer's site (i.e., fuel cell, micro-turbine, photovoltaics, wind generation, etc.). Each of these generation technologies has a variety of operating characteristics that create complexity when they are integrated into the delivery system. Furthermore, despite a customer's ability to self-produce generation, PSE will still need to maintain a system equipped to meet the customer's use and capacity requirements in the event the distributed resource fails. These advances mean that in the future, customers will rely more heavily on the gas delivery system to supply some of their electricity needs.

**C. Planning Process**

The goal of the planning process is to find cost-effective ways to meet customer needs. The delivery system planning process begins with an analysis of the current situation and an understanding of the existing operational and reliability challenges. Planning considerations (inputs) include both internal and external factors, load forecasting, and customer expectations. The planning process also incorporates the impact of one energy type on the other, and optimizes the whole energy delivery system. Having incorporated all of these inputs, planners then determine the magnitude of the issues based on the performance definitions previously mentioned. Alternatives for improving the infrastructure are developed, and the benefits for each are determined. Cost estimates are prepared for each alternative that meets the performance criteria. Lastly, planners select and plan for the alternative that best balances customer needs, company economic parameters, and local and regional plan integration. Exhibit XVI-3 provides a view of this process.

**Exhibit XVI-3**
**Planning Process**

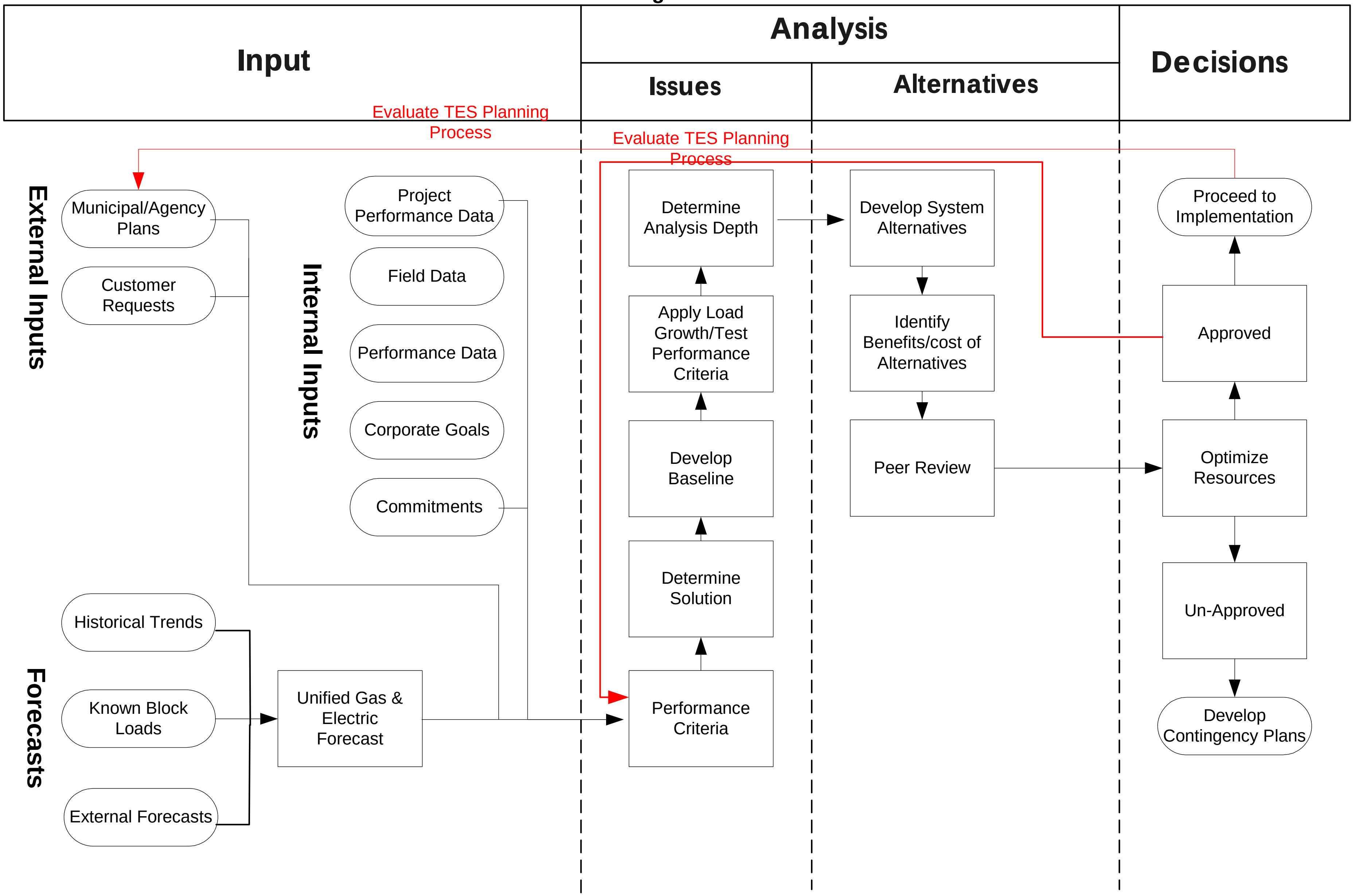



Exhibit No. ___(EMM-6)
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*Inputs*

Internal planning considerations, or inputs, include system performance, company goals and commitments, and load forecasts. External inputs include regulations, municipal and utility improvement plans and customer expectations. System performance information is gathered from field charts, remote telemetry units, supervisory control and data acquisition equipment (SCADA), field employees, and customer feedback. Some information is analyzed over multiple years rather than during a single year's performance. For example, outage information is analyzed over 3 to 5 years, which provides a clearer indication of issues in light of such variables as weather (which can have a significant impact from year to year). Upon project completion, system performance reviews are again analyzed over several years in order to lessen the impact of a single event affecting system performance.

Load forecasting for delivery system planning may be performed at the local city, circuit, or neighborhood level. For these local forecasts, PSE uses a trend of actual system peak-load readings and customer growth within the area. This forecast is augmented with known permitted construction activity that is projected over the next two years. Longer-term forecasting comes from PSE's corporate econometric forecasting method that includes population growth and employment data by county (see Chapter VI). PSE also continues to use its automated meter reading (AMR) technology to facilitate load analysis.

In order to minimize costs, PSE regularly gathers and reviews municipal and utility improvement plans. These plans provide an opportunity to upgrade existing infrastructure or install new infrastructure when system relocation is required or savings can be gained through coordination between utilities. PSE works with outside entities to find mutually beneficial schedules or coordinate installation.

The Company relies on several methods to collect customer feedback. PSE continually investigates customer complaints, and tracks ongoing service issues. Customers receive follow-up correspondence to discuss the concern, and any plans for resolution. These complaints may provide information where field data isn't available or modeling doesn't indicate an area of concern. PSE also relies on customer surveys to provide general information regarding customer expectations and possible specific concerns. For example, in January 2004, PSE surveyed electric customers that were impacted by two large storms. The feedback provided tremendous information and helped validate customer expectations and polish plans.

*Performance Criteria*

PSE primarily categorizes system needs as "capacity" and "reliability". System performance is reviewed with these needs in mind, which forms the basis for planning. For PSE's gas delivery system, performance criteria are defined by:

- Safety and compliance,
- The temperature at which the system is expected to perform,
- The nature of service ("firm supply") each type of customer is contracted for (interruptible vs. firm),
- The minimum pressure that must be maintained in the system,
- The maximum pressure acceptable in the system, and
- The cost customers are willing to pay for target levels of performance.

For PSE's electric system, performance criteria are defined by:

- Safety and compliance,
- The temperature at which the system is expected to perform,
- The level of reliability ("firm supply") each type of customer is contracted for,
- The minimum voltage that must be maintained in the system,
- The maximum voltage acceptable in the system,
- The interconnectivity with other utility systems and resulting requirements, and
- The cost customers are willing to pay for target levels of performance.

These performance criteria, in addition to state and federal requirements, provide the foundation for planning infrastructure improvements. Adhering to these criteria ensures full use of existing facilities before adding new ones. However, this can occasionally be offset by the cost advantages associated with early installation. Each year, PSE identifies new areas experiencing diminishing capacity resulting from load growth, diminished reliability, or simply where customer expectations are on the rise. On smaller distribution systems, annual performance issues are generally resolved within a year or two, while large distribution or transmission performance issues generally take more than two years. In fact, securing substations and transmission facilities can take more than a decade. This makes it all the more important that strong processes are in place for predicting and modeling future issues.

As mentioned earlier, proper planning requires evaluation criteria for capacity and reliability issues. Exhibit XVI-4 shows a typical annual expenditure level for these types of issues.

**Exhibit XVI-4**

| **Capital Planning Initiatives** (millions) | | | | | |
|---|---|---|---|---|---|
| | **2005** | **2006** | **2007** | **2008** | **2009** |
| **Capacity** | $ 73 | $ 87 | $ 59 | $ 68 | $ 66 |
| **Reliability** | $ 83 | $ 79 | $ 79 | $ 71 | $ 66 |

*Planning Tools*

PSE relies on many different tools during the planning process. With the identified planning considerations (inputs), a variety of results (outputs) are derived to help identify and weigh the benefits of each alternative action. Exhibit XVI-5 shows the tools that will be described in more detail in the Least Cost Plan.

**Exhibit XVI-5**

| **Planning Tools** | | | |
|---|---|---|---|
| **Tool** | **Use** | **Inputs** | **Outputs** |
| Advantica Synergee | Network Modeling | Gas and Electric distribution infrastructure and load characteristics | Predicted system performance |
| MUST Power Flow | Network Modeling | Electric transmission infrastructure and load/generation characteristics | Predicted system performance |
| Area Investment Model | Economic Analysis | Cost schedule, growth scenarios | Net present value, revenue requirement |
| Simplified Probabilistic Spreadsheet | Probabilistic Analysis | Outage history, equipment failure probabilities | Outage savings based on probability of occurrence |
| Estimated Unserved Energy | Unserved Energy | Growth/load at specific conditions, annual load profile | Annual unserved energy, O&M costs as a result, value of service in cost terms |
| BudAPP | Project Data Storage | Scope, budget, justification, alternatives and benefits | Predicted benefit score, project scope/start document |
| Expert Choice | Optimization | Projects, benefits, resources/financial constraints | Set of optimal projects for given constraints |

*Modeling Tools*

To facilitate system performance evaluation, PSE uses system models for both its gas and electric delivery systems. The use of sophisticated modeling software and field data, including real-time information, ensures optimal system planning. PSE has a mature gas system model using an Advantica SynerGEE software application. This model is continually updated to reflect new customer loads and system and operational changes. Planners validate the accuracy of the model by comparing its results against actual system performance data. The model helps to predict capacity constraints and subsequent system performance on a variety of degree days and under a variety of load growth scenarios. Where issues surface, the model can then be used to evaluate alternatives and their effectiveness in resolving the issues. Augmenting these alternatives with cost estimates and feasibility analysis helps to ensure the least cost solution to serve both current and future loads. PSE's model is one of the largest integrated system models in the United States.

For the electric distribution system, PSE also uses the Advantica SynerGEE software application. Due to the complexity of the mathematical analysis, the feeder system is modeled regionally rather than as one single large model. Planners use these models to implement accuracy assessments and evaluations similar to those performed on the gas side. As software capability improves, PSE hopes to unify its gas and electric models. This will enhance the Company's ability to meet customer energy needs and take advantage of possible fuel switching opportunities at the lowest possible cost.

For both PSE's gas and electric system modeling, the process begins with the digital creation of the infrastructure and its operational characteristics. For gas infrastructure, these characteristics include the diameter, roughness and length of the pipe, connecting equipment, regulating station equipment and operating pressure. For electric infrastructure, these characteristics include conductor cross-sectional area, resistance, length, construction type, connecting equipment, transformer equipment and voltage settings. PSE then identifies customer loads in the model, either specifically (for large customers) or as block loads through address ranges. Existing customer loads are acquired using PSE's customer information system (CLX) or from actual circuit load readings. From this set up, the planner can then vary temperature conditions, types of customers served (interruptible vs. firm), time of day (at peak daily usage) or with various components out of service (valves closed or switches open). Thereafter, various scenarios of infrastructure or operational adjustments can be modeled in search of the least cost solution to a given issue.

To simulate the performance of the electric transmission system, PSE uses a Power Technologies Inc. (PTI) product called PSS/E, and a General Electric product called PSLF. In addition, PSE uses Managing and Utilizing System Transmission (MUST), another PTI product to study the capability of the power system to move power from one area to another under various conditions. These simulation programs utilize a model of the transmission system 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 Northwest Power Pool (NWPP) and Western Electric Coordinating Council (WECC). WECC is one of 10 regional reliability organizations under the North American Electric Reliability Council (NERC). These power system study programs support PSE's planning process and facilitate demonstration of compliance with reliability performance standards as outlined by WECC and NERC.

*System Alternatives*

PSE has a variety of alternative approaches to solving delivery issues. Gas and electric facility alternatives include:

**<u>Electric</u>**
- 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
- Off load system
  - Distributed Generation
  - Fuel Switching
  - Conservation
  - Load control equipment
  - Possible new tarriffs
- Do nothing

**<u>Gas</u>**
- 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
- Off load system
  - Fuel Switching
  - Conservation
  - Load Control Equipment
  - Possible new tarriffs
- Do nothing

Energy flow can be managed temporarily with some of these same alternatives. This is useful when the issues are short in duration either due to the peaking nature of the issues, or when project completion timing is the problem. Some examples of this include:

- 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 changes to alter turn ratios.
- Temporary siting of mobile equipment such as compressed natural gas (CNG) injection vehicles, liquid natural gas (LNG) injection vehicles, mobile substations, and portable generation.

In every decision-making process, one of the alternatives is to "do nothing". Understanding and managing risk becomes important with this alternative.

*Examples of Project Analysis and Development*

PSE has many examples of this successful planning process: the reinforcement of the Gig Harbor gas system, the reinforcement of the Hansville Peninsula electric distribution system, and the reinforcement of the West Kitsap transmission system are described below. For each project, all the alternatives are reviewed and optimized, and prioritized to determine the most cost-effective solution.

1. Gig Harbor gas distribution system:

   PSE began serving Gig Harbor in 1969 via 6" and 8" high-pressure pipelines installed from Zenith, in the Des Moines area, across Puget Sound to Vashon Island, and then across Colvos passage to the Gig Harbor Peninsula. Annually, PSE has seen a 5 percent to 8 percent increase in customer additions since 1995. PSE began planning in 1995 to resolve the capacity problem expected in 1999. Planning began using SynerGEE to model the growth and to predict when available pipe capacity would begin to adversely impact performance.

   As a solution, PSE chose to install a liquid natural gas (LNG) satellite plant to supply the needed gas on colder days. This plant is loaded with LNG and only operates 20 to 30 days a year. This solution implemented technology never before considered by PSE. A cost analysis of this solution vs. a pipeline water crossing proved the LNG satellite plant was the least cost solution to serve existing and future growth for 20 to 25 years. The construction of the plant was completed in 2004. The peak loads that occurred between 1999 and 2004 were maintained using a mobile LNG vehicle. The cost of the LNG satellite alternative was approximately 40 percent less than a new pipeline. Other system alternatives which were considered and studied to resolve this capacity issue included the following:

a) Tacoma Narrows passage crossing project. This alternative was to install a high-pressure pipeline under the Tacoma Narrows passage from Point Defiance to the south end of the peninsula. This alternative met the needs, but the estimated cost was approximately $33 million.
b) Tacoma Narrows Bridge project. This alternative was to install a high-pressure pipeline on the existing Tacoma Narrows Bridge or on a new proposed bridge. This alternative met the needs, but the state and local permitting agencies would not allow PSE to install this facility due to safety concerns. The estimated cost was approximately $16 million.
c) Firm Supply from neighboring utility. This alternative was to purchase firm supply from PSE's neighboring utility. The estimated cost was approximately $22 million for the connecting pipeline and future gas cost.
d) Home Comfort Control project. This alternative, which did not meet the system need, was to implement the use of a two-way CellNet radio to control the settings on customers' home electronic thermostats. During peak periods, PSE would remotely reduce the thermostat setting a degree or two to limit the system demand. The expected system demand reduction was 6 percent. Unfortunately, a minimum of 14 percent reduction was necessary to maintain reliable service. The estimated cost to execute this program was approximately $6 million.
e) Replace the existing supply pipeline project. This alternative was to replace the existing pipeline that crossed Vashon Island in multiple phases. The estimated cost was approximately $30 million. Additionally, from a reliability and system flexibility standpoint, a new second supply pipeline, as described in alternatives a and b, was more preferable than replacement of the existing supply.

PSE performed an economic comparison several times throughout the development of the scope. Each time, the LNG satellite plant was the best alternative. The result is shown in Exhibit XVI-6.

**Exhibit XVI-6**

| Alternatives | Capital | NPV 30 Yr | Comments |
|---|---|---|---|
| Tacoma Narrow Water Crossing | $33M | ($18.6M) | Potential impacts of ESA. |
| Tacoma Narrow Bridge Crossing | $16M | ($15.4M) | Permitting agencies did not approve. |
| Replace Vashon Crossing | $ 30M | NA | Not evaluated by AIM. |
| LNG Satellite Facility | $13M | ($13.2M) | Siting and permitting would be concern. |
| Firm Supply from Neighbor Utility | $22M | ($13.1M) | Only interruptible service available. Did not meet project objective. |
| Home Thermostat Control Program. | $ 6M | ($8.5M) | Deferred larger project only 1-2 years. Did not meet project objective. |

2. Hansville Peninsula electric distribution system:

The North Kitsap electric system has experienced concerns similar to those of the Gig Harbor area due to its isolation and slow solid growth. PSE began serving the Hansville Peninsula in 1980 via a cable sitting on the floor of the Port Gamble Bay water passage between the town of Port Gamble and the Little Boston Community. Annually, PSE has seen a 0.5 percent increase in customer additions in the Hansville area. PSE began planning in 2003 to resolve the predicted capacity problem expected in 2005. Planning began by using SynerGEE to model growth and to predict when available system capacity would begin to adversely impact performance.

As a result, PSE began looking for additional options including the installation of a new underwater cable. However, due to the length of time needed for study, design and permitting of new facilities, PSE began planning for generation to temporarily support this area in order to prevent the cable from becoming over-utilized and failing. A failure at peak load times would mean that approximately 2,000 customers would be out of service. PSE has installed a temporary generator at Hansville that is operated during colder days, similar to the LNG satellite plant in Gig Harbor. The temporary use of a generator on cold days does not meet the long-term needs of this area and is seen as a bridging solution until permanent facilities are installed. The cost analysis currently underway may demonstrate that a new additional cable is the least cost solution to serve existing and future growth for the next 10 to 20 years.

The other system alternatives considered and studied to resolve this capacity issue include the following:

a) Second distribution submarine cable. This alternative involves laying 6000 feet of 15kV cable across Port Gamble Bay. It meets the near and long term demand for the Hansville community. However, it does not contribute to a project need for additional capacity to serve the Kingston area. The cost of a cable project is estimated at about $4 million.
b) The Kingston Substation. This alternative involves construction of a new distribution substation. The cost of the new substation and related transmission line is about $5 to $7 million. In addition to providing capacity to the peninsula, the new substation would provide future capacity to the town of Kingston.
c) Underwater transmission cable with a substation on the Hansville peninsula. This alternative was ruled out due to an estimated costs ranging from $15 to $20 million.

**Exhibit XVI-7**

| Alternatives | Capital | NPV 30 Yr | Comments |
|---|---|---|---|
| Second Distribution underwater cable | $4 M | ($6.5M) | Under study |
| Kingston Substation | $5-$7 M | ($4.7M) | Under study |
| Transmission Underwater cable | $15-$20 M | N.A. | Is not now considered a viable alternative |

3. West Kitsap transmission system:

PSE serves North Kitsap County via two transmission lines from Bremerton/Valley Junction to Foss Corner. Annually, PSE has seen a 1 to 1.5 percent increase in customer additions. PSE began planning in the early 1990s to resolve the predicted reliability problem expected in 2005. The continuing load growth is limiting the capability of the Bremerton Foss and Valley Junction—Foss 115 KV lines to serve all customers under conditions where one line is out of service. This is called an N-1 condition.

The alternative chosen to resolve the problem was a third transmission line, the Foss—Bangor 115/230 kV transmission line. This alternative meets the need to increase transmission capacity and improve reliability to North Kitsap and Bainbridge Island. The estimated cost is approximately $5 million.

The other system alternatives considered and studied to resolve this reliability issue include the following:

a) Silverdale—Foss Corner 115/230kV transmission line project. This alternative does not provide the full backup required. However, it would have provided an interim solution to the loading and reliability problems until it is extended further into South Bremerton. The estimated cost was approximately $6 to $7 million.
b) Hood Canal submarine cable intertie between Jefferson and Kitsap Counties. This alternative was less robust than the Foss - Bangor transmission line at solving the N-1 issue. The estimated cost was approximately $24 to $30 million.
c) Generation resource. This alternative was considered and ruled out due to siting uncertainties in North Kitsap County. A benefit of this alternative was that it would reduce system losses by approximately 5 percent, or 2 MW. The estimated cost was approximately $20 to $30 million.
d) Westsound transmission line. This alternative, which involves installing a new transmission line between the Bremerton and Winslow substations on Bainbridge Island, meets the requirements of the need statement. However, the estimated cost was approximately $20 to $25 million.

Exhibit XVI-8 shows the economic comparison of the alternatives. The third transmission line, Foss—Bangor, proved to be the least cost alternative.

**Exhibit XVI-8**

| Alternatives | Capital | NPV 30 Yr | Comments |
|---|---|---|---|
| Foss—Bangor Transmission Line | $5M | ($3.9M) | Preferred alternative |
| Foss—Silverdale Transmission Line | $6.3M | ($4.9M) | Does not meet full need |
| Hood Canal Cable | $24M | ($18.9M) | Doesn't solve N-1 entirely |
| Generation | $21M | ($15.8M) | Permitting uncertain |
| West Sound Transmission Line | $22M | ($17.3M) | Meets need, but costly |

4. Everett—Delta gas distribution system:

   PSE serves North Seattle and Everett via 12" and 8" high-pressure pipelines installed from Northwest Pipeline's (NWP) North Seattle Lateral which terminates in the Lynnwood area. This system provides service to approximately 92,000 residential and commercial customers and some of PSE's largest industrial customers. Annually, PSE has seen a 3 percent increase in customer additions in the Everett and Lake Stevens areas and 10 percent in the Marysville and Granite Falls areas. PSE began planning in 1994 to resolve the capacity project expected in 2004.

   The alternative chosen to resolve the problem was the installation of a 16" high-pressure pipeline from the Lake Stevens area across multiple rivers and waterways and across I-5 to the north end of Everett. This solution provides a second source to the North Seattle/Everett system and therefore increases the reliability of service, supports growth for 25 to 30 years and shifts demand off of the North Seattle Lateral so that it can better support growth south. The initial project proposal was to be built by PSE in conjunction with service to a proposed power plant at the north end of Everett. Over time, various proposals for this developed and eventually NWP proposed to construct this line in support of one of the power plant proposals. PSE was able to contract with NWP for inclusion in their proposed project, which was subsequently approved by FERC.

   In 2002, the power plant project backed out of the arrangement with NWP. Even though the FERC approved project was in jeopardy, PSE continued to see this line as the most effective means of meeting the capacity needs. After analysis, PSE entered into negotiations with NWP to continue to construct this line solely for PSE's need. PSE and NWP ultimately established a novel arrangement whereby PSE would fund and own the lateral, and lease it to NWP—who would operate it—for 5 years. After 5 years, subject to FERC approval, the lateral would revert to PSE's operation. NWP successfully completed the installation of the 9.16 mile 16" HP main line in December 2004, in time to meet the growth in the area.

   Other system alternatives that were considered and studied to resolve this capacity issue included the following:

a) Everett Delta Ownership options. Several options were reviewed to determine the most economic arrangement for ownership.

i. The first ownership option was for PSE to construct the pipeline. The estimated cost is approximately $25 million. Project risks could drive project costs to $42 million. However, this option would put PSE on track for completion in 2008. Due to this timing and the previous work already completed by NWP on the project, this was unreasonable. This option would have required PSE to construct "short-term solution" projects, estimated at $7 million, and utilize liquefied natural gas (LNG) and other cold weather actions, estimated to cost $1.4 million annually, to ensure reliable service until the project was completed.

ii. The second ownership option was for NWP to construct the pipeline (with PSE funding because NWP did not have sufficient capital). PSE would own the line after completion, but NWP would continue to operate the line and provide service to PSE. The estimated project cost was approximately $32 million. Under FERC approved rate principles, this option would require PSE to pay approximately $1 million annually for operation and maintenance to NWP.

iii. The third ownership option was for NWP to construct the pipeline (with PSE funding). PSE would own the line after completion, PSE would then lease it to NWP. NWP would operate the lateral as part of its system and provide service through the lateral to PSE. After the 5 year lease term, subject to FERC approval of abandonment of service by NWP, PSE would take over the operation of the line as part of its distribution system. The estimated cost was approximately $32 million due to design and construction to meet the higher standards required by Washington regulation. Through this arrangement, PSE was able to avoid the large annual maintenance charge, and assume actual operations after the 5-year term.

b) Granite Falls project. This alternative was to install a high-pressure pipeline from the Granite Falls high-pressure termination through Marysville to Everett. Detailed analysis showed that this option would not be sufficient without upgrading the Granite Falls high-pressure system as well. The cost of this project became prohibitive relative to its benefit life span due to the immediate need to begin adding additional high-pressure main and gate station capacity. In the initial project development phase this project was determined to be significantly higher in cost than other alternatives and therefore was never revisited in later analysis and cost refinement.

c) North Seattle Lateral upgrade project. This alternative was to have NWP upgrade/expand the North Seattle laterals. This option was significantly more expensive than the Everett—Delta proposal. In addition, it did not increase reliability to this large area, maintaining reliance on only one pipeline feed. The estimated cost was approximately $58 million.

d) Anderson Canyon project. This alternative was an alteration to the route between Lake Stevens and Everett. This pipeline was to be installed from the south end of Lake Stevens to Everett. It traveled along PSE's electric transmission right of way. The substantial length, along with the environmental issues associated with this route made it risky and ultimately infeasible. The estimated cost was approximately $21 million. Project risks could have driven project costs to $38 million.

e) BPA Snohomish project. This alternative was an alteration to the route between Lake Stevens and Everett. This pipeline traveled along BPA's electric transmission right of way. The substantial length, along with the environmental issues associated with this route made it risky and ultimately infeasible. The estimated cost was approximately $22 million. Project risks could have driven project costs to $38 + million.

PSE performed an economic comparison several times throughout the development of this project. Each time, the Everett Delta project (a.iii) was the best alternative. The result is shown in Exhibit XVI-9.

**Exhibit XVI-9**

| Alternatives | Capital | NPV 30 Yr | Comments |
|---|---|---|---|
| Everett-Delta – i | $24M | ($24.6M) | Risks associated with re-start of project. Immediate temporary measures. |
| Everett-Delta – ii | $32M | ($29.8M) | Large O&M annual outlay. |
| Everett-Delta – iii | $32M | ($17.5M) | Passive ownership (via 5-yr. leasing arrangement) |
| North Seattle Lateral upgrade | $58M | ($17.5M) | Does not increase system reliability. Large revenue requirement due to capital outlay. |
| Anderson Canyon | $21M | ($21.3M) | Environmental and property owner impacts, and construction cost risks. |
| BPA Snohomish | $22M | ($22.3M) | Environmental and property owner impacts, and construction cost risks. |

*Decision Making*

To make prudent investment decisions for hundreds of gas and electric projects, an objective way to synthesize, analyze, and optimize projects based on resource constraints is required. These decisions are too complex to be made based solely on instinct or simple analysis. To be successful at this task, PSE initiated the use of value-based budget prioritization. PSE currently uses a technique known as the Analytical Hierarchy Process (AHP) for the allocation of its resources. In order to allocate resources wisely, planners must know both the cost and benefits associated with each project. Planners must also account for how resource constraints affect the optional mix of projects. This helps to determine a project's value for consideration.

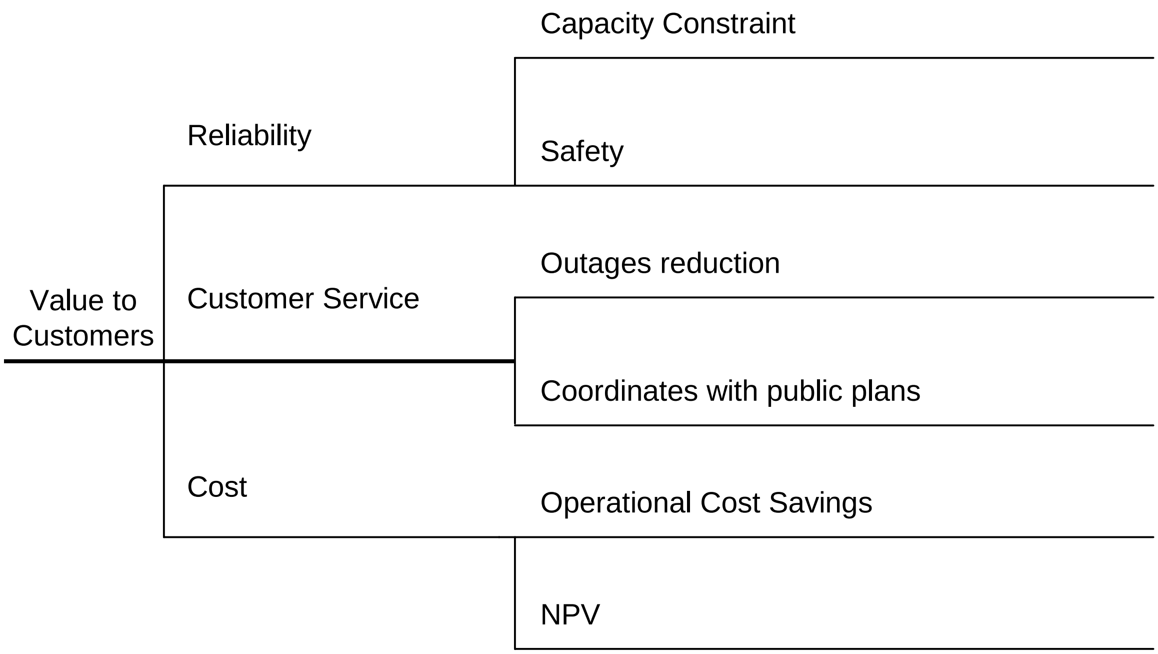
Planners determine the cost of projects using a variety of tools, including historical cost analysis and unit pricing models based on service provider contracts. As projects move through detailed scoping, cost estimates are refined. Planners use a software program called Area Investment Model (AIM) to calculate a wide range of financial performance indicators for each project. This analysis includes the traditional Net Present Value and Rate of Return analysis, but also identifies the future revenue potential as a result of the added capacity gained by a particular solution. This does not drive the need for the project, but allows further comparison for infrastructure that will be in service for 30 to 50 years.

A more difficult task has been to quantify the benefits of a particular project. A single project may have a wide range of benefits. The benefits of the best alternative are assessed, which include both quantitative and qualitative benefits. Some of these benefits include how much energy will not be served in the future, the outages avoided based on the history and probability of equipment failure, the impact that a project or the resolution of an issue may have on public relationships, the reduction in cost due to coordination with municipal projects, and the value of service as determined by customers.

Dr. Thomas Saaty developed the analytical hierarchy process (AHP) circa 1970. He was a professor at the Wharton School of Business. AHP continues to be one of the most highly regarded and widely used decision making theories. It is especially suitable for complex decisions that involve the comparison of decision elements that are difficult to quantify. It involves building a hierarchy ranking of decision elements, then making comparisons between each possible pair in each cluster of common objectives. It captures both subjective and objective evaluation measures, providing a useful mechanism for checking the consistency of the evaluation measures and alternatives suggested by the team, thus reducing bias in decision making. As a result of this benefit analysis, projects receive a score. This score is then synthesized through an AHP application tool, Expert Choice, which optimizes scores and cost given designated financial constraints. The application of AHP for resource allocation decisions proves to be straightforward, with growing use by other organizations such as Xerox, IBM and Lucent. Exhibit XVI-10 represents an example of the hierarchy developed for making project comparisons.

**Exhibit XVI-10**

**Benefit Heirarchy**




## D. System Plans

The planning processes and decision-making methodology described above help to develop the Least Cost Plan. This analysis helps to build short- and long-range plans. For 2005, over 700 projects have been identified for engineering or completion to meet capacity and reliability needs. An example of the proposed 5-year infrastructure plans for predicted system capacity needs is provided. As the plan year gets closer, further analysis is performed to flush out additional alternatives based on more information. As a result, these types of plans may change in an effort to incorporate new information and implement the least cost solution. Exhibit XVI-11 shows gas infrastructure plans and Exhibit XVI-12 shows electric distribution infrastructure plans.

## Exhibit XVI-11

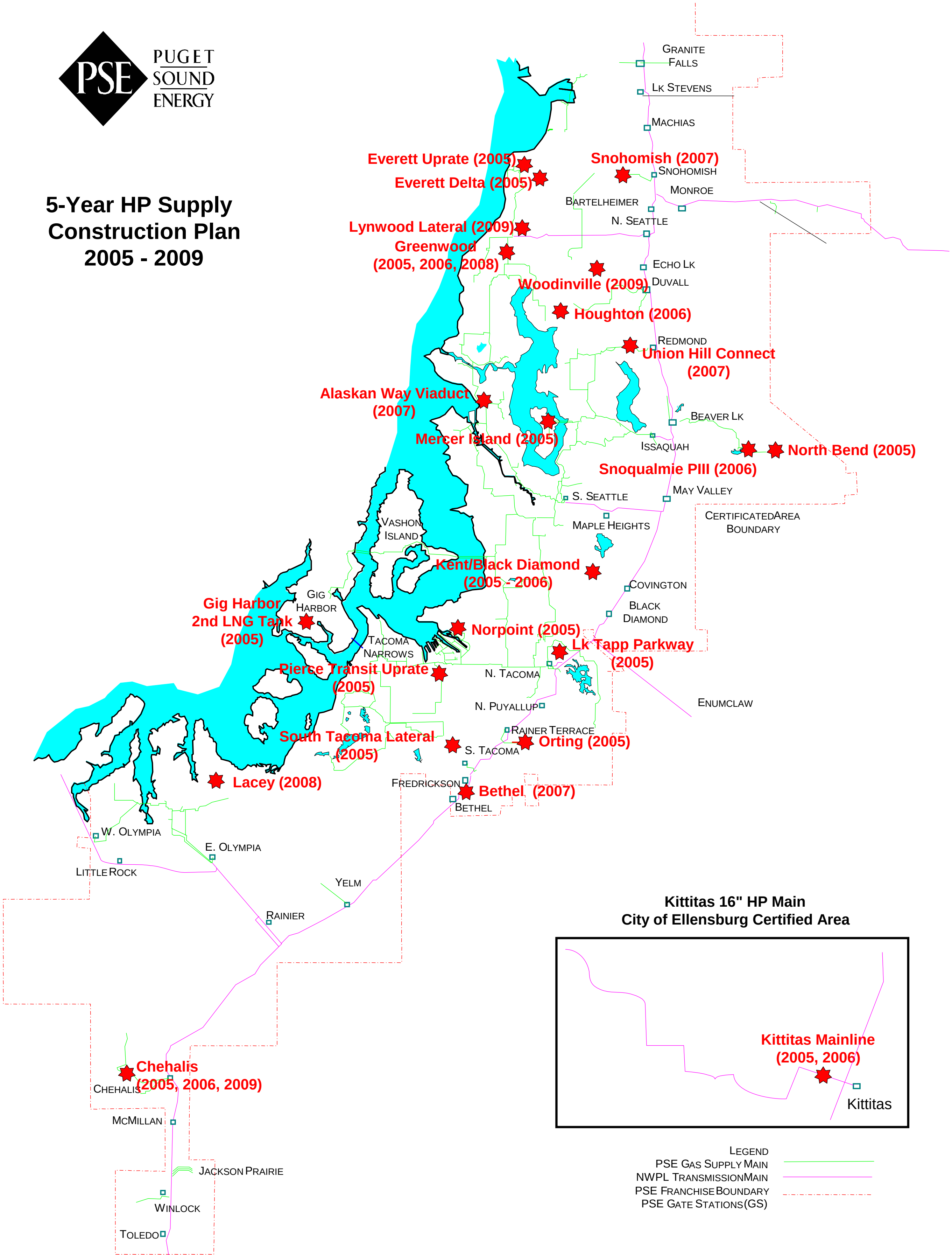
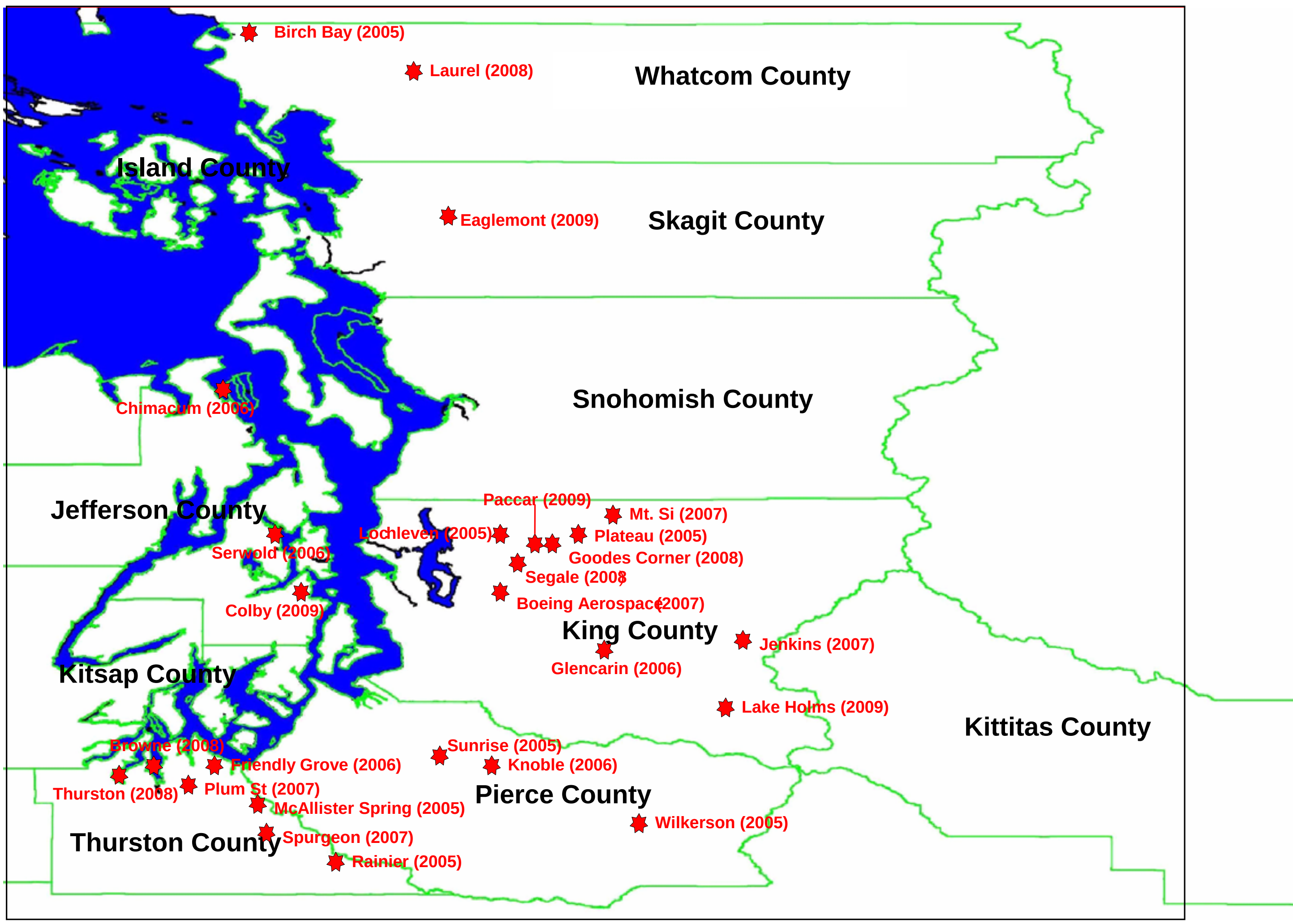


**Exhibit XVI-12**

## 5-Year Substation Construction Plan
**2005 - 2009**



## Exhibit XVI-13
## 5-Year Construction Plan—Gas-HP Supply

| Year | Name of Project | City | Job Description |
|---|---|---|---|
| 2005 | Everett Uprate | Everett | Increase MAOP of system by completing an HP Uprate |
| 2005 | Everett Delta | Everett | Incidental carry-over costs from previous Everett Delta HP job |
| 2005 | Greenwood | Seattle | Greenwood IIA – install 16" HP out of the North Seattle Town Border Station (south) |
| 2005 | Mercer Island | Mercer Island | Increase MAOP of system by completing an HP Uprate |
| 2005 | North Bend | North Bend | Install approximately 16,000' of 8" HP main along Snoqualmie Parkway to SR202 |
| 2005 | Kent/Black Diamond | Kent | Complete paving for Phase 1A and begin engineering for Phase 1B |
| 2005 | Gig Harbor 2nd LNG Tank | Gig Harbor | Purchase and install 2nd LNG tank for existing Gig Harbor LNG plant |
| 2005 | Norpoint | Tacoma | Replace 6" HP with 8" HP, ~10,200 feet |
| 2005 | Lake Tapp Parkway | Bonney Lake | 8" Steel wrapped HP road opportunity |
| 2005 | Pierce Transit Uprate | Tacoma | Increase MAOP of system by completing an HP Uprate |
| 2005 | South Tacoma Lateral | Tacoma | Increase MAOP of system by completing an HP Uprate |
| 2005 | Orting | Orting | Install 8" HP along 144 ST E; tie to the existing 8" to the 8"HP |
| 2005 | Chehalis | Chehalis | Preliminary Engineering for the Installation of 5,000' 8" HP Main |
| 2005 | Kittitas Mainline | Kittitas | Install 108,000 feet of 12" Steel wrapped high pressure main along the Prairie route |
| 2006 | Greenwood | Seattle | Greenwood IIIA – install 16" HP out of the North Seattle Town Border Station (North) |
| 2006 | Houghton | Kirkland | Replace 2500' of 4" with 8" HP Main to DR 2485 |
| 2006 | Snoqualmie PIII | Snoqualmie | Replace 4" HP bottleneck with 12", ~11,600' |
| 2006 | Kent/Black Diamond | Kent | Install 16"HP from 132 Ave SE & 288 ST to Auburn Way N & tie-in to the HP (Ph. 1b) |
| 2006 | Chehalis | Chehalis | Engr., Constr. & Install 5,000' of 8" HP Main |
| 2006 | Kittitas Mainline | Kittitas | Install 12" HP out of Thorp TBS to Suncadia Development, ~4.8 miles |
| 2007 | Snohomish | Snohomish | 8" HP, Upgrade 4" HP out of Snoh, GS to 8:"; retire DR1780 and install new DR |
| 2007 | Union Hill Connect | Redmond | Connect Union Hill Phases; raise set pressure at gate station, ~6000' |
| 2007 | Alaskan Way Viaduct | Seattle | Replace ~ 4000' of 152" HP with 16" HP to accommodate Alaskan Way Viaduct PI work |
| 2007 | Bethel | Bethel | Extend 12" HP from existing 8" HP to serve Cascadia |
| 2008 | Greenwood | Seattle | Install 16" HP from Phase IIIA to W. Greenwood Lateral |
| 2008 | Lacey | Lacey | Extend 8" HP from existing 12" HP to serve Lacey |
| 2009 | Lynnwood Lateral | Lynnwood | Install 16" to bisect Greenlake Loop; connect with LS North of Ship Canal crossing |
| 2009 | Woodinville | Woodinville | Completed Woodinville Phase III; install 16" on TW ROW |
| 2009 | Chehalis | Chehalis | Install 8" HP from GS to TBS |

## Exhibit XVI-14
## 5-Year Construction Plan—Substation

| Year | Name of Substation | County | Job Description |
|---|---|---|---|
| 2005 | Birch Bay | Whatcom | Change to 15 MVA Transformer, 115 KV Substation |
| 2005 | Lochleven | King | Install 25 MVA Transformer, 115 KV Substation (2nd Bank) |
| 2005 | Wilkerson | Pierce | Change to 15 MVA Transformer, 115 KV Substation |
| 2005 | Plateau | King | New, 25 MVA Transformer, 115 KV Substation |
| 2005 | Rainier | Thurston | New, 25 MVA Transformer, 115 KV Substation |
| 2005 | Sunrise | Pierce | New, 25 MVA Transformer, 115 KV Substation |
| 2005 | McAllister Spring | Thurston | Change to 15 MVA Transformer, 115 KV Substation |
| 2006 | Chimacum | Jefferson | New, 25 MVA Transformer, 115 KV Substation |
| 2006 | Glencarin | King | New, 25 MVA Transformer, 115 KV Substation |
| 2006 | Friendly Grove | Thurston | Uprate 55 Kv to 115 KV, change to 5 MVA Transformer, 115 KV Substation |
| 2006 | Knoble | Pierce | New, 25 MVA Transformer, 115 KV Substation |
| 2006 | Serwold | Jefferson | New, 25 MVA Transformer, 115 KV Substation |
| 2007 | Jenkins | King | New, 25 MVA Transformer, 115 KV Substation |
| 2007 | Spurgeon | Thurston | New, 25 MVA Transformer, 115 KV Substation |
| 2007 | Plum Street | Thurston | Uprate 55KV to 115KV, change to 20 MVA Transformer, 115 KV Substation |
| 2007 | Boeing Aerospace | King | 25 MVA Transformer, 115 KV Substation (customer owned to PSE owned) |
| 2007 | Mt. Si | King | New, 25 MVA Transformer, 115 KV Substation |
| 2008 | Laurel | Whatcom | New, 25 MVA Transformer, 115 KV Substation |
| 2008 | Browne | Thurston | New, 25 MVA Transformer, 115 KV Substation |
| 2008 | Thurston | Thurston | Uprate 55KV to 115KV, change to 10 MVA Transformer, 115 KV Substation |
| 2008 | Segale | King | New, 25 MVA Transformer, 115 KV Substation |
| 2008 | Goodes Corner | King | Install 25 MVA Transformer, 115 KV Substation (2nd Bank) |
| 2009 | Eaglemont | Skagit | New, 25 MVA Transformer, 115 KV Substation |
| 2009 | Lake Holms | King | New, 25 MVA Transformer, 115 KV Substation |
| 2009 | Colby | Jefferson | New, 25 MVA Transformer, 115 KV Substation |
| 2009 | Paccar #2 | King | 25 MVA Transformer, 115 KV Substation (2nd Bank) |

## E. Distributed Resource Opportunities

Distributed Resources (DR) are commonly defined as small-scale generation facilities connected to the distribution level of the transmission and distribution grid located near the source of the load being served. DR is not a new concept, dating back to the earliest days of the electric industry. For much of the 20th century, small-scale customer based generation could not compete economically with utility-owned centralized plants. These economics began to change in the mid-1980s when centralized fossil plant technology reached maturity and research and development then focused on micro-turbines and fuel cell technologies.

In addition, customers' electricity and energy requirements began to change. For example, some industrial customers now focus on meeting combined electric and thermal needs through one system, hospitals and computer-based internet service firms now require higher levels of power quality and reliability due to the substantial impact of not having service, and other customers want renewable or green power. In response to these factors and to changing federal laws, small-scale generation has become more common among PSE's large industrial customers. While DR continues to emerge, it is slower than previously expected because the economics remain unattractive.

*Background*

Although DR offers some potential benefits as part of PSE’s distribution system facilities planning process, a host of regulatory, business practice, technical, and market barriers continue to challenge the full-scale implementation of this technology. In May 2000, the National Renewables Energy Laboratories (NREL) issued a report identifying some of these challenges.

Since then federal and state agencies have taken some steps to address the barriers identified by NREL. The United States Department of Energy’s Distributed Energy Resource (DER) program implements a Distributed Energy Resource Strategic Plan. This national effort promotes the “next generation” of clean, efficient, reliable and affordable distributed energy technologies. As a follow-up to FERC’s October 2001 Advance Notice of Proposed Rulemaking (ANOPR), and the National Association of Regulatory Utility Commission’s (NARUC) June 2002 release of the draft Interconnection Agreement and draft Interconnection Procedures, FERC initiated a Notice of Proposed Rulemaking (NOPR) in July 2003. It was designed to finalize the standardization of small generator interconnection agreements and procedures. In October

2003, NARUC published the model agreement for Interconnection and Parallel Operation of Small Distributed Generation Resources as an information tool and to serve as a catalyst for DR interconnection proceedings.

Industry groups have also taken steps to address technology barriers to DR implementation. The Institute of Electric and Electronic Engineers (IEEE) is developing specific and voluntary DR standards. In June 2003, IEEE Standard 1547-2003, Standards for Distributed Resource Interconnection with the Electric Power Systems, was established and approved by the IEEE board. The IEEE Standards Coordinating Committee is currently drafting and establishing technical guidelines for the interconnection of electric power sources greater than 10 MVA to the power transmission grid. A draft paper on the impact of DR to utilities was written by the IEEE Distributed Resources Integration working group. As many of these standards and guidelines become finalized and approved, DR will become easier for small customers to implement.

*PSE's Use of Distributed Resources*

Despite remaining barriers to full-scale DR implementation, PSE strives to incorporate DR elements into its planning process. PSE has developed DR guidelines that identify those projects with the highest probability of serving the least cost capacity deferral alternative. For example, the Hansville Peninsula project mentioned previously is utilizing this technology in order to have time to implement the long-term least cost solution. When the submarine cable supplying electricity approaches its design capacity, the temporary generator is operated to pick up the excess load and protect the cable from prematurely failing prior to completion of a new cable or substation. In addition, PSE currently has over 24 photovoltaics and micro-hydro customer generators connected to the grid company-wide.

PSE implemented a distributed resource peak shaving strategy at Crystal Mountain. Crystal Mountain is an area that could reach peak load capacity capabilities within a few years. The load was projected to climb from 5.9 MVA to 11.2 MVA by 2006-2007. The estimated capital cost for a traditional wire solution was about $2.5 million. PSE decided to refurbish and test a 2.4 MVA diesel standby generator located near the load. PSE ran a test to prove the concept and its feasibility, which provided sufficient justification to defer the $2.5 million traditional system upgrade for three to seven years.

PSE views the DR technology as an alternative for delivering reliable energy at low cost. Currently, PSE monitors and evaluates DR developments at the federal, state and utility levels. From 2000 to 2004, PSE participated in the Universal Interconnect Detail Design project with the Department of Energy (DOE), National Renewable Energy Laboratory (NREL), and General Electric (GE). The final report on this project was issued in December 2004, and emphasized that standard compliance is key for entry into the distributed generation market. It also addressed microgrid application issues, and summarized the detailed study and development of new GE anti-islanding controls. PSE continues to search for opportunities to implement DR and adopt effective and workable solutions already developed by the industry.

## F. Non-Wires Solution (NWS)

*Background* [1]

Over the last 20 years, transmission systems throughout North America have experienced significantly increased end-use *consumption* and grid utilization despite comparatively little investment in new transmission infrastructure. The result of this imbalance is a grid under stress and a growing awareness of the need to reinforce transmission systems across North America including in the Pacific Northwest.

BPA owns and operates approximately three-quarters of the electrical transmission system in the Pacific Northwest. According to “Transmission Planning through a Wide-Angle Lens,” a report published by the BPA in September 2004, “BPA did not undertake any substantial transmission construction between 1987 and 2003.” The report goes on to say that, “Since 1999, the system has operated at or near capacity to meet demand.” The Olympic Peninsula, where PSE serves approximately 45 percent of the load, is one of these congested areas.

In 2001, BPA’s Transmission Business Line (TBL) developed a program aimed at strengthening the existing grid. As part of this process, BPA broadened its strategy to include non-wires solutions such as demand response, distributed generation and conservation measures that reduce peak demand as a means of deferring transmission projects when possible. The goal was to identify and consider potential non-wires solutions that would also be cost-effective.

[1] Some information in this section, regarding BPA’s Transmission Business Line, has been paraphrased from BPA’s “Transmission Planning through a Wide-Angle Lens: A Two-Year Report on BPA’s Non-Wires Solutions Initiative,” published in September 2004.

*The Non-Wires Solutions Roundtable* [2]

In 2003 BPA held its first Non-Wires Solutions (NWS) Roundtable. Comprised of 17 member organizations, including utilities, regulators, renewable resource advocates, environmental interest groups, industrial energy users, an organization of Indian tribes, and independent power generators, the group employs a broad, regional approach to considering non-wires solutions. PSE is a member of the Roundtable via Sue McLain, the Company's Sr. Vice President of Operations.

In the past 18 months the Roundtable focused on the following activities:

- Identifying transmission planning screening criteria—to evaluate whether a non-wires solution might defer a transmission project,
- Reviewing detailed studies for existing problem areas on BPA's transmission system—again to determine when a non-wires solution might defer transmission,
- Reviewing non-wires technologies,
- Defining institutional barriers, which create obstacles for non-wires solutions, and
- Piloting non-wires solutions.

*PSE Activities in the area of NWS*

1. The Conservation Voltage Reduction (CVR) pilot, which is currently in-progress in PSE's System Planning & Operations Group, can be viewed as an NWS application. PSE is working with NEEA in a pilot project to research potential savings by applying CVR technologies. This study involves lowering substation and feeder voltage without adversely affecting power quality to PSE customers. It remains to be seen whether the effort will result in meaningful load reduction at the substation to influence investment decisions.
2. PSE submitted two demand response pricing programs in response to BPA's RFP process for NWS pilots in 2004. The proposed pilot programs were a Community Incentive Peak-Reduction program and a Voluntary Extreme Day Pricing program. The pilots were designed to test winter peak-day demand response potential in a small targeted area of PSE's electric service territory. The technology to test these pilots (PAR3, PEM and AMR) is currently available. PSE may consider the possibility of

[2] Some information in this section, regarding BPA's Non-Wires Solutions Roundtable, has been paraphrased from BPA's "Transmission Planning through a Wide-Angle Lens: A Two-Year Report on BPA's Non-Wires Solutions Initiative," published in September 2004.

evaluating future pilot programs such as these, outside the BPA Non-Wires Request for Proposals process.

In addition to more traditional “wires” solutions, PSE recognizes that there are economic and other factors which make it necessary and appropriate to consider NWS where possible. In conjunction with this, PSE maintains a staunch commitment to the position that such solutions must be as reliable as a transmission or distribution project to ensure that customer reliability is not impacted. The above examples illustrate PSE efforts toward that goal.

# XVII. 2005 ACTION PLAN

The following is the two-year Action Plan to implement PSE's recommended long-term resource strategy. This Action Plan includes, but is not limited to, specific steps to acquire new demand-side and supply resources. Also listed are least cost planning actions related to maintaining access to existing energy resources, enhancing analytical methods, improving risk management, promoting energy policy and regulatory initiatives, and improving system planning methods. For convenience, the Action Plan is organized by topic area.

## A. Electric Resource Acquisition Strategy

This section is divided into activities for resources expected to come on-line in the near-term (2006-2011) and in the long-term (2012-2025).

### A.1. Near-Term (2006-2011) Resource Acquisition Activities

*Energy Efficiency*

Develop new electric and gas energy efficiency savings targets for 2006-2007 informed by Least Cost Plan analyses, and file new program tariffs with the Washington Utilities and Transportation Commission (WUTC) by the end of 2005.

Initiate an energy efficiency resource acquisition Request for Proposal (RFP) process that complies with regulatory requirements. This RFP will address the following: 1) long lead times due to 2006-2007 targets and program commitments needing to be made before the RFP process can be completed; and 2) development of a "targeted" RFP, focused on specific markets and/or technologies that complement PSE's programs.

*Fuel Conversion*

Complete evaluation of single-family and multi-family fuel choice pilots, and explore the feasibility of further developing fuel conversion programs, with input from regulators and stakeholders.

*Demand Management*

Explore the feasibility of implementing one or more demand-response pilots, with input from regulators and stakeholders.

*Green Power Program and Community Renewable Generation*

By the end of 2005, develop a two-year goal for the Green Power program covering the 2006-2007 period.

Continue to encourage small-scale solar or other renewable energy demonstration projects.

*New Electric Resources*

Initiate a competitive solicitation process for new electric energy resources by filing a draft RFP and accompanying materials with the WUTC within 90 days following submittal of this Least Cost Plan.

Complete contractual arrangements and construct the Wild Horse and Hopkins Ridge wind projects.

Implement the Colstrip turbine upgrade to increase project efficiency (PSE's share of the additional project generation is 25 aMW).

### A.2. Long-Term (2012-2025) Resource Acquisition Activities

*New Electric Resources*

Explore contract renewal discussions with expiring cogeneration projects to maintain resource availability.

Explore feasibility, partnering opportunities, and transmission alternatives for remote-located coal-fueled and renewable generation.

Seek opportunities for emergent technologies including biomass, geothermal, and integrated gasification combined cycle (IGCC).

## B. Natural Gas Resource Acquisition Activities

*Energy Efficiency*

Develop new gas energy efficiency savings targets for 2006-2007, informed by Least Cost Plan analyses, and file new program tariffs with the WUTC by the end of 2005.

*New Natural Gas Resources*

Work with Jackson Prairie co-owners to explore deliverability expansion, and work with Northwest Pipeline on related seasonal transportation.

Investigate specific locations for possible conventional and satellite liquefied natural gas (LNG) storage facilities and refine cost estimates for these facilities.

Consider acquisition of delivered bridging peak-supply resources and (discounted) long-term Northwest Pipeline transportation capacity.

Continue monitoring developments at the Sumas, Station 2 and AECO markets, and investigate upstream transportation alternatives.

Continue to monitor development and opportunities related to imported LNG in the region.

## C. Existing Electric Resource Activities

Conduct plant engineering, environmental studies, geotechnical exploration, and preliminary construction to implement the terms of the Baker Hydroelectric Project Settlement Agreement.

Prepare environmental and historic resource management plans; conduct engineering for plant improvements; consult with resource agencies; and begin construction activities, all to implement the terms of the 2004 Snoqualmie Falls Hydroelectric Project license.

Continue contract renewal discussions with the Mid-Columbia PUDs.

## D. Analytical and Process Improvements

*Demand Forecasting*

Refine the long-term geographic area energy and peak load with weather sensitivity, and other key economic factors.

*Electric Resource Analytics*

Explore modifications to PSE's electric portfolio analysis tool to increase flexibility.

Include appropriate consideration of imputed debt, credit requirements, and risk management in evaluating potential new resource acquisitions.

*Gas Resource Analytics*

Incorporate refinements to Sendout/Vector Gas to analyze fixed, banded and market priced gas supply pricing options to support development of long-term hedging strategies.

Conduct additional studies of the potential efficiency of joint LDC/generation fuel planning, including Monte Carlo analysis.

Re-examine design day planning criteria based on updated demand forecast and resource cost assumptions.

## E. Portfolio Operations and Risk Management

Expand long-term gas-for-power risk management capability.

Develop operation and analytic methods for integrating wind into PSE's electric portfolio.

Complete development and implementation of the Long-Term Energy Cost Risk Management Strategy to address the risks of both long-term power cost and long-term PGA gas cost.

As part of developing the Long-Term Energy Cost Risk Management Strategy, study the value placed by PSE customers on lowering energy price volatility in retail power and gas bills.

Enhance and better integrate portfolio and risk management systems.

## F. Policy, Regulatory, and Legislative Initiatives

*Energy Efficiency*

Participate in 2007-2009 Bonneville Power Administration (BPA) Rate Case process to secure a fair share of BPA conservation funding for PSE and other investor-owned utilities.

Work to address regulatory and financial disincentives to utilities for implementing demand-side management.

Develop a recommended approach to address key issues related to demand-response programs, including a cost effectiveness methodology and a cost recovery mechanism.

*New Electric Resources*

Participate in ongoing regional efforts to evaluate the costs and risks of transmission for new resources located outside PSE's service territory.

Continue to participate in the development and determination of the benefits of a regional transmission organization as well as explore other opportunities to improve transmission availability and access in the region.

Remain active in appropriate regional initiatives like the Puget Sound Climate Protection Advisory Committee.

Explore the development of a corporate greenhouse gas (GHG) policy for shareholders and customers.

Actively participate in legislative discussions about a Renewable Portfolio Standard for Washington.

Continue to participate in regional initiatives exploring transmission and resource adequacy standards.

Pursue, as necessary, regulatory mechanisms to address financial impediments and disincentives associated with resource acquisitions that are consistent with the Least Cost Plan.

## G. System Planning

Evaluate opportunities for lower-cost, innovative solutions, which facilitate an appropriate level of system performance at the best long-term cost (such as the TreeWatch and Silicone Injection initiatives).

Continue to evaluate distributed resources technologies and consider their impact to both gas and electric distribution systems.

Continue to evaluate how aging assets are likely to impact system performance and develop remediation plans.

Continue to develop system models and other technologies that facilitate more accurate, customer- and time-sensitive system evaluations regarding system performance (i.e. Stoner SynerGEE implementation, supervisory control and data acquisition (SCADA), and Automated Meter Reading).

# XVIII. REPORT ON APRIL 2003 TWO-YEAR ACTION PLAN

This chapter provides an overview of PSE's efforts in relation to its previous "Action Plan" items. The statements in bold are from the Least Cost Plan filed in 2003.

## I. August 2003 Update

- **Modify Northwest Power Planning Council models and run with PSE data assumptions.**
- **Provide a detailed measure-by-measure summary of results.**
- **Assess the practicality of pursuing specific cost-effective measures based on the analysis.**
- **Incorporate the above results into a revised integrated analysis of supply and demand-side resource alternatives.**
- **Update PSE resource strategy accordingly.**

PSE provided a follow-up to its April 2003 Least Cost Plan with an August 2003 Update. Using its Conservation Screening Model, PSE integrated conservation opportunities into its supply-side model. PSE also modeled an accelerated lighting program and found the approach viable. After the modeling results were considered, PSE issued a Request for Proposal (RFP) for conservation programs, and established a two-year program for 2006-2007. PSE has followed the development of the Northwest Power and Conservation Council (NPCC) models but has neither run nor adopted them.

## II. Conservation and Efficiency

- **Achieve average annual target of 15 aMW and 2.1 million therms of conservation savings per year through 2006.**

During 2004, energy efficiency services programs under the electric Rider and gas Tracker achieved first-year savings of 138,288 MWh (15.79 aMW) at a cost of $20,869,462, and 3,189,819 therms at a cost of $3,781,810. Savings in 2005 are expected to reach levels such that PSE will achieve 100 percent of the two-year (2004-2005) savings goals on or under budget. New two-year goals will be established for 2006–2007 based on previous program experience and the recommendations of the Company's 2005 Least Cost Plan, and after consultation with the Conservation Resources Advisory Group.

- **Achieve an additional 2.5 aMW electricity savings from residential and farm customers, supported by Conservation & Renewable Discount credits to electricity supply-side purchases from BPA.**
  Under the Bonneville Power Administration's (BPA's) Conservation and Renewables Discount (C&RD) program in 2004, PSE saved 34,927 MWh (3.99 aMW) in first-year savings at a cost of $4,126,802 (does not include cost of renewables). PSE will continue to take full advantage of the C&RD credit as long as BPA makes it, or a similar mechanism, available to investor-owned utilities in the future.

- **Assess the impact of conservation programs on peak load and losses.**
  Over the past two years, PSE has actively participated in BPA’s Roundtable Discussion on Non-Wires Solutions to Transmission Issues. A PSE vice president participates on the official Roundtable board, and has sent various experts on transmission and energy efficiency to various Roundtable meetings. As part of the 2004 Roundtable process, PSE conducted an assessment of peak load reductions resulting from energy efficiency measures completed within its service area on the Olympic Peninsula (Kitsap and Jefferson Counties). This assessment estimated total peak load reduction potential by 2008, when BPA anticipates a need to add transmission capacity.

  The 2005 Least Cost Plan also estimates the potential peak load reduction from energy efficiency resources over the 2006–2025 planning period. The results are presented in Chapter VII.

- **Promote information, education and training efforts for energy efficiency products, services and practices, in order to support customer decision-making in selecting, purchasing, maintaining and efficiently using equipment.**
  PSE continues to support customer information, education and training in a variety of ways. Major efforts include the following:
  1) Dedicated specialists on the energy advisor hotline
  2) Brochures and other informational materials sent to customers
  3) Energy audits, efficiency "calculator" tools, energy efficiency information, and other links available on PSE’s website

4) Free electronic energy efficiency newsletters, which showcase case studies, provide information on energy efficient products and technologies, and inform customers of program offerings

Noteworthy is PSE's new program allowing customers to download a year's worth of billing data directly into the energy analysis tool. This tool shows customers how and where they use energy, and directs them to opportunities for saving. Brochures are being refined and updated with objective information on energy efficiency opportunities. PSE also participates in a wide variety of home-show, trade-show and community events and activities to promote efficiency education throughout the year. Training is targeted at vendors, retailers, contractors and trade-allies, who are leveraged as an "extension" of the company's staff to promote energy efficiency with customers. The Company offers technical training opportunities throughout the year for commercial and industrial customers, and actively encourages customers to participate in Resource Conservation Manager, Boiler-Tune-up, Building Operator Certification training and other technical classes offered in conjunction with the Northwest Energy Efficiency Alliance (NEEA) and/or other Puget Sound area utilities.

- **Support local energy efficiency market infrastructure in the communities PSE serves, in addition to continuing support for activities at the regional level through the Northwest Energy Efficiency Alliance.**

  PSE actively works to promote NEEA and other market transformation efforts at local and regional levels. With NEEA, the most notable efforts are the residential lighting, appliances, and Energy Star new construction programs, as well as commercial Leadership in Energy and Environmental Design (LEED) and "Better Bricks" new construction offerings, wastewater, magna-drive, builder operator training, and industrial/specific technologies. PSE supports NEEA's activities by sponsoring an active PSE representative on the board of directors, providing operational and program delivery feedback for program design, and cooperatively promoting and marketing NEEA services in the local area.

  PSE also works closely with local organizations engaged in market transformation activities, including the Northwest Energy Efficiency Council, the Electric League, LEED, and Master Builder organizations throughout the service territory, which are developing models for "Built Green" home development in parallel with Energy Star Northwest Homes. In its work with the Western Washington chapter of American Society of Heating, Refrigerating and Air-Conditioning Engineers (ASHRAE), PSE staff provide comments and feedback on development and adoption of energy codes.

**III. Demand Response Management**

- **Conduct a fuel-conversion pilot to investigate the cost-effectiveness of residential space and water heating conversions from electric resistance units to high-efficiency natural gas, in order to defer the need for electric distribution system capacity upgrades.**

  A fuel conversion pilot is underway. Seventy homes now have natural gas equipment installed. At the end of the current (2004-2005) heating season, PSE will complete an evaluation to determine the energy-savings impacts, review costs in comparison with distribution alternatives, and assess overall program performance. A final report outlining pilot findings will be available by the summer of 2005.

- **Investigate the use of natural gas for multi-family units.**

  PSE is conducting studies to determine the feasibility of installing natural gas in multi-family units. These studies involve a series of interviews to more clearly define the building types, market actors, and decision-making with regard to fuel choice in multi-family buildings. This research will provide a better understanding of the multi-family market, including the economics of and barriers to natural gas use in these facilities, enabling the Company to determine the design of any pilot installations. These feasibility studies and a decision to move forward with a pilot program will be complete by mid-2005.

- **Provide an assessment of the current status and potential future of the role of price responsiveness efforts as a demand-side resource option. This work will build upon the efforts of the existing Time-of-Use Collaborative once the group has completed its assessment of the Company's Time-of-Use program per the commitment in the prior General Rate Case. The August 2003 Least Cost Plan update will include the results of this assessment.**

  On July 1, 2003, PSE submitted a final report and recommendations on its time-of-use (TOU) pricing program to the Washington Utilities and Transportation Commission (WUTC), on behalf of the Time-of-Use Collaborative. The Collaborative recommended that time-responsive pricing options be examined in the context of the Company's least cost planning process, rather than as a separate formal process or timeline.

As part of its compliance with the April 30, 2003 Least Cost Plan Action Plan, PSE retained Charles River Associates to perform an assessment of demand-response technical potential, including price-based strategies. The results of this assessment were included in the Company's August 2003 Least Cost Plan Update. The results of that study were also presented to the Least Cost Planning Advisory Group (LCPAG) on July 27, 2004. The study identified at least 200 MW of cost-effective demand response potential.

As part of this Least Cost Plan, PSE retained Quantec, LLC to perform a study of technical and achievable peak demand reduction potential, and the associated costs of a variety of demand-response products including time-of-use and critical peak pricing strategies. This assessment found that achievable market potential was significantly less than technical potential for all demand-response strategies. The demand response strategy with the largest achievable potential was critical peak pricing, at 155 MW of peak demand reduction.

PSE has also actively participated in the BPA's Roundtable Discussion on Non-Wires Solutions to Transmission Issues. As part of this process, PSE submitted four responses to BPA's RFP for pilot programs for non-wires solutions. Two of PSE's proposals were demand-response programs targeting small retail electric customers in Kitsap and Jefferson Counties, including one proposal to pilot extreme-day peak pricing. At this time BPA has not selected any of PSE's proposals for implementation.

- **Participate in the regional Conservation Voltage Reduction pilot program as a demonstration utility, to examine the cost-effectiveness of energy savings benefits for the customer and the utility, as well as other impacts.**

  PSE has signed a Memorandum of Agreement with NEEA to be a demonstration utility for the regional Conservation Voltage Reduction (CVR) pilot program. The program seeks energy savings through small reductions to voltage levels on circuits targeted for distribution system upgrades in the near future. A PSE substation and substation feeders have been selected for the pilot. The original program timeline was delayed several months because an Underwriters Laboratories (UL) listing needed to be procured for the CVR equipment. That listing has been obtained, but the newly designed units are not expected to be available until mid-year 2005. Closer to the equipment delivery date, PSE will recruit customer participants. If the pilot continues as planned, field monitoring will take place for one year beginning early summer 2005, with analysis and results expected early in 2007.

## IV. Renewable Resources

- **Continue to study the issues associated with integrating wind resources into PSE's distribution system. In particular, identify and evaluate lower-cost alternatives to the use of new simple-cycle gas turbines to back up intermittent wind generation.**

  PSE, working with Golden Energy, developed a robust analysis of the integration costs of wind energy. Using Mid-C hydro resources as the backup energy source, the study found that the total cost for the initial wind farm investments was in the range of $1.74/MWh to $5.40/MWh. Refer to Appendix D for the wind integration Phase II report.

- **Explore the feasibility of other renewable resources such as biomass, solar and geothermal energy.**

  PSE has funded biomass and solar energy projects through its customer-supported green tag program. These projects are discussed in the "Existing Resources" section. PSE supports the Center for Distributed Generation and Thermal Distribution at the Washington State University Energy Program with its efforts to accomplish geothermal energy development in the Northwest.

## V. Peaking Resources

- **Look for lower-cost alternatives to simple-cycle gas turbines, including peaking power supply contracts, and peak-oriented demand response programs.**

  In planning for peak energy needs, PSE does not plan to purchase more simple-cycle gas turbine (SCGT) peakers. PSE uses a mix of fixed- and index-priced contracts, call options, and spot market. This mix is a lower-cost alternative to acquiring SCGTs.

- **Actively participate in regional processes focusing on electric resource adequacy.**

  PSE supports regional discussion on resource adequacy standards and notes that the issue was brought up in the Fifth Pacific Northwest Electric Power and Conservation Plan. Utilities need to work regionally, and the region needs to work with interconnected areas within the Washington Electricity Coordinating Council (WECC) to develop standards and identify the load-resource capacity balance.

### VI. Supply-Side Resource Acquisition

- **Continue to monitor market opportunities for acquisition of generation assets or power contracts.**

  In 2003, the expectation was that resource opportunities would come from the supply developed by non-utilities. However, today many opportunities arise because of the demand for new resources from PSE. PSE will continue to consider both sources, unsolicited supply offers and responses to RFPs, in order to procure the least-cost mix of resources for its customers.

- **Issue RFP for supply from large-scale, commercially feasible renewable resources.**

  PSE initially issued an RFP for wind projects. However, at the direction of the WUTC, the wind RFP was rolled into the All-Source RFP. As a result of that RFP process, PSE signed letters of intent with two wind farms totaling 388 megawatts of capacity.

### VII. Energy Supply – Gas

- **Perform detailed analysis of expected long-term supply basin pricing differentials to assist in determination of preferred pipeline alternatives.**

  PSE continues to utilize a gas price forecast that is specific to the various supply basins accessible to PSE. The price forecast relies on a North American fundamentals model that considers regional demand growth, drilling economics, environmental restrictions and pipeline infrastructure developments to predict pricing differentials. Individual basin prices are used in the Sendout model. Vector Gas facilitates a Monte Carlo simulation of different pricing patterns and relationships to guide the selection of optimal pipeline resources.

- **Develop further refinement of the Propane Air options and cost estimates.**

  PSE has recognized the growing cost efficiencies in smaller-scale liquefied natural gas (LNG) and satellite LNG peaking facilities based on its experience with the Gig Harbor facility. An additional benefit is that LNG can be blended into the flowing gas stream without the potential for flame "lift-off" as with propane-air. Therefore, PSE has focused on LNG-based peaking rather than propane-based peaking.

- **Analyze specific new pipeline projects.**

  PSE continues to monitor all pipeline development proposals and has included several in the current Least Cost Plan analysis.

- **Explore additional storage options.**

  PSE has reviewed the costs and availability of storage services provided by two third-parties in the region. One of the projects was removed from the Least Cost Plan analysis because it provided services similar to Jackson Prairie but at a much higher cost, and because it required incremental pipeline capacity.

- **Evaluate the cost and benefits of upstream pipeline capacity.**

  PSE has included an analysis and a recommendation for resource acquisition related to upstream capacity in the current Least Cost Plan.

- **Perform feasibility study on expandability of Jackson Prairie storage capacity and deliverability (beyond the current project).**

  PSE and the other Jackson Prairie owners are in the process of analyzing and costing a proposed deliverability expansion to supplement the ongoing capacity expansion. When resources allow, PSE will continue to research the potential for incremental development and the related costs (and risks).

- **Examine feasibility of gas reserve ownership as an alternative or supplement to fixed price hedges.**

  PSE has discussed the availability and pricing of dedicated gas reserves with several gas suppliers. In the current tight market conditions, none has indicated a willingness to consider a sale of reserves at anything other than forward market price. Development or purchase of dedicated reserves would present significant additional volume risk to PSE and its customers, which is not likely to be offset by the risk mitigation provided by the known price. PSE will continue to discuss and analyze options as opportunities arise.

### VIII. Energy Demand Forecasting

- **Develop more detailed load shape and duration data to facilitate greater optimization of resources and potential for further gas/electric synergies.**

  Chapter VI details the methodology and results of the forecasting. New load forecast highlights include changes in estimating the 8760 load shape and in allowing long-term growth rates to vary by month.

- **Analyze results of electric to gas conversion pilot program to determine impacts on gas and electric load, and implication for regulatory policy.**

  As mentioned in section III (above), a single-family fuel conversion pilot is underway. Seventy homes now have natural gas equipment installed. At the end of the current (2004-2005) heating season, PSE will complete an evaluation to determine the energy-savings impacts, review costs in comparison to distribution alternatives, and assess overall program performance. A final report of pilot findings will be available by late summer 2005. PSE is also conducting studies to determine the feasibility of installing natural gas in multi-family units. This research will provide a better understanding of the multi-family market, including the economics of and barriers to natural gas use in these facilities, enabling the Company to determine the design of any pilot installations. These feasibility studies and a decision to move forward with a pilot installation program will be complete by mid-2005. Load and policy implications can be assessed upon completion of these pilots and market research.

### IX. Distribution Facilities Planning

- **Participate with other Edison Electric Institute utilities in the Federal Energy Regulatory Commission (FERC) Notice of Proposed Rulemaking (NOPR) process for distributed generation. The FERC NOPR for distributed generation will be issued in the spring of 2003.**

  PSE followed the progression of this issuance.

- **Seek opportunities to deploy distributed generation for least-cost capacity deferral.**

  Distributed resources continue to emerge, although slower than previously expected because the economics remain unattractive. However, PSE continues to evaluate the implementation of distributed resources as an alternative to projects.

- **Continue the collaboration with the DOE/NREL/GE Universal Interconnect project.**
  From 2000-2004, PSE participated in the Universal Interconnect Detail Design project with The Department of Energy (DOE), National Renewable Energy Laboratory (NREL), and General Electric (GE). The final report on this project was issued in December 2004, and emphasized that standard compliance is key to entry into the distributed generation market. It also addressed microgrid application issues, and summarized the detailed study and development of new GE anti-islanding controls.

- **Track distributed generation technologies and applications that can impact and improve the gas and electric distribution planning process.**
  PSE continues to educate itself regarding these technologies through its technology review process wherein applications of new technologies are evaluated for implementation by PSE.

## X. Integrated Resource Modeling

- **Continue ongoing process of evaluating new gas and electricity resource alternatives and development of integrated resource strategies to meet customer needs.**
  PSE has initiated a large gas hedging strategy that will study gas supplies for both the gas and electric needs to identify strategies that balance price and risk.

- **Continue development of databases to support modeling and better assess the impacts of alternative gas price scenarios, resource costs, and load forecasts on PSE's resource portfolio.**
  PSE used knowledge and experience gained from the RFP process to better inform the modeling this year. Improvements were made in valuing wind integration costs, determining new resource costs, identifying the transmission problem, and creating realistic portfolios.

- **Continue working with software developers of resource planning models to better address PSE's resource planning issues, resource alternatives and policy options.**
  PSE’s conservation screening model was developed based on its portfolio screening model. For the RFP and subsequent resource evaluation process, as well as for this Least Cost Plan, PSE made numerous improvements to the models.

# LIST OF ACRONYMS AND INITIALISMS

| | |
|---|---|
| ACQ | Annual Contract Quantity |
| AECO | Alberta Energy Company (AECO is the common name for the Alberta gas hub) |
| AEO | Annual Energy Outlook |
| AGA | American Gas Association |
| AHP | Analytic Hierarchy Process |
| AIM | Area Investment Model |
| AMR | Automatic Meter Reading |
| aMW | Average Megawatts |
| ANG | Alberta Natural Gas |
| ATC | Available Transmission Capacity |
| BAU | Business As Usual (electric scenario) |
| BC | British Columbia |
| Bcf | Billions of Cubic Feet |
| BPA | Bonneville Power Administration |
| BTu | British Thermal Unit |
| C&RD | Conservation and Renewables Discount |
| CAIR | Clean Air Interstate Rule |
| CAMR | Clean Air Mercury Rule |
| CCCT | Combined-cycle Combustion Turbines |
| CERA | Cambridge Energy Research Associates |
| CHP | Combined Heat and Power (Cogeneration) |
| CM | Current Momentum (electric scenario) |
| CNG | Compressed Natural Gas |
| CO2 | Carbon Dioxide |
| CPAC | Climate Protection Advisory Committee |
| CRAG | Conservation Resource Advisory Group |
| CSM | Conservation Screening Model |
| CT | Combustion Turbine |
| CVR | Conservation Voltage Reduction or Conservation Voltage Regulation |
| DG | Distributed Generation |
| DOE | Department of Energy (Federal) |
| DOE | Department of Ecology (State) |

# LIST OF ACRONYMS AND INITIALISMS

| | |
|---|---|
| DR | District Regulator or Distributed Resource |
| DSM | Demand Side Management |
| Dth | Deca-therm |
| Dth/d | Deca-therm per day |
| EFP | Exchange for Physical |
| EIA | Energy Information Administration, US Department of Energy |
| EPA | Environmental Protection Agency |
| ESA | Endangered Species Act |
| FAS133 | Financial Accounting Statement #133, Accounting for Derivative Instruments and Hedging Activities |
| FASB | Financial Accounting Standards Board |
| FERC | Federal Energy Regulatory Commission |
| FIN46 | Financial Accounting Standards Board Interpretation Consolidation of Variable Interest Entities |
| FOM | Fixed Operation and Maintenance |
| FOR | Forced Outage Rate |
| GHG | Green House Gases |
| GTN | Gas Transmission Northwest |
| GW | Green World (electric scenario) |
| HDD | Heating Degree Days |
| HP | High Pressure |
| HPA | Hydraulic Project Approval |
| HVAC | Heating, Ventilation and Air Conditioning |
| IGCC | Integrated Gasification Combined Cycle |
| IP | Intermediate Pressure |
| IPP | Independent Power Producer |
| ISDA | International Swaps and Derivatives Association |
| JP | Jackson Prairie |
| kV | Kilovolt |
| kW | Kilowatt |
| kWH | Kilowatt-hour |
| LCP | Least Cost Plan |
| LCPAG | Least Cost Plan Advisory Group |

# LIST OF ACRONYMS AND INITIALISMS

| | |
|---|---|
| LDC | Local Distribution Company |
| LG | Low Growth (electric scenario) |
| LLC | Limited Liability Corporation |
| LNG | Liquefied Natural Gas |
| LP | Low Pressure or Liquid Propane |
| LS | Liquid Storage (NWP storage tariff) |
| MAOP | Maximum Allowable Operating Pressure |
| Mcf | Million Cubic Feet |
| MDQ | Maximum Daily Quantity |
| Mid-C | Mid-Columbia |
| MIT | Massachusetts Institute of Technology |
| MMBtu | Million British Thermal Units |
| MW | Megawatts |
| MWH | Megawatt Hours |
| NEB | National Energy Board (Canada) |
| NEEA | Northwest Energy Efficiency Alliance |
| NEPA | National Environmental Policy Act |
| NGTL | Nova Gas Transmission Ltd |
| NOx | Nitrogen Oxides |
| NPCC | Northwest Power and Conservation Council |
| NPDES | National Pollutant Discharge Elimination System |
| NPV | Net Present Value |
| NTAC | Northwest Transmission Assessment Committee |
| NUG | Non Utility Generators, specifically Tenaska, Sumas, and March Point |
| NWEC | Northwest Energy Coalition |
| NWP | Northwest Pipeline |
| NWPP | Northwest Power Pool |
| NWS | Non-Wire Solutions |
| NYMEX | New York Mercantile Exchange |
| O&M | Operation and Maintenance |
| OASIS | Open Access Same-time Information System |
| OPS | Office of Pipeline Safety |
| PBA | Power Bridging Agreement |

# LIST OF ACRONYMS AND INITIALISMS

| | |
|---|---|
| PGA | Purchase Gas Adjustment |
| PGSS | Peak Gas Supply Service |
| PPA | Purchase Power Agreement |
| PSCAA | Puget Sound Clean Air Agency |
| PSE | Puget Sound Energy |
| PSIG | Pounds per Square Inch Gauge |
| PSM | Portfolio Screening Model |
| PTC | Production Tax Credit |
| PUD | Public Utility District |
| PURPA | Public Utility Regulatory Policies Act |
| RAS | Remedial Action Scheme |
| RFP | Request for Proposal |
| RG | Robust Growth (electric scenario) |
| RGGI | Regional Greenhouse Gas Initiative |
| RMATS | Rocky Mountain Area Transmission Study |
| RPS | Renewable Portfolio Standard |
| RTO | Regional Transmission Organization |
| S&P | Standard and Poor's, a credit rating agency |
| SEC | Securities and Exchange Commission |
| SEPA | State Environmental Policy Act |
| SO2 | Sulfur Dioxide |
| SGS | Storage Gas Service (NWP storage service) |
| STW | Steel Wrapped (type of gas pipe) |
| TCPL | Trans Canada Pipeline |
| TF | Transmission Firm (NWP transportation tariff) |
| TI | Transmission Interruptible (NWP transportation tariff) |
| TIG | Transmission Issues Group |
| TS | Transmission Solution (electric scenario) |
| WAC | Washington Administrative Code |
| WACC | Weighted Average Cost of Capital |
| WCI | West Coast Initiative |
| WECC | Western Electricity Coordinating Council |
| WUTC | Washington Utilities and Transportation Commission |

# APPENDIX A
# STAKEHOLDER INTERACTION

This appendix addresses stakeholder issues, including public input to the Least Cost Plan process and specific stakeholder areas of concern. This appendix further provides an overview of PSE's commitment to public involvement in the planning process, and describes its public input process. PSE briefly summarizes the formal Least Cost Plan Advisory Group (LCPAG) and Conservation Resource Advisory Group (CRAG) meetings held to date. Next, in response to the Washington Utilities and Transportation Commission (WUTC) October 3, 2003 letter commenting upon PSE's April 30, 2003 Least Cost Plan and August 2003 Least Cost Plan Update, PSE delineates its response to each comment and points the reader to the Least Cost Plan section that addresses the subject matter for each. The end of this chapter summarizes the major stakeholder issues identified during the Least Cost Plan process to date, organized around major themes. Again, in describing these issues of concern, PSE provides references to relevant portions of the Least Cost Plan.

## A. Public Participation

PSE maintains an open commitment to actively encouraging public involvement in its Least Cost Plan process. As of April 30, 2005, ten formal LCPAG meetings, four CRAG meetings, as well as dozens of informal meetings and communications have taken place. Stakeholders that have actively participated in one or more meetings include WUTC staff; the Public Counsel; individual customers from industrial and commercial classes; Northwest Pipeline; conservation and renewable resource advocates; the Northwest Power Planning Council; project developers; other utilities; and the Washington State Department of Community, Trade and Economic Development.

Stakeholder meetings provided a venue for constructive feedback and useful information to guide the least cost planning process. Stakeholder suggestions and practical information were invaluable to the development of this Least Cost Plan. PSE wishes to thank those who attended the least cost planning meetings for the time and energy they devoted to this Least Cost Plan process. PSE encourages the continuation of this active participation as the Company's planning process proceeds.

While the LCPAG and CRAG groups meet separately, they share many common members.

The LCPAG's scope includes all elements of the Least Cost Plan. The CRAG is more narrowly focused on energy efficiency and demand-side resources.

*Conservation Resources Advisory Group*

Key to the development of PSE's overall demand-side resource strategy is the CRAG. It was formally established as part of the settlement of PSE's 2001 general rate case, which the WUTC approved in Docket Nos. UE-11570 and UG-011571 (called Conservation Agreement). The group's specific purpose is to work with PSE toward the development of energy efficiency plans, targets and budgets. CRAG membership was established by the Conservation Agreement and consists of WUTC staff; Public Counsel, Attorney General's Office; Northwest Power and Conservation Council; Industrial Customers of Northwest Utilities (ICNU); Northwest Industrial Gas Users (NWIGU); NW Energy Coalition and Natural Resources Defense Council; Energy Project (representing Low Income Agencies); Washington State Department of Community, Trade and Economic Development; and DOE Weatherization Assistance Program provider network. In addition to the official CRAG membership, customer representatives have also participated in CRAG meetings including Microsoft, Kemper Development, and King County.

The CRAG participated in the development of the Company's 2005 Least Cost Plan and energy efficiency program review through a series of formal meetings to review and offer feedback on the assessment of all demand-side resources (energy efficiency, fuel conversion, and demand response). Many members of the CRAG also participated in other aspects of PSE's least cost planning advisory process. PSE appreciates the contributions of these organizations and individuals.

The following section provides an overview of the LCPAG and CRAG meetings convened as of April 30, 2005.

*Least Cost Plan Advisory Group Kick-off Meeting: February 9, 2004*

PSE presented an update on its wind and all-source requests for proposal (RFPs) including a status summary, process schedules and products requested. PSE also discussed 2004 work items for the 2005 Least Cost Plan.

*Conservation Resource Advisory Group Meeting:  February 9, 2004*

This meeting covered the Energy Efficiency RFP process and timeline, a rider/tracker summary, a Conservation and Renewables Discount (C&RD) update, a Measurement and Evaluation Plan Update, a Bonneville Power Administration (BPA) Non-Wires Solution update, and a discussion of topics for future meetings.

*Least Cost Plan Advisory Group Meeting:  April 14, 2004*

PSE presented its working draft of the 2005 Least Cost Plan Table of Contents.  The discussion included an overview of the Least Cost Plan schedule.  PSE provided a resource acquisition update, involving an overview of the acquisition process, evaluation criteria, wind acquisition goals, and key transaction issues.  Finally, Cambridge Economic Research Associates (CERA) led a presentation detailing their North American gas outlook, methodology highlights, scenario process and selected results, as well as regional gas issues.

*Least Cost Plan Advisory Group Meeting:  June 14, 2004*

PSE provided briefings on (1) energy efficiency RFP responses and (2) both wind and all-source RFP progress.  Following these briefings, there was a natural gas planning update.  The meeting wrapped up with a review of generic electric resource assumptions.

*Least Cost Plan Advisory Group Meeting:  July 27, 2004*

There was a brief, high-level discussion regarding resource acquisitions in which it was mentioned that construction cost risks were a significant concern and that short-listed wind projects were reliant on PSE’s ability to access production tax credits (PTC).   A presentation regarding demand side resource analysis followed, including a review of demand response technical potential, as well as a plan for updating conservation, fuel conversion and demand response.  PSE provided an update on its new long-term planning model and a review of its gas peak-day planning standard.  PSE presented an energy efficiency RFP update that outlined the Company’s shortlist.  Finally, PSE updated the group on its all-source RFP, including stage one process and analysis, short list selections and a stage two process update.

*Conservation Resource Advisory Group Meeting:  July 27, 2004*

This meeting included a 2004 energy efficiency mid-year program summary and an overview of highlights to date.  The selection of a project shortlist for the Energy Efficiency RFP and the schedule for major energy efficiency planning activities, including support for the 2005 Least Cost Plan, were also discussed.

*Least Cost Plan and Conservation Resource Advisory Groups Joint Meeting: October 12, 2004*
Meeting topics included: the resource acquisition status; financial issues including risk management, credit, and imputed debt; and the electric and gas planning status. Quantec gave a presentation on its 2005-2024 Demand-Side Resource Analysis Preliminary Results including the scope and framework of its analysis, its methodology, technical and achievable potentials for electric and gas energy efficiency (residential and commercial use), demand response, and fuel conversion. Quantec also outlined upcoming steps in its process, which focused on such areas as energy efficiency, fuel conversion and demand response.

*Conservation Resource Advisory Group Meeting: October 12, 2004*
This meeting covered selection of the finalist projects from the Energy Efficiency RFP process and presented the draft results of the 2005 Least Cost Plan demand-side resource potential assessment for energy efficiency, fuel conversion, and demand response.

*Least Cost Plan Advisory Group Meeting: November 9, 2004*
PSE began this meeting with a presentation on the regional transmission situation, outlining constraints and regional efforts toward resolution. Additionally, the Company pointed out challenges to resolving these issues as well as the pros and cons of PSE's options in light of the current situation. PSE followed this a discussion of short- and long-term gas markets, an overview of existing gas resources and an update on potential resources (both peaking and base load). Next, PSE provided information about its electric modeling process flow and analytic improvements. Finally, the long-term risk management group presented hedging team report highlights, a list of goals for meeting PSE's long-term energy cost risk management strategy, a position assessment, and an evaluation of alternatives.

*Least Cost Plan Advisory Group Meeting: December 8, 2004*
PSE provided an update on its long-term risk management project. This was followed by an overview of the Hopkins Ridge wind project and development schedule. Next, the Company then presented CERA's recently released 2004 Rear View Mirror gas price forecast within the confines of the confidentiality terms outlined in its contract with CERA. PSE discussed its electric planning environment for the 2005 Least Cost Plan, and identified key issues including

transmission, environmental considerations, new demand-side resources, financial issues, the resource development process and gas price forecast. PSE then gave a presentation on how the Company plans to use portfolios and scenarios to analytically explore its key issues. Greenhouse gas and carbon costs dominated this discussion. PSE addressed the current gas planning environment, identifying key issues such as the decrease in liquidity at Sumas as producers sell more gas at Station 2. Finally, PSE presented the key uncertainties facing its gas Least Cost Plan analysis including long-term pricing, price volatility, and load uncertainty.

*Least Cost Plan Advisory Group Meeting: January 12, 2005*

PSE presented the gas and electric portfolio and scenario combinations to be tested in the Least Cost Plan. LCPAG participants were encouraged to ask questions and offer feedback regarding these scenarios. The meeting wrapped up with an overview of developments pertaining to the following hydro resources: the Baker River and Snoqualmie Falls hydroelectric projects, the White River Project, and PSE's Mid-Columbia contracts.

*Least Cost Plan Advisory Group Meeting: February 9, 2005*

The meeting convened with brief progress updates on PSE's Electric Modeling and Gas Planning efforts. This was followed by a detailed discussion of the Company's customer and sales forecasts, including specific modeling information, forecast assumptions, results and uncertainties. BPA then gave a presentation on the current regional transmission situation, which involved information about current projects, transmission line constraints, no wires solutions and other related issues.

*Conservation Resource Advisory Group Meeting: February 9, 2005*

This meeting covered the final results of the 2005 Least Cost Plan demand-side resource potential assessment for energy efficiency, fuel conversion, and demand response. Further information included a 2004 energy efficiency year-end program summary and an overview of program highlights. A discussion of topics for future meetings concluded the presentation.

*Least Cost Plan Advisory Group Meeting: March 24, 2005*

This was the final meeting prior to the preparation of PSE's 2005 Least Cost Plan external draft document. PSE provided information on the draft electric and gas analytical results. Also presented was an overview of the electric and gas key conclusions and acquisition strategies.

**B. Additional Regulatory Direction**

Following the submittal of PSE's previous Least Cost Plan and Least Cost Plan Update, the WUTC issued a letter dated October 3, 2003 from Ms. Carole J. Washburn, Executive Secretary, to Mr. Steve Reynolds, President and Chief Executive Officer, Puget Sound Energy. The letter accepted the plan and provided a list of 12 specific recommendations for PSE's next Least Cost Plan. Each of the recommendations for this Least Cost Plan is set forth below, along with references to the chapters where a more detailed discussion of the topic can be found.

1. Recommendation - Modeling: *"The Company should refine its modeling techniques using information quarried from journals of economics, operations research, and optimization as well as the software market. A better set of software tools may emerge to aid the industry in dealing with increasing price and market risk. In particular, we encourage exploration of a system built upon a foundation of mathematical programming instead of human judgment and simulation alone. PSE should also continue to invest in the human capital necessary to successfully carry out its planning effort."*

Incorporation into Plan: PSE continues to advance its analytical capabilities. Information about improvements to the electric methodology and tools can be found in Chapter X. This plan also marks the initial use of Sendout and Vector Gas models for long-term natural gas resource planning. A complete discussion of the gas methodology and tools can be found in Chapter XIV. PSE believes its plan has a solid analytical and mathematical base. PSE has also improved its internal planning capability. Since the previous plan, PSE has formed an energy resource planning group staffed with six employees.

2. Recommendation - Modeling: *"We anticipate further research and thought in the area of decision-making. The balance of risk between ratepayer and investor clearly affects the resource strategy the Company favors. It also is implicit in the modeling assumptions used. Thus, a continued emphasis is needed on the assessment and balancing of risk throughout managerial decision-making."*

Incorporation into Plan: As part of its long-term risk management project, discussed in Chapter XV, PSE is studying the value customers place on energy price risk.

3. Recommendation - Modeling: *"We want greater transparency in the underlying data, assumptions, and mechanisms modeled in the forecast of natural gas prices at the major Northwest delivery points. If current consultants cannot provide details on the construction of its forecast, then other consultants should be selected."*

Incorporation into Plan: Chapter V provides detail about the short- and long-term gas price forecasts used by PSE. It also provides information about the Company's decision-making process for choosing its long-term forecast, the reasons why PSE does not develop an in-house long-term forecast, and the significant benefits of using a long-term forecast generated by a national firm specializing in natural gas pricing. A representative for CERA spoke on April 14, 2004 to the LCPAG group to provide the background on the gas forecast scenarios.

4. Recommendation - Electricity: *"Although PSE annually updates and frequently reviews its demand forecast, the synthetic assumptions regarding component load shapes is a shortcoming. Some empirical work on component load shapes could make a significant improvement. PSE should explicitly consider some additional load research and end-use modeling."*

Incorporation into Plan: As described in Chapter VI, section B, PSE has updated its methodology for producing hourly load shapes. Since the previous Least Cost Plan, PSE has also completed a Residential Appliance Saturation Survey to inform its estimates of energy efficiency potential and its load forecast.

5. Recommendation - Electricity: *"Gas and electric plans both strongly depend on the forecast of natural gas prices. Better price forecasts would improve both. Price forecasts should be transparent to the reader and should provide sufficient detail to reveal assumptions and methodology. The presentation or accompanying technical appendices should include macroeconomic assumptions, the effects of likely gas pipeline operations, the differences in gas demand in regions of the US, and the process of exploration, development and operations of gas wells. The plan should explicitly describe any underlying models and statistical format. These would include, among others, R-squared, t-statistic, D-W statistic."*

Incorporation into Plan: See response to recommendation 3 above.

6. Recommendation - Electricity: *"The supply alternatives considered cover the major fuel types. However, a longer list of resources would be preferable. The Company should consider specific current technologies at their offered prices, more generic alternatives, and new technologies reasonably close to commercialization. Of course, the option of purchasing new contracts to replace those that expire should be included in the supply alternatives."*

Incorporation into Plan: PSE considers a wide range of generic resource alternatives including emerging technologies in developing its Least Cost Plan. From the range of alternatives, PSE selects proven technologies, representing the various resource types that could be reasonably expected to be included in PSE's portfolio, to evaluate through detailed analytical models. The analytical methodology and generic resource alternatives are set forth in Chapter X. Outside the Least Cost Plan, PSE does further analyses and comparisons of current and emerging technologies.

7. Recommendation - Electricity: *"The research on wind power is very helpful. Additional work should concentrate on reliability issues to determine what extra capacity resource is needed for adequate system reliability. In this matter, we encourage cooperation with other electric utilities and regional bodies."*

Incorporation into Plan: PSE continues to study wind reliability and integration issues. Appendix C provides more details on wind integration issues and costs.

8. Recommendation - Natural Gas: *"The gas planning model used by PSE is respected in the field. However, the model appears to have limited ability to assess and model risk. PSE should carefully consider whether these capabilities can be added to the current model or if a search for new tools should be made."*

Incorporation into Plan: PSE replaced U-Plan-G with Sendout and the risk analysis add-in Vector gas, as well as the required computing infrastructure, for its long-term gas resource modeling needs. Sendout is widely used in the industry, including several other gas utilities in the Pacific Northwest. Vector Gas is a new risk analysis add-in for Sendout. PSE's Least Cost Plan is the first long-term resource plan to use the Vector Gas risk analysis module to analyze price and temperature risk. Additional information about the model can be found in Chapter XIV and Appendix H.

9. Recommendation - Natural Gas: *"A gas design day is a "stress case" which represents an extreme for which planned Company operation will be adequate. In past plans, the Company used a 1-in-50-year standard of extreme weather events, a 55 heating-degree-day observed in 1949-1950. This plan used a 51 heating-degree-day as design day, a 1-in-20-year standard of protection. This change will make PSE's current system capacity, built for 1-in-50 standard, adequate for a longer period of time. It will also allow more capacity to be available for capacity release activity.*

*"Although the change does not seem great in magnitude, the plan was silent as to the effect of this change. The Company has said that the 1-in-20-year is closer to the industry standard. Nevertheless, a study of the benefits and costs of the change, including an assessment for the likelihood of re-light events is needed. PSE should analyze and defend the new gas design day standard in its next plan. For guidance, PSE may want to revisit work done in the TAC meetings surrounding the 1995 Washington Natural Gas Least Cost Plan."*

Incorporation into Plan: PSE performed a probabilistic benefit/cost analysis on peak-day planning standards and updated its planning standard from 51 to 52 HDD. A detailed account of the analysis supporting the new peak day planning standard can be found in Appendix I. It was presented at the LCPAG meeting on June 14, 2004.

10. Recommendation: Natural Gas: *"The Company should explore opportunities for obtaining gas supply contracts at fixed prices for durations of a decade or more. This exploration should be in collaboration with other LDCs in Washington state and the region."*

Incorporation into Plan: The Company has explored the options to secure long-term fix-priced gas supply. Such supplies are beginning to become more available and are described in more detail in Chapter XIII. However, long-term fix-priced gas supply contracts create significant credit issues and counter-party credit management issues, described more in Chapter IV.

11. Natural Gas: *"The area of distribution planning should have contained discussion of the Everett-Delta project as well as the Whidbey LNG facility as examples of detailed specific events for discussion."*

Incorporation into Plan: A robust discussion of distribution planning can be found in Chapter XVI.

12. Conservation: *"The Company expanded its consideration of conservation alternatives in its August 31 [2003] filing. As PSE expands its conservation efforts, we urge the Company to supplement information from the NWPPC database with data and expertise from other organizations and consultants."*

Incorporation into Plan: Chapter VII of this Least Cost Plan describes PSE's planning efforts in the area of demand-side resources. The chapter includes detailed information about the conservation analysis, methodology and results used by PSE in its planning process. For specific information about the main data sources used in these studies, refer to Chapter VII. This Least Cost Plan used information from NWPCC, consultants, and PSE's own expertise to develop its conservation estimates.

Final Report

# Assessment of Technical and Achievable Demand-Side Resource Potentials

***Prepared for:***
Puget Sound Energy

***April 20, 2005***

quantec

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# Acknowledgements

This project was a uniquely complex undertaking and took nearly one year to complete. New methodologies had to be developed to address its many analytic demands. It also required compilation of a large amount of data from multiple sources. We relied heavily on the staff in various departments at Puget Sound Energy, particularly Villamor Gamponia, Bill Donahue, Tom MacLean, Eric Brateng, Robert Yetter, Philip Popoff and Aliza Seelig for data and analytic support. Without their active participation, generous assistance and timely response to our requests for information we could not have met the many challenges of this project.

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Our enduring gratitude goes to our project manager, William Hopkins, who worked closely with us in every step of the way and provided invaluable insight and direction, while allowing us to exercise our independent judgment and to maintain our objectivity.

# Contents

# Tables & Figures

# I. Introduction

This report presents the results of a comprehensive assessment of electric and gas demand-side resource potentials in Puget Sound Energy (PSE) service area. The study was commissioned by PSE in an effort to examine demand-side resources, including energy-efficiency, fuel conversion, and demand-response, that may be incorporated into PSE's 2006-2025, twenty-year Least Cost Plan (LCP). The principal goals of the study were as follows:

- Investigate the "technical" and "achievable" potentials for the complete range of demand-side resources, including energy-efficiency, electric-to-gas fuel conversion, and demand response strategies, taking into account the interactions among various resource options and resource acquisition scenarios.
- Update the results of the 2004-2023 energy efficiency potentials study using more recent market data in the residential, commercial, and industrial sectors in the Company's service area; extend the analysis to the 2006-2025 planning period.[1]
- Employ simple, flexible, and transparent approaches consistent with industry-standard methods consistent with those used by the Northwest Power and Energy Efficiency Council, relying on most recent technical and local market data.
- Create discrete "bundles" of demand-side resource potentials comprised of groups of homogeneous measures and provide supply curves for each bundle that would allow the demand-side resource options to be evaluated against supply options on an equal basis in PSE's least-cost, integrated resource planning process.

Studies such as this require compilation of large amounts of data from multiple sources on existing demand management strategies, technologies, and market dynamics that affect their adoption. They also rely on assumptions concerning the future, particularly changes in demand for energy codes and standards, energy-efficiency technologies, market conditions, and consumer behavior. It is, therefore, inevitable that the findings of this study will have to be revisited periodically to take into account the impacts of emerging technologies and the changing dynamics of the energy markets.

## Demand-Side Resource Definitions

The overall approach in this study distinguishes between two distinct, yet related, definitions of resource potential that are widely used in utility resource planning: 1) "technical potential" and 2) "achievable potential." Technical potential assumes that all demand-side resource opportunities may be captured regardless of their costs or market barriers. Achievable potential, on the other hand, represents that portion of technical potential that is likely to be available over the planning horizon given resource costs, prevailing market barriers and administrative program costs that may limit the implementation of demand-side measures. For the purpose of this study, "achievable" energy-efficiency and fuel conversion potentials are defined as that portion of technical savings potentials that can be acquired under prevailing barriers that prevent a full market penetration and at a levelized per-unit cost of less than 11.5 cents per kWh for electricity and less 1.05 dollars per therm for gas inclusive of program administration and delivery costs.

## General Approach

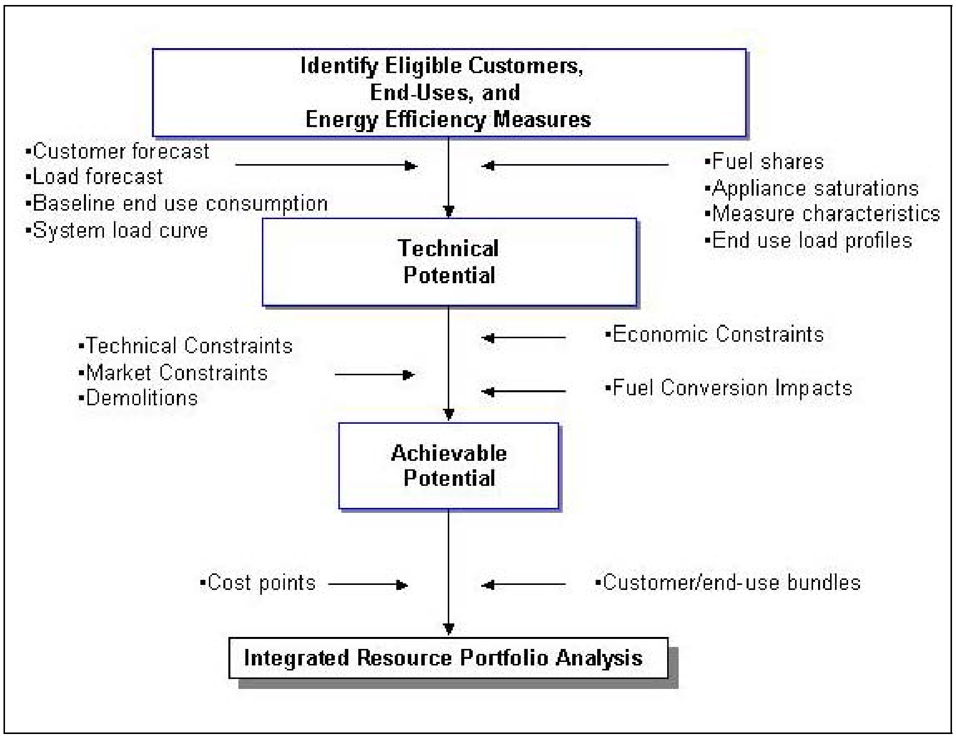
The general methodology and analytic techniques in this study conform to standard practices and methods used in the utility industry. Given the scope and analytic requirements of this study, it was necessary to devise a methodology and the necessary tools that could effectively address the complexities of evaluating long-term potentials for each of the three demand-side management resource acquisition strategies, namely gas and electric energy-efficiency, electric-to-gas- fuel conversion, and demand response, while taking into account the interactions among them.

---

1 In 2003, PSE commissioned a study to investigate the "technical" and "achievable" electric and gas conservation potentials in its service area for the 2004-2023 planning horizon, as part of its 2003 least-cost planning process. The results of that study were filed with the Washington Utilities and Transportation Commission in the August 2003 update to PSE's Least Cost Plan, originally filed in April 2003 under Docket UE-030594.

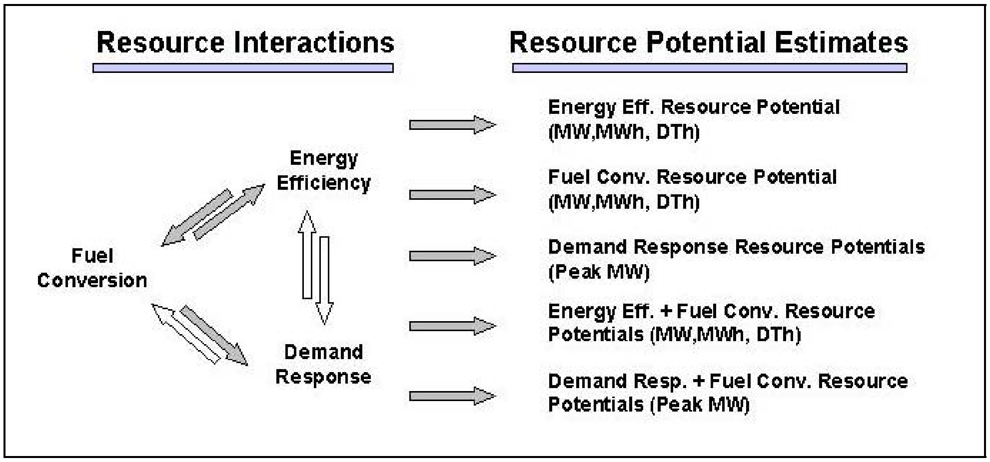
The unique characteristics of specific demand-side resources notwithstanding, the general methodology in this study is best described as a combined "top-down/bottom-up" approach that begins with the current load forecast, decomposes it into its constituent customer class and end-use components, and examines the effect of the range of energy efficiency technologies and strategies on each end use, while taking into account fuel shares, current market saturations, technical feasibility, and economic viability. These unique impacts are then aggregated to produce energy efficiency potentials at the end-use, customer class, and system levels. This general methodology is diagrammatically presented in Figure I.1.

**Figure I.1: General Methodology for Assessment of Demand-Side Resource Potentials**




Technical interactions among the three demand-side resources, particularly energy-efficiency and fuel conversion and, to a lesser extent, energy-efficiency and demand-response, posed a further methodological challenge in this study. Due to their inherently unique characteristics and types of load impacts that they generate, analyses of energy-efficiency, fuel conversion, and demand response potentials necessarily require different methodologies and data. While capable of producing reliable estimates for each demand-side resource individually, these methodologies must also have the capability to accurately account for interactions among these resources, particularly capturing the effects of fuel conversion on electric energy efficiency potentials.

**Figure I.2: Demand-Side Resource Interactions**




## Organization of this Report

This document is organized in five parts. Part II describes the methodology, data sources, and results of electric and gas resource assessments. Part III is devoted to the analysis of fuel conversion potentials. Part IV presents development of the resource bundles and acquisition scenarios used in PSE's integrated resource portfolio analysis. The results of the analysis of demand-response potentials are presented in Part V. Data, assumptions, and other supporting material used in this study are presented in the Appendices A through D.

# *II. Energy-Efficiency Resource Potentials*

## Scope

The principle objective in the analysis of energy efficiency potentials was to obtain reasonable and reliable estimates of long-run opportunities for energy-efficiency opportunities throughout PSE's service area. Energy efficiency resource potentials for electricity and gas were analyzed for the residential, commercial, and industrial sectors. Six residential segments (existing and new construction single-family, multi-family, and manufactured homes) and 20 commercial segments (ten building types within the existing and new structure segments each) were considered.

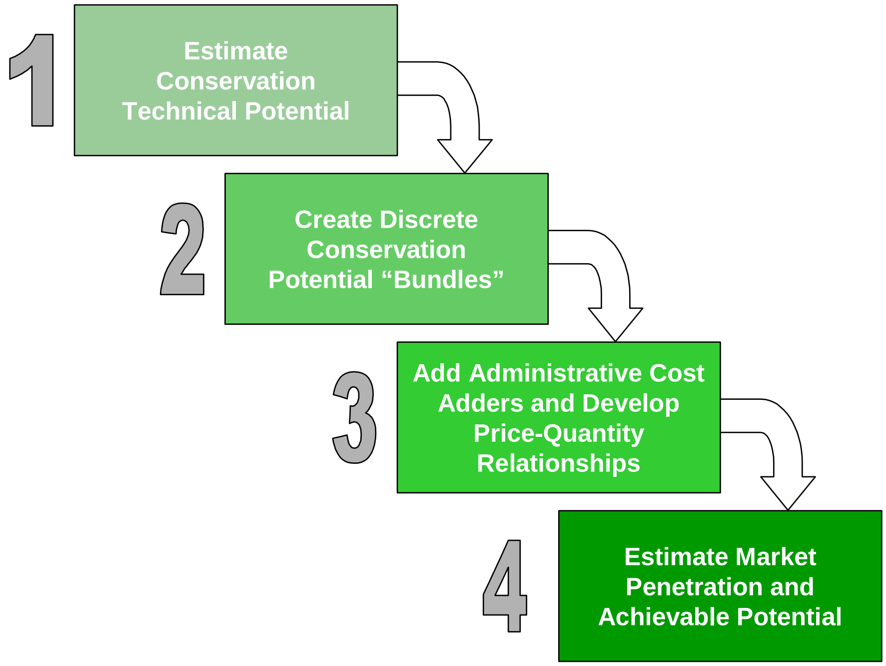
## Methodology

As shown diagrammatically in Figure II.1, the general approach for derivation of energy efficiency resource potentials consisted of four sequential steps:

- Estimate technical energy efficiency potential
- Create discrete energy efficiency potential "bundles"
- Add administrative cost adders and develop price-quantity relationships
- Estimate market penetration and achievable potential

***1) Estimate technical energy efficiency potential***: Technical energy efficiency potentials were derived using either a "bottom-up" or a "top-down" approach. The bottom-up analysis, which was applied to the residential and commercial sectors, integrated measure-specific data (per-unit costs, absolute and relative savings, impacts by time period) with baseline building stock data (base- case fuel saturations, measure saturations, feasibility factors) and baseline energy-use data to produce estimates of levelized per-unit resource cost ($/kWh and $/therm) and total savings for each measure included in the analysis. This analysis was conducted using Quantec's ForecastPro® model, described later in this section.

**Figure II.1: Methodological Approach**




The top-down analysis, which was applied to the industrial sector, first disaggregates loads into end uses and industrial classification. It then applies the data on overall percentage savings at the industry/end-use level, as well as costs and measure life, to produce levelized costs and total savings.

The rate and timing of equipment replacement are important considerations in estimating energy efficiency potentials. In this study, technical energy efficiency potentials were analyzed under two scenarios depending on assumed timing of equipment replacement:

- Instantaneous technical potential (early equipment replacement) assumes savings from a total, instantaneous conversion to the most energy-efficient technologies and measures. All equipment is converted immediately in this hypothetical case regardless of the age of the equipment.
- Phase-in technical potential (normal equipment replacement) assumes savings from conversion to the most energy-efficient technologies and measures when equipment is replaced at the end of its useful life (or upon burnout). The distinction between early and normal replacement options has important implications for planning and timing of how energy efficiency resources are acquired over time, and is used in

developing the alternative energy efficiency acquisition scenarios. It is important to note, however, that in the long run, such as the 20-year plan developed by PSE, the two estimates converge.

***2) Create discrete energy efficiency potential "bundles:"*** Measure-specific technical potentials were aggregated into unique cost-based resource "bundles" that are homogeneous with respect to customer sectors, markets segment, and end-use load shapes.[2]

Economic potential is typically viewed as a subset of technical potential, which includes only those measures that pass a certain cost threshold or economic criterion based on the utility's avoided generation costs. However, the notion of economic potential relates to resource planning efforts where energy efficiency resources are analyzed separately from supply side resources. PSE's integrated resource planning (IRP) effort obviates the need to apply such a screen. The price-quantity combinations in the bundles provide the information needed to dynamically evaluate energy efficiency resource economics within the IRP process.

***3) Add administrative cost adders and develop price-quantity relationships***: This step involved adjusting per/unit costs of each energy-efficiency measure reflecting program design, administration, and delivery costs. Measure-specific savings were then grouped in price-quantity combinations. The resulting "supply curves" provided discrete blocks of energy efficiency potential within each bundle. Consistent with past PSE program experience, a program administration and delivery cost adder was applied to each measure/bundle combination, resulting in minor shifts of the price-quantity relationships (supply curves) within the technical potential bundles.

***4) Estimate market penetration and achievable potential***: The last step in this approach consists of estimating market diffusion rates for each resource bundle taking into account potential market barriers based on data available from past program experiences with similar measures. These estimates are then applied to the price-

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[2] The industrial sector has one bundle each for electric and gas savings due to the lack of data on specific load shapes for the wide variety industrial process loads.

quantity combinations to derive estimates of “achievable” potential for each resource bundle within PSE service area.

Expected market penetration rates, derived from industry literature, previous planning studies, and energy-efficiency program evaluations conducted by Quantec and PSE’s previous programmatic experiences as recorded in the company’s tracking system, were used to derive estimates of achievable potential. These estimates take into account the company’s ability to ramp up programs and customers’ willingness to adopt measures assuming incentives fully cover all incremental energy efficiency measure costs. Finally, since very high cost measures were unlikely to be selected by the IRP model, all measures with a per-unit cost of conserved energy in excess of 11.5 cents per kWh for electricity, and 1.05 dollars per therm for gas were excluded from further analysis.

Since the impacts of price-induced conservation and the impacts of previous energy-efficiency programs are implicitly captured in PSE’s load forecast, no further adjustments were made to account for the effects of “naturally-occurring” energy efficiency in this study.

## Residential and Commercial Sector Bottom-Up Approach

### Measures Considered

In the residential and commercial sectors, energy efficiency resource potentials were derived based on an analysis of 127 *unique* electric measures and 62 *unique* gas measures. Since many of the energy efficiency measures are applied to multiple segments and building types, a total of 1,756 electric and 736 gas measure/structure combinations were included in the analysis. All major end uses in all 15 major industrial segments in PSE’s service area, including wastewater treatment, were analyzed.

The Northwest Power and Conservation Council was the primary source for electric measures in the residential and commercial sectors. This list was augmented by additional measures from the California Energy Commission’s Database on Energy Efficiency Resources (DEER). The list of gas measures in all sectors was compiled mainly from DEER. A complete list of measures and their sources are provided in Appendix A.

As a preliminary screening criterion, only measures that are commonly available, based on well understood technology, and applicable to the buildings and end-uses in PSE's area were included in the analysis. The residential and commercial segments and end uses considered in this study are shown in Tables II.1 and II.2, respectively.

**Table II.1: Residential Dwelling Types and End Uses**[3]

| Segments | Electric End Uses | Gas End Uses |
|---|---|---|
| Single Family | Central AC | Cooking |
| Multifamily | Cooking | Drying |
| Manufactured | Drying | Space Heat |
| | Freezer | Water Heat |
| | Heat Pump | Other |
| | Lighting | |
| | Plug Loads | |
| | Refrigeration | |
| | Room AC | |
| | Space Heat | |
| | Water Heat | |
| | Other | |

**Table II.2: Commercial Building Types and End Uses**[4]

| Segments | Electric End Uses | Gas End Uses |
|---|---|---|
| Office | Cooking | Cooking |
| Dry Goods Retail | Cooling | Pool Heat |
| Restaurant | Space Heat | Space Heat |
| Grocery | Lighting | Water Heat |
| Warehouse | Plug Load | Other |
| School | Refrigeration | |
| University | Ventilation | |
| Hospital & Heath Care | Water Heat | |
| Hotel | Other | |
| Miscellaneous | | |

3 Clothes washer and dishwasher measures are modeled within the water heat end use.

4 The PSE model has further breakouts by type of lighting (e.g., 2 foot, 4-foot, 8-foot, outdoor) and cooling (e.g., chillers, packaged, heat pump) systems.

## Data Modeling

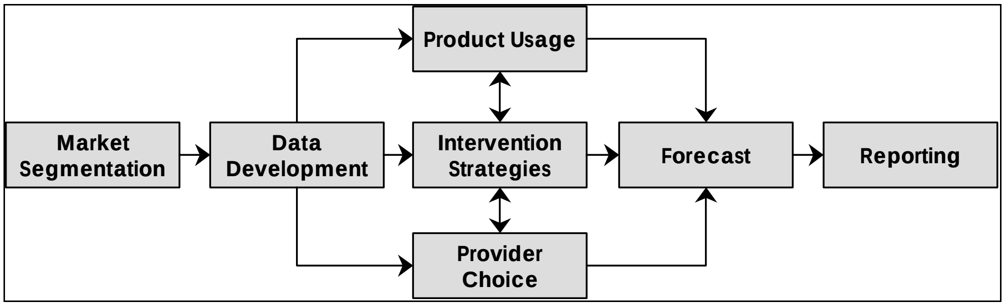
Concurrent assessment of energy-efficiency and fuel-conversion resource potentials poses significant analytic challenges. Due to their inherently unique characteristics and the types of load impacts that they generate, analyses of energy efficiency and fuel conversion necessarily require different methodologies and data. While capable of producing reliable estimates for each demand-side resource individually, these methodologies must also have the capability to accurately account for interactions among these resources, particularly capturing the effects of fuel conversion on gas and electric energy efficiency potentials.

Estimates of technical energy-efficiency and fuel conversion potential for the residential and commercial sectors were derived using Quantec's ForecastPro® model, a SAS-based proprietary electric and gas end-use forecasting and energy efficiency potentials assessment tool. The conceptual underpinnings and analytic procedures of this model are based on standard practices in the utility industry and are consistent with the methods used by the Northwest Power and Conservation Council in its assessment of regional electric conservation potentials.

For each customer class, application of the model involves three steps: 1) producing separate, end use-specific forecasts of loads over the 20-year planning horizon and calibrating the end-use forecasts to PSE's 20-year aggregate customer class forecasts to ensure consistency between the two, 2) producing a second forecast for each end use that incorporates saturations and energy impacts of all feasible energy-efficiency and fuel conversion measures, and 3) calculating technical potentials by end use and measure as the difference between the two forecasts.

Algorithms used in the model follow a standard bottom-up approach that is implemented through seven operating modules: Market Segmentation, Data Development, Product Usage, Provider Choice, Intervention Strategies, Forecasting, and Reporting (see Figure II.2).

**Figure II.2: ForecastPro® Modules and Structure**




Product Usage, Provider Choice, Intervention Strategies, and Forecast modules are the main analytic components of the Model. The Product Usage module tracks the unit energy consumption (UEC) by end use equipment, taking into account building type, fuel type, equipment vintage, and efficiency level. The Provider Choice module focuses on customers' choice of equipment as a nested function of fuel type and efficiency levels. The Intervention Strategies module captures the impacts of alternative energy efficiency strategies on the usage, market shares, and the resulting demand for energy by fuel type. Three general classes of impacts may be modeled:

- ***Equipment Efficiency***. These scenarios modify efficiency shares. The technical potential scenario assigns a 100% share to the most efficient equipment level for each end use, while the achievable potential scenario assigns less than a 100% share to the most efficient option.
- ***Usage Retrofit***. These scenarios reduce energy usage given the equipment customers already have (e.g., improve the efficiency of existing equipment by installing retrofit efficiency measures or through better O&M procedures).
- ***Fuel Conversion***. These scenarios modify the forecasted choices or market shares among fuel sources. Separate sets of assumptions are applied to existing and new construction buildings.[5]

Finally, the Forecast Module incorporates all the information compiled from the other modules – Usage, Choice, and Intervention Strategies – related to the overall economic growth of the market segment and equipment lifetime (decay) functions to create final forecasts under alternative scenarios.

### Application of ForecastPro®

Energy efficiency potentials in the residential and commercial sectors were estimated in four sequential steps described below.

***1) Develop Base Case Forecast:*** The base case end-use forecast was calibrated to PSE's econometric energy sales forecasts and appliance and equipment saturations from commercial and residential surveys. This step provides an estimate of future energy consumption in the absence of new energy efficiency programs. It establishes a benchmark against which the impacts of the phase-in technical and achievable energy-efficiency potentials can be assessed. The effects of equipment standards and naturally occurring efficiency improvements, which emanate from the reduction of usage as low-efficiency equipment is retired, are also taken into account in the base case forcast.

***2) Determine Measure Impacts:*** This step involved integrating measure-specific data (per-unit costs, savings, and measure life) with baseline building stock data (base-case fuel saturations, measure applicability factors, current measure saturations) and base case-calibrated energy usage data to produce estimates of levelized costs per unit of conserved energy.

***3) Estimate Phased-In Technical Potential:*** Technical potential for energy efficiency was then estimated through the Intervention Strategies module, which effectively overrides the Base Case energy usage and market equipment efficiency shares. Alternative scenarios are incorporated directly into the relevant Product Usage and Provider Choice forecasts. Phased-in technical potentials were calculated by subtracting the energy forecast associated with the highest possible penetration of energy-efficiency measures from the base case forecast.

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[5] The Fuel Conversion scenarios for PSE's Residential electric sector are described in Section III of this report.

***4) Estimate Achievable Potential and Create Resource Bundles:*** Achievable potentials were developed using the levelized cost thresholds and assumed market penetration rates. As with technical potential, alternative usage and choice forecast scenarios were developed, and the potential was calculated by subtracting this forecast from the base case forecast. The impacts are then aggregated into bundles and integrated into the LCP model for further resource screening and analysis.

**Base Case Forecast Calibration**

An accurate assessment of energy efficiency potential requires that base conditions closely approximate the historical sales and the load forecast. In this study calibration was achieved by reconciling end-use estimates to PSE's 2006-2025 sector-level, weather-normalized forecasts. In each market segment, end use energy consumption is calculated in each forecast year as:

$$EUSE_{ijf} = ACCTS_i \times UPA_i \times SAT_{ij} \times FSH_{ijf} \times ESH_{ijfe} \times EUI_{ijfe} \text{ ,}$$

where,

$EUSE_{ijf}$ = total energy consumption for end use *j* in building type *i* using fuel *f*

$ACCTS_i$ = the number of accounts/customers in segment *i*

$UPA_i$ = the units per account in segment *i* (average floorspace per account in commercial segments, number of dwellings in the residential sector)

$SAT_{ij}$ = share of customers in segment *i* with by end use j

$FSH_{ijf}$ = share of fuel *f* in end use *j* in segment *i*

$ESH_{ijfe}$ = market share of the equipment with efficiency level *e* in the equipment segment *ijf*

$EUI_{ijfe}$ = energy consumption per unit ($Ft^2$ floorspace for commercial, number of dwellings for residential) use by the equipment configuration *ijfe*

The formulation above is the basis for determining the effects of energy-efficiency measures at the end-use level and simply states that energy use for each end-use within customer and building type is a function of change in the above variables. Annual base case forecast is then derived as the sum of $EUSE_{ijf}$ across all segments and end uses. The total number of residential and commercial customers was obtained from PSE's

January 2005 sales and customer forecast. Net customer growth was calculated by adjusting new construction forecasts by expected demolition rates in existing structures.[6]

The share of residential customers across the single- family, multi-family, and manufactured segments were derived by applying their respective shares from PSE's 2004 Residential Appliance Saturation Survey (RASS) to the residential sector customer forecast totals. These shares are assumed to remain constant over the forecast horizon. Commercial building shares were derived from the 2002 Northwest Commercial Building Stock Assessment (CBSA), focusing on buildings in PSE's service area.[7] The RASS and CBSA data were also used to develop building-specific square footage profiles, equipment saturations, and fuel and efficiency shares.

The calibration process resulted in average adjustments of +0.1% for electricity and +8.9% for gas EUI's in the residential sector and +4.4% and –10.6%for electricity and gas, respectively, in the commercial sector.

**Calculation of Retrofit and Replacement Measure Savings**

The basic equation for estimating retrofit energy efficiency measure savings follows industry standards and is unchanged from PSE's 2003 Least Cost Plan:

$$SAVE_{ijfm} = EUI_{ijfe} \times PCTSAV_{ijfem} \times APPFACTOR_{ijfem} \times INCFACTOR_{ijfem} \text{ ,}$$

where:

$SAVE_{ijfm}$ = annual energy savings for measure m for end-use j in building type i using fuel f

$EUI_{ijfe}$ = calibrated annual end-use energy consumption for the equipment configuration ijfe

$PCTSAV_{ijfem}$ = is the percentage savings of measure m relative to the base usage for the equipment configuration ijfe, taking into account measure interactions such as lighting and HVAC

[6] Annual residential building demolitions are estimated at 0.8%, while commercial demolitions are estimated at 0.37%.

[7] 2002 Commercial Building Stock Assessment, Northwest Energy Efficiency Alliance report.

*$APPFACTOR_{ijfem}$* = is the fraction of the floor space or households that is applicable to install measure m. For non-competing measures, which are primarily non-lighting, this estimate is generally close to 100%, with lesser amounts due to engineering limitations (for example, the share of buildings with enough room in the wall cavities to install additional insulation). For competing measures within an end use, such as various types of lighting retrofits, this factor is used to represent the share of the end use associated with the measure.

*$INCFACTOR_{ijfem}$* = fraction of the applicable end-use, floorspace or households that has not yet been converted to measure m.

## Measure Stacking and Interaction Effects

Stacking effects occur as a result of sequential ordering of *complementary* retrofit measures such as wall, ceiling, and floor insulation are applied to a single end use. Since measure savings are always calculated in terms of reductions in end use consumption, clearly, installation of one measure will reduce the savings potentials of subsequent measures. To incorporate stacking effects it is necessary to establish a rolling, reduced baseline as each new measure is added. This is shown in equations 3 through 5, where measures 1, 2, and 3 are applied to end use ijfe:

*(1)*

$$SAVE_{ijf\,1} = EUI_{ijfe} \times PCTSAV_{ijfe1} \times APPFACTOR_{ijfe1} \times INCFACTOR_{ijfe1}$$

*(2)*

$$SAVE_{ijf\,2} = (EUI_{ijfe} - SAVE_{ijf\,1}) \times PCTSAV_{ijfe2} \times APPFACTOR_{ijfe2} \times INCFACTOR_{ijfe2}$$

*(3)*

$$SAVE_{ijf\,3} = (EUI_{ijfe} - SAVE_{ijf\,1} - SAVE_{ijf\,2}) \times PCTSAV_{ijfe3} \times APPFACTOR_{ijfe3} \times INCFACTOR_{ijfe3}$$

A similar effect occurs when different measures compete for the same end use (e.g. retrofit and replacement opportunities). As with the stacking effect, if retrofit opportunities are captured first, replacement of existing equipment with high-efficiency equipment can be expected to have a smaller impact on EUI than it would have had the replacement take place first. Clearly, the ordering of complementary measures and retrofit versus replacement decisions depend on practical considerations concerning energy-efficiency program design and implementation. For the purposes of this study, it was assumed that measures with the highest savings opportunities would be implemented first and retrofits will always precede equipment replacement.

## Industrial Sector Top-Down Approach

Due to the more complex nature of the industrial market, end uses, and equipment on the one hand, and the lack of reliable information on measure-specific saturations on the other, energy efficiency potential in the industrial sector was analyzed using an alternative, top-down approach involving two steps. First, total firm industrial loads were disaggregated into standard SIC classes based on PSE's 2003 sales data. PSE's total industrial loads were further broken into major end uses within each class using data from the U.S. Department of Energy, Energy Information Administration.[8] Table II.3 shows the SICs and the electric and gas end uses considered in the analysis. Second, for each end use, we estimated potential savings and per-unit cost of the potential savings, relying on available data from a large number of industrial energy-efficiency programs in the Northwest and California, and market information on PSE's customers available from industrial accounts representatives.

8 See Us Department of Energy, Energy Information Administration, Manufacturing Energy Consumption Survey.

**Table II.3: Industrial Segments and End Uses**

| Segments | Electric End Uses | Gas End Uses |
|---|---|---|
| Food/kindred products | HVAC | HVAC |
| Lumber/wood products | Indirect boiler | Process boiler (upgrade/controls/ht recovery) |
| Paper/allied products | Lighting | Process boiler O&M |
| Printing/publishing | Motors (excluding compressed air O&M) | Process heat |
| Chemical/allied products | Motors compressed air O&M | Process other |
| Petroleum related | Electrochemical Process | Steam distribution systems |
| Rubber/plastics products | Process heat | Other |
| Stone/clay/glass/concrete products | Process other | |
| Primary metal industries | Refrigeration/process cooling | |
| Fabricated metal products | Other | |
| Machinery, except electrical | | |
| Electric/electronic equipment | | |
| Transportation equipment | | |
| Instruments/related products | | |
| Water and Wastewater | | |
| Miscellaneous | | |

### Measure Aggregation

Equal treatment of demand-side and supply options is a fundamental principle of integrated resource planning. Since individual energy-efficiency measures produce relatively small savings, they cannot compete effectively with large supply-side options. To create an even playing field, these measures must be combined into large-enough blocks that they are comparable in size to supply options. For the purposes of this analysis, all energy-efficiency measures were aggregated into six bundles with similar end-use and load shape characteristics Table II.4 shows the bundle assignments for the residential and commercial sectors. All industrial measures were assigned to a single bundle.

**Table II.4: Residential and Commercial Bundles**

| Bundle | End-Uses | |
|---|---|---|
| | Electric | Gas |
| HVAC | Space Heat, Heat Pumps, Central and Room Air Conditioners | NA |
| Lighting | Lighting | NA |
| Water Heating | Water Heat | NA |
| Appliances & Plug Loads | Cooking, Drying, Freezer, Refrigerator, Plug Loads | NA |
| Space Heat | NA | Furnaces |
| Base Load | NA | Cooking, Drying, Water Heat |

Each bundle is comprised of multiple price-quantity points. The price component of each bundle represents the levelized cost of conserved energy inclusive of incremental measure costs (material & installation), program administration and implementation costs, and quantifiable avoided non-energy O&M costs or savings. Electric and gas energy-efficiency measures were respectively aggregated into nine electric and eight gas cost categories shown in Tables II.5 and II.6.

**Table II.5: Electric Price-Quantity Combinations**

| **Block** (Price-Quantity Combination) | **Measure Levelized Cost Thresholds** |
|---|---|
| Cost Level A | ≤ $0.045/kWh |
| Cost Level B | $0.045 to $0.055/kWh |
| Cost Level C | $0.055 to $0.065/kWh |
| Cost Level D | $0.065 to $0.075/kWh |
| Cost Level E | $0.075 to $0.085/kWh |
| Cost Level F | $0.085 to $0.095/kWh |
| Cost Level G | $0.095 to $0.105/kWh |
| Cost Level H | $0.105 to $0.115/kWh |
| Cost Level I | > $0.115/kWh |

**Table II.6: Gas Price-Quantity Combinations**

| **Block** (Price-Quantity Combination) | **Measure Levelized Cost Thresholds** |
|---|---|
| Cost Level A | ≤ $0.45/therm |
| Cost Level B | $0.45 to $0.55/therm |
| Cost Level C | $0.55 to $0.65/therm |
| Cost Level D | $0.65 to $0.75/therm |
| Cost Level E | $0.75 to $0.85/therm |
| Cost Level F | $0.85 to $0.95/therm |
| Cost Level G | $0.95 to $1.05/therm |
| Cost Level H | > $1.05/therm |

### Determination of Achievable Potentials

A variety of factors affect market penetration of energy-efficiency measures, including inherent market barriers resulting from the customers' tendency to avoid the potential administrative and financial burdens, program marketing strategies, and delivery mechanisms. This is why some energy-efficiency programs, even with full incremental cost incentives, can have a wide range of penetration rates, seldom achieving full market saturation. The available information suggests that, although incentive levels do play a significant role in determining program success, other, non-financial factors may play an equal, if not more important, role.

Estimates of market penetration in this study were based on the expectation of what full incremental cost rebates, consistent with a 10% administrative cost adder, are likely achieve on average. The penetration rates for electric and gas potential across end-use bundles are reported in Tables II.7 and II.8, respectively. All of the rates range from 30% to 60%, with the great majority set equal to 50% of technical potential.

**Table II.7: Penetration Rates for Electric Bundles**

| Sector/Vintage | Appliances | HVAC | Lighting | Water Heat |
|---|---|---|---|---|
| **Commercial** | | | | |
| Existing | 50% | 50% | 50% | 50% |
| New Construction | 50% | 50% | 50% | 50% |
| **Residential** | | | | |
| Existing | 60% | 60% | 30% | 60% |
| New Construction | 50% | 50% | 50% | 50% |
| **Industrial** | | | | |
| All | 50% | 50% | 50% | 50% |

**Table II.8: Penetration Rates for Gas Bundles**

| Sector/Vintage | Appliances | HVAC | Lighting | Water Heat |
|---|---|---|---|---|
| **Commercial** | | | | |
| Existing | 50% | 50% | 50% | 50% |
| New Construction | 50% | 50% | 50% | 50% |
| **Residential** | | | | |
| Existing | 60% | 60% | 60% | 60% |
| New Construction | 50% | 50% | 50% | 50% |
| **Industrial** | | | | |
| All | 50% | 50% | 50% | 50% |

## Data Sources

The full assessment of energy efficiency resource potentials required compilation of a large database of measure-specific technical, economic, and market data from a large number of primary and secondary sources. The main sources of data used in this study included, but were not limited to, the following.

1. ***Puget Sound Energy***: Latest load forecasts, load shapes, economic assumptions, historical energy efficiency and load management program activities, 2004 residential appliance saturation survey (RASS) designed with a particular emphasis on obtaining market to support this study, and the Commercial Building Stock Assessment (CBSA) - a study of the Northwest's commercial building characteristics sponsored jointly by the Bonneville Power Administration, the Northwest Energy

Efficiency Alliance, and PSE. A complete list of data elements provided by PSE is shown in Table II.9.

**Table II.9: PSE Data Sources**

| PSE Data Source | Key Variables | Use in This Study |
|---|---|---|
| 2005 Load Forecasts: Gas and Electric; Commercial, Residential and Industrial | Energy and Peak Forecasts, Customer Counts, Employment and Population Forecasts | Base Case Calibration, Energy efficiency Potential Share of Forecast, Per Customer Use for Calibration, New Construction Forecast |
| Energy efficiency Tracking Database | Energy efficiency Measures Installed Between 1990 and 2004 | Incomplete Factors |
| 2004 Residential Energy Study (RASS) | Dwelling Characteristics, Equipment Saturations, and Fuel Shares | Dwelling Type Breakouts, Square Footage per Dwelling, Applicability Factors, Incomplete Factors, Forecast Calibration |
| 2003 Commercial Building Stock Assessment (CBSA) | Building Characteristics, Equipment Saturations, and Fuel Shares | Building Type Breakouts, Square Footage per Dwelling, Applicability Factors, Incomplete Factors, Forecast Calibration |
| 2003 Least Cost Plan | Equipment Usage, Measure Characteristics | Starting Values for Residential (UEC) and Commercial (EUI) End Use Consumption Estimates, Starting Values for Measure Characteristics (savings, cost, life) |

2. ***Pacific Northwest Energy Studies*****:** Several entities in Northwest provided data critical to this study, including the Northwest Power and Conservation Council (NWPCC), the Regional Technical Forum (RTF), the Northwest Energy Efficiency Alliance (the Alliance), and Tacoma Public Utilities (TPU). This information included technical information on measure savings, costs and lives, hourly end-use load shapes, and commercial building and energy characteristics. Details are provided in Table II.10.

**Table II.10: Pacific Northwest Data Sources**

| Pacific Northwest Data Source | Key Variables | Use in This Study |
|---|---|---|
| NWPCC 2004 Power Plan | Measure Data, Energy efficiency Potential Estimates | Measure Savings, Costs and Lives, and Cross-Check of PSE Potential Estimates |
| NWPPP Hourly Electric Load Model (HELM) | Hourly Load Shapes | Hourly End-Use Load Shapes for Residential, Commercial, and Industrial Sectors |
| RTF Web Site | Measure Data | Measure Savings, Costs and Lives |
| TPU Hourly Electric Load Model (HELM) | Hourly Load Shapes | Hourly End-Use Load Shapes for the Residential Sector |
| Alliance 2004 Commercial buildings Stock Assessment (in progress) | Building Characteristics, Equipment Saturations, and Fuel Shares | Building Type Breakouts, Square Footage per Building, Applicability Factors, Incomplete Factors, Forecast Calibration |
| 2002 Clean Electricity Options for the Pacific Northwest: An Assessment of Efficiency and Renewable Potentials through the Year 2020 (Tellus Institute report prepared for the NW Energy Coalition | Conservation Program Market Penetration Estimates | Energy efficiency Bundle Market Penetration Estimates |

3. ***California Energy Commission*:** This study relied heavily on information available through DEER. These data included information on energy-efficiency measure costs and savings, measure applicability factors, and technical feasibility factors. The list of gas measures in all sectors was compiled mainly from DEER.

4. ***Equipment Vendors:*** Cost data for various measures were compiled from the original sources and, where necessary, updated based on most recent information available from regional equipment suppliers.

5. ***Ancillary Sources:*** Other data sources consisted primarily of available information from past energy efficiency market studies, energy efficiency potential studies and evaluations of energy-efficiency programs in the Northwest and elsewhere in the country. The U.S. Department of Energy, Energy Information Administration Office of Industrial Technologies was a primary source for information on the industrial sector.

## Summary of the Results

Based on the results of this study, cumulative 20-year technical energy efficiency potentials in PSE's service area are estimated at 895.5 aMW (average megaWatts) of electricity and 38,223,912 decatherms of natural gas savings, of which 297 aMW (33%) and 10,788,029 decatherms (28%) are expected to be achievable. Achievable savings represent 9.3% of the electric load and 8.6% of projected gas use over the 2006-2025, 20-year planning period.

As shown in Table II.11, the commercial sector accounts for the largest share of achievable electricity savings (147.6 aMW), followed by the residential sector (133.4 aMW) over 20 years. The industrial sector accounts for 15.9 aMW of electricity savings during the same period.

**Table II.11: 2006 - 2025 Electric Technical and Achievable Potential**

| Sector | 2025 Total Load (aMW) | 20-Year Cumulative Potential (aMW/% of Baseline) | |
|---|---|---|---|
| | | Technical | Achievable |
| Residential | 1,450 | 375.8 | 133.4 |
| | | 26% | 9% |
| Commercial | 1,578 | 503.7 | 147.6 |
| | | 32% | 9% |
| Industrial | 158 | 15.9 | 15.9 |
| | | 10% | 10% |
| ***Total*** | ***3,186*** | ***895.4*** | ***296.9*** |

The largest share of achievable natural gas potential is expected to be in the residential sector, which accounts for nearly 60% of total achievable natural gas savings. The commercial and industrial sectors respectively account for 37% and 3% of the achievable gas energy efficiency potential, respectively (see Table II.12).

The estimated amount of achievable electric energy efficiency potential in PSE service area is largely consistent with regional estimates provided in the Northwest Power and Conservation Council's 5th Northwest Regional Electric Power and Conservation Plan. Based on the Council's "medium-case" forecast, 2,797 aMW of achievable electric energy efficiency potential is likely to be available regionally by the year 2025. The 297 aMW of achievable potential by PSE resulting from this assessment represents nearly 11% of the 2,797 aMW regional potential.

**Table II.12: 2006 – 2025 Natural Gas Technical and Achievable Potential**

| Sector | 2025 Total Gas Sales (dth) | 20-Year Cumulative Potential (dth as % of Baseline) | |
|---|---|---|---|
| | | **Technical** | **Achievable** |
| Residential | 75,278,759 | 27,738,747 | 6,334,280 |
| | | *36.8%* | *8.4%* |
| Commercial | 42,637,285 | 10,170,241 | 3,864,537 |
| | | *23.9%* | *9.1%* |
| Industrial | 4,028,666 | 314,924 | 314,924 |
| | | *7.8%* | *7.8%* |
| ***Total*** | ***121,944,710*** | ***38,223,912*** | ***10,513,741*** |

This relatively small variance may be the result of a number of factors including, among others, differences in customer mix, fuel saturation and levels of past conservation activity, and market conditions that affect customers' acceptance of energy efficiency measures. It also stems from the Council's use of a 4% discount rate in its economic screening of energy efficiency measures, which is lower than the 7.5% discount rate used in this study. Since the levelized, per-unit cost of conserved energy is a major criterion for defining "achievable" potential, use of the higher discount rate reduces long-term achievable energy savings by increasing the per unit cost of some technical potential above the $0.115 per kWh achievable potential threshold used in this assessment. This effect is also evidenced by the fact that PSE's estimates of technical energy efficiency potential relative to its load are indeed higher than those of the Council.

**Residential Sector**

Technical electric energy efficiency potentials in the residential sector are estimated at 376 aMW over the 2006-2025 planning horizon, 133.4 aMW (36%) of which is expected to be achievable (see Table II.13). Technical and achievable electric energy efficiency potentials in the residential sector represent nearly 26% and 9.2% of the residential load forecast in 2025. Nearly 60% of all achievable electric energy efficiency potentials fall in the low-cost category of less than 4.5 cents per kWh. As shown in Figure II.3, savings in lighting, achieved mainly through installation of energy-efficient lighting technologies such as compact fluorescent light bulbs and fixtures, represent the largest electric energy efficiency potential in the residential sector, accounting for 42% of the sector's achievable savings. The results also show that about 24% of achievable savings in the residential sector may be obtained through installation of measures to improve space-heating performance such as insulation, weatherization, and equipment replacement. The remaining savings can be achieved through the implementation of water-heating measures such as water heating equipment upgrade (20%), installation of ENERGY STAR®-rated appliances (13%), and cooling measures (1%). The largest portion (68%) of electric energy-efficiency potentials are in single-family dwellings (Figure II.4).

**Table II.13: Distributions of Residential Sector Electric Energy Efficiency Potentials by Cost Category**

| **Cost Category** ($/kWh) | **Technical Potential** | | **Achievable Potential** | |
|---|---|---|---|---|
| | 2025 aMW | % | 2025 aMW | % |
| **Categories** | | | | |
| A: less than $0.045 | 182.2 | 48% | 79.0 | 59% |
| B: $0.045 to $0.055 | 1.4 | 0% | 0.8 | 1% |
| C: $0.055 to $0.065 | 8.7 | 2% | 4.5 | 3% |
| D: $0.065 to $0.075 | 21.4 | 6% | 8.8 | 7% |
| E: $0.075 to $0.085 | 14.9 | 4% | 7.7 | 6% |
| F: $0.085 to $0.095 | 20.9 | 6% | 12.2 | 9% |
| G: $0.095 to $0.105 | 31.5 | 8% | 15.7 | 12% |
| H: $0.105 to $0.115 | 10.3 | 3% | 4.7 | 4% |
| I: $0.115 and higher | 84.5 | 22% | | |
| *Total* | *375.8* | | *133.4* | |
| **Econometric Forecast 2025** | **1450.2** | | **1450.2** | |
| **Percent of Baseline** | **25.9%** | | **9.2%** | |

**Figure II.3: Distribution of Residential Sector Achievable Electric Energy Efficiency Potential by End-Use**

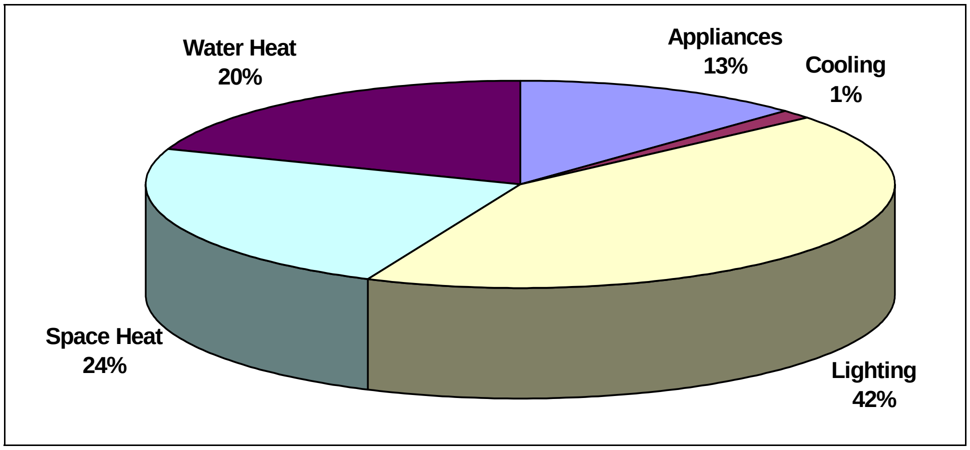
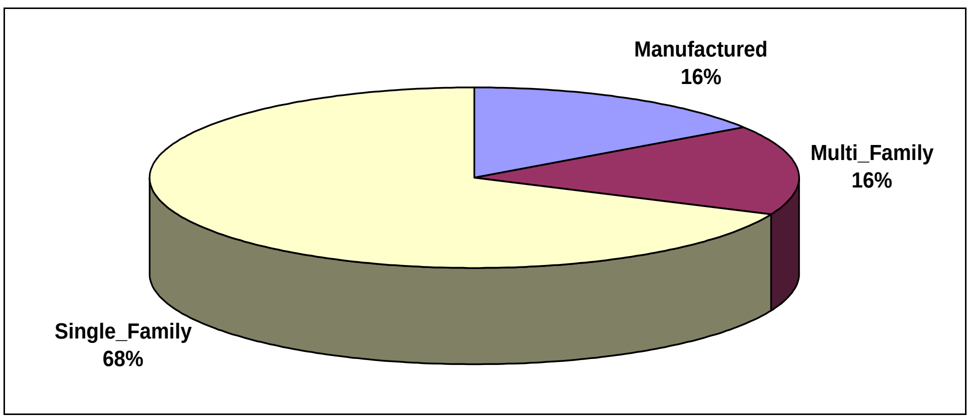



**Figure II.4: Figure Distribution of Achievable Electric Energy Efficiency Potential by Dwelling Type Residential Sector**




Gas energy-efficiency potentials in the residential sector are estimated at 27.7 million decatherms, 6.3 million decatherms (23%) of which is expected to be achievable. Approximately 22% (1.4 million decatherms) of the achievable potential can be achieved at an average cost of 45 cents per decatherm or less (Table II.14). As shown in Figure II.6, expected savings in space heating is the largest component of the achievable gas energy efficiency potential in the residential sector and account for nearly 69% of the gas savings potential. Upgrade of heating equipment with alternative, more energy-efficient equipment provides the main source for the potential savings. The results also show that installation of more efficient water heaters and application of measures that improve performance of existing water heating equipment (e.g., insulation and, to a lesser degree, water-saving measures and home weatherization) together account for more than 31% of the gas energy efficiency potential in the residential sector (Figure II.5).

Single-family dwellings account for the largest share (62%) of gas energy-efficiency potentials in the residential sector. Multi-family dwellings account for 33% of the remaining gas energy-efficiency potential in this sector (Figure II.6).

**Table II.14: Distribution of Residential Sector Technical and Achievable Gas Energy Efficiency Potential by Cost Category**

| **Cost Category** ($/therm) | **Technical Potential** | | **Achievable Potential** | |
|---|---|---|---|---|
| | **2025 Decatherms** | **%** | **2025 Decatherms** | **%** |
| **Categories** | | | | |
| A: less than $0.45 | 2,158,495 | 8% | 1,366,457 | 22% |
| B: $0.45 to $0.55 | 6,254 | 0% | 4,125 | 0% |
| C: $0.55 to $0.65 | 1,324,505 | 5% | 797,666 | 13% |
| D: $0.65 to $0.75 | 2,053,946 | 7% | 1,240,053 | 20% |
| E: $0.75 to $0.85 | 311,278 | 1% | 289,316 | 5% |
| F: $0.85 to $0.95 | 966,054 | 3% | 1,615,936 | 26% |
| G: $0.95 to $1.05 | 253,500 | 1% | 1,020,726 | 16% |
| H: $1.05 and higher | 20,664,714 | 74% | | |
| *Total* | *27,738,747* | | *6,334,280* | |
| **Econometric Forecast 2025** | **75,278,759** | | **75,278,759** | |
| **Percent of Baseline** | **36.8%** | | **8.4%** | |

**Figure II.5: Distribution of Residential Sector Achievable Natural Gas Energy Efficiency Potential by End-Use**

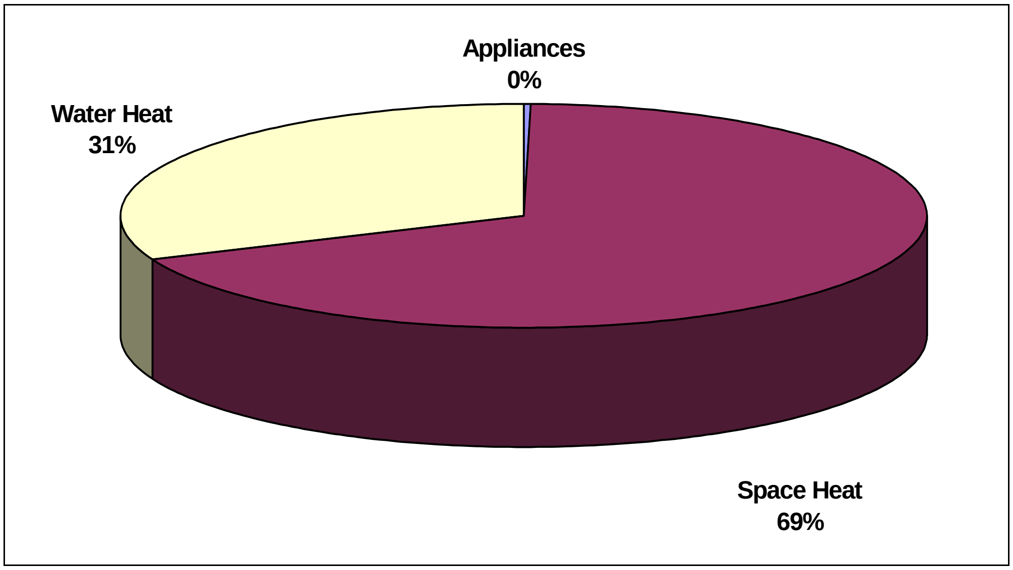
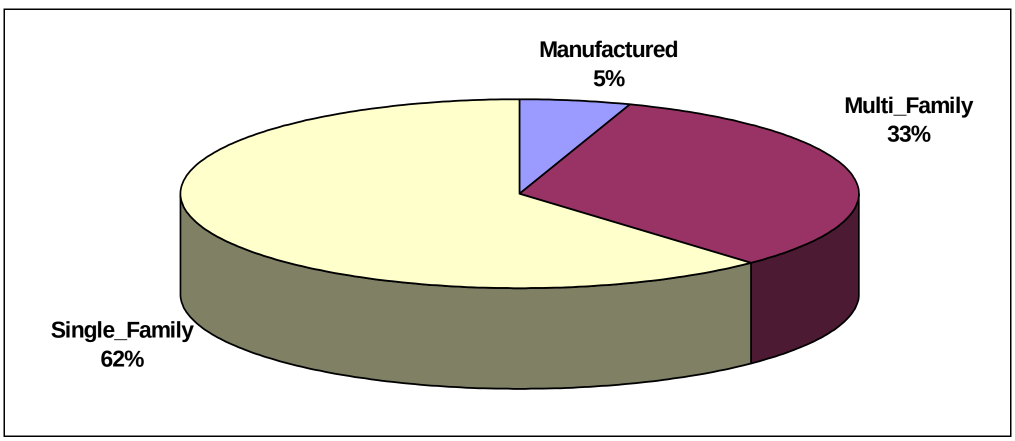



**Figure II.6: Distribution of Residential Sector Achievable Natural Gas Energy efficiency Potential by Facility Type**




### Commercial Sector

Total electric energy efficiency potential in the commercial sector is estimated at nearly 504 aMW, nearly 148 aMW of which (29%) are expected to be achievable. About 54% of the achievable electric energy efficiency potential in the commercial sector falls in the low cost category of less than 4.5 cents per kWh (Table II.15). As can be seen in Figure

II.7, lighting retrofit represents the largest potential for electricity savings. Nearly 45% of potential electricity savings in the commercial sector are attributable to the application of energy-efficient lighting. Retrofit, upgrade, and better operation and maintenance of HVAC equipment are also shown to be effective energy efficiency measures, which account for more than 38% of the total electricity savings potential in this sector. High-efficiency office and cooking equipment (plug loads) account for 14% of the savings potential, while water heating measures account for 3% of total commercial-sector electricity savings (Figure II.7).

Office buildings account for nearly one-third of achievable electric energy-efficiency potentials in the commercial sector. Retail establishments and educational facilities represent the second and third largest shares of electric energy-efficiency opportunities in the commercial sector (Figure II.8).

**Table II.15: Distribution of Commercial Sector Technical and Achievable Electric Energy Efficiency Potential by Cost Category**

| **Cost Category** ($/kWh) | **Technical Potential** | | **Achievable Potential** | |
|---|---|---|---|---|
| | **2025 aMW** | **%** | **2025 aMW** | **%** |
| **Categories** | | | | |
| A: less than $0.045 | 147.9 | 29% | 80.1 | 54% |
| B: $0.045 to $0.055 | 19.2 | 4% | 9.7 | 7% |
| C: $0.055 to $0.065 | 49.9 | 10% | 24.2 | 16% |
| D: $0.065 to $0.075 | 13.2 | 3% | 6.8 | 5% |
| E: $0.075 to $0.085 | 13.0 | 3% | 6.8 | 5% |
| F: $0.085 to $0.095 | 13.0 | 3% | 6.6 | 4% |
| G: $0.095 to $0.105 | 13.8 | 3% | 7.0 | 5% |
| H: $0.105 to $0.115 | 12.5 | 2% | 6.5 | 4% |
| I: $0.115 and higher | 221.2 | 44% | | |
| *Total* | *503.7* | | *147.6* | |
| **Econometric Forecast 2025** | **1578.1** | | **1578.1** | |
| **Percent of Baseline** | **31.9%** | | **9.4%** | |

**Figure II.7: Distribution of Commercial Sector Achievable Electric Energy Efficiency Potential by End-Use**

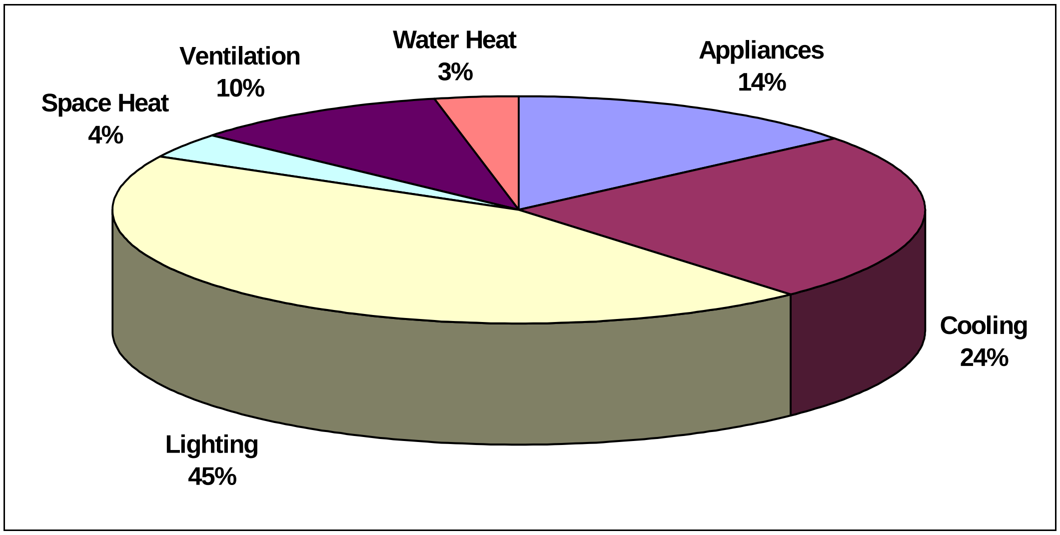
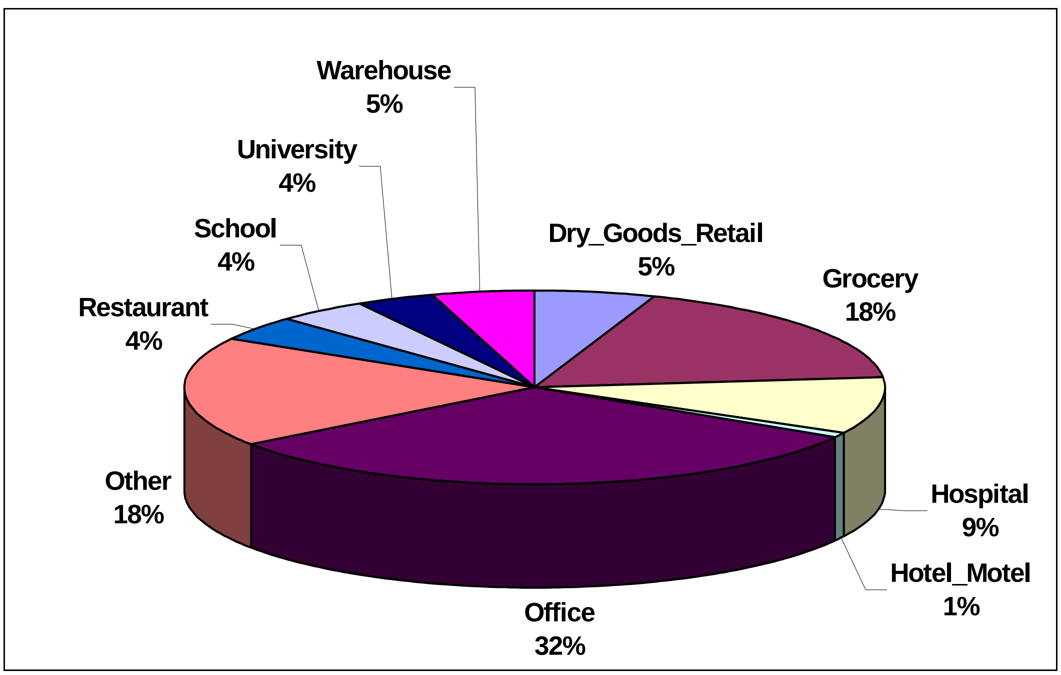



**Figure II.8: Distribution of Commercial Sector Achievable Electric Energy Efficiency Potential by Facility Type**




The results of this study show that there are large opportunities in the commercial sector for gas conservation. Technical gas energy efficiency potentials in the commercial sector are estimated at more than 10 million decatherms, with achievable opportunities of nearly 3.9 million decatherms, representing more than 9% of total load in 2025. Approximately 70% of this potential can be expected to be achievable at a cost of less than $0.55 per therm (Table II.16).

As Figure II.9 illustrates, space heating, water heating, and appliance energy efficiency measures provide the largest potentials for gas savings in the commercial sector. These measures respectively represent 52% (space heating), 37% (water heating), and 10% (appliances – primarily cooking) of the total achievable gas energy efficiency potential in the commercial sector. Pool heating energy efficiency measures accounts for a small share of the total gas savings potential in this sector. Office buildings, hospitals, and institutional facilities together account for nearly 45% of the commercial sector gas energy-efficiency potentials. A large portion of this opportunity is found in the general, unclassified segment of the commercial sector (Figure II.10).

**Table II.16: Distribution of Commercial Sector Technical and Achievable Gas Energy Efficiency Potentials by Cost Category**

| **Cost Category** ($/therm) | **Technical Potential** | | **Achievable Potential** | |
|---|---|---|---|---|
| | **2025 dth** | **%** | **2025 dth** | **%** |
| **Categories** | | | | |
| A: less than $0.45 | 3,850,791 | 38% | 2,006,699 | 52% |
| B: $0.45 to $0.55 | 2,385,109 | 23% | 1,072,278 | 28% |
| C: $0.55 to $0.65 | 759,667 | 7% | 376,642 | 10% |
| D: $0.65 to $0.75 | 517,424 | 5% | 245,922 | 6% |
| E: $0.75 to $0.85 | 97,981 | 1% | 52,415 | 1% |
| F: $0.85 to $0.95 | 110,312 | 1% | 57,267 | 1% |
| G: $0.95 to $1.05 | 109,673 | 1% | 53,314 | 1% |
| H: $1.05 and higher | 2,339,285 | 23% | | |
| *Total* | *10,170,241* | | *3,864,537* | |
| **Econometric Forecast 2025** | 42,637,285 | | 42,637,285 | |
| **Percent of Baseline** | 23.9% | | 9.1% | |

**Figure II.9: Distribution of Commercial Sector Achievable Gas Energy Efficiency Potential by End-Use**

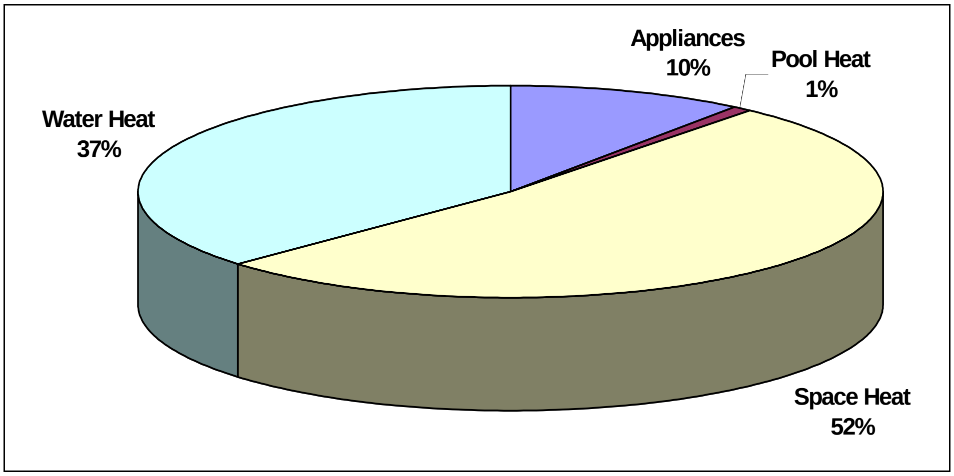
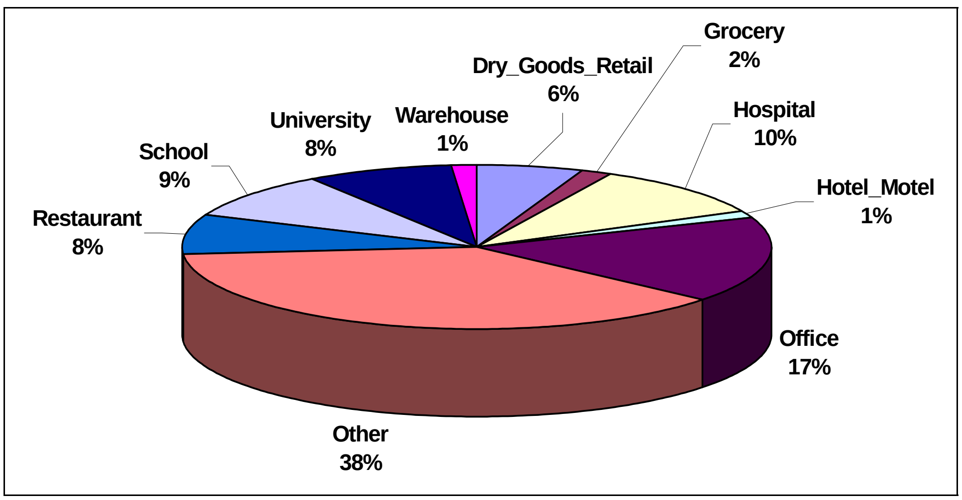



**Figure II.10: Distribution of Commercial Sector Achievable Gas Energy Efficiency Potential by Facility Type**




## Industrial Sector

Technical and achievable electric and gas energy-efficiency potentials were estimated for all major end uses and within fourteen major industrial sectors and wastewater treatment in PSE's service territory. Achievable electric energy-efficiency potentials in the industrial sector are estimated at 2.2 million MWh or an equivalence of 15.9 aMW, representing approximately 10% of the total industrial load in 2025, an average cost of

2.2 cents per kWh (see Table II.17). As shown in Figure II.11, 48% of this potential is attributable to efficiency gains in motor upgrades. Facility improvements, primarily HVAC and lighting retrofits, account for nearly 25% of the potential. Energy efficiency improvements in refrigeration and process cooling account for an additional 7% of the potential.

**Table II.17: Distribution of Industrial Sector Electric Energy-Efficiency Potentials by End Use**

| Electric Market Segments | 2025 Cumulative Savings (MWh) | 2025 Cumulative Savings (aMW) | Levelized CCE* ($/kWh) |
|---|---|---|---|
| **Uncoded/Miscoded/Invalid** | | | |
| HVAC | 237,233 | 1.8 | 0.051 |
| Indirect Boiler | | | |
| Lighting | 150,139 | 1.7 | 0.036 |
| Other - Not Reported | | | |
| Process Electro Chemical | | | |
| Process Heat | | | |
| Process Other | | | |
| Motors | 1,475,765 | 9.8 | 0.014 |
| Motors | 1,449,312 | 8.3 | 0.015 |
| Compressed Air O&M | 26,453 | 1.5 | 0.017 |
| Refrigeration/Process Cooling | 176,377 | 1.3 | 0.017 |
| Wastewater Treatment | 170,430 | 1.24 | 0.042 |
| ***Total*** | ***2,209,944*** | ***15.9*** | ***0.022*** |

* Cost of Conserved Energy is levelized cost of efficiency measure cost, not including program administration costs.

Long-term achievable gas energy-efficiency potentials are estimated at 315,000 decatherms (Tables II. 18). As shown in Figure II.12, boilers and process heating represent the largest portions of gas energy-efficiency potentials in the industrial sector, each accounting for 39% of the estimated achievable potential. HVAC upgrades account for an additional 14% gain in gat energy-efficiency potential. At average levelized per-unit costs of 2.2 cents per kWh and slightly over 20 cents per therm, all industrial energy efficiency measures considered in this assessment fall in low-cost resource categories. Estimates of achievable electric and gas energy-efficiency potentials by industrial classification are shown in Tables II.19 and II.20 respectively.

**Table II.18: Industrial Gas Energy Efficiency Potential by End-Use**

| Gas End Use | 2025 Cumulative Savings (therms) | Levelized CCE* ($/therms) |
|---|---|---|
| **Uncoded/Miscoded/Invalid** | | |
| HVAC | 674,546 | 0.621 |
| Process Boiler: | 4,000,372 | |
| Boiler (Upgrade/Controls/Heat Recovery) | 1,112,789 | 0.172 |
| Boiler O&M | 244,711 | 0.101 |
| Steam Distribution Systems | 2,642,873 | 0.127 |
| Other - Not Reported | - - - | |
| Process Heat | - - - | |
| Process Other | - - - | |
| ***Total*** | 4,674,918 | ***0.201*** |

* Cost of Conserved Energy is levelized cost of efficiency measure cost, not including program administration costs.

**Figure II.11: Industrial Electric Energy Efficiency Potential by End-Use**

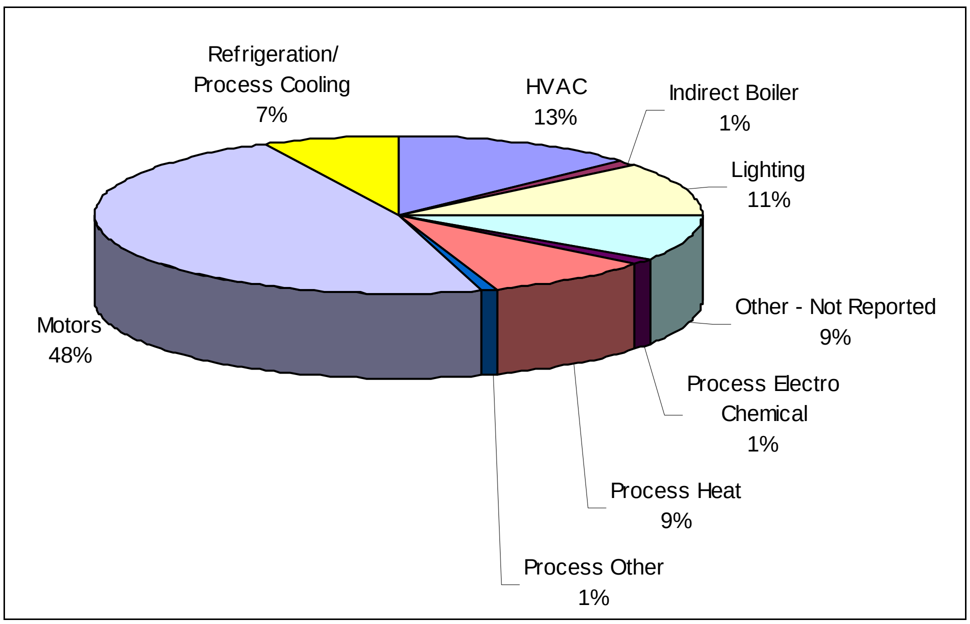


**Figure II.12: Industrial Gas Energy Efficiency Potential by End-Use**

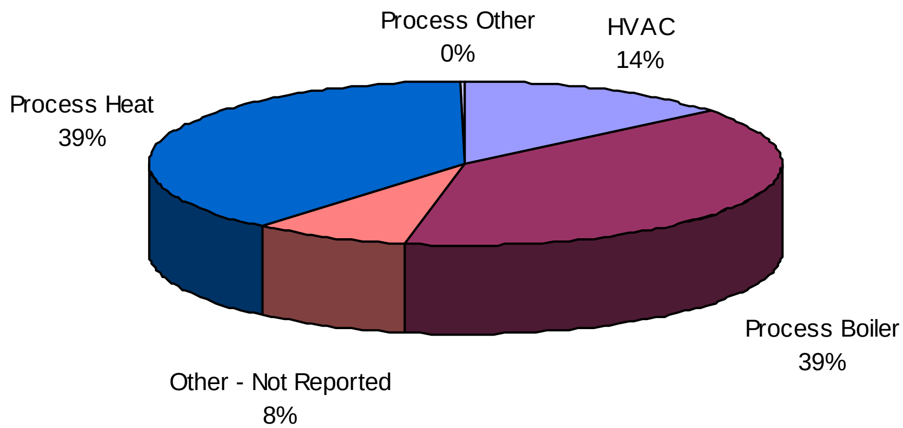



**Table II.19: Industrial Electric Energy Efficiency Potential by SIC**

| Electric Market Segments | | 2025 Cumulative Savings (MWh) | 2025 Cumulative Savings (aMW) | Levelized CCE* ($/kWh) |
|---|---|---|---|---|
| **Uncoded/Miscoded/Invalid** | | | | |
| 20 | Food/Kindred Products | 636,742 | 4.2 | 0.017 |
| 24 | Lumber/Wood Products | 272,045 | 1.7 | 0.016 |
| 26 | Paper/Allied Products | 118,669 | 0.7 | 0.017 |
| 27 | Printing/Publishing | 38,993 | 0.3 | 0.033 |
| 28 | Chemical/Allied Products | 284,393 | 1.9 | 0.015 |
| 29 | Petroleum Related | 39,247 | 0.2 | 0.015 |
| 30 | Rubber/Misc. Plastics Products | 82,204 | 0.6 | 0.020 |
| 32 | Stone/Clay/Glass/Concrete Prod. | 78,859 | 0.6 | 0.016 |
| 33 | Primary Metal Industries | 5,271 | 0.0 | 0.016 |
| 34 | Fabricated Metal Products | 89,520 | 0.9 | 0.025 |
| 35 | Machinery, except Electrical | 104,565 | 0.8 | 0.027 |
| 36 | Electric/Electronic Equip. | 97,151 | 0.8 | 0.028 |
| 37 | Transportation Equipment | 110,039 | 1.0 | 0.032 |
| 38 | Instruments/Related Products | 53,876 | 0.5 | 0.035 |
| 1629 | Wastewater Treatment | 170,430 | 0.3 | 0.042 |
| 39 | Miscellaneous | 27,940 | 1.2 | 0.044 |
| ***Total*** | | ***2,209,944*** | ***15.9*** | ***0.022*** |

* Cost of Conserved Energy (CCE) is levelized cost of efficiency measure cost, not including program administration costs.

**Table II.20: Industrial Gas Energy Efficiency Potential by SIC**

| Gas Market Segments | | 2025 Cumulative Savings (Decatherms) | Levelized CCE* ($/therms) |
|---|---|---|---|
| **Uncoded/Miscoded/Invalid** | | | |
| 20 | Food/Kindred Products | 2,283,233 | 0.150 |
| 24 | Lumber/Wood Products | 218,111 | 0.170 |
| 26 | Paper/Allied Products | 24,428 | 0.140 |
| 27 | Printing/Publishing | 76,670 | 0.279 |
| 28 | Chemical/Allied Products | 343,522 | 0.141 |
| 29 | Petroleum Related | 41,413 | 0.134 |
| 30 | Rubber/Misc. Plastics Products | 68,109 | 0.225 |
| 32 | Stone/Clay/Glass/Concrete Prod. | 112,075 | 0.283 |
| 33 | Primary Metal Industries | 45,227 | 0.233 |
| 34 | Fabricated Metal Products | 476,068 | 0.296 |
| 35 | Machinery, except Electrical | 112,086 | 0.621 |
| 36 | Electric/Electronic Equip. | 117,071 | 0.234 |
| 37 | Transportation Equipment | 367,576 | 0.227 |
| 38 | Instruments/Related Products | 90,261 | 0.236 |
| 39 | Miscellaneous | 299,071 | 0.279 |
| ***Total*** | | ***4,674,918*** | ***0.201*** |

* Cost of Conserved Energy (CCE) is levelized cost of efficiency measure cost, not including program administration costs.

## Resource Acquisition Timing

Timing is an important element in developing strategies to acquire energy-efficiency resources. Consistent with the definitions established by the Northwest Power and Conservation Council, PSE distinguishes between “lost opportunities” and “retrofits” in considering energy-efficiency potentials. Lost opportunities such as energy-efficiency potentials in new construction and upgrades to equipment upon their natural replacement tend to be timing-dependent and must be captured as they become available. Retrofits, on the other, are assumed to remain available over time.

The results of this assessment, as shown in Figure II.13, indicate that more than two-thirds (68%) of electric energy efficiency potentials in the residential sector are comprised of retrofit opportunities, while lost opportunities account for a grater portion of electric energy efficiency potentials in the commercial sector (57% compared to 43%). With respect to natural gas energy efficiency, potentials, however, lost opportunities are larger in both residential and commercial sectors (see Figure II.14). All of the estimated electric and gas energy efficiency potentials in the industrial sector are shown to result from retrofits.

**Figure II.13: Electric Energy Efficiency Potentials: Retrofit vs. Lost Opportunities**

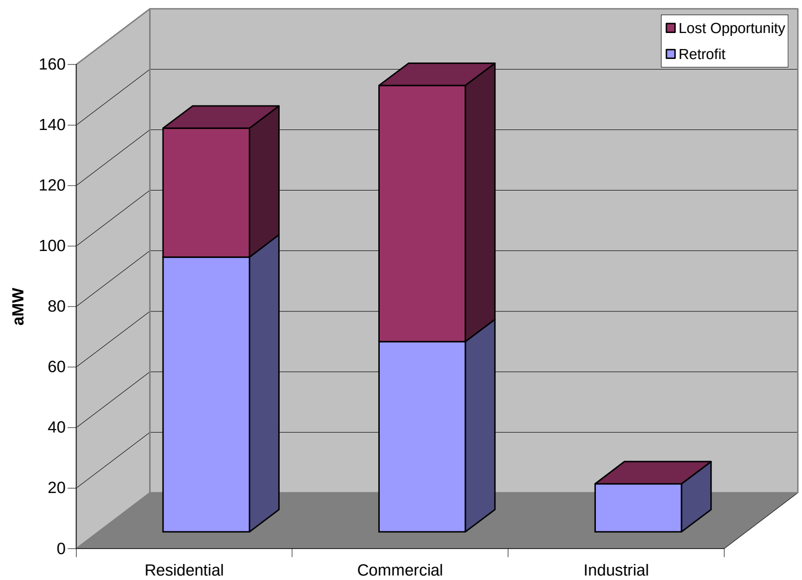
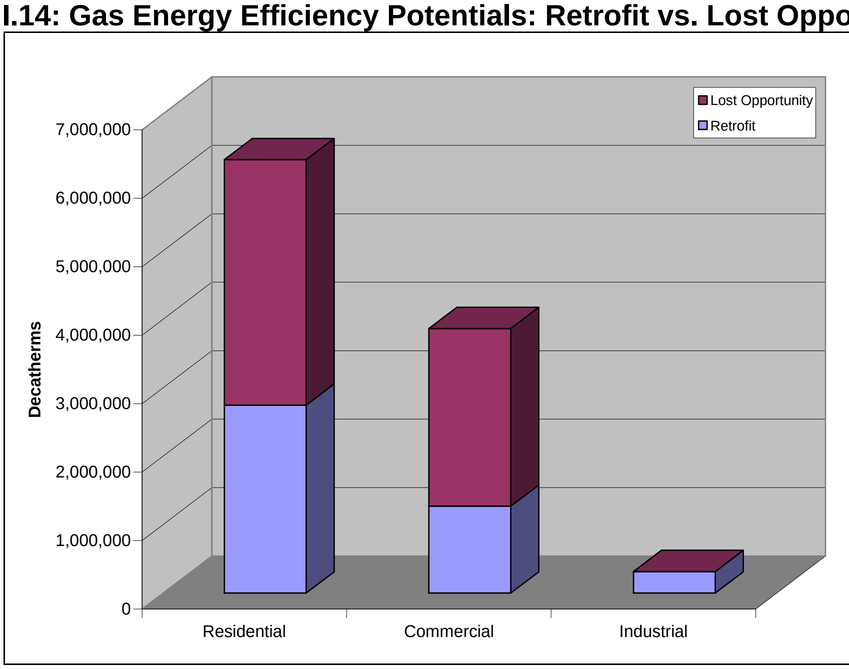



**Figure II.14: Gas Energy Efficiency Potentials: Retrofit vs. Lost Opportunities**



Estimates of achievable electric energy efficiency potentials from this study are slightly lower than those reported in the 2003 LCP report. A comparison of the results of the two studies shows a decline in electric energy efficiency potentials in the residential and commercial sectors and a slight increase in the industrial sector. In aggregate, achievable electric energy efficiency potential decreased by approximately 9.5% (from 328 aMW to 297 aMW). This difference is explained by several intervening factors including the effects of PSE's demand-side management activities in 2004, refinements to measure data, changes in assumptions regarding saturation of energy-efficient technologies, and, particularly, changes in load forecasts. Gas energy efficiency potentials were nearly unchanged, declining modestly from 10.8 million decatherms in 2003 to 10.6 million decatherms in 2005.

# III. Fuel Conversion Resource Potentials

## Scope

Potentials for fuel conversion were made only for the population of residential customers in PSE's combined electric and gas service area as electric energy efficiency resource. Additional fuel conversion potential, as an electric resource alternative, may be available from PSE electric customers in areas served by other gas utilities. However, lack of data on the capability to serve additional loads, coverage of existing gas distribution systems, and line extension plans of other gas utilities precludes quantifying this additional potential.

Four end uses (space heating, water heating, cooking, and clothes drying) were examined. For each, conversion potentials were estimated under both "normal" and "early" equipment replacement scenarios. Under the normal replacement scenario, it is assumed that conversions would occur at a naturally occurring pace upon failing of existing equipment. The early replacement scenario assumes a more aggressive approach where conversions are made during the first ten years of the planning horizon regardless of age and condition of existing equipment.

## Methodology

Fuel conversion resources augment electric energy-efficiency potentials in reducing total electric loads. At the same time, fuel conversion precludes realizing the full electric energy efficiency potentials of affected electric end uses because the substitution of gas appliances for electric replaces the some opportunities to install electric efficiency measures. Fuel conversion also results in increased consumption of natural gas, which, in turn, diminishes the savings from for gas energy efficiency. Due to this interdependency, analyses of electric energy efficiency and fuel conversion potentials must be performed simultaneously, explicitly taking account interactions between the two resource options.

Fuel conversion potentials were, therefore, assessed in conjunction with electric and gas energy efficiency potentials in the context of the ForecastPro® model. The basis equation for assessment of fuel conversion was the same as that of energy-efficiency and began with the same general equation for estimating the base case end-use forecast that is:

$$EUSE_{ijf} = ACCTS_i \times UPA_i \times SAT_{ij} \times FSH_{ijf} \times ESH_{ijfe} \times EUI_{ijfe} \, ,$$

The only exception is that in this case, equipment market shares ($ESH_{ijfe}$) were adjusted to represent electric equipment subject to conversion.

Fuel conversion savings potentials were estimated using the same bottom-up approach and the same data sources as for energy efficiency (see Section II). The assessment followed a four-step process, similar to the procedure used in estimating energy-efficiency potentials and was as follows.

***1.) Develop Base Case Forecast***. The analysis began with the same base case forecast, representing the starting fuel shares for existing and new construction for space heating, water heating, and appliances.

***2.) Determine Measure Impacts***. Analysis of fuel conversion began with compiling a list of potential measures and establishing baseline displacements of electric consumption for each measure. This list was then screened for measures that seemed most applicable to PSE's residential customer base according to the results of the residential appliance saturation survey. Four end uses were selected for inclusion in the final analysis:

- Electric furnace to gas furnace
- Electric water heat to gas water heat
- Electric range to gas range
- Electric dryer to gas dryer

Both standard and high efficiency gas appliances were considered in developing the resulting increases in gas consumption. A complete list of measures and applicable assumptions for each are shown in Table III.1.

**Table III.1: List of Fuel Conversion Measures**

| End Use | Gas Measure | Electric Baseline |
|---|---|---|
| **Space Heating** | Standard Furnace, 80 AFUE, 60 kBtu | Electric Furnace |
| Base use = 8895 kWh/yr | Condensing Furnace, 92 AFUE w/ VSD | Electric Furnace |
| Seattle, Zone 1 | Condensing Furnace, 96 AFUE w/ VSD | Electric Furnace |
| (NWPCC-1998, Part 2, p.G-76) | | |
| **Water Heating** | Storage Water Heater, 50 gal., EF=.59 | Electric Water Heater, 50 gal. |
| Base use = 3800 kWh/yr | Storage Water Heater, 50 gal., EF=.63 | Electric Water Heater, 50 gal. |
| (NWPCC-1998, Part 2, p.G-76) | Storage Water Heater, 50 gal., EF=.70 | Electric Water Heater, 50 gal. |
| **Appliances** | Gas Dryer | Electric Dryer |
| | Gas Dryer w/ Moisture Sens. | Electric Dryer |
| | Standard Gas Range, Free-Standing, 30" | Electric Range, 30" |
| | Convection Gas Range, Free-Standing, 30" | Electric Range, 30" |

***3.) Estimate Phase-In Technical Potential***. Technical potentials for fuel conversion were estimated through the Intervention Strategies Module in ForecastPro®, by overriding the base case fuel shares with 100% gas shares in applicable homes. The phase-in technical potential was calculated by subtracting the energy forecast associated with the highest possible penetration of gas fuel shares from the base case forecast.

***4.) Create Bundles and Estimate Achievable Potential***. Achievable potential applies market penetration rates of 50% for all applicable end-uses of eligible customers. Again, the potential was calculated by subtracting this forecast from the base case forecast. The impacts were then aggregated into bundles for screening and integration in PSE's IRP process.

Acquisition of fuel conversion potentials were analyzed under two alternative scenarios for timing of equipment replacements:

- ***Normal Replacement***, which assumes that fuel conversions take place only upon natural retirement or failure of the existing equipment.

- ***Early Replacement***, which assumes that achievable fuel conversions are accelerated through early replacement over the first ten years of the planning horizon regardless of the age and condition of existing equipment.

The effects of fuel conversion on gas consumption were also analyzed under two scenarios concerning the efficiency of gas equipment: 1) minimum standard gas efficiency appliances and 2) high-efficiency gas appliances. Each of these scenarios was then assessed in conjunction with two (normal and accelerated acquisition) replacement and electric energy-efficiency resource acquisition strategies (see Section IV).

## Summary of the Results

Table III.2 shows the technical and achievable electricity savings resulting from fuel conversion for the normal and early replacement scenarios. Under the normal replacement scenario, fuel conversion is estimated to provide 132.8 aMW in technical potential and 62.5 aMW in achievable potential. In an accelerated conversion scenario that assumes early equipment replacement, technical and achievable potentials are expected to increase to 189.5 aMW and 101.5 aMW respectively.

**Table III.2: Effects of Fuel Conversion on Residential Electric Energy Efficiency Potentials**

| Electric Resource Potential – 2025 | Without Fuel Conversion (aMW) | With Normal Replacement (aMW) | With Early Replacement (aMW) |
|---|---|---|---|
| **Technical** | | | |
| Fuel Conversion Potential (gross) | | 132.8 | 189.5 |
| Energy Efficiency | 375.8 | 338.5 | 321.2 |
| Total Technical Potential | 375.8 | 471.2 | 510.7 |
| As % of Residential Load | 25.9% | 32.5% | 35.2% |
| **Achievable** | | | |
| Fuel Conversion Potential (gross) | | 62.5 | 101.5 |
| Energy Efficiency | 133.4 | 127.9 | 123.5 |
| Total Achievable Potential | 133.4 | 190.4 | 224.9 |
| As % of Residential Load | 9.2% | 13.1% | 15.5% |

Appliance conversions account for more than half of the achievable fuel conversion potential under the normal conversion scenario; HVAC equipment, mainly space heat conversions, and water heating measures each represent approximately 25% of additional fuel conversion resource potentials (Table III.3).

**Table III.3: Fuel Conversion Electric Energy Efficiency Potentials by End Use**

| End-Use | Equipment Replacement Scenario | |
|---|---|---|
| | **Normal** (aMW) | **Early** (aMW) |
| Appliances | 32.7 | 40.5 |
| HVAC | 15.4 | 29.6 |
| Water Heat | 14.3 | 31.4 |
| ***Total*** | ***62.5*** | ***101.5*** |

### Effects of Fuel Conversion on Electric Energy Efficiency Potentials

Fuel conversion will reduce opportunities for upgrade of applicable electric equipment and hence diminish the potentials for electric energy efficiency. As can be seen in Table III.3, achievable electric energy efficiency potentials will be reduced from 133.4 aMW to 127.9 aMW under the normal replacement scenario and to 123.5 aMW under the early replacement fuel conversion scenario.

**Table III.4: Effects of Fuel Conversion on Residential Electric Energy Efficiency Potentials**

| Electric Resource Potential - 2025 | Without Fuel Conversion (aMW) | With Normal Replacement (aMW) | With Early Replacement (aMW) |
|---|---|---|---|
| **Technical** | | | |
| Fuel Conversion Potential | | 132.8 | 189.5 |
| Energy Efficiency | 375.8 | 338.5 | 321.2 |
| Total Technical Potential | 375.8 | 471.2 | 510.7 |
| As % of Residential Load | 25.9% | 32.5% | 35.2% |
| **Achievable** | | | |
| Fuel Conversion Potential | | 62.5 | 101.5 |
| Energy Efficiency | 133.4 | 127.9 | 123.5 |
| Total Achievable Potential | 133.4 | 190.4 | 224.9 |
| As % of Residential Load | 9.2% | 13.1% | 15.5% |

### Effects of Fuel Conversion on Gas Energy Efficiency Potentials

Increases in gas consumption due to fuel conversions were examined under both "standard" (current state and federal codes) and "high" equipment efficiency levels (the same as those used in energy efficiency potential). As shown in Table III.4, fuel conversion potential would increase natural gas usage by nearly 7.8 million decatherms (technical) and 4.2 million decatherms (achievable) under the standard efficiency scenario, and 7 million decatherms (technical) and 3.6 million decatherms (achievable) under the high-efficiency equipment scenario. The efficiency level of the gas equipment has no impact on the amount of electric load reduction from fuel conversion.

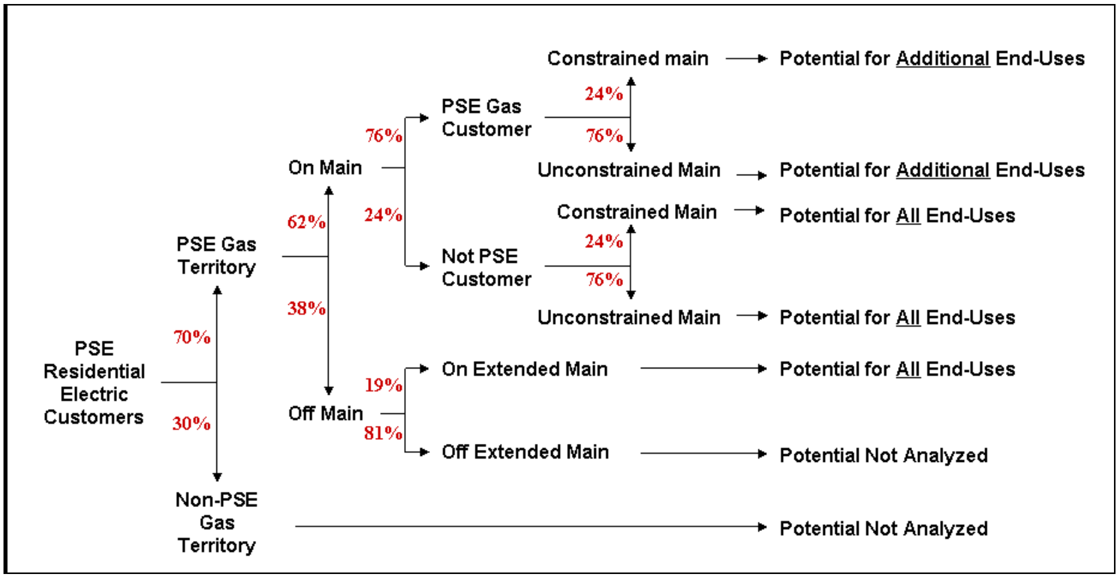
**Table III.5: Effects of Fuel Conversion on Residential Gas Load**

| Efficiency Level of New Gas Appliances | Standard | | High | |
|---|---|---|---|---|
| | Technical (Decatherms) | Achievable (Decatherms) | Technical (Decatherms) | Achievable (Decatherms) |
| Increased Use Due to Fuel Conversion | 7,763,444 | 4,169,422 | 6,987,099 | 3,752,480 |
| Gas Use Increase as % of Residential Load | 10.3% | 5.5% | 9.3% | 5.0% |

### Scope of Fuel Conversion Opportunities

Service availability and distribution system constraints are important considerations in assessing the achievable potentials for fuel conversion. As Figure III.1 demonstrates, PSE provides gas service to 70% of residential customers in its electric service area. Of these customers, 62% are on gas mains, of which 76% are currently receiving gas services from PSE. Moreover, current loads indicate that 24% of customers who are served by PSE are on constrained gas mains, although in the long term most of these constrained mains would likely be upgraded. Based on this data, approximately 33% of all customers offer an opportunity for conversions without imposing additional main extension or hook-up costs, because they are already PSE gas customers that are simply converting additional end uses. Another 15% of PSE's customers could be converted from all-electric to gas (10% in areas where gas is already available and 5% through short main extensions).[9]

**Figure III.1: Geographic Distribution of Residential Gas Customers by Utility Service Area, Service Availability, and System Characteristics**

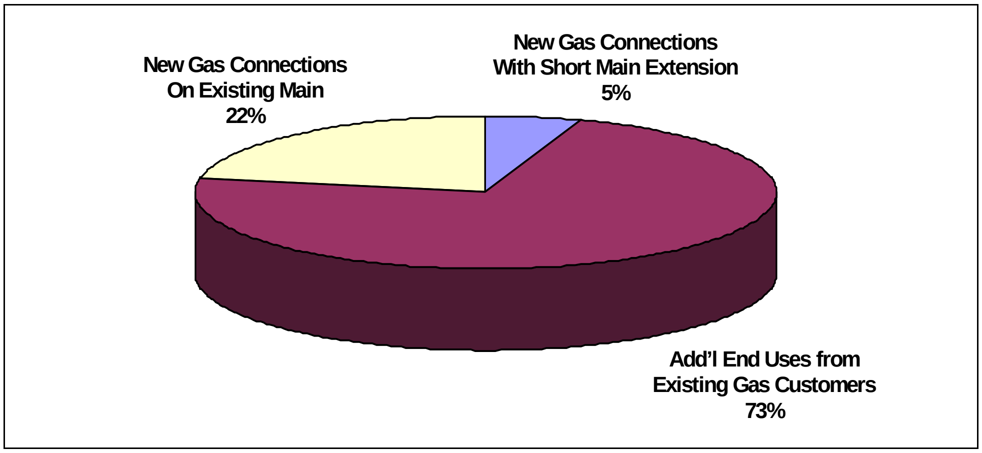



As can be seen in Figure III.2, under the normal conversion scenario, nearly three-quarters of fuel conversion potential comes from existing PSE gas customers that convert additional end uses, while relatively small proportions of fuel conversion potential are attributable to hook-up of entirely new gas customers.

Although the amounts of conversion potential per customer tend to be large among customers who are not currently hooked up, capturing such opportunities would require significant additional investments in customer hookup and/or expansion of the existing distribution system. Based on PSE records, average hook-up costs for new customers is estimated at $2,175 each.

9 The customer shares for the various branches in Figure III.1 were derived from PSE Customer Information System and mapping of zip+4 census track codes to PSE's gas distribution system.

**Figure III.2: Distribution of Electric Energy Savings from Fuel Conversion by Source**




Hook-up costs for new customers, combined with the additional gas fuel costs, have important ramifications in terms of overall fuel conversion resource costs. The effects of additional hook-up and fuel costs on electric efficiency fuel conversion costs were analyzed under the accelerated and normal conversion scenarios assuming standard and high-efficiency gas equipment.

As shown in Table III.5, the addition of fuel and hook-up costs can be expected to increase the cost of conserved electricity fro fuel conversion dramatically for all ened-uses. For example, under the normal replacement scenario, assuming standard efficiency gas equipment (column 2), average fuel conversion resource costs for appliance conversions can be expected to more than double (from $14.3/MWh to $37,1/MWh) once additional fuel costs are taken into account. Inclusion of hook-up costs for new customers will nearly quadruple the cost of conserved energy from $14.3/MWh to $56.3/MWh. Due to the higher starting costs under the accelerated scenario, the incremental costs of additional fuel and hook-up will have a smaller relative effect and will increase resource costs by about 25% for standard efficiency appliances.

**Table III.6: Effects of Additional Fuel (Gas) and New Service Hook-up Costs on Fuel Conversion Electric Efficiency Resource Costs**

| Scenario | Normal Replacement | | Accelerated Replacement | |
|---|---|---|---|---|
| **Equipment Efficiency** | **Standard** | **High** | **Standard** | **High** |
| **Existing Gas Customers – Gas Appliance Costs Only, No Fuel Costs ($/MWh)** | | | | |
| Appliances | $14.3 | $38.7 | $80.0 | $104.4 |
| HVAC | $9.7 | $18.5 | $27.9 | $36.7 |
| Water Heat | $10.0 | $12.7 | $16.2 | $18.9 |
| **Existing Gas Customers - With Additional Gas Fuel Costs ($/MWh)** | | | | |
| Appliances | $37.1 | $61.5 | $102.8 | $127.2 |
| HVAC | $43.4 | $52.1 | $61.6 | $70.3 |
| Water Heat | $32.7 | $35.4 | $38.9 | $41.6 |
| **New Customers - With Additional Gas Fuel & Service Hook-Up Costs ($/MWh)** | | | | |
| Appliances | $56.3 | $80.8 | $123.0 | $147.5 |
| HVAC | $62.8 | $71.6 | $81.0 | $89.8 |
| Water Heat | $45.8 | $48.5 | $52.0 | $54.7 |

# IV. Resource Portfolios

While an accurate assessment of achievable demand-side potentials represented an important objective of this study, the paramount consideration was to construct portfolios of electric and natural gas energy efficiency resource options, which could be compared with and evaluated against supply options on a balanced and consistent basis.

To facilitate the incorporation of the results of this study into PSE's least-cost, integrated resource planning process, electricity and natural gas energy efficiency potential estimates for each sector were disaggregated into distinct cost-based "bundles" of energy efficiency resource for each fuel and customer class. The grouping of measures into cost bundles begins with ranking of all measures by their respective cost per energy unit saved to create "measure supply curves" as shown in Figures IV.1 and IV.2, irrespective of sector or end use. (The vertical axis in each figure shows cumulative savings; the horizontal axis shows the levelized cost per unit of conserved energy). The measures are then assigned to specific resource bundles based on sector, and end use load characteristics.

Eight electric and seven gas cost-group "bundles" were created by grouping energy efficiency measures with similar cost and load-shape characteristics. Electric and gas measures with costs above the thresholds of $0.115/kWh or $1.05/therm were not considered economic or achievable. The composition of electric and natural gas energy efficiency resources and their associated cost ranges are shown in Tables IV.1 and IV.2. More detailed breakdowns of the electricity and natural gas energy efficiency resource bundles by market segment are presented in Tables IV.3 and IV.4.

As shown in Table IV.1, nearly 60% of achievable electricity savings in the residential sector, 54% of the achievable savings in the commercial sector, and all potential savings in the industrial sector fall in the low-cost category. With respect to natural gas, energy efficiency potentials are more evenly distributed across the five cost categories, particularly in the residential sector (see Table IV.2). Again, a significant portion of energy efficiency potential in the residential (22%) and commercial (52%) sectors, and all potential savings in the industrial sector fall in the low cost category.

**Figure IV.1: Electric Achievable Potential Measure Supply Curve (1024 Points)**

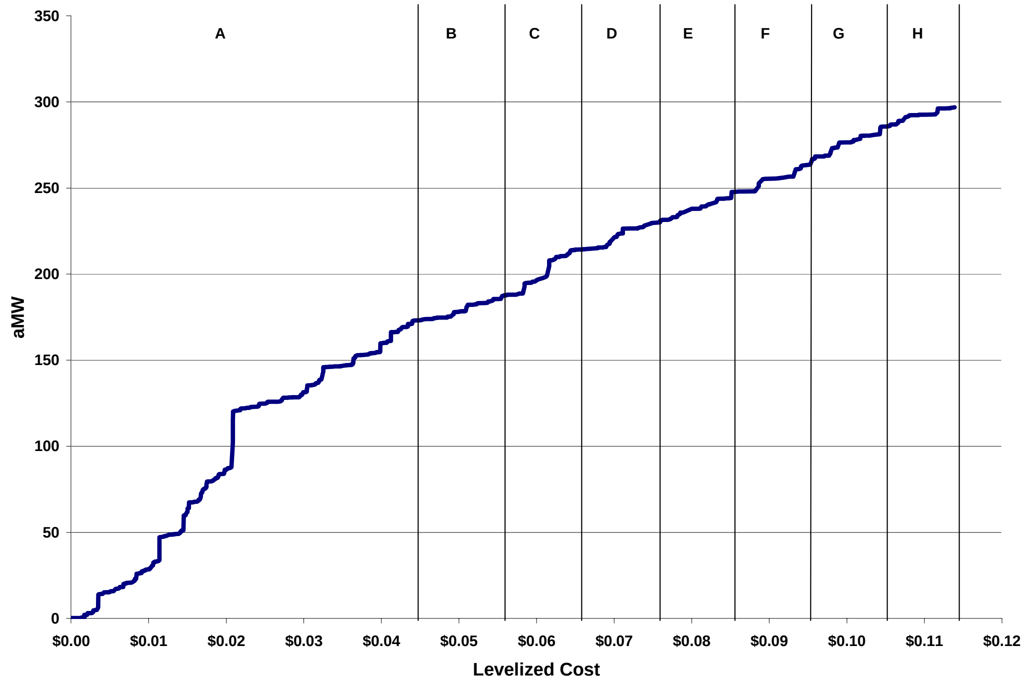
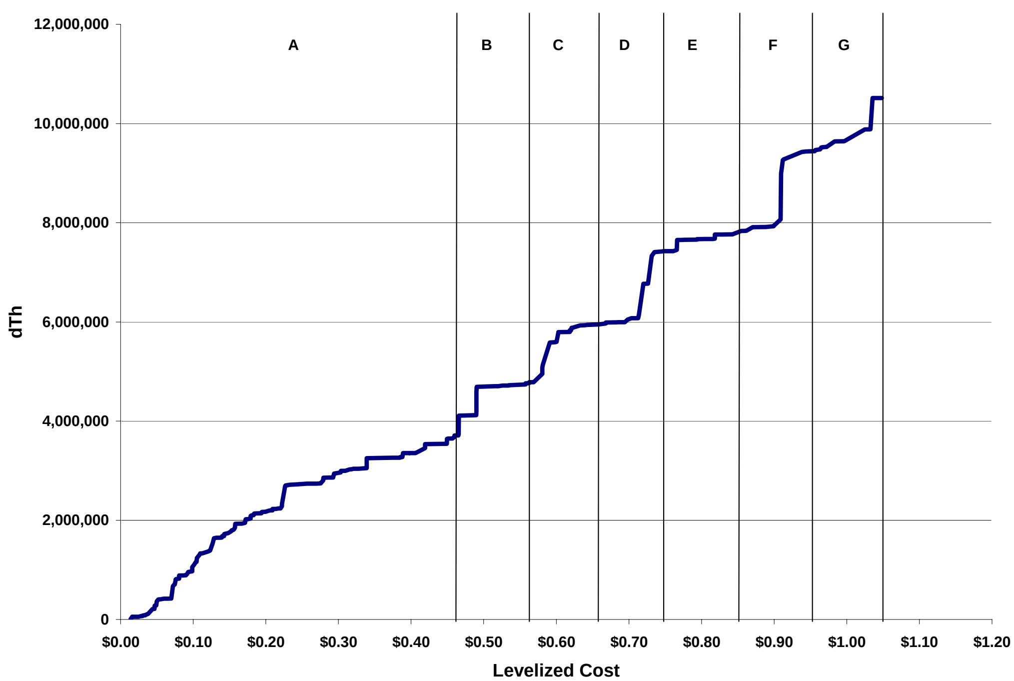



**Figure IV.2: Gas Achievable Potential Measure Supply Curve (278 Points)**



Fuel conversion potentials were assigned to the same end use bundles as energy efficiency to produce bundles that represent the net combination of energy efficiency and fuel conversion. The costs of these fuel conversion/energy efficiency bundles include PSE's costs to serve the additional natural gas demand (commodity costs and new service hookup costs, where applicable) and the costs of the new gas end use appliances.

Allocation of achievable energy efficiency potentials to electric and gas resource bundles are shown in Tables IV.3 and IV.4, respectively.

Table IV.1: Technical and Achievable Electric Energy Efficiency Potential by Sector and Cost Groups, 2025 aMW

| Electricity Cost Category | Residential | | Commercial | | Industrial | | Total All Sectors | |
|---|---|---|---|---|---|---|---|---|
| | Technical Potential | Achievable Potential | Technical Potential | Achievable Potential | Technical Potential | Achievable Potential | Technical Potential | Achievable Potential |
| A: less than $0.045/kWh | 182.2 | 79.0 | 147.9 | 80.1 | 15.9 | 15.9 | 346.0 | 175.0 |
| B: $0.045 - $0.055/kWh | 1.4 | 0.8 | 19.2 | 9.7 | | | 20.5 | 10.5 |
| C: $0.055 - $0.065/kWh | 8.7 | 4.5 | 49.9 | 24.2 | | | 58.6 | 28.7 |
| D: $0.065 - $0.075/kWh | 21.4 | 8.8 | 13.2 | 6.8 | | | 34.6 | 15.5 |
| E: $0.075 - $0.085/kWh | 14.9 | 7.7 | 13.0 | 6.8 | | | 28.0 | 14.5 |
| F: $0.085 - $0.095/kWh | 20.9 | 12.2 | 13.0 | 6.6 | | | 33.9 | 18.7 |
| G: $0.095 - $0.105/kWh | 31.5 | 15.7 | 13.8 | 7.0 | | | 45.3 | 22.7 |
| H: $0.105 - $0.115/kWh | 10.3 | 4.7 | 12.5 | 6.5 | | | 22.8 | 11.2 |
| I: > $0.115/kWh | 84.5 | | 221.2 | | | | 305.6 | |
| ***Total*** | ***375.8*** | ***133.4*** | ***503.7*** | ***147.6*** | ***15.9*** | ***15.9*** | ***895.4*** | ***296.9*** |

Table IV.2: Technical and Achievable Natural Gas Energy Efficiency Potential by Sector and Cost Groups, 2025 dth

| Gas Cost Category | Residential | | Commercial | | Industrial | | Total All Sectors | |
|---|---|---|---|---|---|---|---|---|
| | Technical Potential | Achievable Potential | Technical Potential | Achievable Potential | Technical Potential | Achievable Potential | Technical Potential | Achievable Potential |
| A: less than $0.45/therm | 2,158,495 | 1,366,457 | 3,850,791 | 2,006,699 | 314,924 | 314,924 | 6,324,211 | 3,688,080 |
| B: $0.45 - $0.55/therm | 6,254 | 4,125 | 2,385,109 | 1,072,278 | | | 2,391,363 | 1,076,403 |
| C: $0.55 - $0.65/therm | 1,324,505 | 797,666 | 759,667 | 376,642 | | | 2,084,172 | 1,174,308 |
| D: $0.65 - $0.75/therm | 2,053,946 | 1,240,053 | 517,424 | 245,922 | | | 2,571,370 | 1,485,975 |
| E: $0.75 - $0.85/therm | 311,278 | 289,316 | 97,981 | 52,415 | | | 409,259 | 341,731 |
| F: $0.85 - $0.95/therm | 966,054 | 1,615,936 | 110,312 | 57,267 | | | 1,076,366 | 1,673,203 |
| G: $0.95 - $1.05/therm | 253,500 | 1,020,726 | 109,673 | 53,314 | | | 363,173 | 1,074,040 |
| H: >$1.05/therm | 20,664,714 | | 2,339,285 | | | | 23,003,999 | |
| ***Total*** | ***27,738,747*** | ***6,334,280*** | ***10,170,241*** | ***3,864,537*** | ***314,924*** | ***314,924*** | ***38,223,912*** | ***10,513,741*** |

**Table IV.3: Achievable Electricity Energy Efficiency Potentials by Resource Bundle and Segment (Base Case Cumulative aMW 2006-2025)**

| Segment/Bundle | A<br>less than $0.045/kWh | B<br>$0.045 - $0.055/kWh | C<br>$0.055 - $0.065/kWh | D<br>$0.065 - $0.075/kWh | E<br>$0.075 - $0.085/kWh | F<br>$0.085 - $0.095/kWh | G<br>$0.095 - $0.105/kWh | H<br>$0.105 - $0.115/kWh |
|---|---|---|---|---|---|---|---|---|
| **Residential** | | | | | | | | |
| Existing- Appliances | 6.7 | | | 2.7 | | 4.9 | 3.0 | |
| Existing- HVAC | 17.6 | 0.8 | 0.7 | 4.4 | 3.5 | 3.2 | 2.8 | 0.0 |
| Existing- Lighting | 26.4 | | 0.6 | | 1.0 | | 2.2 | 1.1 |
| Existing- Water Heat | 6.9 | | 2.3 | | 2.1 | 3.5 | 4.7 | 2.1 |
| New- Appliances | | | | 0.4 | 0.3 | 0.2 | 0.8 | 0.0 |
| New- HVAC | | | | | | | 0.0 | |
| New- Lighting | 20.5 | | 0.5 | | 0.8 | | 1.7 | 0.9 |
| New- Water Heat | 0.9 | | 0.5 | 1.3 | | 0.5 | 0.5 | 0.6 |
| *Subtotal Residential* | *79.0* | *0.8* | *4.5* | *8.8* | *7.7* | *12.2* | *15.7* | *4.7* |
| **Commercial** | | | | | | | | |
| Existing- Appliances | 9.5 | 1.1 | 3.0 | | 0.1 | 2.8 | 0.0 | 0.2 |
| Existing- HVAC | 24.2 | 2.1 | 7.4 | 3.6 | 2.1 | 0.3 | 1.6 | 1.5 |
| Existing- Lighting | 14.2 | 2.3 | 3.3 | 1.3 | 1.8 | 0.6 | 2.5 | 2.0 |
| Existing- Water Heat | 0.4 | 0.0 | 0.0 | | | | 0.0 | |
| New- Appliances | 5.0 | 0.6 | 1.9 | | 0.1 | 1.8 | 0.0 | 0.1 |
| New- HVAC | 15.7 | 1.9 | 6.1 | 0.9 | 1.5 | 0.5 | 0.8 | 1.2 |
| New- Lighting | 11.0 | 1.7 | 2.5 | 1.0 | 1.3 | 0.5 | 2.1 | 1.5 |
| New- Water Heat | 0.1 | 0.0 | 0.0 | | | | 0.0 | |
| *Subtotal Commercial* | *80.1* | *9.7* | *24.2* | *6.8* | *6.8* | *6.6* | *7.0* | *6.5* |
| **Industrial Existing- General** | 15.9 | | | | | | | |
| ***Total All Sectors*** | ***175.0*** | ***10.5*** | ***28.7*** | ***15.5*** | ***14.5*** | ***18.7*** | ***22.7*** | ***11.2*** |

**Table IV.4: Achievable Gas Energy Efficiency Potentials by Resource Bundle and Segment (Base Case Cumulative Decatherms 2006-2025)**

| Segment/Bundle | A<br>less than $0.45/therm | B<br>$0.45 - $0.55/therm | C<br>$0.55 - $0.65/therm | D<br>$0.65 - $0.75/therm | E<br>$0.75 - $0.85/therm | F<br>$0.85 - $0.95/therm | G<br>$0.95 - $1.05/therm |
|---|---|---|---|---|---|---|---|
| **Residential** | | | | | | | |
| Existing- Base Load | 434,955 | 4,125 | 24,032 | | 90,436 | 490,038 | 22,550 |
| Existing- Space Heat | 745,165 | | 21,397 | 1,230,822 | 198,880 | 1,125,898 | 115,356 |
| New- Base Load | 186,338 | | 752,237 | 9,231 | | | |
| New- Space Heat | | | | | | | 882,821 |
| *Subtotal Residential* | *1,366,457* | *4,125* | *797,666* | *1,240,053* | *289,316* | *1,615,936* | *1,020,726* |
| **Commercial** | | | | | | | |
| Existing- Base Load | 491,157 | 580,765 | 2,516 | 145,633 | 34,583 | 26,035 | 47,197 |
| Existing- Space Heat | 820,594 | 44,940 | 227,384 | 24,380 | 15,230 | | 1,196 |
| New- Base Load | 273,678 | 418,181 | 507 | 53,083 | 1,378 | 25,278 | 2,748 |
| New- Space Heat | 421,270 | 28,392 | 146,235 | 22,826 | 1,224 | 5,954 | 2,173 |
| *Subtotal Commercial* | *2,006,699* | *1,072,278* | *376,642* | *245,922* | *52,415* | *57,267* | *53,314* |
| **Industrial Existing- General** | 314,924 | | | | | | |
| ***Total All Sectors*** | ***3,688,080*** | ***1,076,403*** | ***1,174,308*** | ***1,485,975*** | ***341,731*** | ***1,673,203*** | ***1,074,040*** |

## Electric Demand-Side Resource Acquisition Scenarios

In assessing long-run demand-side resource potentials, how the resources are acquired over time has significant ramifications for the IRP process. A large portion of energy efficiency and fuel conversion potential is made up of finite resources, particularly savings from retrofits and early replacement. Thus, the amount of demand-side resources already acquired affects current and future potentials. The timing for the acquisition of demand-side resources must take into account practical administrative and logistical considerations, as well as potential market barriers.

In this analysis, two alternative scenarios for acquisition of achievable electric energy efficiency resources were considered: “Base Case,” and “Accelerated.” The base-case scenario assumes that energy efficiency resources would be acquired in equal annual proportions over the 20-year planning horizon, which equates to approximately 15 aMW per year. Under the accelerated scenario, it is assumed that energy efficiency resource acquisition would be accelerated and all achievable retrofit or early replacement resources would be acquired during the first ten years of the plan. On average, the accelerated case results in 24 aMW per year over the first ten years and 5 aMW per year over the last ten years.

Similarly, different scenarios for the timing of fuel conversion acquisition were developed. The “Normal Replacement” scenario acquires fuel conversion at the time of naturally occurring appliance replacement, when the useful life of the electric appliance is complete, averaging about 3 aMW per year. This is analogous to the base case for energy efficiency. The “Early Replacement” scenario assumes all possible electric appliances are converted in the first ten years, which is analogous to the Accelerated Case for energy efficiency. The Early Replacement scenario for fuel conversion acquires approximately 10 aMW of savings per year for the first ten years and none afterward.

In order to fully consider all reasonable mixes of energy efficiency resources in the IRP process, six scenarios were constructed by combining the timing of energy efficiency resource acquisition (normal and accelerated), timing of fuel conversion resource acquisition (normal replacement, early replacement), and equipment efficiency in conversions (standard efficiency, high efficiency). See Table IV.5.

**Table IV.5: Residential Electric Energy Efficiency and Fuel Conversion Scenarios**

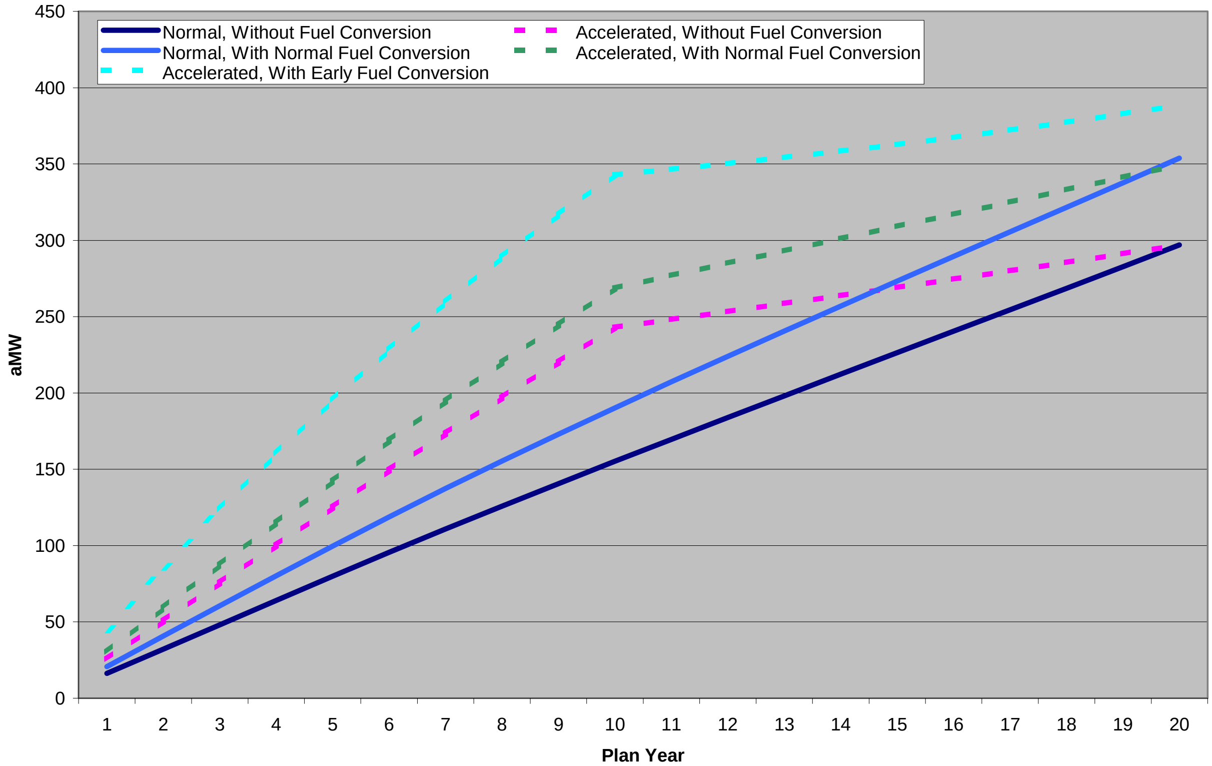
| Scenario | Energy Efficiency | Fuel Conversion | Gas Increase |
|---|---|---|---|
| **Scenario 1**: Normal EE, No FC | Constant Rate of Acquisition | NA | NA |
| **Scenario 2**: Accelerated EE, No FC | Accelerated Acquisition | NA | NA |
| **Scenario 3**: Normal EE, Normal FC, Standard | Constant Rate of Acquisition | Normal Replacement | Standard Efficiency |
| **Scenario 4**: Normal EE, Normal FC, High | Constant Rate of Acquisition | Normal Replacement | High Efficiency |
| **Scenario 5**: Accelerated EE, Normal FC, Standard | Accelerated Acquisition | Normal Replacement | Standard Efficiency |
| **Scenario 6**: Accelerated EE, High FC, High | Accelerated Acquisition | Normal Replacement | High Efficiency |
| **Scenario 7**: Accelerated EE, Early FC, Standard | Accelerated Acquisition | Early Replacement | Standard Efficiency |
| **Scenario 8**: Accelerated EE, Early FC, High | Accelerated Acquisition | Early Replacement | High Efficiency |

With respect to electric energy-efficiency potentials, the eight scenarios described in Table IV.5 are in effect reduced to five cases, since various levels of equipment efficiency in fuel conversion merely affect increases in gas consumption and have no impact on electric potentials. The five resource acquisition scenarios for electric energy efficiency are as follows:

1. Base case energy efficiency without fuel conversion
2. Accelerated energy efficiency without fuel conversion
3. Base case energy efficiency with normal replacement fuel conversion
4. Accelerated energy efficiency with normal replacement fuel conversion
5. Accelerated energy efficiency with early replacement fuel conversion

The five electric energy efficiency resource acquisition scenarios are illustrated graphically in Figure IV.3. The size and average cost for various resource bundles under the three combined energy efficiency and fuel conversion scenarios are reported in Tables IV.6, IV.7, and IV.8 respectively.

**Figure IV.3: Electric Energy Efficiency Resource Acquisition Scenarios**



### Table IV.6: Achievable Resource Potentials: Base Case Energy Efficiency & Normal Replacement Fuel Conversion

| Segment/Bundle | A<br>Less than $0.045/kWh | B<br>$0.045 - $0.055/kWh | C<br>$0.055 - $0.065/kWh | D<br>$0.065 - $0.075/kWh | E<br>$0.075 - $0.085/kWh | F<br>$0.085 - $0.095/kWh | G<br>$0.095 - $0.105/kWh | H<br>$0.105 - $0.115/kWh |
|---|---|---|---|---|---|---|---|---|
| **Residential** | | | | | | | | |
| Existing- Appliances | 38.3 | | 1.1 | 1.9 | | 4.9 | 3.0 | |
| Existing- HVAC | 20.5 | 0.8 | 11.8 | 4.2 | 3.4 | 3.1 | 2.5 | 0.0 |
| Existing- Lighting | 26.4 | | 0.6 | | 1.0 | | 2.2 | 1.1 |
| Existing- Water Heat | 18.3 | 2.4 | 2.0 | | 1.9 | 3.0 | 4.3 | 1.8 |
| New- Appliances | | | | 0.3 | 0.3 | 0.2 | 0.8 | 0.0 |
| New- HVAC | | | | | | | 0.0 | |
| New- Lighting | 20.5 | | 0.5 | | 0.8 | | 1.7 | 0.9 |
| New- Water Heat | 0.8 | | 0.4 | 1.2 | | 0.4 | 0.4 | 0.6 |
| ***Total Residential*** | ***124.9*** | ***3.2*** | ***16.4*** | ***7.7*** | ***7.3*** | ***11.6*** | ***15.0*** | ***4.4*** |

### Table IV.7: Achievable Resource Potentials: Accelerated Energy Efficiency & Normal Replacement Fuel Conversion

| Segment/Bundle | A<br>Less than $0.045/kWh | B<br>$0.045 - $0.055/kWh | C<br>$0.055 - $0.065/kWh | D<br>$0.065 - $0.075/kWh | E<br>$0.075 - $0.085/kWh | F<br>$0.085 - $0.095/kWh | G<br>$0.095 - $0.105/kWh | H<br>$0.105 - $0.115/kWh |
|---|---|---|---|---|---|---|---|---|
| **Residential** | | | | | | | | |
| Existing- Appliances | 31.6 | 6.7 | 1.1 | 2.3 | | 4.9 | 3.0 | |
| Existing- HVAC | 18.8 | | 11.9 | 0.7 | 4.1 | 3.0 | | 5.0 |
| Existing- Lighting | 26.4 | | | 0.6 | | | 1.0 | 3.3 |
| Existing- Water Heat | 17.5 | 2.4 | | 1.6 | | 2.0 | 2.5 | 5.5 |
| New- Appliances | | | | 0.3 | 0.3 | 0.2 | 0.8 | 0.0 |
| New- HVAC | | | | | | | 0.0 | |
| New- Lighting | 20.5 | | 0.5 | | 0.8 | | 1.7 | 0.9 |
| New- Water Heat | 0.8 | | 0.4 | 1.2 | | 0.4 | 0.4 | 0.6 |
| ***Total Residential*** | ***115.7*** | ***9.1*** | ***13.9*** | ***6.8*** | ***5.2*** | ***10.6*** | ***9.4*** | ***15.4*** |

**Table IV.8: Achievable Resource Potentials: Accelerated Energy Efficiency & Early Replacement Fuel Conversion**

| Segment/Bundle | A<br>Less than $0.045/kWh | B<br>$0.045 - $0.055/kWh | C<br>$0.055 - $0.065/kWh | D<br>$0.065 - $0.075/kWh | E<br>$0.075 - $0.085/kWh | F<br>$0.085 - $0.095/kWh | G<br>$0.095 - $0.105/kWh | H<br>$0.105 - $0.115/kWh |
|---|---|---|---|---|---|---|---|---|
| **Residential** | | | | | | | | |
| Existing- Appliances | | 6.7 | | 2.3 | | 4.9 | 42.1 | 1.4 |
| Existing- HVAC | 14.5 | | 19.3 | 0.7 | 15.2 | 3.0 | | 5.0 |
| Existing- Lighting | 26.4 | | | 0.6 | | | 1.0 | 3.3 |
| Existing- Water Heat | 35.1 | 1.8 | | 1.6 | | 2.0 | 2.5 | 5.5 |
| New- Appliances | | | | 0.3 | 0.3 | 0.2 | 0.8 | 0.0 |
| New- HVAC | | | | | | | 0.0 | |
| New- Lighting | 20.5 | | 0.5 | | 0.8 | | 1.7 | 0.9 |
| New- Water Heat | 0.8 | | 0.4 | 1.2 | | 0.4 | 0.4 | 0.6 |
| ***Total Residential*** | ***97.4*** | ***8.5*** | ***20.2*** | ***6.8*** | ***16.2*** | ***10.6*** | ***48.5*** | ***16.8*** |

# V. Demand Response Potentials

## Scope

Demand-response (or demand-responsive) resources are comprised of flexible, price-responsive loads that may be curtailed or interrupted during system emergencies or when wholesale market prices exceed the utility's supply cost. Acquisition of demand-response resources may be based on either reliability considerations or economic/market objectives. Objectives of demand response may be met through a broad range of price-based (e.g., time-varying rates and interruptible tariffs) or incentive-based (e.g., direct load control, demand buy-back, demand bidding, and dispatchable stand-by generation) strategies. In this assessment, five demand-response options were considered, similar to those examined in PSE's 2003 Least Cost Plan:

***1) Direct Load Control***: This strategy allows the utility to remotely interrupt or cycle electrical equipment and appliances such as water heaters, space heaters, and central air-conditioners. Direct load control programs are generally best suited for the residential and, to a lesser extent, small commercial sectors.

***2) Time-of-Use Rates***: This demand response option consists of two-part pricing structures designed to encourage customers to curtail consumption during peak or shift it to off-peak hours. TOU tariffs are designed to reflect the utility's marginal cost of power supply.

***3) Critical Peak Pricing***: Critical peak or extreme-day pricing refers to incentive-based, demand-response strategies that aim to preempt system emergencies by encouraging customers to curtail their loads for a limited number of hours during the year. The amount of incentive is generally based on the utility's avoided cost of supply during extreme peak events. For the purpose of this study, critical peak is defined as loads coinciding with the highest one percentile region (87 hours) of PSE's system load duration curve.

***4) Curtailment Contracts***: These refer to contractual arrangements between the utility and its large customers who agree to curtail or interrupt their operations for a predetermined period when requested by the utility. The duration and frequency of such requests and levels of load reduction are also stipulated in the contract. Customers who agree to participate are typically compensated either through lower rates or fixed payments.

***5) Demand Buyback***: Under demand buyback arrangements, the utility offers payments to customers for reducing their demand when requested by the utility. The buyback amount generally depends on market prices published by the utility ahead of the curtailment event, and the level of reduction is verified against an agreed upon baseline usage level.

## Methodology

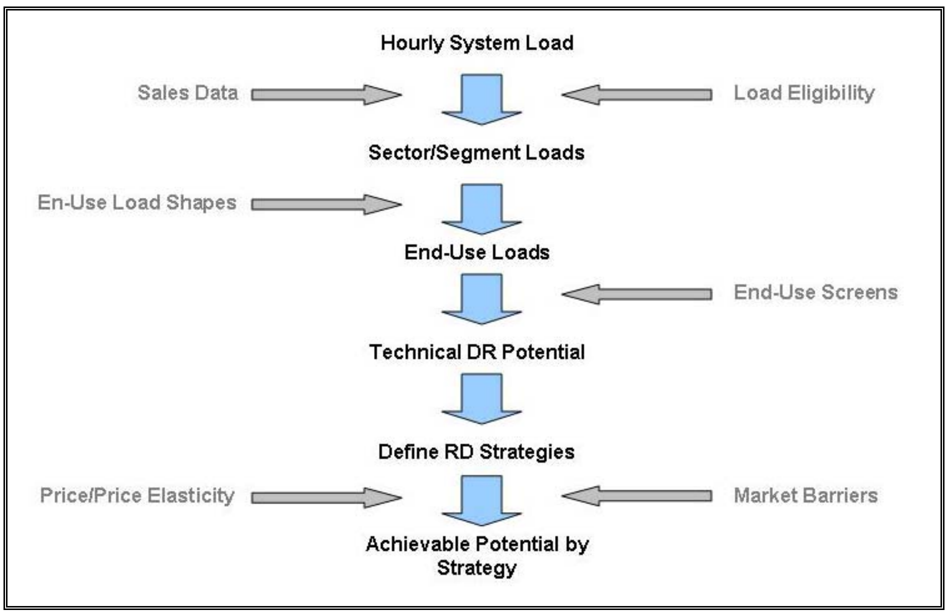
As in the case with energy efficiency and fuel conversion, demand response opportunities were assessed in terms of both “technical” and “achievable” potential.

***Technical Potential***: In the context of demand response, technical potential assumes that all applicable end-use loads in all customer sectors are wholly or partially available for curtailment, except for those customer segments (e.g., hospitals) and end-uses (e.g., restaurant cooking loads), which clearly do not lend themselves to interruption.

***Achievable Potential***: Achievable potential is a subset of technical potential and takes into account the customers’ ability and willingness to participate in load reduction programs subject to their unique business priorities, operating requirements, and economic (price) considerations. Evaluation of achievable potential is a significant refinement of the Company’s 2003 Least Cost Plan assessment of demand response, which focused on technical potential. In this assessment, estimates of achievable potential were derived by adjusting technical potentials by two factors: expected rates of ***program*** and ***event*** participation. Assumed rates of program and event participation were estimated based on the recent experiences of PSE, other utilities in the Northwest, other national utilities, and Regional Transmission Organizations (RTOs) that have offered similar programs.

Demand response options are not equally applicable to or effective in all segments of the electricity consumer market, and their impacts tend to be end-use specific. Recognizing this, the study employed a "bottom-up" approach, which involved first breaking down PSE's system load by sector, market segment, and end use; estimating demand response potentials at the end-use level; and then aggregating the end-use resource potentials estimates to sector and system levels. The approach was implemented in seven steps as follows. The general approach for estimation of demand response potentials is illustrated in Figure V.1.

**Figure V.1: Demand-Response Potentials Assessment Methodology**




***1) Define customer sectors and market segments***. System load was disaggregated into four sectors: 1) residential, 2) commercial, 3) industrial, and 4) other. The commercial sector was further broken down into eleven segments. Consistent with the analysis of energy efficiency potentials assessment, 14 industrial sectors (wastewater treatment was not included) and 11 commercial segments were analyzed.

***2) Create sector and segment load profiles***. NWPCC's regional load profiles were applied to PSE's sales data to generate sector- and segment-specific load shapes.

***3) Develop sector- and segment-specific typical peak day load profiles***. "Typical" weekday profiles were developed for winter (January and February) and summer (July and August). Contributions to system peak for each customer class and market segments were estimated based on class and end-use load shapes obtained from the Northwest Power and Conservation Council. Since PSE's system peak typically occurs during winter months, summer period was not considered (see Table V.1).

**Table V.1: Class and Market Segment Contributions to System Peak**

| Sector/Segment | Winter a.m. | Winter p.m. |
|---|---|---|
| **Industrial** | 164,584 | 159,757 |
| **Commercial** | | |
| Education | 186,342 | 112,843 |
| Food Stores | 23,350 | 23,761 |
| Hospitals | 18,034 | 16,196 |
| Hotels/Motels | 47,107 | 47,974 |
| Other Health | 52,341 | 42,712 |
| Miscellaneous | 369,354 | 356,268 |
| Offices | 295,318 | 243,606 |
| Assembly | 30,480 | 29,897 |
| Restaurants | 8,436 | 9,339 |
| Retail | 157,670 | 166,697 |
| Warehouses | 232,038 | 121,477 |
| **Residential** | 1,800,324 | 1,958,354 |

***4) Screen customer segments and end uses for eligibility.*** This step involved screening of customers for applicability of specific demand-response strategies. For example, the hospital segment and certain commercial end uses such as cooking loads in the restaurant segment were excluded.

***5) Estimate end-use shares by sector and market segments***. End-use shares were estimated by applying annual end-use load profiles obtained from the Northwest Power and Conservation Council. End-Use contributions to peak load by customer class and market segment are shown in Table V.2

**Table V.2: End-Use Shares by Customer Class and Market Segment**

| Sector/Segment | Space Heat | Cooling | Water Heating | Lighting | Refrigeration | Plug Load | Process |
|---|---|---|---|---|---|---|---|
| **Industrial** | 8,229 | 16,458 | 8,229 | 41,146 | 16,458 | 16,458 | 57,604 |
| **Commercial** | | | | | | | |
| Education | 21,632 | 1,694 | 7,191 | 125,805 | 7,837 | 22,183 | |
| Food Stores | 4,091 | 14 | 690 | 4,282 | 13,920 | 1,251 | |
| Hospitals | 5,806 | 1,552 | | 7,385 | 1,141 | 5,267 | |
| Hotels/Motels | 13,354 | 4,307 | 4,967 | 27,262 | 1,718 | 7,631 | |
| Other Health | 6,903 | 2,635 | 184 | 25,439 | 379 | 16,998 | |
| Miscellaneous | 249,352 | 3,037 | 9,150 | 154,179 | 7,358 | 38,772 | |
| Offices | 31,570 | 75,591 | 3,036 | 127,393 | 1,900 | 66,113 | |
| Assembly | 7,020 | 2,566 | 194 | 20,596 | 1,324 | 4,917 | |
| Restaurants | 380 | 92 | 55 | 5,253 | 2,568 | 1,625 | |
| Retail | 49,184 | 24,081 | 2,541 | 111,751 | 3,715 | 22,173 | |
| Warehouses | 40,247 | 10,208 | 1,913 | 111,766 | 6,099 | 61,805 | |
| **Residential** | 1,051,486 | 3,706 | 351,448 | 225,013 | | 392,908 | |

***6) Estimate technical potential***. Technical potential for each demand response strategy is assumed to be a function of customer eligibility in each class, affected end-uses in that class, and the expected impact of the strategy on the targeted end-uses. Analytically, technical potential (*TP*) for demand-response strategy *s* was calculated as the sum of impacts at the end-use level *e* generated in customer class *c* by the strategy, that is:

$$TP_s = \sum TP_{sce}$$

and

$$TP_{sce} = LE_{cs} \times EUS_{cs} \times LI_{se}$$

where,

- $LE_c$ (load eligibility) represents the percent of customer class loads that are eligible for strategy *s*
- $EUS_{cs}$ (end-use share) represents share of end-use *e* in customer class *c*
- $LI_{se}$ (load impact) is percent reduction in end-use load *e* resulting from strategy *s*

Load eligibility thresholds were established by calculating the percent of load by customer class and market segment that meet load criterion for each strategy. For example, only those customers with minimum loads of 250 kW were deemed eligible for participation in curtailment contracts and demand buy-back strategies; and maximum load for residential and small commercial TOU strategy was set at 30kW.

For each demand-response strategy, estimates of end-use load impacts were developed by applying the fraction of load for each end use that might be curtailed based on available data from the California Energy Commission's recent assessments of load reduction opportunities in commercial and industrial buildings and impact evaluations of demand-side management programs.

PSE's hourly system load and sales by customer class, and end-use load shapes available from the Northwest Power and Conservation Council, served as the primary data sources for this assessment. Estimates of expected load impacts resulting from various demand response strategies were based on data available from the commercial and industrial Enhanced Automation Study sponsored by the California Energy Commission, and the experiences of PSE and other utilities in the Northwest with various demand-side management programs. Expected load impacts by affected end uses from the five demand response strategies are shown in Table V.3.

***7) Estimate achievable potential***. Finally, for each demand response strategy, achievable potential (*AP*) was then calculated as the product of technical potential, program participation rate (*PP*) and expected event participation (*EP*) rates, that is:

$$AP_s = \sum TP_{sce} \times PP_s \times EP_s$$

Estimates of potential program penetration and event participation were derived through a review of available research literature on a large number of demand response programs offered by national RTOs and utilities in the Northwest and elsewhere in the country (see Table V.4). See Appendix D for bibliography of the reviewed reports and data sources.

**Table V.3: Expected Load Impacts Resulting from Demand Response Strategies**

| Sector/Segment | Space Heating | Cooling | Hot Water | Lighting | Plug Load | Process |
|---|---|---|---|---|---|---|
| **Industrial** | 20% | 20% | 20% | 20% | 12% | 12% |
| **Commercial** | | | | | | |
| Education | 13% | 13% | 13% | 13% | 12% | |
| Food Stores | 18% | 18% | 18% | 18% | 12% | |
| Hospitals | 12% | 12% | 12% | 12% | 12% | |
| Hotels/Motels | 12% | 12% | 12% | 12% | 12% | |
| Other Health | 15% | 15% | 15% | 15% | 12% | |
| Miscellaneous | 12% | 12% | 12% | 12% | 12% | |
| Offices | 13% | 13% | 13% | 13% | 12% | |
| Assembly | 12% | 12% | 12% | 12% | 12% | |
| Restaurants | 12% | 12% | 12% | 12% | 12% | |
| Retail | 12% | 12% | 12% | 12% | 12% | |
| Warehouses | 12% | 12% | 12% | 12% | 12% | |
| **Residential** | 30% | 10% | 19% | 10% | 10% | |

**Table V.4: Assumed Program and Event Participation Rates**

| Customer Class | Direct Load Control | Curtailment Contracts | TOU | Critical Peak Pricing | Demand Buy-Back |
|---|---|---|---|---|---|
| **Industrial** | | | | | |
| Program Participation | | 25% | 25% | 50% | 50% |
| Event Participation | | 90% | 90% | 75% | 30% |
| **Commercial** | | | | | |
| Program Participation | 0% | 25% | 25% | 50% | 75% |
| Event Participation | 0% | 90% | 90% | 75% | 30% |
| **Residential** | | | | | |
| Program Participation | 25% | | 35% | 50% | |
| Event Participation | 100% | | 90% | 75% | |

## Summary of the Results

The results of this assessment, as summarized in Table V.4, indicate that critical peak pricing and direct load control of residential space heating and water heating, with achievable potentials of 155 MW (4.6% of system peak) and 95 MW (2.8% of system peak), respectively, offer the largest opportunities for demand response interventions.

Achievable peak reductions from time-of-use tariffs are estimated at 49 MW, representing 1.5% of system peak. Opportunities resulting from curtailment contracts and demand buy-back are expected to be relatively small, averaging between 0.5% and 0.8% of system peak. Although the potentials for different demand response strategies are not mutually exclusive, hence not additive, it is estimated that combinations of these strategies could achieve 200 MW to 300 MW of total peak demand reduction.

The demand-response strategies considered here also vary significantly with respect to their costs. Costs for direct load control, time-of-use tariffs, and critical peak pricing were estimated on a kW basis. For direct load control and time-of-use tariffs, costs were estimated using the most recent data from PSE and other regional utilities with experience in similar programs, especially Portland General Electric Company. For both strategies, it was assumed that the total estimated achievable potentials would be captured in five years and that participants would remain in the program for seven years, after which customers would have to be re-recruited if the savings are to continue. The choice of the seven-year participation was based on the expectation that most customers tend to relocate after seven years or less.

**Table V.5: Demand-Response Potentials Summary - 2025**

| Sector | Direct Load Control | TOU | Critical Peak Pricing | Curtail-ment Contracts | Demand Buy-Back |
|---|---|---|---|---|---|
| **Industrial** | | | | | |
| Technical Potential (MW) | - - - | 4.9 | 19.8 | 12.2 | 14.8 |
| Achievable Potential (MW) | - - - | 1.7 | 7.4 | 2.7 | 4.4 |
| **Commercial** | | | | | |
| Technical Potential (MW) | - - - | 14.8 | 164.5 | 66.4 | 75.5 |
| Market Potential (MW) | - - - | 5.2 | 72.1 | 14.9 | 22.6 |
| **Residential** | | | | | |
| Technical Potential (MW) | 381.3 | 121.5 | 202.5 | - - - | - - - |
| Achievable Potential (MW) | 95.3 | 42.5 | 75.9 | - - - | - - - |
| **Total*** | | | | | |
| Technical Potential (MW) | 381 | 141 | 387 | 79 | 90 |
| % of System Peak | 11.2% | 4.1% | 11.4% | 2.3% | 2.7% |
| Achievable Potential (MW) | 95 | 49 | 155 | 18 | 27 |
| % of System Peak | 2.8% | 1.5% | 4.6% | 0.5% | 0.8% |
| **Average Cost ($/kW)** | $55.0 | $44.1 | $21.6 | NA | NA |
| **Average Cost ($/MWh)** | NA | NA | NA | $154.7 | $154.7 |

* Since not all demand response strategies are mutually exclusive, the figures are not additive.

The results of the analysis show that, based on the available data, critical peak pricing has the lowest average cost at $21.6 per kW represents the least-cost option. Time-of use-tariffs ($44.1/kW) and direct load control ($55/kW) have the next lowest costs.

Since participant incentives for curtailment contracts and demand-buy-back programs are generally based on reduction in energy, costs for these strategies were estimated on a dollar-per-MWh basis. Based on the results of the commercial- and industrial-sector load reduction programs offered by PSE and other regional utilities during the summer of 2001, the achievable potentials for these strategies appear to be relatively small, mainly due to low program and/or event participation. The data shows that of the 457 eligible customers only 19 (4%), representing about 3% of the eligible load, participated in PSE's program.

Through its demand buy-back program in 2001, PSE was able to acquire a total of 21.1 MWh (approximately 2 MW) at an average cost of nearly $155/MWh. Participation levels in such programs are to a large extent a function of incentive amounts, but they also depend on the customers' willingness and ability to commit to curtailment. An analysis of PSE's program activity during the spring and summer of 2001 indicates that load response to prices was indeed relatively inelastic, with an estimated elasticity of 0.8%. This indicates that a 1% increase in incentives is likely to increase load reduction by 0.8%. The results of this analysis suggest that significantly larger prices must be paid if PSE is to capture all or most of the expected achievable potential for such demand response strategies.

Assessment of demand-response potential poses considerable analytic challenges and tends to be less precise than for energy efficiency. This is particularly the case in assessing achievable potentials for market-based strategies such as curtailment contracts and demand buy-back, due to the lack of sufficient market data on the participant's willingness to participate in such programs. In its assessment of demand-response strategies, PSE has relied on innovative methods and the best available data. A more accurate assessment of the achievable amounts of demand-response potentials would require better market data and more rigorous analyses of customers' willingness to participate in demand-response programs. The results of this assessment, therefore, are to be regarded as indicative, rather than conclusive.

# Appendix A: Energy Efficiency Measures

**Table A.1: Commercial Energy Efficiency Measures - Puget Sound Energy**

| Fuel | End Use | Measure Name | 2003 LCP | 2005 LCP Tech | 2005 LCP Achievable | 2004 NWPPC |
|---|---|---|---|---|---|---|
| Electric | HVAC | Air-Cooled HP Package, 5 tons, SEER=11 | | x | x | |
| Electric | HVAC | Air-Cooled HP Package, 5 tons, SEER=12 | | x | x | x |
| Electric | HVAC | Chiller Tune-Up / Diagnostics | x | x | x | |
| Electric | HVAC | Clock / Programmable Thermostat | x | x | x | |
| Electric | HVAC | Cool Roofs (Reflective and Spray Evaporative) | x | x | | x |
| Electric | HVAC | Decrease Cooling Tower Approach Temperature, 300 Tons, 6 Deg F | | x | x | x |
| Electric | HVAC | Duct Insulation | x | x | x | x |
| Electric | HVAC | Duct Repair and Sealing | x | x | x | |
| Electric | HVAC | DX Tune-Up / Diagnostics | x | x | x | |
| Electric | HVAC | EMS Optimization | x | x | x | x |
| Electric | HVAC | Energy Efficient Fan & Pump Motors (ODP) | x | x | x | x |
| Electric | HVAC | HE Chiller, 0.51 kW/ton, 300 Tons | x | x | x | |
| Electric | HVAC | Hi-Eff DX Packaged System, 10 tons, EER=11.3 | x | x | x | x |
| Electric | HVAC | High Efficiency Windows (Low-E Glass or Multiple Glazed) | x | x | x | x |
| Electric | HVAC | Installation of Air Side Economizers | x | x | x | x |
| Electric | HVAC | Installation of Automated Building Ventilation Control ( Via Occupancy Sensors, CO2 Sensors, Etc.) | x | x | x | x |
| Electric | HVAC | Installation of Chiller Economizers (water side) | x | x | x | x |
| Electric | HVAC | Installation of Direct of Indirect Evaporative Cooling, Evaporative Pre-Cooling, and Absorption Cooling | x | x | | x |
| Electric | HVAC | Installation of Energy Management Systems | x | x | x | x |
| Electric | HVAC | Insulation of Pipes | x | x | x | x |
| Electric | HVAC | Occupancy Sensor for room HVAC units | | x | x | |
| Electric | HVAC | Optimize Chilled Water and Condenser Water Settings | x | x | x | x |

| Fuel | End Use | Measure Name | 2003 LCP | 2005 LCP Tech | 2005 LCP Achiev able | 2004 NWPPC |
|---|---|---|---|---|---|---|
| Electric | HVAC | Primary/Secondary De-coupled Chilled Water System | | x | x | x |
| Electric | HVAC | Roof / Ceiling Insulation | x | x | x | x |
| Electric | HVAC | Two-Speed Cooling Tower, 300 Tons | | x | x | x |
| Electric | HVAC | VSD Chiller, 0.47 kW/ton, 300 Tons | | x | x | |
| Electric | HVAC | VSD Cooling Tower, 300 Tons | | x | x | x |
| Electric | HVAC | VSD, ASD Fan & Pump Applications | x | x | x | x |
| Electric | Lighting | 10 % More Efficient Design (Lighting) | x | | | |
| Electric | Lighting | 20 % More Efficient Design (Lighting) | x | | | |
| Electric | Lighting | 4' 1L T5HO, EB | x | x | x | x |
| Electric | Lighting | 4' 1L T8 Premium, EB | x | x | x | x |
| Electric | Lighting | 4' 2L T5HO, EB | x | x | x | x |
| Electric | Lighting | 4' 2L T8 Premium, EB | x | x | x | x |
| Electric | Lighting | RET 2L4'T8, 1EB | x | | | |
| Electric | Lighting | 4' 3L T8 Premium, EB | | x | x | |
| Electric | Lighting | 4' 3L T8, EB | | x | x | x |
| Electric | Lighting | 4' 4L T8 Premium, EB | x | x | x | |
| Electric | Lighting | 4' 4L T8, EB | | x | x | x |
| Electric | Lighting | 8' 1L T12, 60W, EB | x | x | x | x |
| Electric | Lighting | 8' 2L T12, 60W, EB | x | x | x | x |
| Electric | Lighting | 8' 2L T8, EB | | x | x | x |
| Electric | Lighting | ROB 2L4' Premium T8, 1EB | x | | | |
| Electric | Lighting | ROB 4L4' Premium T8, 1EB | x | | | |
| Electric | Lighting | CFL Screw-in, Modular 18W | x | x | x | |
| Electric | Lighting | Continuous Dimming, 10-4' Fluorescent Fixtures | x | x | x | x |
| Electric | Lighting | Continuous Dimming, 5-4' Fluorescent Fixtures | x | x | x | x |
| Electric | Lighting | Continuous Dimming, 5-8' Fluorescent Fixtures | x | x | x | x |
| Electric | Lighting | Halogen PAR Flood, 90W | x | x | x | |
| Electric | Lighting | High Pressure Sodium 250W Lamp | x | | | x |
| Electric | Lighting | Metal Halide, 50W | x | x | | x |
| Electric | Lighting | HPS, 50W | | x | | x |
| Electric | Lighting | Occupancy Sensor, 4-4' Fluorescent Fixtures | x | x | x | x |

| Fuel | End Use | Measure Name | 2003 LCP | 2005 LCP Tech | 2005 LCP Achiev able | 2004 NWPPC |
|---|---|---|---|---|---|---|
| Electric | Lighting | Occupancy Sensor, 4-8' Fluorescent Fixtures | x | x | x | x |
| Electric | Lighting | Occupancy Sensor, 8-4' Fluorescent Fixtures | x | x | x | x |
| Electric | Lighting | Outdoor Lighting Controls (Photocell/Timeclock) | x | | | x |
| Electric | Lighting | LED Exit Signs | | | | x |
| Electric | Other | ENERGY STAR or Better Office Equipment: Computer | x | x | x | x |
| Electric | Other | ENERGY STAR or Better Office Equipment: Copiers | x | x | x | x |
| Electric | Other | ENERGY STAR or Better Office Equipment: Monitors | x | x | x | x |
| Electric | Other | ENERGY STAR or Better Office Equipment: Printers | x | x | x | x |
| Electric | Other | High-Efficiency Convection Oven | x | x | x | |
| Electric | Other | High-Efficiency Range and Oven | x | | | |
| Electric | Other | Smart Networks | x | x | x | x |
| Electric | Refrigeration | Anti-Sweat (Humidistat) Controls | x | x | x | x |
| Electric | Refrigeration | Compressor VSD retrofit | x | x | x | x |
| Electric | Refrigeration | Demand Control Defrost - Electric | x | x | x | x |
| Electric | Refrigeration | Demand Control Defrost - Hot Gas | x | x | x | x |
| Electric | Refrigeration | High Efficiency Case Fans | x | x | x | |
| Electric | Refrigeration | High-Efficiency Compressors | x | x | x | x |
| Electric | Refrigeration | Installation of Floating Condenser Head Pressure Controls | x | x | x | x |
| Electric | Refrigeration | Night Covers for Display Cases | x | x | x | |
| Electric | Refrigeration | Reduced Speed or Cycling of Evaporator Fans | x | x | | x |
| Electric | Refrigeration | Refrigeration Commissioning | x | x | x | |
| Electric | Refrigeration | Strip Curtains for Walk-Ins | x | x | x | |
| Electric | Water Heating | Demand controlled circulating systems | x | x | | x |
| Electric | Water Heating | Heat Pump Water Heater | x | x | | x |
| Electric | Water Heating | High-Efficiency Water Heater (electric) | x | x | | x |
| Electric | Water Heating | Hot Water (SHW) Pipe Insulation | x | x | x | x |
| Electric | Water Heating | Low-Flow Showerheads | | | | x |
| Electric | Water Heating | Faucet Aerators | | | | x |
| Electric | Water Heating | Chemical Dishwashing system | | | | x |
| Gas | HVAC | Boiler Tune-Up | x | x | x | |
| Gas | HVAC | Clock / Programmable Thermostat | x | x | x | |

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| Fuel | End Use | Measure Name | 2003 LCP | 2005 LCP Tech | 2005 LCP Achievable | 2004 NWPPC |
|---|---|---|---|---|---|---|
| Gas | HVAC | Duct Insulation | x | x | x | x |
| Gas | HVAC | Duct Repair and Sealing | x | x | x | |
| Gas | HVAC | High Efficiency Gas Furnace/Boiler | x | x | x | |
| Gas | HVAC | High Efficiency Windows (Multiple Glazed, Low Emissivity) | x | x | x | x |
| Gas | HVAC | Installation of Air Side Heat Recovery Systems | x | x | | x |
| Gas | HVAC | Installation of Energy Management Systems (EMS) | x | x | x | x |
| Gas | HVAC | Insulation (ceiling) | x | x | | x |
| Gas | HVAC | Insulation (wall) | x | x | x | x |
| Gas | HVAC | Insulation of Pipes | x | x | x | x |
| Gas | HVAC | Occupancy Sensor for room HVAC units | | x | x | |
| Gas | HVAC | Stack Heat Exchanger | x | x | x | |
| Gas | Other | Efficient Infrared Griddle | x | x | x | |
| Gas | Other | High-Efficiency Convection Oven | x | x | x | |
| Gas | Other | Infrared Conveyer Oven | x | x | x | |
| Gas | Other | Infrared Fryer | x | x | x | |
| Gas | Other | Installation of Solar Pool/Spa Heating Systems | x | x | x | |
| Gas | Other | Installation of Swimming Pool / Spa Covers | x | x | x | |
| Gas | Other | Power Burner Fryer | x | x | x | |
| Gas | Other | Power Burner Oven | x | x | | |
| Gas | Water Heating | High-Efficiency Water Heater (gas), 100 gal., 88 kBTU, EF=.80 | x | x | | |
| Gas | Water Heating | High-Efficiency Water Heater (gas), 100 gal., 120 kBTU, EF=.95 | | x | x | |
| Gas | Water Heating | Hot Water (SHW) Pipe Insulation | x | x | x | x |
| Gas | Water Heating | Tankless Water Heater | x | x | x | x |
| Gas | Water Heating | Water Heater Tank Blanket/Insulation | x | x | x | x |

**Table A.2: Residential Energy Efficiency Measures – Puget Sound Energy**

| Fuel | End Use | Measure Name | 2003 LCP | 2005 LCP Tech | 2005 LCP Achiev able | 2004 NWPPC |
|---|---|---|---|---|---|---|
| Electric | HVAC | Addition of Attic and Crawlspace Ventilation | x | | | x |
| Electric | HVAC | Air-to-Air Heat Exchangers | x | | | x |
| Electric | HVAC | Ceiling R-0 to R-19 Insulation | x | x | x | x |
| Electric | HVAC | Ceiling R-19 to R-30 Insulation | | x | | |
| Electric | HVAC | Ceiling R-19 to R-38 Insulation | x | x | | x |
| Electric | HVAC | Comprehensive Shell Air Sealing – Inf. Reduction | x | x | | x |
| Electric | HVAC | Duct Testing and Sealing | x | x | | |
| Electric | HVAC | Duct Insulation (R-3 to R-8) | x | x | x | x |
| Electric | HVAC | ENERGY STAR New Construction | x | x | | x |
| Electric | HVAC | ENERGY STAR New Construction Plus | x | x | | |
| Electric | HVAC | ENERGY STAR or better Air Source Heat Pump, HSPF=8.0 | x | x | x | x |
| Electric | HVAC | ENERGY STAR or better Air Source Heat Pump, HSPF=8.5 | x | x | x | |
| Electric | HVAC | ENERGY STAR or better Room AC, 10 kBtu, EER=10.7 | x | x | | x |
| Electric | HVAC | ENERGY STAR or better Room AC, 12 kBtu, EER=10.7 | x | x | | |
| Electric | HVAC | ENERGY STAR or better Room AC, 14 kBtu, EER=10.7 | x | x | | |
| Electric | HVAC | ENERGY STAR or better Room AC, 8 kBtu, EER=10.7 | x | x | | |
| Electric | HVAC | ENERGY STAR Programmable Thermostat (Electronic w/ Adaptive Recovery) | x | x | x | x |
| Electric | HVAC | Floor R-0 to R-30 Insulation-Batts | x | x | x | x |
| Electric | HVAC | Floor R-5 to R-25 Insulation-Batts | | x | | |
| Electric | HVAC | Furnace Blower Motor Replacement | x | | | |
| Electric | HVAC | Geothermal Heat Pump | x | x | | x |
| Electric | HVAC | High-Efficiency Central AC, SEER=12 | | x | | |
| Electric | HVAC | High-Efficiency Central AC, SEER=14 | | x | | |
| Electric | HVAC | High Efficiency Ventilating Fans | x | | | |
| Electric | HVAC | HVAC Diagnostic Testing, Repair and Maintenance | x | x | x | x |
| Electric | HVAC | PTCS Duct Sealing &O&M | | x | x | x |
| Electric | HVAC | Super Good Cents / ENERGY STAR New Man. Housing | x | x | x | x |
| Electric | HVAC | Super Good Cents / ENERGY STAR New Man. Housing Plus | x | x | | |

| Fuel | End Use | Measure Name | 2003 LCP | 2005 LCP Tech | 2005 LCP Achievable | 2004 NWPPC |
|---|---|---|---|---|---|---|
| Electric | HVAC | Wall 2x4 R-0 to Blow-In R-13 Insulation (.86) | x | x | | x |
| Electric | HVAC | Wall 2x4 R-0 to Blow-In R-19 Insulation | | x | x | |
| Electric | HVAC | Windows (high efficiency / ENERGY STAR+) | x | x | x | x |
| Electric | Lighting | CFL Fixtures, 0.5 hr/day | x | x | | x |
| Electric | Lighting | CFL Fixtures, 2.5 hr/day | x | x | x | x |
| Electric | Lighting | CFL Fixtures, 6.0 hr/day | x | x | x | x |
| Electric | Lighting | CFL, 0.5 hr/day | x | x | x | x |
| Electric | Lighting | CFL, 2.5 hr/day | x | x | x | x |
| Electric | Lighting | CFL, 6.0 hr/day | x | x | x | x |
| Electric | Lighting | Fluorescent Torchieries, 0.5 hr/day | x | x | | x |
| Electric | Lighting | Fluorescent Torchieries, 2.5 hr/day | x | x | x | x |
| Electric | Lighting | Fluorescent Torchieries, 6.0 hr/day | x | x | x | x |
| Electric | Other | Convection Oven | x | x | | x |
| Electric | Other | ENERGY STAR or better Freezer | x | x | x | x |
| Electric | Other | ENERGY STAR or better Refrigerator | x | x | x | x |
| Electric | Other | High Efficiency Dryer With Moisture Sensor | | x | x | x |
| Electric | Other | Powerstrip with Occupancy Sensor | x | x | | x |
| Electric | Other | Removal of Secondary Freezer | x | x | x | x |
| Electric | Other | Removal of Secondary Refrigerator | x | x | x | x |
| Electric | Water Heating | Drain Water Heat Recovery (GFX) | x | x | x | x |
| Electric | Water Heating | Energy Star DW (EF=0.58) | x | x | x | x |
| Electric | Water Heating | Energy Star Vertical-Axis Clothes Washer: SEHA CW Tier 2 (EF=3.25) | x | x | x | x |
| Electric | Water Heating | Faucet Aerators | | x | x | x |
| Electric | Water Heating | HE Water Heater (EF=0.95) | x | x | x | x |
| Electric | Water Heating | Heat Pump Water Heater (EF=2.9) | x | x | | x |
| Electric | Water Heating | Horizontal-Axis Clothes Washer: Energy Star CW (EF=2.5) | x | x | x | x |
| Electric | Water Heating | Hot Water Heater Tank Wrap (R-10) | | x | x | x |
| Electric | Water Heating | Hot Water Pipe Insulation | x | x | x | x |
| Electric | Water Heating | Low-Flow Showerheads | x | x | x | x |
| Electric | Water Heating | Solar Water Heater | x | x | | x |

| Fuel | End Use | Measure Name | 2003 LCP | 2005 LCP Tech | 2005 LCP Achiev able | 2004 NWPPC |
|---|---|---|---|---|---|---|
| Electric | Water Heating | Tankless Water Heater (EF=0.98) | x | x | | x |
| Electric | Water Heating | Water Heater Thermostat Setback | x | x | x | x |
| Gas | HVAC | Addition of Attic and Crawlspace Ventilation | x | | | x |
| Gas | HVAC | Ceiling R-0 to R-19 Insulation Blown-in (.71) | x | x | x | x |
| Gas | HVAC | Ceiling R-19 to R-30 Insulation Blown in (.73) | | x | | |
| Gas | HVAC | Ceiling R-19 to R-38 Insulation Blown in (.73) | x | x | | x |
| Gas | HVAC | Comprehensive Shell Air Sealing – Inf. Reduction | x | x | x | x |
| Gas | HVAC | Condensing Furnace, 92 AFUE | x | x | x | x |
| Gas | HVAC | Condensing Furnace, 96 AFUE | x | x | x | |
| Gas | HVAC | Duct Insulation (R-3 to R-8) | x | x | | x |
| Gas | HVAC | Duct Testing and Sealing | x | x | | |
| Gas | HVAC | ENERGY STAR New Construction | x | x | | x |
| Gas | HVAC | ENERGY STAR New Construction Plus | x | x | | |
| Gas | HVAC | ENERGY STAR Programmable Thermostat | x | x | x | x |
| Gas | HVAC | Floor R-0 to R-30 Insulation-Batts | x | x | | x |
| Gas | HVAC | Floor R-5 to R-25 Insulation-Batts | | x | | |
| Gas | HVAC | Furnace Diagnostic Testing, Repair and Maintenance | x | x | x | x |
| Gas | HVAC | High Efficiency Condensing Boiler (AFUE = 90%) | x | x | | x |
| Gas | HVAC | Integrated Space and Water Heating | x | x | | x |
| Gas | HVAC | Natural Choice / ENERGY STAR New Man. Housing | x | x | | x |
| Gas | HVAC | PTCS Duct Sealing & O&M | | x | x | x |
| Gas | HVAC | Wall 2x4 R-0 to Blow-In R-13 Insulation (.86) | x | x | | x |
| Gas | HVAC | Wall 2x4 R-0 to Blow-In R-19 Insulation | | x | x | |
| Gas | HVAC | Windows (high efficiency / ENERGY STAR+) | x | x | x | x |
| Gas | Other | Convection Oven | x | x | | x |
| Gas | Other | High Efficiency Dryer With Moisture Sensor | | x | x | |
| Gas | Water Heating | Drain Water Heat Recovery (GFX) | x | x | x | x |
| Gas | Water Heating | Energy Star DW (EF=0.58) | x | x | | |
| Gas | Water Heating | Energy Star Vertical-Axis Clothes Washer | x | x | | |
| Gas | Water Heating | Faucet Aerators | | x | x | x |
| Gas | Water Heating | HE Water Heater (EF=0.63) | x | x | x | x |

| Fuel | End Use | Measure Name | 2003 LCP | 2005 LCP Tech | 2005 LCP Achiev able | 2004 NWPPC |
|---|---|---|---|---|---|---|
| Gas | Water Heating | HE Water Heater (EF=0.70) | x | x | | |
| Gas | Water Heating | Horizontal-Axis Clothes Washer | x | x | | |
| Gas | Water Heating | Hot Water Heater Tank Wrap (R-10) | | x | x | x |
| Gas | Water Heating | Hot Water Pipe Insulation | x | x | x | x |
| Gas | Water Heating | Low-Flow Showerheads | x | x | x | x |
| Gas | Water Heating | Solar Water Heater | x | x | | x |
| Gas | Water Heating | Tankless Water Heater (EF=0.82) | x | x | | x |
| Gas | Water Heating | Water Heater Thermostat Setback | x | x | x | x |

**Table A.3: Other Energy Efficiency Measures - Puget Sound Energy**

| Fuel | End Use | Measure Name | 2003 LCP | 2005 LCP Tech | 2005 LCP Achieva ble | 2004 NWPPC |
|---|---|---|---|---|---|---|
| Electric | Other | LED Traffic Signals | | | | x |
| Electric | Other | Vending Machine Controller | | | | x |
| Electric | Other | Premium Efficiency Motors | | | | x |

# Appendix B: Measure Inputs

## Segment Definitions

### Residential

1= Single Family - Existing Construction

2= Multifamily - Existing Construction

3= Manufactured Homes – Existing Construction

4= Single Family - New Construction

5= Multifamily - New Construction

6= Manufactured Homes – New Construction

### Commercial

1= Existing Construction

2= New Construction

**Building Definitions**

### Commercial

1 = Office

2 = Retail

3 = Restaurant

4 = Grocery

5 = Warehouse

6 = School

7 = University

8 = Hospital

9 = Lodging

10 = Miscellaneous

## Residential

### Table B.1: Residential Electric

| Segment | Building | Base Number | Measure Number | Measure Name | Stock Usage | Base Usage | Incomplete Factor | Energy Savings | Feasibility Factor | Measure Life | Full Per Unit Cost | Full Base Measure Cost |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 1 | 120 | 120 | Base Heat Pump, 3 ton, HSPF=6.8 | 4989.83 | 4490.85 | 100.00% | 0.00% | 100.00% | 18 | $0.00 | $2,275.00 |
| 1 | 1 | 120 | 121 | ENERGY STAR or better Air Source Heat Pump, HSPF=8.0 | 4989.83 | 4490.85 | 82.00% | 15.00% | 50.00% | 18 | $160.00 | $2,275.00 |
| 1 | 1 | 120 | 122 | ENERGY STAR or better Air Source Heat Pump, HSPF=8.5 | 4989.83 | 4490.85 | 99.14% | 20.00% | 50.00% | 18 | $620.00 | $2,275.00 |
| 1 | 1 | 120 | 123 | ENERGY STAR Programmable Thermostat (Electronic w/ Adaptive Recovery) | 4989.83 | 4989.83 | 47.29% | 6.00% | 80.00% | 12 | $150.00 | $2,275.00 |
| 1 | 1 | 120 | 124 | Ceiling R-0 to R-19 Insulation | 4989.83 | 4989.83 | 52.98% | 24.29% | 67.00% | 30 | $812.70 | $2,275.00 |
| 1 | 1 | 120 | 125 | Ceiling R-19 to R-38 Insulation | 4989.83 | 4989.83 | 52.98% | 8.40% | 33.00% | 30 | $812.70 | $2,275.00 |
| 1 | 1 | 120 | 126 | Floor R-0 to R-30 Insulation-Batts | 4989.83 | 4989.83 | 54.50% | 24.12% | 33.00% | 30 | $1,512.00 | $2,275.00 |
| 1 | 1 | 120 | 127 | Wall 2x4 R-0 to Blow-In R-19 Insulation | 4989.83 | 4989.83 | 54.50% | 20.01% | 50.00% | 30 | $1,063.70 | $2,275.00 |
| 1 | 1 | 120 | 128 | Comprehensive Shell Air Sealing - Inf. Reduction | 4989.83 | 4989.83 | 40.00% | 6.34% | 90.00% | 10 | $650.00 | $2,275.00 |
| 1 | 1 | 120 | 129 | PTCS Duct Sealing &O&M | 4989.83 | 4989.83 | 72.00% | 25.32% | 50.00% | 20 | $750.00 | $2,275.00 |
| 1 | 1 | 120 | 130 | Duct Insulation (R-3 to R-8) | 4989.83 | 4989.83 | 21.64% | 9.01% | 50.00% | 30 | $376.00 | $2,275.00 |
| 1 | 1 | 120 | 131 | HVAC Diagnostic Testing, Repair and Maintenance | 4989.83 | 4989.83 | 48.43% | 4.00% | 100.00% | 10 | $123.00 | $2,275.00 |
| 1 | 1 | 120 | 132 | Windows (high efficiency / ENERGY STAR+) | 4989.83 | 4989.83 | 84.98% | 16.90% | 75.00% | 30 | $3,100.69 | $2,275.00 |
| 1 | 1 | 160 | 160 | Base Room Air Conditioner, 12 kBtu, EER=9.7 | 738.64 | 685.34 | 100.00% | 0.00% | 100.00% | 15 | $0.00 | $279.00 |
| 1 | 1 | 160 | 161 | ENERGY STAR or better Room AC, 12 kBtu, EER=10.7 | 738.64 | 685.34 | 99.11% | 9.35% | 100.00% | 18 | $406.00 | $279.00 |
| 1 | 1 | 180 | 180 | Base Resistance Space Heating | 8008.29 | 8008.29 | 100.00% | 0.00% | 100.00% | 18 | $0.00 | $1,500.00 |
| 1 | 1 | 180 | 181 | ENERGY STAR or better Air Source Heat Pump, HSPF=8.0 | 8008.29 | 8008.29 | 82.00% | 52.33% | 3.50% | 18 | $160.00 | $1,500.00 |
| 1 | 1 | 180 | 182 | ENERGY STAR or better Air Source Heat Pump, HSPF=8.5 | 8008.29 | 8008.29 | 99.14% | 55.14% | 1.17% | 18 | $620.00 | $1,500.00 |
| 1 | 1 | 180 | 183 | ENERGY STAR Programmable Thermostat (Electronic w/ Adaptive Recovery) | 8008.29 | 8008.29 | 47.29% | 6.00% | 80.00% | 12 | $100.00 | $1,500.00 |
| 1 | 1 | 180 | 184 | Ceiling R-0 to R-19 Insulation | 8008.29 | 8008.29 | 52.98% | 24.29% | 67.00% | 30 | $812.70 | $1,500.00 |
| 1 | 1 | 180 | 185 | Ceiling R-19 to R-38 Insulation | 8008.29 | 8008.29 | 52.98% | 8.40% | 33.00% | 30 | $812.70 | $1,500.00 |
| 1 | 1 | 180 | 186 | Floor R-0 to R-30 Insulation-Batts | 8008.29 | 8008.29 | 54.50% | 24.12% | 33.00% | 30 | $1,512.00 | $1,500.00 |
| 1 | 1 | 180 | 187 | Wall 2x4 R-0 to Blow-In R-19 Insulation | 8008.29 | 8008.29 | 54.50% | 20.01% | 50.00% | 30 | $1,063.70 | $1,500.00 |
| 1 | 1 | 180 | 188 | Comprehensive Shell Air Sealing - Inf. Reduction | 8008.29 | 8008.29 | 40.00% | 6.34% | 90.00% | 10 | $650.00 | $1,500.00 |
| 1 | 1 | 180 | 189 | PTCS Duct Sealing &O&M | 8008.29 | 8008.29 | 72.00% | 8.00% | 50.00% | 20 | $750.00 | $1,500.00 |
| 1 | 1 | 180 | 190 | Duct Insulation (R-3 to R-8) | 8008.29 | 8008.29 | 21.64% | 9.01% | 50.00% | 30 | $376.00 | $1,500.00 |
| 1 | 1 | 180 | 191 | HVAC Diagnostic Testing, Repair and Maintenance | 8008.29 | 8008.29 | 48.43% | 4.00% | 100.00% | 10 | $123.00 | $1,500.00 |
| 1 | 1 | 180 | 192 | Windows (high efficiency / ENERGY STAR+) | 8008.29 | 8008.29 | 84.98% | 16.90% | 75.00% | 30 | $3,100.69 | $1,500.00 |
| 1 | 1 | 200 | 200 | Base Lighting Combined | 2328.00 | 2328.00 | 100.00% | 0.00% | 100.00% | 1 | $0.00 | #N/A |
| 1 | 1 | 200 | 201 | CFL, 6.0 hr/day | 2328.00 | 2328.00 | 69.28% | 21.31% | 90.00% | 5 | $4.50 | #N/A |
| 1 | 1 | 200 | 202 | CFL, 2.5 hr/day | 2328.00 | 2328.00 | 89.04% | 39.27% | 90.00% | 7 | $4.50 | #N/A |
| 1 | 1 | 200 | 203 | CFL, 0.5 hr/day | 2328.00 | 2328.00 | 93.77% | 4.42% | 90.00% | 7 | $4.50 | #N/A |

## Table B.1: Residential Electric

| Segment | Building | Base Number | Measure Number | Measure Name | Stock Usage | Base Usage | Incomplete Factor | Energy Savings | Feasibility Factor | Measure Life | Full Per Unit Cost | Full Base Measure Cost |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 1 | 200 | 204 | CFL Fixtures, 6.0 hr/day | 2328.00 | 2328.00 | 69.28% | 21.31% | 5.00% | 8 | $23.33 | #N/A |
| 1 | 1 | 200 | 205 | CFL Fixtures, 2.5 hr/day | 2328.00 | 2328.00 | 89.04% | 39.27% | 5.00% | 10 | $23.33 | #N/A |
| 1 | 1 | 200 | 206 | CFL Fixtures, 0.5 hr/day | 2328.00 | 2328.00 | 93.77% | 4.42% | 5.00% | 10 | $23.33 | #N/A |
| 1 | 1 | 200 | 207 | Fluorescent Torchieries, 6.0 hr/day | 2328.00 | 2328.00 | 100.00% | 21.31% | 5.00% | 5 | $23.00 | #N/A |
| 1 | 1 | 200 | 208 | Fluorescent Torchieries, 2.5 hr/day | 2328.00 | 2328.00 | 100.00% | 39.27% | 5.00% | 7 | $23.00 | #N/A |
| 1 | 1 | 200 | 209 | Fluorescent Torchieries, 0.5 hr/day | 2328.00 | 2328.00 | 100.00% | 4.42% | 5.00% | 7 | $23.00 | #N/A |
| 1 | 1 | 300 | 300 | Base Refrigerator, 20 cu.ft. | 848.44 | 848.44 | 100.00% | 0.00% | 100.00% | 15 | $0.00 | $549.99 |
| 1 | 1 | 300 | 301 | ENERGY STAR or better Refrigerator | 848.44 | 678.75 | 73.54% | 15.00% | 100.00% | 15 | $79.00 | $549.99 |
| 1 | 1 | 310 | 310 | Base Secondary Refrigerator | 1000.00 | 1000.00 | 100.00% | 0.00% | 100.00% | 15 | $0.00 | #N/A |
| 1 | 1 | 310 | 311 | Removal of Secondary Refrigerator | 1000.00 | 1000.00 | 100.00% | 100.00% | 15.00% | 7 | $200.00 | #N/A |
| 1 | 1 | 400 | 400 | Base Freezer | 823.49 | 823.49 | 100.00% | 0.00% | 100.00% | 15 | $0.00 | $309.99 |
| 1 | 1 | 400 | 401 | ENERGY STAR or better Freezer | 823.49 | 658.79 | 92.80% | 10.00% | 100.00% | 15 | $50.00 | $309.99 |
| 1 | 1 | 410 | 410 | Base Secondary Freezer | 950.00 | 950.00 | 100.00% | 0.00% | 100.00% | 15 | $0.00 | #N/A |
| 1 | 1 | 410 | 411 | Removal of Secondary Freezer | 950.00 | 950.00 | 100.00% | 100.00% | 7.50% | 7 | $200.00 | #N/A |
| 1 | 1 | 500 | 500 | Base 40 gal. Water Heating (EF=0.917) | 3636.00 | 3489.29 | 100.00% | 0.00% | 100.00% | 15 | $0.00 | $189.99 |
| 1 | 1 | 500 | 501 | Heat Pump Water Heater (EF=2.9) | 3636.00 | 3636.00 | 99.90% | 50.00% | 40.00% | 15 | $1,750.00 | $189.99 |
| 1 | 1 | 500 | 502 | HE Water Heater (EF=0.95) | 3636.00 | 3489.29 | 93.70% | 3.47% | 40.00% | 15 | $80.00 | $189.99 |
| 1 | 1 | 500 | 503 | Solar Water Heater | 3636.00 | 3636.00 | 99.00% | 50.00% | 10.00% | 15 | $5,500.00 | $189.99 |
| 1 | 1 | 500 | 504 | Low-Flow Showerheads | 3636.00 | 3636.00 | 20.41% | 8.70% | 95.00% | 10 | $20.00 | $189.99 |
| 1 | 1 | 500 | 505 | Hot Water Pipe Insulation | 3636.00 | 3636.00 | 31.61% | 1.05% | 75.00% | 15 | $5.80 | $189.99 |
| 1 | 1 | 500 | 506 | Water Heater Thermostat Setback | 3636.00 | 3636.00 | 78.03% | 4.26% | 50.00% | 15 | $15.00 | $189.99 |
| 1 | 1 | 500 | 507 | Tankless Water Heater (EF=0.98) | 3636.00 | 3636.00 | 100.00% | 13.10% | 10.00% | 15 | $1,200.00 | $189.99 |
| 1 | 1 | 500 | 508 | Drain Water Heat Recovery (GFX) | 3636.00 | 3636.00 | 100.00% | 24.60% | 35.00% | 15 | $550.00 | $189.99 |
| 1 | 1 | 500 | 509 | Horizontal-Axis Clothes Washer: Energy Star CW (EF=2.5) | 3636.00 | 3636.00 | 97.00% | 12.37% | 50.00% | 14 | $280.00 | $189.99 |
| 1 | 1 | 500 | 510 | Energy Star Vertical-Axis Clothes Washer: SEHA CW Tier 2 (EF=3.25) | 3636.00 | 3636.00 | 78.97% | 15.01% | 50.00% | 14 | $350.00 | $189.99 |
| 1 | 1 | 500 | 511 | Energy Star DW (EF=0.58) | 3636.00 | 3636.00 | 82.42% | 5.00% | 100.00% | 13 | $70.00 | $189.99 |
| 1 | 1 | 500 | 512 | Hot Water Heater Tank Wrap (R-10) | 3636.00 | 3636.00 | 31.32% | 10.00% | 90.00% | 15 | $17.00 | $189.99 |
| 1 | 1 | 500 | 513 | Faucet Aerators | 3636.00 | 3636.00 | 73.40% | 1.65% | 90.00% | 15 | $4.82 | $189.99 |
| 1 | 1 | 600 | 600 | Base Dryer | 564.00 | 564.00 | 100.00% | 0.00% | 100.00% | 14 | $0.00 | $249.98 |
| 1 | 1 | 600 | 601 | High Efficiency Dryer With Moisture Sensor | 564.00 | 564.00 | 79.31% | 31.91% | 100.00% | 14 | $100.00 | $249.98 |
| 1 | 1 | 700 | 700 | Base Central AC, SEER=10 | 327.00 | 327.00 | 100.00% | 0.00% | 100.00% | 18 | $0.00 | $2,321.00 |
| 1 | 1 | 700 | 701 | High-Efficiency Central AC, SEER=12 | 327.00 | 255.06 | 99.14% | 16.67% | 100.00% | 18 | $277.00 | $2,321.00 |
| 1 | 1 | 700 | 702 | High-Efficiency Central AC, SEER=14 | 327.00 | 255.06 | 99.14% | 28.57% | 100.00% | 18 | $795.00 | $2,321.00 |
| 1 | 1 | 900 | 900 | Base Conventional Oven | 573.95 | 573.95 | 100.00% | 0.00% | 100.00% | 15 | $0.00 | $349.99 |
| 1 | 1 | 900 | 901 | Convection Oven | 573.95 | 573.95 | 100.00% | 14.46% | 100.00% | 15 | $120.00 | $349.99 |
| 1 | 1 | 950 | 950 | Base Plug Loads | 3389.50 | 3389.50 | 100.00% | 0.00% | 100.00% | 20 | $0.00 | #N/A |
| 1 | 1 | 950 | 951 | Powerstrip with Occupancy Sensor | 3389.50 | 3389.50 | 100.00% | 0.80% | 100.00% | 20 | $90.00 | #N/A |
| 2 | 1 | 120 | 120 | Base Exhaust Air Heat Pump, 2 ton, HSPF=6.8 | 1985.35 | 1786.82 | 100.00% | 0.00% | 50.00% | 18 | $0.00 | $1,900.00 |
| 2 | 1 | 120 | 121 | ENERGY STAR or better Air Source Heat Pump, HSPF=8.0 | 1985.35 | 1786.82 | 100.00% | 15.00% | 50.00% | 18 | $160.00 | $1,900.00 |
| 2 | 1 | 120 | 122 | ENERGY STAR or better Air Source Heat Pump, HSPF=8.5 | 1985.35 | 1786.82 | 100.00% | 20.00% | 50.00% | 18 | $620.00 | $1,900.00 |

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## Table B.1: Residential Electric

| Segment | Building | Base Number | Measure Number | Measure Name | Stock Usage | Base Usage | Incomplete Factor | Energy Savings | Feasibility Factor | Measure Life | Full Per Unit Cost | Full Base Measure Cost |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2 | 1 | 120 | 123 | ENERGY STAR Programmable Thermostat (Electronic w/ Adaptive Recovery) | 1985.35 | 1985.35 | 89.36% | 6.00% | 80.00% | 12 | $150.00 | $1,900.00 |
| 2 | 1 | 120 | 124 | Ceiling R-0 to R-19 Insulation | 1985.35 | 1985.35 | 59.83% | 14.20% | 67.00% | 30 | $447.20 | $1,900.00 |
| 2 | 1 | 120 | 125 | Ceiling R-19 to R-38 Insulation | 1985.35 | 1985.35 | 59.83% | 2.20% | 33.00% | 30 | $447.20 | $1,900.00 |
| 2 | 1 | 120 | 126 | Floor R-0 to R-30 Insulation-Batts | 1985.35 | 1985.35 | 59.91% | 10.56% | 33.00% | 30 | $582.40 | $1,900.00 |
| 2 | 1 | 120 | 127 | Wall 2x4 R-0 to Blow-In R-19 Insulation | 1985.35 | 1985.35 | 59.91% | 26.33% | 50.00% | 30 | $624.00 | $1,900.00 |
| 2 | 1 | 120 | 128 | Comprehensive Shell Air Sealing - Inf. Reduction | 1985.35 | 1985.35 | 20.00% | 14.40% | 90.00% | 10 | $650.00 | $1,900.00 |
| 2 | 1 | 120 | 129 | PTCS Duct Sealing &O&M | 1985.35 | 1985.35 | 36.00% | 17.27% | 50.00% | 20 | $630.00 | $1,900.00 |
| 2 | 1 | 120 | 130 | Duct Insulation (R-3 to R-8) | 1985.35 | 1985.35 | 39.99% | 0.68% | 50.00% | 30 | $376.00 | $1,900.00 |
| 2 | 1 | 120 | 132 | Windows (high efficiency / ENERGY STAR+) | 1985.35 | 1985.35 | 95.07% | 26.80% | 75.00% | 30 | $1,129.69 | $1,900.00 |
| 2 | 1 | 160 | 160 | Base Room Air Conditioner, 8 kBtu, EER=9.7 | 409.25 | 379.71 | 100.00% | 0.00% | 100.00% | 15 | $0.00 | $219.99 |
| 2 | 1 | 160 | 161 | ENERGY STAR or better Room AC, 8 kBtu, EER=10.7 | 409.25 | 379.71 | 100.00% | 9.35% | 100.00% | 18 | $270.00 | $219.99 |
| 2 | 1 | 180 | 180 | Base Resistance Space Heating | 2772.91 | 2772.91 | 100.00% | 0.00% | 100.00% | 18 | $0.00 | $990.00 |
| 2 | 1 | 180 | 181 | ENERGY STAR or better Air Source Heat Pump, HSPF=8.0 | 2772.91 | 2772.91 | 82.00% | 45.23% | 4.57% | 18 | $160.00 | $990.00 |
| 2 | 1 | 180 | 182 | ENERGY STAR or better Air Source Heat Pump, HSPF=8.5 | 2772.91 | 2772.91 | 100.00% | 48.45% | 1.52% | 18 | $620.00 | $990.00 |
| 2 | 1 | 180 | 183 | ENERGY STAR Programmable Thermostat (Electronic w/ Adaptive Recovery) | 2772.91 | 2772.91 | 89.36% | 6.00% | 80.00% | 12 | $100.00 | $990.00 |
| 2 | 1 | 180 | 184 | Ceiling R-0 to R-19 Insulation | 2772.91 | 2772.91 | 59.83% | 14.20% | 67.00% | 30 | $447.20 | $990.00 |
| 2 | 1 | 180 | 185 | Ceiling R-19 to R-38 Insulation | 2772.91 | 2772.91 | 59.83% | 2.20% | 33.00% | 30 | $447.20 | $990.00 |
| 2 | 1 | 180 | 186 | Floor R-0 to R-30 Insulation-Batts | 2772.91 | 2772.91 | 59.91% | 10.56% | 33.00% | 30 | $582.40 | $990.00 |
| 2 | 1 | 180 | 187 | Wall 2x4 R-0 to Blow-In R-19 Insulation | 2772.91 | 2772.91 | 59.91% | 26.33% | 50.00% | 30 | $624.00 | $990.00 |
| 2 | 1 | 180 | 188 | Comprehensive Shell Air Sealing - Inf. Reduction | 2772.91 | 2772.91 | 20.00% | 14.40% | 90.00% | 10 | $650.00 | $990.00 |
| 2 | 1 | 180 | 189 | PTCS Duct Sealing &O&M | 2772.91 | 2772.91 | 36.00% | 6.00% | 50.00% | 20 | $630.00 | $990.00 |
| 2 | 1 | 180 | 190 | Duct Insulation (R-3 to R-8) | 2772.91 | 2772.91 | 39.99% | 0.68% | 50.00% | 30 | $376.00 | $990.00 |
| 2 | 1 | 180 | 192 | Windows (high efficiency / ENERGY STAR+) | 2772.91 | 2772.91 | 95.07% | 26.80% | 75.00% | 30 | $1,129.69 | $990.00 |
| 2 | 1 | 200 | 200 | Base Lighting Combined | 1088.00 | 1088.00 | 100.00% | 0.00% | 100.00% | 1 | $0.00 | #N/A |
| 2 | 1 | 200 | 201 | CFL, 6.0 hr/day | 1088.00 | 1088.00 | 72.68% | 21.31% | 90.00% | 5 | $4.50 | #N/A |
| 2 | 1 | 200 | 202 | CFL, 2.5 hr/day | 1088.00 | 1088.00 | 86.19% | 39.27% | 90.00% | 7 | $4.50 | #N/A |
| 2 | 1 | 200 | 203 | CFL, 0.5 hr/day | 1088.00 | 1088.00 | 96.50% | 4.42% | 90.00% | 7 | $4.50 | #N/A |
| 2 | 1 | 200 | 204 | CFL Fixtures, 6.0 hr/day | 1088.00 | 1088.00 | 72.68% | 21.31% | 5.00% | 8 | $23.33 | #N/A |
| 2 | 1 | 200 | 205 | CFL Fixtures, 2.5 hr/day | 1088.00 | 1088.00 | 86.19% | 39.27% | 5.00% | 10 | $23.33 | #N/A |
| 2 | 1 | 200 | 206 | CFL Fixtures, 0.5 hr/day | 1088.00 | 1088.00 | 96.50% | 4.42% | 5.00% | 10 | $23.33 | #N/A |
| 2 | 1 | 200 | 207 | Fluorescent Torchieries, 6.0 hr/day | 1088.00 | 1088.00 | 100.00% | 21.31% | 5.00% | 5 | $23.00 | #N/A |
| 2 | 1 | 200 | 208 | Fluorescent Torchieries, 2.5 hr/day | 1088.00 | 1088.00 | 100.00% | 39.27% | 5.00% | 7 | $23.00 | #N/A |
| 2 | 1 | 200 | 209 | Fluorescent Torchieries, 0.5 hr/day | 1088.00 | 1088.00 | 100.00% | 4.42% | 5.00% | 7 | $23.00 | #N/A |
| 2 | 1 | 300 | 300 | Base Refrigerator, 15 cu.ft. | 653.80 | 653.80 | 100.00% | 0.00% | 100.00% | 15 | $0.00 | $429.99 |
| 2 | 1 | 300 | 301 | ENERGY STAR or better Refrigerator | 653.80 | 523.04 | 93.83% | 15.00% | 100.00% | 15 | $59.00 | $429.99 |
| 2 | 1 | 310 | 310 | Base Secondary Refrigerator | 1000.00 | 1000.00 | 100.00% | 0.00% | 100.00% | 15 | $0.00 | #N/A |
| 2 | 1 | 310 | 311 | Removal of Secondary Refrigerator | 1000.00 | 1000.00 | 100.00% | 100.00% | 1.00% | 7 | $200.00 | #N/A |
| 2 | 1 | 400 | 400 | Base Freezer | 598.90 | 598.90 | 100.00% | 0.00% | 100.00% | 15 | $0.00 | $309.99 |

# Table B.1: Residential Electric

| Segment | Building | Base Number | Measure Number | Measure Name | Stock Usage | Base Usage | Incomplete Factor | Energy Savings | Feasibility Factor | Measure Life | Full Per Unit Cost | Full Base Measure Cost |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2 | 1 | 400 | 401 | ENERGY STAR or better Freezer | 598.90 | 479.12 | 100.00% | 10.00% | 100.00% | 15 | $50.00 | $309.99 |
| 2 | 1 | 410 | 410 | Base Secondary Freezer | 950.00 | 950.00 | 100.00% | 0.00% | 100.00% | 15 | $0.00 | #N/A |
| 2 | 1 | 410 | 411 | Removal of Secondary Freezer | 950.00 | 950.00 | 100.00% | 100.00% | 0.50% | 7 | $200.00 | #N/A |
| 2 | 1 | 500 | 500 | Base 40 gal. Water Heating (EF=0.917) | 3092.27 | 2967.50 | 100.00% | 0.00% | 100.00% | 15 | $0.00 | $189.99 |
| 2 | 1 | 500 | 501 | Heat Pump Water Heater (EF=2.9) | 3092.27 | 3092.27 | 99.90% | 50.00% | 40.00% | 15 | $1,750.00 | $189.99 |
| 2 | 1 | 500 | 502 | HE Water Heater (EF=0.95) | 3092.27 | 2967.50 | 93.70% | 3.47% | 40.00% | 15 | $80.00 | $189.99 |
| 2 | 1 | 500 | 503 | Solar Water Heater | 3092.27 | 3092.27 | 99.00% | 50.00% | 10.00% | 15 | $5,500.00 | $189.99 |
| 2 | 1 | 500 | 504 | Low-Flow Showerheads | 3092.27 | 3092.27 | 27.24% | 5.11% | 95.00% | 10 | $20.00 | $189.99 |
| 2 | 1 | 500 | 505 | Hot Water Pipe Insulation | 3092.27 | 3092.27 | 62.57% | 1.24% | 75.00% | 15 | $5.80 | $189.99 |
| 2 | 1 | 500 | 506 | Water Heater Thermosat Setback | 3092.27 | 3092.27 | 83.71% | 4.26% | 50.00% | 15 | $15.00 | $189.99 |
| 2 | 1 | 500 | 507 | Tankless Water Heater (EF=0.98) | 3092.27 | 3092.27 | 100.00% | 13.10% | 10.00% | 15 | $1,200.00 | $189.99 |
| 2 | 1 | 500 | 508 | Drain Water Heat Recovery (GFX) | 3092.27 | 3092.27 | 100.00% | 24.70% | 25.00% | 15 | $550.00 | $189.99 |
| 2 | 1 | 500 | 509 | Horizontal-Axis Clothes Washer: Energy Star CW (EF=2.5) | 3092.27 | 3092.27 | 97.00% | 9.91% | 50.00% | 14 | $280.00 | $189.99 |
| 2 | 1 | 500 | 510 | Energy Star Vertical-Axis Clothes Washer: SEHA CW Tier 2 (EF=3.25) | 3092.27 | 3092.27 | 91.76% | 12.07% | 50.00% | 14 | $350.00 | $189.99 |
| 2 | 1 | 500 | 511 | Energy Star DW (EF=0.58) | 3092.27 | 3092.27 | 96.44% | 4.02% | 100.00% | 13 | $70.00 | $189.99 |
| 2 | 1 | 500 | 512 | Hot Water Heater Tank Wrap (R-10) | 3092.27 | 3092.27 | 53.10% | 10.00% | 90.00% | 15 | $17.00 | $189.99 |
| 2 | 1 | 500 | 513 | Faucet Aerators | 3092.27 | 3092.27 | 73.40% | 1.94% | 90.00% | 15 | $4.82 | $189.99 |
| 2 | 1 | 600 | 600 | Base Dryer | 564.00 | 564.00 | 100.00% | 0.00% | 100.00% | 14 | $0.00 | $249.98 |
| 2 | 1 | 600 | 601 | High Efficiency Dryer With Moisture Sensor | 564.00 | 564.00 | 95.49% | 31.91% | 100.00% | 14 | $100.00 | $249.98 |
| 2 | 1 | 700 | 700 | Base Central AC, SEER=10 | 327.00 | 327.00 | 100.00% | 0.00% | 100.00% | 18 | $0.00 | $2,321.00 |
| 2 | 1 | 700 | 701 | High-Efficiency Central AC, SEER=12 | 327.00 | 255.06 | 100.00% | 16.67% | 100.00% | 18 | $277.00 | $2,321.00 |
| 2 | 1 | 700 | 702 | High-Efficiency Central AC, SEER=14 | 327.00 | 255.06 | 100.00% | 28.57% | 100.00% | 18 | $795.00 | $2,321.00 |
| 2 | 1 | 900 | 900 | Base Conventional Oven | 465.15 | 465.15 | 100.00% | 0.00% | 100.00% | 15 | $0.00 | $349.99 |
| 2 | 1 | 900 | 901 | Convection Oven | 465.15 | 465.15 | 100.00% | 18.27% | 100.00% | 15 | $120.00 | $349.99 |
| 2 | 1 | 950 | 950 | Base Plug Loads | 1534.18 | 1534.18 | 100.00% | 0.00% | 100.00% | 20 | $0.00 | #N/A |
| 2 | 1 | 950 | 951 | Powerstrip with Occupancy Sensor | 1534.18 | 1534.18 | 100.00% | 1.78% | 100.00% | 20 | $90.00 | #N/A |
| 3 | 1 | 120 | 120 | Base Heat Pump, 2 ton, HSPF=6.8 | 5320.23 | 4788.21 | 100.00% | 0.00% | 100.00% | 18 | $0.00 | $1,900.00 |
| 3 | 1 | 120 | 121 | ENERGY STAR or better Air Source Heat Pump, HSPF=8.0 | 5320.23 | 4788.21 | 82.00% | 15.00% | 50.00% | 18 | $160.00 | $1,900.00 |
| 3 | 1 | 120 | 122 | ENERGY STAR or better Air Source Heat Pump, HSPF=8.5 | 5320.23 | 4788.21 | 94.36% | 20.00% | 50.00% | 18 | $620.00 | $1,900.00 |
| 3 | 1 | 120 | 123 | ENERGY STAR Programmable Thermostat (Electronic w/ Adaptive Recovery) | 5320.23 | 5320.23 | 71.49% | 6.00% | 80.00% | 12 | $150.00 | $1,900.00 |
| 3 | 1 | 120 | 124 | Ceiling R-0 to R-19 Insulation | 5320.23 | 5320.23 | 59.70% | 10.30% | 67.00% | 25 | $687.22 | $1,900.00 |
| 3 | 1 | 120 | 125 | Ceiling R-19 to R-30 Insulation | 5320.23 | 5320.23 | 59.70% | 6.25% | 33.00% | 25 | $864.60 | $1,900.00 |
| 3 | 1 | 120 | 126 | Floor R-5 to R-25 Insulation-Batts | 5320.23 | 5320.23 | 57.36% | 8.60% | 33.00% | 25 | $817.60 | $1,900.00 |
| 3 | 1 | 120 | 127 | Wall 2x4 R-0 to Blow-In R-13 Insulation (.86) | 5320.23 | 5320.23 | 57.36% | 3.20% | 50.00% | 25 | $1,660.00 | $1,900.00 |
| 3 | 1 | 120 | 128 | Comprehensive Shell Air Sealing - Inf. Reduction | 5320.23 | 5320.23 | 40.00% | 5.20% | 90.00% | 10 | $300.00 | $1,900.00 |
| 3 | 1 | 120 | 129 | PTCS Duct Sealing &O&M | 5320.23 | 5320.23 | 72.00% | 17.00% | 50.00% | 20 | $450.00 | $1,900.00 |
| 3 | 1 | 120 | 130 | Duct Insulation (R-3 to R-8) | 5320.23 | 5320.23 | 18.62% | 9.58% | 50.00% | 25 | $245.00 | $1,900.00 |
| 3 | 1 | 120 | 131 | HVAC Diagnostic Testing, Repair and Maintenance | 5320.23 | 5320.23 | 64.19% | 4.00% | 100.00% | 10 | $123.00 | $1,900.00 |

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## Table B.1: Residential Electric

| Segment | Building | Base Number | Measure Number | Measure Name | Stock Usage | Base Usage | Incomplete Factor | Energy Savings | Feasibility Factor | Measure Life | Full Per Unit Cost | Full Base Measure Cost |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 3 | 1 | 120 | 132 | Windows (high efficiency / ENERGY STAR+) | 5320.23 | 5320.23 | 79.47% | 24.80% | 75.00% | 25 | $1,467.24 | $1,900.00 |
| 3 | 1 | 160 | 160 | Base Room Air Conditioner, 10 kBtu, EER=9.7 | 579.93 | 538.08 | 100.00% | 0.00% | 100.00% | 15 | $0.00 | $249.99 |
| 3 | 1 | 160 | 161 | ENERGY STAR or better Room AC, 10 kBtu, EER=10.7 | 579.93 | 538.08 | 94.33% | 9.35% | 100.00% | 18 | $338.00 | $249.99 |
| 3 | 1 | 180 | 180 | Base Resistance Space Heating | 9184.13 | 9184.13 | 100.00% | 0.00% | 100.00% | 18 | $0.00 | $990.00 |
| 3 | 1 | 180 | 181 | ENERGY STAR or better Air Source Heat Pump, HSPF=8.0 | 9184.13 | 9184.13 | 82.00% | 55.68% | 49.88% | 18 | $160.00 | $990.00 |
| 3 | 1 | 180 | 182 | ENERGY STAR or better Air Source Heat Pump, HSPF=8.5 | 9184.13 | 9184.13 | 94.36% | 58.29% | 16.63% | 18 | $620.00 | $990.00 |
| 3 | 1 | 180 | 183 | ENERGY STAR Programmable Thermostat (Electronic w/ Adaptive Recovery) | 9184.13 | 9184.13 | 71.49% | 6.00% | 80.00% | 12 | $100.00 | $990.00 |
| 3 | 1 | 180 | 184 | Ceiling R-0 to R-19 Insulation | 9184.13 | 9184.13 | 59.70% | 10.30% | 67.00% | 25 | $687.22 | $990.00 |
| 3 | 1 | 180 | 185 | Ceiling R-19 to R-30 Insulation | 9184.13 | 9184.13 | 59.70% | 6.25% | 33.00% | 25 | $864.60 | $990.00 |
| 3 | 1 | 180 | 186 | Floor R-5 to R-25 Insulation-Batts | 9184.13 | 9184.13 | 57.36% | 8.60% | 33.00% | 25 | $817.60 | $990.00 |
| 3 | 1 | 180 | 187 | Wall 2x4 R-0 to Blow-In R-13 Insulation (.86) | 9184.13 | 9184.13 | 57.36% | 3.20% | 50.00% | 25 | $1,660.00 | $990.00 |
| 3 | 1 | 180 | 188 | Comprehensive Shell Air Sealing - Inf. Reduction | 9184.13 | 9184.13 | 40.00% | 5.20% | 90.00% | 10 | $300.00 | $990.00 |
| 3 | 1 | 180 | 189 | PTCS Duct Sealing &O&M | 9184.13 | 9184.13 | 72.00% | 10.00% | 50.00% | 20 | $450.00 | $990.00 |
| 3 | 1 | 180 | 190 | Duct Insulation (R-3 to R-8) | 9184.13 | 9184.13 | 18.62% | 9.58% | 50.00% | 25 | $245.00 | $990.00 |
| 3 | 1 | 180 | 191 | HVAC Diagnostic Testing, Repair and Maintenance | 9184.13 | 9184.13 | 64.19% | 4.00% | 100.00% | 10 | $123.00 | $990.00 |
| 3 | 1 | 180 | 192 | Windows (high efficiency / ENERGY STAR+) | 9184.13 | 9184.13 | 79.47% | 24.80% | 75.00% | 25 | $1,467.24 | $990.00 |
| 3 | 1 | 200 | 200 | Base Lighting Combined | 1690.00 | 1690.00 | 100.00% | 0.00% | 100.00% | 1 | $0.00 | #N/A |
| 3 | 1 | 200 | 201 | CFL, 6.0 hr/day | 1690.00 | 1690.00 | 68.13% | 21.31% | 90.00% | 5 | $4.50 | #N/A |
| 3 | 1 | 200 | 202 | CFL, 2.5 hr/day | 1690.00 | 1690.00 | 87.17% | 39.27% | 90.00% | 7 | $4.50 | #N/A |
| 3 | 1 | 200 | 203 | CFL, 0.5 hr/day | 1690.00 | 1690.00 | 94.14% | 4.42% | 90.00% | 7 | $4.50 | #N/A |
| 3 | 1 | 200 | 204 | CFL Fixtures, 6.0 hr/day | 1690.00 | 1690.00 | 68.13% | 21.31% | 5.00% | 8 | $23.33 | #N/A |
| 3 | 1 | 200 | 205 | CFL Fixtures, 2.5 hr/day | 1690.00 | 1690.00 | 87.17% | 39.27% | 5.00% | 10 | $23.33 | #N/A |
| 3 | 1 | 200 | 206 | CFL Fixtures, 0.5 hr/day | 1690.00 | 1690.00 | 94.14% | 4.42% | 5.00% | 10 | $23.33 | #N/A |
| 3 | 1 | 200 | 207 | Fluorescent Torchieries, 6.0 hr/day | 1690.00 | 1690.00 | 100.00% | 21.31% | 5.00% | 5 | $23.00 | #N/A |
| 3 | 1 | 200 | 208 | Fluorescent Torchieries, 2.5 hr/day | 1690.00 | 1690.00 | 100.00% | 39.27% | 5.00% | 7 | $23.00 | #N/A |
| 3 | 1 | 200 | 209 | Fluorescent Torchieries, 0.5 hr/day | 1690.00 | 1690.00 | 100.00% | 4.42% | 5.00% | 7 | $23.00 | #N/A |
| 3 | 1 | 300 | 300 | Base Refrigerator, 15 cu.ft. | 854.43 | 854.43 | 100.00% | 0.00% | 100.00% | 15 | $0.00 | $429.99 |
| 3 | 1 | 300 | 301 | ENERGY STAR or better Refrigerator | 854.43 | 683.54 | 79.39% | 15.00% | 100.00% | 15 | $59.00 | $429.99 |
| 3 | 1 | 310 | 310 | Base Secondary Refrigerator | 1000.00 | 1000.00 | 100.00% | 0.00% | 100.00% | 15 | $0.00 | #N/A |
| 3 | 1 | 310 | 311 | Removal of Secondary Refrigerator | 1000.00 | 1000.00 | 100.00% | 100.00% | 11.00% | 7 | $200.00 | #N/A |
| 3 | 1 | 400 | 400 | Base Freezer | 807.52 | 807.52 | 100.00% | 0.00% | 100.00% | 15 | $0.00 | $309.99 |
| 3 | 1 | 400 | 401 | ENERGY STAR or better Freezer | 807.52 | 646.01 | 94.93% | 10.00% | 100.00% | 15 | $50.00 | $309.99 |
| 3 | 1 | 410 | 410 | Base Secondary Freezer | 950.00 | 950.00 | 100.00% | 0.00% | 100.00% | 15 | $0.00 | #N/A |
| 3 | 1 | 410 | 411 | Removal of Secondary Freezer | 950.00 | 950.00 | 100.00% | 100.00% | 5.50% | 7 | $200.00 | #N/A |
| 3 | 1 | 500 | 500 | Base 40 gal. Water Heating (EF=0.917) | 2183.51 | 2095.41 | 100.00% | 0.00% | 100.00% | 15 | $0.00 | $189.99 |
| 3 | 1 | 500 | 501 | Heat Pump Water Heater (EF=2.9) | 2183.51 | 2183.51 | 99.90% | 50.00% | 40.00% | 15 | $1,750.00 | $189.99 |
| 3 | 1 | 500 | 502 | HE Water Heater (EF=0.95) | 2183.51 | 2095.41 | 93.70% | 3.47% | 40.00% | 15 | $80.00 | $189.99 |
| 3 | 1 | 500 | 503 | Solar Water Heater | 2183.51 | 2183.51 | 99.00% | 50.00% | 10.00% | 15 | $5,500.00 | $189.99 |
| 3 | 1 | 500 | 504 | Low-Flow Showerheads | 2183.51 | 2183.51 | 21.10% | 7.23% | 95.00% | 10 | $20.00 | $189.99 |

## Table B.1: Residential Electric

| Segment | Building | Base Number | Measure Number | Measure Name | Stock Usage | Base Usage | Incomplete Factor | Energy Savings | Feasibility Factor | Measure Life | Full Per Unit Cost | Full Base Measure Cost |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 3 | 1 | 500 | 505 | Hot Water Pipe Insulation | 2183.51 | 2183.51 | 57.52% | 1.75% | 75.00% | 15 | $5.80 | $189.99 |
| 3 | 1 | 500 | 506 | Water Heater Thermosat Setback | 2183.51 | 2183.51 | 90.09% | 4.26% | 50.00% | 15 | $15.00 | $189.99 |
| 3 | 1 | 500 | 507 | Tankless Water Heater (EF=0.98) | 2183.51 | 2183.51 | 100.00% | 13.10% | 10.00% | 15 | $1,200.00 | $189.99 |
| 3 | 1 | 500 | 508 | Drain Water Heat Recovery (GFX) | 2183.51 | 2183.51 | 100.00% | 25.00% | 25.00% | 15 | $550.00 | $189.99 |
| 3 | 1 | 500 | 509 | Horizontal-Axis Clothes Washer: Energy Star CW (EF=2.5) | 2183.51 | 2183.51 | 97.00% | 14.47% | 50.00% | 14 | $280.00 | $189.99 |
| 3 | 1 | 500 | 510 | Energy Star Vertical-Axis Clothes Washer: SEHA CW Tier 2 (EF=3.25) | 2183.51 | 2183.51 | 89.06% | 17.54% | 50.00% | 14 | $350.00 | $189.99 |
| 3 | 1 | 500 | 511 | Energy Star DW (EF=0.58) | 2183.51 | 2183.51 | 93.43% | 7.89% | 100.00% | 13 | $70.00 | $189.99 |
| 3 | 1 | 500 | 512 | Hot Water Heater Tank Wrap (R-10) | 2183.51 | 2183.51 | 31.94% | 10.00% | 90.00% | 15 | $17.00 | $189.99 |
| 3 | 1 | 500 | 513 | Faucet Aerators | 2183.51 | 2183.51 | 73.40% | 2.74% | 90.00% | 15 | $4.82 | $189.99 |
| 3 | 1 | 600 | 600 | Base Dryer | 564.00 | 564.00 | 100.00% | 0.00% | 100.00% | 14 | $0.00 | $249.98 |
| 3 | 1 | 600 | 601 | High Efficiency Dryer With Moisture Sensor | 564.00 | 564.00 | 88.35% | 31.91% | 100.00% | 14 | $100.00 | $249.98 |
| 3 | 1 | 700 | 700 | Base Central AC, SEER=10 | 452.00 | 452.00 | 100.00% | 0.00% | 100.00% | 18 | $0.00 | $2,321.00 |
| 3 | 1 | 700 | 701 | High-Efficiency Central AC, SEER=12 | 452.00 | 352.56 | 94.36% | 16.67% | 100.00% | 18 | $277.00 | $2,321.00 |
| 3 | 1 | 700 | 702 | High-Efficiency Central AC, SEER=14 | 452.00 | 352.56 | 94.36% | 28.57% | 100.00% | 18 | $795.00 | $2,321.00 |
| 3 | 1 | 900 | 900 | Base Conventional Oven | 514.06 | 514.06 | 100.00% | 0.00% | 100.00% | 15 | $0.00 | $349.99 |
| 3 | 1 | 900 | 901 | Convection Oven | 514.06 | 514.06 | 100.00% | 14.78% | 100.00% | 15 | $120.00 | $349.99 |
| 3 | 1 | 950 | 950 | Base Plug Loads | 1265.57 | 1265.57 | 100.00% | 0.00% | 100.00% | 20 | $0.00 | #N/A |
| 3 | 1 | 950 | 951 | Powerstrip with Occupancy Sensor | 1265.57 | 1265.57 | 100.00% | 1.44% | 100.00% | 20 | $90.00 | #N/A |
| 4 | 1 | 120 | 120 | Base Heat Pump, 4 ton, HSPF=6.8 | 3967.71 | 3967.71 | 100.00% | 0.00% | 100.00% | 18 | $0.00 | $2,600.00 |
| 4 | 1 | 120 | 121 | ENERGY STAR or better Air Source Heat Pump, HSPF=8.0 | 3272.40 | 3272.40 | 82.00% | 15.00% | 40.00% | 18 | $160.00 | $2,600.00 |
| 4 | 1 | 120 | 122 | ENERGY STAR or better Air Source Heat Pump, HSPF=8.5 | 3272.40 | 3272.40 | 99.14% | 20.00% | 40.00% | 18 | $620.00 | $2,600.00 |
| 4 | 1 | 120 | 137 | Geothermal Heat Pump | 3967.71 | 3967.71 | 100.00% | 51.94% | 20.00% | 18 | $6,472.00 | $2,600.00 |
| 4 | 1 | 120 | 138 | ENERGY STAR New Construction | 3967.71 | 3967.71 | 99.14% | 30.00% | 50.00% | 30 | $3,000.00 | $2,600.00 |
| 4 | 1 | 120 | 139 | ENERGY STAR New Construction Plus | 3967.71 | 3967.71 | 99.14% | 40.00% | 50.00% | 30 | $5,000.00 | $2,600.00 |
| 4 | 1 | 160 | 160 | Base Room Air Conditioner, 14 kBtu, EER=9.7 | 738.64 | 738.64 | 100.00% | 0.00% | 100.00% | 15 | $0.00 | $349.00 |
| 4 | 1 | 160 | 161 | ENERGY STAR or better Room AC, 14 kBtu, EER=10.7 | 738.64 | 738.64 | 99.11% | 9.35% | 100.00% | 25 | $473.00 | $349.00 |
| 4 | 1 | 200 | 200 | Base Lighting Combined | 2328.00 | 2328.00 | 100.00% | 0.00% | 100.00% | 1 | $0.00 | #N/A |
| 4 | 1 | 200 | 201 | CFL, 6.0 hr/day | 2328.00 | 2328.00 | 69.28% | 21.31% | 90.00% | 5 | $4.50 | #N/A |
| 4 | 1 | 200 | 202 | CFL, 2.5 hr/day | 2328.00 | 2328.00 | 89.04% | 39.27% | 90.00% | 7 | $4.50 | #N/A |
| 4 | 1 | 200 | 203 | CFL, 0.5 hr/day | 2328.00 | 2328.00 | 93.77% | 4.42% | 90.00% | 7 | $4.50 | #N/A |
| 4 | 1 | 200 | 204 | CFL Fixtures, 6.0 hr/day | 2328.00 | 2328.00 | 69.28% | 21.31% | 5.00% | 8 | $23.33 | #N/A |
| 4 | 1 | 200 | 205 | CFL Fixtures, 2.5 hr/day | 2328.00 | 2328.00 | 89.04% | 39.27% | 5.00% | 10 | $23.33 | #N/A |
| 4 | 1 | 200 | 206 | CFL Fixtures, 0.5 hr/day | 2328.00 | 2328.00 | 93.77% | 4.42% | 5.00% | 10 | $23.33 | #N/A |
| 4 | 1 | 200 | 207 | Fluorescent Torchieries, 6.0 hr/day | 2328.00 | 2328.00 | 100.00% | 21.31% | 5.00% | 5 | $23.00 | #N/A |
| 4 | 1 | 200 | 208 | Fluorescent Torchieries, 2.5 hr/day | 2328.00 | 2328.00 | 100.00% | 39.27% | 5.00% | 7 | $23.00 | #N/A |
| 4 | 1 | 200 | 209 | Fluorescent Torchieries, 0.5 hr/day | 2328.00 | 2328.00 | 100.00% | 4.42% | 5.00% | 7 | $23.00 | #N/A |
| 4 | 1 | 300 | 300 | Base Refrigerator, 20 cu.ft. | 675.76 | 675.76 | 100.00% | 0.00% | 100.00% | 15 | $0.00 | $549.99 |
| 4 | 1 | 300 | 301 | ENERGY STAR or better Refrigerator | 675.76 | 675.76 | 73.54% | 15.00% | 100.00% | 15 | $79.00 | $549.99 |
| 4 | 1 | 400 | 400 | Base Freezer | 655.80 | 655.80 | 100.00% | 0.00% | 100.00% | 15 | $0.00 | $309.99 |
| 4 | 1 | 400 | 401 | ENERGY STAR or better Freezer | 655.80 | 655.80 | 92.80% | 10.00% | 100.00% | 15 | $50.00 | $309.99 |

Exhibit No. ___(EMM-6)
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## Table B.1: Residential Electric

| Segment | Building | Base Number | Measure Number | Measure Name | Stock Usage | Base Usage | Incomplete Factor | Energy Savings | Feasibility Factor | Measure Life | Full Per Unit Cost | Full Base Measure Cost |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 4 | 1 | 500 | 500 | Base 40 gal. Water Heating (EF=0.917) | 3090.60 | 3090.60 | 100.00% | 0.00% | 100.00% | 15 | $0.00 | $189.99 |
| 4 | 1 | 500 | 501 | Heat Pump Water Heater (EF=2.9) | 3090.60 | 3090.60 | 99.90% | 50.00% | 40.00% | 15 | $1,750.00 | $189.99 |
| 4 | 1 | 500 | 502 | HE Water Heater (EF=0.95) | 3090.60 | 3090.60 | 93.70% | 3.47% | 40.00% | 15 | $80.00 | $189.99 |
| 4 | 1 | 500 | 503 | Solar Water Heater | 3090.60 | 3090.60 | 99.00% | 50.00% | 10.00% | 15 | $5,500.00 | $189.99 |
| 4 | 1 | 500 | 507 | Tankless Water Heater (EF=0.98) | 3090.60 | 3090.60 | 100.00% | 13.10% | 10.00% | 15 | $903.00 | $189.99 |
| 4 | 1 | 500 | 508 | Drain Water Heat Recovery (GFX) | 3090.60 | 3090.60 | 100.00% | 25.00% | 35.00% | 15 | $400.00 | $189.99 |
| 4 | 1 | 500 | 509 | Horizontal-Axis Clothes Washer: Energy Star CW (EF=2.5) | 3090.60 | 3090.60 | 95.00% | 13.33% | 50.00% | 14 | $280.00 | $189.99 |
| 4 | 1 | 500 | 510 | Energy Star Vertical-Axis Clothes Washer: SEHA CW Tier 2 (EF=3.25) | 3090.60 | 3090.60 | 78.97% | 16.16% | 50.00% | 14 | $350.00 | $189.99 |
| 4 | 1 | 500 | 511 | Energy Star DW (EF=0.58) | 3090.60 | 3090.60 | 82.42% | 5.00% | 100.00% | 13 | $70.00 | $189.99 |
| 4 | 1 | 500 | 512 | Hot Water Heater Tank Wrap (R-10) | 3090.60 | 3090.60 | 31.32% | 10.00% | 90.00% | 15 | $17.00 | $189.99 |
| 4 | 1 | 500 | 513 | Faucet Aerators | 3090.60 | 3090.60 | 73.40% | 1.65% | 90.00% | 15 | $4.82 | $189.99 |
| 4 | 1 | 600 | 600 | Base Dryer | 564.00 | 564.00 | 100.00% | 1.94% | 100.00% | 14 | $0.00 | $249.98 |
| 4 | 1 | 600 | 601 | High Efficiency Dryer With Moisture Sensor | 564.00 | 564.00 | 79.31% | 31.91% | 100.00% | 14 | $100.00 | $249.98 |
| 4 | 1 | 700 | 700 | Base Central AC, SEER=10 | 236.00 | 236.00 | 100.00% | 0.00% | 100.00% | 18 | $0.00 | $2,321.00 |
| 4 | 1 | 700 | 701 | High-Efficiency Central AC, SEER=12 | 236.00 | 236.00 | 99.14% | 16.67% | 100.00% | 18 | $277.00 | $2,321.00 |
| 4 | 1 | 700 | 702 | High-Efficiency Central AC, SEER=14 | 236.00 | 236.00 | 99.14% | 28.57% | 100.00% | 18 | $795.00 | $2,321.00 |
| 4 | 1 | 900 | 900 | Base Conventional Oven | 573.95 | 573.95 | 100.00% | 0.00% | 100.00% | 15 | $0.00 | $349.99 |
| 4 | 1 | 900 | 901 | Convection Oven | 573.95 | 573.95 | 100.00% | 11.67% | 100.00% | 15 | $120.00 | $349.99 |
| 4 | 1 | 950 | 950 | Base Plug Loads | 3389.50 | 3389.50 | 100.00% | 0.00% | 100.00% | 20 | $0.00 | #N/A |
| 4 | 1 | 950 | 951 | Powerstrip with Occupancy Sensor | 3389.50 | 3389.50 | 100.00% | 0.39% | 100.00% | 20 | $90.00 | #N/A |
| 5 | 1 | 120 | 120 | Base Exhaust Air Heat Pump, 2 ton, HSPF=6.8 | 1247.71 | 1247.71 | 100.00% | 0.00% | 50.00% | 18 | $0.00 | $1,900.00 |
| 5 | 1 | 120 | 121 | ENERGY STAR or better Air Source Heat Pump, HSPF=8.0 | 2783.05 | 2783.05 | 100.00% | 15.00% | 40.00% | 18 | $160.00 | $1,900.00 |
| 5 | 1 | 120 | 122 | ENERGY STAR or better Air Source Heat Pump, HSPF=8.5 | 2783.05 | 2783.05 | 100.00% | 20.00% | 40.00% | 18 | $620.00 | $1,900.00 |
| 5 | 1 | 120 | 138 | ENERGY STAR New Construction | 1247.71 | 1247.71 | 100.00% | 30.00% | 50.00% | 30 | $2,000.00 | $1,900.00 |
| 5 | 1 | 120 | 139 | ENERGY STAR New Construction Plus | 1247.71 | 1247.71 | 100.00% | 40.00% | 50.00% | 30 | $3,500.00 | $1,900.00 |
| 5 | 1 | 160 | 160 | Base Room Air Conditioner, 10 kBtu, EER=9.7 | 389.28 | 389.28 | 100.00% | 0.00% | 100.00% | 15 | $0.00 | $249.99 |
| 5 | 1 | 160 | 161 | ENERGY STAR or better Room AC, 10 kBtu, EER=10.7 | 389.28 | 389.28 | 100.00% | 9.35% | 100.00% | 25 | $338.00 | $249.99 |
| 5 | 1 | 200 | 200 | Base Lighting Combined | 1088.00 | 1088.00 | 100.00% | 0.00% | 100.00% | 1 | $0.00 | #N/A |
| 5 | 1 | 200 | 201 | CFL, 6.0 hr/day | 1088.00 | 1088.00 | 72.68% | 21.31% | 90.00% | 5 | $4.50 | #N/A |
| 5 | 1 | 200 | 202 | CFL, 2.5 hr/day | 1088.00 | 1088.00 | 86.19% | 39.27% | 90.00% | 7 | $4.50 | #N/A |
| 5 | 1 | 200 | 203 | CFL, 0.5 hr/day | 1088.00 | 1088.00 | 96.50% | 4.42% | 90.00% | 7 | $4.50 | #N/A |
| 5 | 1 | 200 | 204 | CFL Fixtures, 6.0 hr/day | 1088.00 | 1088.00 | 72.68% | 21.31% | 5.00% | 8 | $23.33 | #N/A |
| 5 | 1 | 200 | 205 | CFL Fixtures, 2.5 hr/day | 1088.00 | 1088.00 | 86.19% | 39.27% | 5.00% | 10 | $23.33 | #N/A |
| 5 | 1 | 200 | 206 | CFL Fixtures, 0.5 hr/day | 1088.00 | 1088.00 | 96.50% | 4.42% | 5.00% | 10 | $23.33 | #N/A |
| 5 | 1 | 200 | 207 | Fluorescent Torchieries, 6.0 hr/day | 1088.00 | 1088.00 | 100.00% | 21.31% | 5.00% | 5 | $23.00 | #N/A |
| 5 | 1 | 200 | 208 | Fluorescent Torchieries, 2.5 hr/day | 1088.00 | 1088.00 | 100.00% | 39.27% | 5.00% | 7 | $23.00 | #N/A |
| 5 | 1 | 200 | 209 | Fluorescent Torchieries, 0.5 hr/day | 1088.00 | 1088.00 | 100.00% | 4.42% | 5.00% | 7 | $23.00 | #N/A |
| 5 | 1 | 300 | 300 | Base Refrigerator, 15 cu.ft. | 637.83 | 637.83 | 100.00% | 0.00% | 100.00% | 15 | $0.00 | $429.99 |
| 5 | 1 | 300 | 301 | ENERGY STAR or better Refrigerator | 637.83 | 637.83 | 93.83% | 15.00% | 100.00% | 15 | $59.00 | $429.99 |
| 5 | 1 | 400 | 400 | Base Freezer | 583.93 | 583.93 | 100.00% | 0.00% | 100.00% | 15 | $0.00 | $309.99 |

## Table B.1: Residential Electric

| Segment | Building | Base Number | Measure Number | Measure Name | Stock Usage | Base Usage | Incomplete Factor | Energy Savings | Feasibility Factor | Measure Life | Full Per Unit Cost | Full Base Measure Cost |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 5 | 1 | 400 | 401 | ENERGY STAR or better Freezer | 583.93 | 583.93 | 100.00% | 10.00% | 100.00% | 15 | $50.00 | $309.99 |
| 5 | 1 | 500 | 500 | Base 40 gal. Water Heating (EF=0.917) | 2628.43 | 2628.43 | 100.00% | 0.00% | 100.00% | 15 | $0.00 | $189.99 |
| 5 | 1 | 500 | 501 | Heat Pump Water Heater (EF=2.9) | 2628.43 | 2628.43 | 99.90% | 50.00% | 40.00% | 15 | $1,750.00 | $189.99 |
| 5 | 1 | 500 | 502 | HE Water Heater (EF=0.95) | 2628.43 | 2628.43 | 93.70% | 3.47% | 40.00% | 15 | $80.00 | $189.99 |
| 5 | 1 | 500 | 503 | Solar Water Heater | 2628.43 | 2628.43 | 99.00% | 50.00% | 10.00% | 15 | $5,500.00 | $189.99 |
| 5 | 1 | 500 | 507 | Tankless Water Heater (EF=0.98) | 2628.43 | 2628.43 | 100.00% | 13.10% | 10.00% | 15 | $903.00 | $189.99 |
| 5 | 1 | 500 | 508 | Drain Water Heat Recovery (GFX) | 2628.43 | 2628.43 | 100.00% | 28.70% | 25.00% | 15 | $400.00 | $189.99 |
| 5 | 1 | 500 | 509 | Horizontal-Axis Clothes Washer: Energy Star CW (EF=2.5) | 2628.43 | 2628.43 | 97.00% | 10.67% | 50.00% | 14 | $280.00 | $189.99 |
| 5 | 1 | 500 | 510 | Energy Star Vertical-Axis Clothes Washer: SEHA CW Tier 2 (EF=3.25) | 2628.43 | 2628.43 | 91.76% | 13.01% | 50.00% | 14 | $350.00 | $189.99 |
| 5 | 1 | 500 | 511 | Energy Star DW (EF=0.58) | 2628.43 | 2628.43 | 96.44% | 4.34% | 100.00% | 13 | $70.00 | $189.99 |
| 5 | 1 | 500 | 512 | Hot Water Heater Tank Wrap (R-10) | 2628.43 | 2628.43 | 53.10% | 10.00% | 90.00% | 15 | $17.00 | $189.99 |
| 5 | 1 | 500 | 513 | Faucet Aerators | 2628.43 | 2628.43 | 73.40% | 1.94% | 90.00% | 15 | $4.82 | $189.99 |
| 5 | 1 | 600 | 600 | Base Dryer | 564.00 | 564.00 | 100.00% | 0.00% | 100.00% | 14 | $0.00 | $249.98 |
| 5 | 1 | 600 | 601 | High Efficiency Dryer With Moisture Sensor | 564.00 | 564.00 | 95.49% | 31.91% | 100.00% | 14 | $100.00 | $249.98 |
| 5 | 1 | 700 | 700 | Base Central AC, SEER=10 | 236.00 | 236.00 | 100.00% | 0.00% | 100.00% | 18 | $0.00 | $2,321.00 |
| 5 | 1 | 700 | 701 | High-Efficiency Central AC, SEER=12 | 236.00 | 236.00 | 100.00% | 16.67% | 100.00% | 18 | $277.00 | $2,321.00 |
| 5 | 1 | 700 | 702 | High-Efficiency Central AC, SEER=14 | 236.00 | 236.00 | 100.00% | 28.57% | 100.00% | 18 | $795.00 | $2,321.00 |
| 5 | 1 | 900 | 900 | Base Conventional Oven | 465.15 | 465.15 | 100.00% | 0.00% | 100.00% | 15 | $0.00 | $349.99 |
| 5 | 1 | 900 | 901 | Convection Oven | 465.15 | 465.15 | 100.00% | 19.13% | 100.00% | 15 | $120.00 | $349.99 |
| 5 | 1 | 950 | 950 | Base Plug Loads | 1534.18 | 1534.18 | 100.00% | 0.00% | 100.00% | 20 | $0.00 | #N/A |
| 5 | 1 | 950 | 951 | Powerstrip with Occupancy Sensor | 1534.18 | 1534.18 | 100.00% | 1.98% | 100.00% | 20 | $90.00 | #N/A |
| 6 | 1 | 120 | 120 | Base Heat Pump, 3 ton, HSPF=6.8 | 4972.87 | 4972.87 | 100.00% | 0.00% | 100.00% | 18 | $0.00 | $2,275.00 |
| 6 | 1 | 120 | 121 | ENERGY STAR or better Air Source Heat Pump, HSPF=8.0 | 1965.16 | 1965.16 | 82.00% | 15.00% | 50.00% | 18 | $160.00 | $2,275.00 |
| 6 | 1 | 120 | 122 | ENERGY STAR or better Air Source Heat Pump, HSPF=8.5 | 1965.16 | 1965.16 | 94.36% | 20.00% | 50.00% | 18 | $620.00 | $2,275.00 |
| 6 | 1 | 120 | 138 | Super Good Cents / ENERGY STAR New Man. Housing | 4972.87 | 4972.87 | 100.00% | 30.00% | 50.00% | 25 | $1,500.00 | $2,275.00 |
| 6 | 1 | 120 | 139 | Super Good Cents / ENERGY STAR New Man. Housing Plus | 4972.87 | 4972.87 | 100.00% | 40.00% | 50.00% | 25 | $3,000.00 | $2,275.00 |
| 6 | 1 | 160 | 160 | Base Room Air Conditioner, 10 kBtu, EER=9.7 | 579.93 | 579.93 | 100.00% | 0.00% | 100.00% | 15 | $0.00 | $249.99 |
| 6 | 1 | 160 | 161 | ENERGY STAR or better Room AC, 10 kBtu, EER=10.7 | 579.93 | 579.93 | 94.33% | 9.35% | 100.00% | 25 | $338.00 | $249.99 |
| 6 | 1 | 200 | 200 | Base Lighting Combined | 1690.00 | 1690.00 | 100.00% | 0.00% | 100.00% | 1 | $0.00 | #N/A |
| 6 | 1 | 200 | 201 | CFL, 6.0 hr/day | 1690.00 | 1690.00 | 68.13% | 21.31% | 90.00% | 5 | $4.50 | #N/A |
| 6 | 1 | 200 | 202 | CFL, 2.5 hr/day | 1690.00 | 1690.00 | 87.17% | 39.27% | 90.00% | 7 | $4.50 | #N/A |
| 6 | 1 | 200 | 203 | CFL, 0.5 hr/day | 1690.00 | 1690.00 | 94.14% | 4.42% | 90.00% | 7 | $4.50 | #N/A |
| 6 | 1 | 200 | 204 | CFL Fixtures, 6.0 hr/day | 1690.00 | 1690.00 | 68.13% | 21.31% | 5.00% | 8 | $23.33 | #N/A |
| 6 | 1 | 200 | 205 | CFL Fixtures, 2.5 hr/day | 1690.00 | 1690.00 | 87.17% | 39.27% | 5.00% | 10 | $23.33 | #N/A |
| 6 | 1 | 200 | 206 | CFL Fixtures, 0.5 hr/day | 1690.00 | 1690.00 | 94.14% | 4.42% | 5.00% | 10 | $23.33 | #N/A |
| 6 | 1 | 200 | 207 | Fluorescent Torchieries, 6.0 hr/day | 1690.00 | 1690.00 | 100.00% | 21.31% | 5.00% | 5 | $23.00 | #N/A |
| 6 | 1 | 200 | 208 | Fluorescent Torchieries, 2.5 hr/day | 1690.00 | 1690.00 | 100.00% | 39.27% | 5.00% | 7 | $23.00 | #N/A |
| 6 | 1 | 200 | 209 | Fluorescent Torchieries, 0.5 hr/day | 1690.00 | 1690.00 | 100.00% | 4.42% | 5.00% | 7 | $23.00 | #N/A |
| 6 | 1 | 950 | 951 | Powerstrip with Occupancy Sensor | 1265.57 | 1265.57 | 100.00% | 1.71% | 100.00% | 20 | $90.00 | #N/A |

# Table B.2: Residential Gas

| Segment | Building | Base Number | Measure Number | Measure Name | Stock Usage | Base Usage | Incomplete Factor | Energy Savings | Feasibility Factor | Measure Life | Full Per Unit Cost | Full Base Measure Cost |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 1 | 180 | 180 | Base Furnace, 80 AFUE, 100 kbtu | 691.75 | 648.52 | 100.00% | 0.00% | 100.00% | 20 | $0.00 | $2,300.00 |
| 1 | 1 | 180 | 181 | Condensing Furnace, 92 AFUE | 691.75 | 648.52 | 90.00% | 13.04% | 40.00% | 20 | $724.00 | $2,300.00 |
| 1 | 1 | 180 | 182 | Condensing Furnace, 96 AFUE | 691.75 | 648.52 | 95.98% | 16.67% | 40.00% | 20 | $978.00 | $2,300.00 |
| 1 | 1 | 180 | 183 | ENERGY STAR Programmable Thermostat7 | 691.75 | 691.75 | 35.65% | 6.00% | 80.00% | 12 | $100.00 | $2,300.00 |
| 1 | 1 | 180 | 184 | Ceiling R-0 to R-19 Insulation Blown-in (.71) | 691.75 | 691.75 | 4.95% | 24.29% | 67.00% | 30 | $812.70 | $2,300.00 |
| 1 | 1 | 180 | 185 | Ceiling R-19 to R-38 Insulation Blown in (.73) | 691.75 | 691.75 | 4.95% | 8.40% | 33.00% | 30 | $812.70 | $2,300.00 |
| 1 | 1 | 180 | 186 | Floor R-0 to R-30 Insulation-Batts | 691.75 | 691.75 | 55.33% | 6.67% | 33.00% | 30 | $1,512.00 | $2,300.00 |
| 1 | 1 | 180 | 187 | Wall 2x4 R-0 to Blow-In R-19 Insulation | 691.75 | 691.75 | 55.33% | 20.01% | 50.00% | 30 | $1,063.70 | $2,300.00 |
| 1 | 1 | 180 | 188 | Comprehensive Shell Air Sealing - Inf. Reduction | 691.75 | 691.75 | 40.00% | 6.34% | 90.00% | 10 | $650.00 | $2,300.00 |
| 1 | 1 | 180 | 189 | PTCS Duct Sealing & O&M | 691.75 | 691.75 | 72.00% | 10.00% | 50.00% | 20 | $750.00 | $2,300.00 |
| 1 | 1 | 180 | 190 | Duct Insulation (R-3 to R-8) | 691.75 | 691.75 | 20.14% | 4.04% | 50.00% | 30 | $376.00 | $2,300.00 |
| 1 | 1 | 180 | 191 | Furnace Diagnostic Testing, Repair and Maintenance | 691.75 | 691.75 | 46.51% | 4.00% | 100.00% | 10 | $123.00 | $2,300.00 |
| 1 | 1 | 180 | 192 | Windows (high efficiency / ENERGY STAR+) | 691.75 | 691.75 | 85.26% | 6.98% | 75.00% | 30 | $3,100.69 | $2,300.00 |
| 1 | 1 | 180 | 194 | Integrated Space and Water Heating | 691.75 | 691.75 | 100.00% | 17.40% | 10.00% | 20 | $4,085.93 | $2,300.00 |
| 1 | 1 | 500 | 500 | Base 40 gal. Water Heating (EF=0.59) | 214.84 | 196.63 | 100.00% | 0.00% | 100.00% | 15 | $224.00 | $269.99 |
| 1 | 1 | 500 | 501 | HE Water Heater (EF=0.63) | 214.84 | 196.63 | 88.00% | 6.35% | 45.00% | 15 | $307.00 | $269.99 |
| 1 | 1 | 500 | 502 | HE Water Heater (EF=0.70) | 214.84 | 196.63 | 88.00% | 15.71% | 45.00% | 15 | $552.00 | $269.99 |
| 1 | 1 | 500 | 503 | Solar Water Heater | 214.84 | 214.84 | 99.00% | 50.00% | 33.00% | 15 | $5,500.00 | $269.99 |
| 1 | 1 | 500 | 504 | Low-Flow Showerheads | 214.84 | 214.84 | 22.20% | 8.60% | 95.00% | 10 | $20.00 | $269.99 |
| 1 | 1 | 500 | 505 | Hot Water Pipe Insulation | 214.84 | 214.84 | 33.50% | 4.61% | 75.00% | 10 | $5.80 | $269.99 |
| 1 | 1 | 500 | 506 | Water Heater Thermosat Setback | 214.84 | 214.84 | 75.77% | 4.26% | 50.00% | 10 | $15.00 | $269.99 |
| 1 | 1 | 500 | 507 | Tankless Water Heater (EF=0.82) | 214.84 | 214.84 | 79.90% | 27.70% | 25.00% | 15 | $1,700.00 | $269.99 |
| 1 | 1 | 500 | 508 | Drain Water Heat Recovery (GFX) | 214.84 | 214.84 | 100.00% | 37.59% | 25.00% | 15 | $550.00 | $269.99 |
| 1 | 1 | 500 | 509 | Horizontal-Axis Clothes Washer | 214.84 | 214.84 | 97.00% | 12.37% | 100.00% | 14 | $374.00 | #N/A |
| 1 | 1 | 500 | 510 | Energy Star Vertical-Axis Clothes Washer | 214.84 | 214.84 | 75.41% | 15.01% | 100.00% | 14 | $324.00 | #N/A |
| 1 | 1 | 500 | 511 | Energy Star DW (EF=0.58) | 214.84 | 214.84 | 80.69% | 5.00% | 100.00% | 13 | $204.00 | #N/A |
| 1 | 1 | 500 | 512 | Hot Water Heater Tank Wrap (R-10) | 214.84 | 214.84 | 31.32% | 10.00% | 90.00% | 15 | $17.00 | $189.99 |
| 1 | 1 | 500 | 513 | Faucet Aerators | 214.84 | 214.84 | 73.40% | 1.40% | 90.00% | 15 | $4.82 | $189.99 |
| 1 | 1 | 700 | 700 | Base Dryer | 71.54 | 71.54 | 100.00% | 0.00% | 100.00% | 14 | $0.00 | $299.98 |
| 1 | 1 | 700 | 701 | High Efficiency Dryer With Moisture Sensor | 71.54 | 71.54 | 77.80% | 31.82% | 100.00% | 14 | $100.00 | $299.98 |
| 1 | 1 | 900 | 900 | Base Conventional Oven | 44.85 | 44.85 | 100.00% | 0.00% | 100.00% | 15 | $0.00 | $429.99 |
| 1 | 1 | 900 | 901 | Convection Oven | 44.85 | 44.85 | 100.00% | 15.92% | 100.00% | 15 | $120.00 | $429.99 |
| 2 | 1 | 180 | 180 | Base Furnace, 80 AFUE,60 kbtu | 650.24 | 609.60 | 100.00% | 0.00% | 100.00% | 20 | $0.00 | $1,900.00 |
| 2 | 1 | 180 | 181 | Condensing Furnace, 92 AFUE | 650.24 | 609.60 | 90.00% | 13.04% | 40.00% | 20 | $635.00 | $1,900.00 |
| 2 | 1 | 180 | 182 | Condensing Furnace, 96 AFUE | 650.24 | 609.60 | 95.98% | 16.67% | 40.00% | 20 | $787.00 | $1,900.00 |
| 2 | 1 | 180 | 183 | ENERGY STAR Programmable Thermostat | 650.24 | 650.24 | 35.65% | 6.00% | 80.00% | 12 | $100.00 | $1,900.00 |
| 2 | 1 | 180 | 184 | Ceiling R-0 to R-19 Insulation Blown-in (.71) | 650.24 | 650.24 | 4.95% | 14.24% | 67.00% | 30 | $584.80 | $1,900.00 |
| 2 | 1 | 180 | 185 | Ceiling R-19 to R-38 Insulation Blown in (.73) | 650.24 | 650.24 | 4.95% | 2.20% | 33.00% | 30 | $584.80 | $1,900.00 |
| 2 | 1 | 180 | 186 | Floor R-0 to R-30 Insulation-Batts | 650.24 | 650.24 | 55.33% | 10.56% | 33.00% | 30 | $762.00 | $1,900.00 |
| 2 | 1 | 180 | 187 | Wall 2x4 R-0 to Blow-In R-19 Insulation | 650.24 | 650.24 | 55.33% | 26.33% | 50.00% | 30 | $424.30 | $1,900.00 |
| 2 | 1 | 180 | 188 | Comprehensive Shell Air Sealing - Inf. Reduction | 650.24 | 650.24 | 20.00% | 14.40% | 90.00% | 10 | $486.00 | $1,900.00 |
| 2 | 1 | 180 | 189 | PTCS Duct Sealing & O&M | 650.24 | 650.24 | 36.00% | 6.28% | 50.00% | 20 | $630.00 | $1,900.00 |

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# Table B.2: Residential Gas

| Segment | Building | Base Number | Measure Number | Measure Name | Stock Usage | Base Usage | Incomplete Factor | Energy Savings | Feasibility Factor | Measure Life | Full Per Unit Cost | Full Base Measure Cost |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2 | 1 | 180 | 190 | Duct Insulation (R-3 to R-8) | 650.24 | 650.24 | 20.14% | 3.30% | 50.00% | 30 | $245.00 | $1,900.00 |
| 2 | 1 | 180 | 192 | Windows (high efficiency / ENERGY STAR+) | 691.75 | 691.75 | 85.26% | 10.90% | 75.00% | 30 | $1,477.28 | $1,900.00 |
| 2 | 1 | 180 | 194 | Integrated Space and Water Heating | 650.24 | 650.24 | 100.00% | 13.80% | 10.00% | 20 | $4,085.93 | $1,900.00 |
| 2 | 1 | 500 | 500 | Base 40 gal. Water Heating (EF=0.59) | 201.95 | 184.83 | 100.00% | 0.00% | 100.00% | 15 | $224.00 | $269.99 |
| 2 | 1 | 500 | 501 | HE Water Heater (EF=0.63) | 201.95 | 184.83 | 88.00% | 6.35% | 45.00% | 15 | $307.00 | $269.99 |
| 2 | 1 | 500 | 502 | HE Water Heater (EF=0.70) | 201.95 | 184.83 | 88.00% | 15.71% | 45.00% | 15 | $552.00 | $269.99 |
| 2 | 1 | 500 | 503 | Solar Water Heater | 201.95 | 201.95 | 99.00% | 50.00% | 33.00% | 15 | $5,500.00 | $269.99 |
| 2 | 1 | 500 | 504 | Low-Flow Showerheads | 201.95 | 201.95 | 22.20% | 8.60% | 95.00% | 10 | $20.00 | $269.99 |
| 2 | 1 | 500 | 505 | Hot Water Pipe Insulation | 201.95 | 201.95 | 33.50% | 4.76% | 75.00% | 15 | $5.80 | $269.99 |
| 2 | 1 | 500 | 506 | Water Heater Thermosat Setback | 201.95 | 201.95 | 75.77% | 4.26% | 50.00% | 10 | $15.00 | $269.99 |
| 2 | 1 | 500 | 507 | Tankless Water Heater (EF=0.82) | 201.95 | 201.95 | 79.90% | 27.70% | 25.00% | 15 | $1,700.00 | $269.99 |
| 2 | 1 | 500 | 508 | Drain Water Heat Recovery (GFX) | 201.95 | 201.95 | 100.00% | 39.68% | 25.00% | 15 | $550.00 | $269.99 |
| 2 | 1 | 500 | 509 | Horizontal-Axis Clothes Washer | 201.95 | 201.95 | 97.00% | 9.91% | 100.00% | 14 | $374.00 | #N/A |
| 2 | 1 | 500 | 510 | Energy Star Vertical-Axis Clothes Washer | 201.95 | 201.95 | 75.41% | 12.07% | 100.00% | 14 | $324.00 | #N/A |
| 2 | 1 | 500 | 511 | Energy Star DW (EF=0.58) | 201.95 | 201.95 | 80.69% | 4.02% | 100.00% | 13 | $204.00 | #N/A |
| 2 | 1 | 500 | 512 | Hot Water Heater Tank Wrap (R-10) | 201.95 | 201.95 | 53.10% | 10.00% | 90.00% | 15 | $17.00 | $189.99 |
| 2 | 1 | 500 | 513 | Faucet Aerators | 201.95 | 201.95 | 73.40% | 1.40% | 90.00% | 15 | $4.82 | $189.99 |
| 2 | 1 | 550 | 550 | Base Boiler (AFUE = 80%) | 650.24 | 583.55 | 100.00% | 0.00% | 100.00% | 20 | $0.00 | $4,800.00 |
| 2 | 1 | 550 | 551 | High Efficiency Condensing Boiler (AFUE = 90%) | 650.24 | 583.55 | 100.00% | 13.33% | 50.00% | 20 | $734.00 | $4,800.00 |
| 2 | 1 | 700 | 700 | Base Dryer | 67.25 | 67.25 | 100.00% | 0.00% | 100.00% | 14 | $0.00 | $299.98 |
| 2 | 1 | 700 | 701 | High Efficiency Dryer With Moisture Sensor | 67.25 | 67.25 | 77.80% | 31.82% | 100.00% | 14 | $100.00 | $299.98 |
| 2 | 1 | 900 | 900 | Base Conventional Oven | 42.16 | 42.16 | 100.00% | 0.00% | 100.00% | 15 | $0.00 | $429.99 |
| 2 | 1 | 900 | 901 | Convection Oven | 42.16 | 42.16 | 100.00% | 16.85% | 100.00% | 15 | $120.00 | $429.99 |
| 3 | 1 | 180 | 180 | Base Furnace, 80 AFUE, 80 kbtu | 691.75 | 648.52 | 100.00% | 0.00% | 100.00% | 20 | $0.00 | $2,100.00 |
| 3 | 1 | 180 | 181 | Condensing Furnace, 92 AFUE | 691.75 | 648.52 | 90.00% | 13.04% | 40.00% | 20 | $680.00 | $2,100.00 |
| 3 | 1 | 180 | 182 | Condensing Furnace, 96 AFUE | 691.75 | 648.52 | 95.98% | 16.67% | 40.00% | 20 | $882.00 | $2,100.00 |
| 3 | 1 | 180 | 183 | ENERGY STAR Programmable Thermostat | 691.75 | 691.75 | 35.65% | 6.00% | 80.00% | 12 | $100.00 | $2,100.00 |
| 3 | 1 | 180 | 184 | Ceiling R-0 to R-19 Insulation Blown-in (.71) | 691.75 | 691.75 | 4.95% | 10.30% | 67.00% | 25 | $757.83 | $2,100.00 |
| 3 | 1 | 180 | 185 | Ceiling R-19 to R-30 Insulation Blown in (.73) | 691.75 | 691.75 | 4.95% | 6.25% | 33.00% | 25 | $953.44 | $2,100.00 |
| 3 | 1 | 180 | 186 | Floor R-5 to R-25 Insulation-Batts | 691.75 | 691.75 | 55.33% | 8.60% | 33.00% | 25 | $902.00 | $2,100.00 |
| 3 | 1 | 180 | 187 | Wall 2x4 R-0 to Blow-In R-13 Insulation (.86) | 691.75 | 691.75 | 55.33% | 17.63% | 50.00% | 25 | $1,660.00 | $2,100.00 |
| 3 | 1 | 180 | 188 | Comprehensive Shell Air Sealing - Inf. Reduction | 691.75 | 691.75 | 40.00% | 5.20% | 90.00% | 10 | $300.00 | $2,100.00 |
| 3 | 1 | 180 | 189 | PTCS Duct Sealing & O&M | 691.75 | 691.75 | 72.00% | 10.00% | 50.00% | 20 | $450.00 | $2,100.00 |
| 3 | 1 | 180 | 190 | Duct Insulation (R-3 to R-8) | 691.75 | 691.75 | 20.14% | 3.30% | 50.00% | 25 | $245.00 | $2,100.00 |
| 3 | 1 | 180 | 191 | Furnace Diagnostic Testing, Repair and Maintenance | 691.75 | 691.75 | 46.51% | 4.00% | 100.00% | 10 | $123.00 | $2,100.00 |
| 3 | 1 | 180 | 192 | Windows (high efficiency / ENERGY STAR+) | 691.75 | 691.75 | 85.26% | 24.80% | 75.00% | 25 | $1,617.98 | $2,100.00 |
| 3 | 1 | 180 | 194 | Integrated Space and Water Heating | 691.75 | 691.75 | 100.00% | 36.52% | 10.00% | 20 | $4,085.93 | $2,100.00 |
| 3 | 1 | 500 | 500 | Base 40 gal. Water Heating (EF=0.59) | 214.84 | 196.63 | 100.00% | 0.00% | 100.00% | 15 | $224.00 | $269.99 |
| 3 | 1 | 500 | 501 | HE Water Heater (EF=0.63) | 214.84 | 196.63 | 88.00% | 6.35% | 45.00% | 15 | $307.00 | $269.99 |
| 3 | 1 | 500 | 502 | HE Water Heater (EF=0.70) | 214.84 | 196.63 | 88.00% | 15.71% | 45.00% | 15 | $552.00 | $269.99 |
| 3 | 1 | 500 | 503 | Solar Water Heater | 214.84 | 214.84 | 99.00% | 50.00% | 33.00% | 15 | $5,500.00 | $269.99 |
| 3 | 1 | 500 | 504 | Low-Flow Showerheads | 214.84 | 214.84 | 22.20% | 8.60% | 95.00% | 10 | $20.00 | $269.99 |
| 3 | 1 | 500 | 505 | Hot Water Pipe Insulation | 214.84 | 214.84 | 33.50% | 4.33% | 75.00% | 15 | $5.80 | $269.99 |
| 3 | 1 | 500 | 506 | Water Heater Thermosat Setback | 214.84 | 214.84 | 75.77% | 4.26% | 50.00% | 5 | $15.00 | $269.99 |

## Table B.2: Residential Gas

| Segment | Building | Base Number | Measure Number | Measure Name | Stock Usage | Base Usage | Incomplete Factor | Energy Savings | Feasibility Factor | Measure Life | Full Per Unit Cost | Full Base Measure Cost |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 3 | 1 | 500 | 507 | Tankless Water Heater (EF=0.82) | 214.84 | 214.84 | 79.90% | 27.70% | 25.00% | 15 | $1,700.00 | $269.99 |
| 3 | 1 | 500 | 508 | Drain Water Heat Recovery (GFX) | 214.84 | 214.84 | 100.00% | 35.83% | 25.00% | 15 | $550.00 | $269.99 |
| 3 | 1 | 500 | 509 | Horizontal-Axis Clothes Washer | 214.84 | 214.84 | 97.00% | 14.47% | 100.00% | 14 | $374.00 | #N/A |
| 3 | 1 | 500 | 510 | Energy Star Vertical-Axis Clothes Washer | 214.84 | 214.84 | 75.41% | 17.54% | 100.00% | 14 | $324.00 | #N/A |
| 3 | 1 | 500 | 511 | Energy Star DW (EF=0.58) | 214.84 | 214.84 | 80.69% | 7.89% | 100.00% | 13 | $204.00 | #N/A |
| 3 | 1 | 500 | 512 | Hot Water Heater Tank Wrap (R-10) | 214.84 | 214.84 | 31.94% | 10.00% | 90.00% | 15 | $17.00 | $189.99 |
| 3 | 1 | 500 | 513 | Faucet Aerators | 214.84 | 214.84 | 73.40% | 1.40% | 90.00% | 15 | $4.82 | $189.99 |
| 3 | 1 | 700 | 700 | Base Dryer | 71.54 | 71.54 | 100.00% | 0.00% | 100.00% | 14 | $0.00 | $299.98 |
| 3 | 1 | 700 | 701 | High Efficiency Dryer With Moisture Sensor | 71.54 | 71.54 | 77.80% | 31.82% | 100.00% | 14 | $100.00 | $299.98 |
| 3 | 1 | 900 | 900 | Base Conventional Oven | 44.85 | 44.85 | 100.00% | 0.00% | 100.00% | 15 | $0.00 | $429.99 |
| 3 | 1 | 900 | 901 | Convection Oven | 44.85 | 44.85 | 100.00% | 17.78% | 100.00% | 15 | $120.00 | $429.99 |
| 4 | 1 | 180 | 180 | Base Furnace, 80 AFUE, 120 kbtu | 575.15 | 575.15 | 100.00% | 0.00% | 100.00% | 20 | $0.00 | $2,500.00 |
| 4 | 1 | 180 | 181 | Condensing Furnace, 92 AFUE | 575.15 | 575.15 | 90.00% | 13.04% | 40.00% | 20 | $731.00 | $2,500.00 |
| 4 | 1 | 180 | 182 | Condensing Furnace, 96 AFUE | 575.15 | 575.15 | 95.98% | 16.67% | 40.00% | 20 | $1,073.00 | $2,500.00 |
| 4 | 1 | 180 | 194 | Integrated Space and Water Heating | 575.15 | 575.15 | 100.00% | 24.50% | 20.00% | 20 | $4,085.93 | $2,500.00 |
| 4 | 1 | 180 | 195 | ENERGY STAR New Construction | 575.15 | 575.15 | 96.04% | 30.00% | 50.00% | 25 | $3,000.00 | $2,500.00 |
| 4 | 1 | 180 | 196 | ENERGY STAR New Construction Plus | 575.15 | 575.15 | 96.04% | 40.00% | 50.00% | 25 | $5,000.00 | $2,500.00 |
| 4 | 1 | 500 | 500 | Base 40 gal. Water Heating (EF=0.59) | 276.68 | 276.68 | 100.00% | 0.00% | 100.00% | 15 | $224.00 | $269.99 |
| 4 | 1 | 500 | 501 | HE Water Heater (EF=0.63) | 276.68 | 276.68 | 88.00% | 6.35% | 40.00% | 15 | $307.00 | $269.99 |
| 4 | 1 | 500 | 502 | HE Water Heater (EF=0.70) | 276.68 | 276.68 | 88.00% | 15.71% | 40.00% | 15 | $552.00 | $269.99 |
| 4 | 1 | 500 | 503 | Solar Water Heater | 276.68 | 276.68 | 99.00% | 50.00% | 25.00% | 15 | $5,500.00 | $269.99 |
| 4 | 1 | 500 | 507 | Tankless Water Heater (EF=0.82) | 276.68 | 276.68 | 79.90% | 27.70% | 50.00% | 15 | $903.00 | $269.99 |
| 4 | 1 | 500 | 508 | Drain Water Heat Recovery (GFX) | 276.68 | 276.68 | 100.00% | 31.26% | 50.00% | 15 | $400.00 | $269.99 |
| 4 | 1 | 500 | 509 | Horizontal-Axis Clothes Washer | 276.68 | 276.68 | 97.00% | 13.33% | 100.00% | 14 | $374.00 | #N/A |
| 4 | 1 | 500 | 510 | Energy Star Vertical-Axis Clothes Washer | 276.68 | 276.68 | 75.41% | 16.16% | 100.00% | 14 | $324.00 | #N/A |
| 4 | 1 | 500 | 511 | Energy Star DW (EF=0.58) | 276.68 | 276.68 | 80.69% | 5.00% | 100.00% | 13 | $204.00 | #N/A |
| 4 | 1 | 500 | 512 | Hot Water Heater Tank Wrap (R-10) | 276.68 | 276.68 | 31.32% | 10.00% | 90.00% | 15 | $17.00 | $189.99 |
| 4 | 1 | 500 | 513 | Faucet Aerators | 276.68 | 276.68 | 73.40% | 1.40% | 90.00% | 15 | $4.82 | $189.99 |
| 4 | 1 | 700 | 700 | Base Dryer | 71.54 | 71.54 | 100.00% | 0.00% | 100.00% | 14 | $0.00 | $299.98 |
| 4 | 1 | 700 | 701 | High Efficiency Dryer With Moisture Sensor | 71.54 | 71.54 | 77.80% | 31.82% | 100.00% | 14 | $100.00 | $299.98 |
| 4 | 1 | 900 | 900 | Base Conventional Oven | 44.85 | 44.85 | 100.00% | 0.00% | 100.00% | 15 | $0.00 | $429.99 |
| 4 | 1 | 900 | 901 | Convection Oven | 44.85 | 44.85 | 100.00% | 17.91% | 100.00% | 15 | $120.00 | $429.99 |
| 5 | 1 | 180 | 180 | Base Furnace, 80 AFUE, 80 kbtu | 540.64 | 540.64 | 100.00% | 0.00% | 100.00% | 20 | $0.00 | $2,100.00 |
| 5 | 1 | 180 | 181 | Condensing Furnace, 92 AFUE | 540.64 | 540.64 | 90.00% | 13.04% | 40.00% | 20 | $680.00 | $2,100.00 |
| 5 | 1 | 180 | 182 | Condensing Furnace, 96 AFUE | 540.64 | 540.64 | 95.98% | 16.67% | 40.00% | 20 | $882.00 | $2,100.00 |
| 5 | 1 | 180 | 194 | Integrated Space and Water Heating | 540.64 | 540.64 | 100.00% | 8.21% | 20.00% | 20 | $4,085.93 | $2,100.00 |
| 5 | 1 | 180 | 195 | ENERGY STAR New Construction | 540.64 | 540.64 | 96.04% | 30.00% | 50.00% | 20 | $2,000.00 | $2,100.00 |
| 5 | 1 | 180 | 196 | ENERGY STAR New Construction Plus | 540.64 | 540.64 | 96.04% | 40.00% | 50.00% | 25 | $3,500.00 | $2,100.00 |
| 5 | 1 | 500 | 500 | Base 40 gal. Water Heating (EF=0.59) | 260.08 | 260.08 | 100.00% | 0.00% | 100.00% | 25 | $224.00 | $269.99 |
| 5 | 1 | 500 | 501 | HE Water Heater (EF=0.63) | 260.08 | 260.08 | 88.00% | 6.35% | 40.00% | 15 | $307.00 | $269.99 |
| 5 | 1 | 500 | 502 | HE Water Heater (EF=0.70) | 260.08 | 260.08 | 88.00% | 15.71% | 40.00% | 15 | $552.00 | $269.99 |
| 5 | 1 | 500 | 503 | Solar Water Heater | 260.08 | 260.08 | 99.00% | 50.00% | 25.00% | 15 | $5,500.00 | $269.99 |
| 5 | 1 | 500 | 507 | Tankless Water Heater (EF=0.82) | 260.08 | 260.08 | 79.90% | 27.70% | 50.00% | 15 | $903.00 | $269.99 |
| 5 | 1 | 500 | 508 | Drain Water Heat Recovery (GFX) | 260.08 | 260.08 | 100.00% | 33.28% | 50.00% | 15 | $400.00 | $269.99 |

## Table B.2: Residential Gas

| Segment | Building | Base Number | Measure Number | Measure Name | Stock Usage | Base Usage | Incomplete Factor | Energy Savings | Feasibility Factor | Measure Life | Full Per Unit Cost | Full Base Measure Cost |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 5 | 1 | 500 | 509 | Horizontal-Axis Clothes Washer | 260.08 | 260.08 | 97.00% | 10.67% | 100.00% | 14 | $374.00 | #N/A |
| 5 | 1 | 500 | 510 | Energy Star Vertical-Axis Clothes Washer | 260.08 | 260.08 | 75.41% | 13.01% | 100.00% | 14 | $324.00 | #N/A |
| 5 | 1 | 500 | 511 | Energy Star DW (EF=0.58) | 260.08 | 260.08 | 80.69% | 4.34% | 100.00% | 13 | $204.00 | #N/A |
| 5 | 1 | 500 | 512 | Hot Water Heater Tank Wrap (R-10) | 260.08 | 260.08 | 53.10% | 10.00% | 90.00% | 15 | $17.00 | $189.99 |
| 5 | 1 | 500 | 513 | Faucet Aerators | 260.08 | 260.08 | 73.40% | 1.40% | 90.00% | 15 | $4.82 | $189.99 |
| 5 | 1 | 700 | 700 | Base Dryer | 67.25 | 67.25 | 100.00% | 0.00% | 100.00% | 14 | $0.00 | $299.98 |
| 5 | 1 | 700 | 701 | High Efficiency Dryer With Moisture Sensor | 67.25 | 67.25 | 77.80% | 31.82% | 100.00% | 14 | $100.00 | $299.98 |
| 5 | 1 | 900 | 900 | Base Conventional Oven | 42.16 | 42.16 | 100.00% | 0.00% | 100.00% | 15 | $0.00 | $429.99 |
| 5 | 1 | 900 | 901 | Convection Oven | 42.16 | 42.16 | 100.00% | 15.71% | 100.00% | 15 | $120.00 | $429.99 |
| 6 | 1 | 180 | 180 | Base Furnace, 80 AFUE, 80 kbtu | 575.15 | 575.15 | 100.00% | 0.00% | 100.00% | 20 | $0.00 | $2,100.00 |
| 6 | 1 | 180 | 181 | Condensing Furnace, 92 AFUE | 575.15 | 575.15 | 90.00% | 13.04% | 40.00% | 20 | $680.00 | $2,100.00 |
| 6 | 1 | 180 | 182 | Condensing Furnace, 96 AFUE | 575.15 | 575.15 | 95.98% | 16.67% | 40.00% | 20 | $882.00 | $2,100.00 |
| 6 | 1 | 180 | 194 | Integrated Space and Water Heating | 575.15 | 575.15 | 100.00% | 16.59% | 20.00% | 20 | $4,085.93 | $2,100.00 |
| 6 | 1 | 180 | 195 | Natural Choice / ENERGY STAR New Man. Housing | 575.15 | 575.15 | 96.04% | 30.00% | 100.00% | 25 | $2,000.00 | $2,100.00 |
| 6 | 1 | 500 | 500 | Base 40 gal. Water Heating (EF=0.59) | 260.08 | 260.08 | 100.00% | 0.00% | 100.00% | 15 | $224.00 | $269.99 |
| 6 | 1 | 500 | 501 | HE Water Heater (EF=0.63) | 260.08 | 260.08 | 88.00% | 6.35% | 40.00% | 15 | $307.00 | $269.99 |
| 6 | 1 | 500 | 502 | HE Water Heater (EF=0.70) | 260.08 | 260.08 | 88.00% | 15.71% | 40.00% | 15 | $552.00 | $269.99 |
| 6 | 1 | 500 | 503 | Solar Water Heater | 260.08 | 260.08 | 99.00% | 50.00% | 25.00% | 15 | $5,500.00 | $269.99 |
| 6 | 1 | 500 | 507 | Tankless Water Heater (EF=0.82) | 260.08 | 260.08 | 79.90% | 27.70% | 50.00% | 15 | $903.00 | $269.99 |
| 6 | 1 | 500 | 508 | Drain Water Heat Recovery (GFX) | 260.08 | 260.08 | 100.00% | 29.89% | 50.00% | 15 | $400.00 | $269.99 |
| 6 | 1 | 500 | 509 | Horizontal-Axis Clothes Washer | 260.08 | 260.08 | 97.00% | 15.21% | 100.00% | 14 | $374.00 | #N/A |
| 6 | 1 | 500 | 510 | Energy Star Vertical-Axis Clothes Washer | 260.08 | 260.08 | 75.41% | 18.44% | 100.00% | 14 | $324.00 | #N/A |
| 6 | 1 | 500 | 511 | Energy Star DW (EF=0.58) | 260.08 | 260.08 | 80.69% | 8.30% | 100.00% | 13 | $204.00 | #N/A |
| 6 | 1 | 500 | 512 | Hot Water Heater Tank Wrap (R-10) | 260.08 | 260.08 | 31.94% | 10.00% | 90.00% | 15 | $17.00 | $189.99 |
| 6 | 1 | 500 | 513 | Faucet Aerators | 260.08 | 260.08 | 73.40% | 1.40% | 90.00% | 15 | $4.82 | $189.99 |
| 6 | 1 | 700 | 700 | Base Dryer | 71.54 | 71.54 | 100.00% | 0.00% | 100.00% | 14 | $0.00 | $299.98 |
| 6 | 1 | 700 | 701 | High Efficiency Dryer With Moisture Sensor | 71.54 | 71.54 | 77.80% | 31.82% | 100.00% | 14 | $100.00 | $299.98 |
| 6 | 1 | 900 | 900 | Base Conventional Oven | 44.85 | 44.85 | 100.00% | 0.00% | 100.00% | 15 | $0.00 | $429.99 |
| 6 | 1 | 900 | 901 | Convection Oven | 44.85 | 44.85 | 100.00% | 17.78% | 100.00% | 15 | $120.00 | $429.99 |

## Commercial

### Table B.3: Commercial Electric

| Segment | Building | Base Number | Measure Number | Measure Name | Stock Usage | Base Usage | Incomplete Factor | Energy Savings | Feasibility Factor | Measure Life | Full Per Unit Cost | Full Base Measure Cost |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 1 | 110 | 110 | Base Fluorescent Fixture, 4' 4L T12, 34W, 2EEMAG | 5.29 | 5.29 | 100.00% | 0.00% | 100.00% | 10 | $1.51 | $1.51 |
| 1 | 1 | 110 | 111 | 4' 4L T8 Premium, EB | 5.29 | 4.77 | 100.00% | 25.00% | 16.67% | 16 | $0.50 | $1.51 |
| 1 | 1 | 110 | 112 | 4' 2L T8 Premium, EB, reflector | 5.29 | 4.77 | 100.00% | 62.50% | 16.67% | 16 | $0.74 | $1.51 |
| 1 | 1 | 110 | 113 | Occupancy Sensor, 4-4' Fluorescent Fixtures | 5.29 | 4.77 | 79.56% | 30.00% | 40.00% | 9 | $0.52 | $1.51 |
| 1 | 1 | 110 | 114 | Continuous Dimming, 5-4' Fluorescent Fixtures | 5.29 | 4.77 | 100.00% | 75.00% | 40.00% | 11 | $3.93 | $1.51 |
| 1 | 1 | 110 | 115 | 4' 2L T5HO, EB | 5.29 | 4.77 | 100.00% | 18.75% | 16.67% | 16 | $0.29 | $1.51 |
| 1 | 1 | 110 | 116 | 4' 4L T8, EB | 5.29 | 4.77 | 100.00% | 22.22% | 16.67% | 16 | $0.21 | $1.51 |
| 1 | 1 | 110 | 117 | 4' 3L T8, EB | 5.29 | 4.77 | 100.00% | 38.20% | 16.67% | 16 | $0.10 | $1.51 |
| 1 | 1 | 110 | 118 | 4' 3L T8 Premium, EB | 5.29 | 4.77 | 100.00% | 42.36% | 16.67% | 16 | $0.32 | $1.51 |
| 1 | 1 | 120 | 120 | Base Fluorescent Fixture, 4' 2L T12, 34W, 1EEMAG | 5.29 | 5.29 | 100.00% | 0.00% | 100.00% | 10 | $2.78 | $2.78 |
| 1 | 1 | 120 | 121 | 4' 2L T8 Premium, EB | 5.29 | 4.77 | 100.00% | 25.00% | 33.33% | 16 | $0.77 | $2.78 |
| 1 | 1 | 120 | 122 | 4' 1L T8 Premium, EB, reflector | 5.29 | 4.77 | 100.00% | 61.11% | 33.33% | 16 | $1.58 | $2.78 |
| 1 | 1 | 120 | 123 | Occupancy Sensor, 8-4' Fluorescent Fixtures | 5.29 | 4.77 | 79.56% | 30.00% | 40.00% | 9 | $0.45 | $2.78 |
| 1 | 1 | 120 | 124 | Continuous Dimming, 10-4' Fluorescent Fixtures | 5.29 | 4.77 | 100.00% | 75.00% | 40.00% | 11 | $3.82 | $2.78 |
| 1 | 1 | 120 | 125 | 4' 1L T5HO, EB | 5.29 | 4.77 | 100.00% | 13.90% | 33.33% | 16 | $0.59 | $2.78 |
| 1 | 1 | 130 | 130 | Base Fluorescent Fixture, 8' 2L T12, 60W, 1EEMAG | 5.29 | 5.29 | 100.00% | 0.00% | 100.00% | 10 | $1.82 | $1.82 |
| 1 | 1 | 130 | 131 | 8' 2L T12, 60W, EB | 5.29 | 4.77 | 26.59% | 10.57% | 25.00% | 16 | $0.17 | $1.82 |
| 1 | 1 | 130 | 132 | 8' 1L T12, 60W, EB, reflector | 5.29 | 4.77 | 100.00% | 55.30% | 25.00% | 16 | $0.79 | $1.82 |
| 1 | 1 | 130 | 133 | Occupancy Sensor, 4-8' Fluorescent Fixtures | 5.29 | 4.77 | 79.56% | 30.00% | 40.00% | 9 | $0.54 | $1.82 |
| 1 | 1 | 130 | 134 | Continuous Dimming, 5-8' Fluorescent Fixtures | 5.29 | 4.77 | 100.00% | 75.00% | 40.00% | 11 | $4.09 | $1.82 |
| 1 | 1 | 130 | 135 | 8' 2L T8, EB | 5.29 | 4.77 | 100.00% | 52.80% | 50.00% | 16 | $0.36 | $1.82 |
| 1 | 1 | 140 | 140 | Base Incandescent Flood, 75W | 5.29 | 5.29 | 100.00% | 0.00% | 100.00% | 1 | $3.66 | $3.66 |
| 1 | 1 | 140 | 141 | CFL Screw-in, Modular 18W | 5.29 | 4.77 | 72.49% | 65.30% | 90.00% | 5 | $2.25 | $3.66 |
| 1 | 1 | 150 | 150 | Base Incandescent Flood, 150W PAR | 5.29 | 5.29 | 100.00% | 0.00% | 100.00% | 1 | $1.76 | $1.76 |
| 1 | 1 | 150 | 151 | Halogen PAR Flood, 90W | 5.29 | 5.29 | 100.00% | 40.00% | 10.00% | 1 | $0.18 | $1.76 |
| 1 | 1 | 150 | 152 | Metal Halide, 50W | 5.29 | 5.29 | 93.86% | 52.00% | 45.00% | 6 | $9.40 | $1.76 |
| 1 | 1 | 150 | 153 | HPS, 50W | 5.29 | 5.29 | 93.86% | 56.00% | 45.00% | 6 | $4.80 | $1.76 |
| 1 | 1 | 160 | 160 | Base 4' 3L T12, 34W, 1EEMAG | 5.29 | 5.29 | 100.00% | 0.00% | 100.00% | 10 | $0.55 | $0.55 |
| 1 | 1 | 160 | 161 | 4' 3L T8, EB | 5.29 | 4.77 | 100.00% | 22.61% | 75.00% | 16 | $0.05 | $0.55 |
| 1 | 1 | 160 | 162 | 4' 3L T8 Premium, EB | 5.29 | 4.77 | 100.00% | 22.61% | 75.00% | 16 | $0.13 | $0.55 |
| 1 | 1 | 160 | 163 | 4' 2L T8 Premium, EB, reflector | 5.29 | 4.77 | 100.00% | 53.04% | 40.00% | 16 | $0.28 | $0.55 |
| 1 | 1 | 160 | 164 | 4' 1L T5HO, EB | 5.29 | 4.77 | 100.00% | 46.09% | 75.00% | 16 | $0.05 | $0.55 |
| 1 | 1 | 180 | 180 | Base Fluorescent Fixture 4' 4L T8, 1EB | 4.24 | 4.24 | 100.00% | 0.00% | 100.00% | 16 | $1.69 | $1.69 |
| 1 | 1 | 180 | 181 | 4' 4L T8 Premium, EB | 4.24 | 3.81 | 100.00% | 3.60% | 100.00% | 16 | $0.30 | $1.69 |
| 1 | 1 | 180 | 182 | Occupancy Sensor, 4-4' Fluorescent Fixtures | 4.24 | 3.81 | 79.56% | 30.00% | 40.00% | 9 | $0.52 | $1.69 |
| 1 | 1 | 185 | 185 | Base Fluorescent Fixture 4' 3L T8, 1EB | 4.24 | 3.60 | 100.00% | 0.00% | 100.00% | 16 | $3.15 | $3.15 |
| 1 | 1 | 185 | 186 | 4' 3L T8 Premium, EB | 4.24 | 3.81 | 100.00% | 6.70% | 100.00% | 16 | $0.43 | $3.15 |
| 1 | 1 | 190 | 190 | Base Fluorescent Fixture 4' 2L T8, 1EB | 4.24 | 3.60 | 100.00% | 0.00% | 100.00% | 16 | $2.97 | $2.97 |
| 1 | 1 | 190 | 191 | 4' 2L T8 Premium, EB | 4.24 | 3.81 | 100.00% | 8.50% | 100.00% | 16 | $0.27 | $2.97 |
| 1 | 1 | 190 | 192 | Occupancy Sensor, 8-4' Fluorescent Fixtures | 4.24 | 3.81 | 79.56% | 30.00% | 40.00% | 9 | $0.45 | $2.97 |

# Table B.3: Commercial Electric

| Segment | Building | Base Number | Measure Number | Measure Name | Stock Usage | Base Usage | Incomplete Factor | Energy Savings | Feasibility Factor | Measure Life | Full Per Unit Cost | Full Base Measure Cost |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 1 | 200 | 200 | Base Centrifugal Chiller, 0.65 kW/ton, 300 tons | 3.76 | 3.76 | 100.00% | 0.00% | 100.00% | 20 | $1.38 | $1.38 |
| 1 | 1 | 200 | 201 | Chiller Tune-Up / Diagnostics | 3.76 | 3.76 | 90.00% | 5.00% | 100.00% | 5 | $0.11 | $1.38 |
| 1 | 1 | 200 | 202 | Installation of Automated Building Ventilation Control ( Via Occupancy Sensors, CO2 Sensors, Etc.) | 3.76 | 3.76 | 100.00% | 10.00% | 50.00% | 10 | $0.29 | $1.38 |
| 1 | 1 | 200 | 203 | Roof / Ceiling Insulation | 3.76 | 3.76 | 8.70% | 3.00% | 50.00% | 20 | $0.33 | $305.98 |
| 1 | 1 | 200 | 204 | Cool Roofs (Reflective and Spray Evaporative) | 3.76 | 3.76 | 100.00% | 1.81% | 90.00% | 10 | $0.24 | $230.50 |
| 1 | 1 | 200 | 205 | EMS Optimization | 3.76 | 3.76 | 75.00% | 1.00% | 100.00% | 5 | $0.00 | $0.00 |
| 1 | 1 | 200 | 206 | High Efficiency Windows (Low-E Glass or Multiple Glazed) | 3.76 | 3.76 | 99.43% | 9.26% | 75.00% | 30 | $0.06 | $40.43 |
| 1 | 1 | 200 | 207 | Installation of Energy Management Systems | 3.76 | 3.76 | 19.08% | 10.00% | 50.00% | 10 | $0.18 | $1.38 |
| 1 | 1 | 200 | 208 | Insulation of Pipes | 3.76 | 3.76 | 50.00% | 1.00% | 50.00% | 20 | $0.00 | $0.45 |
| 1 | 1 | 200 | 209 | Installation of Chiller Economizers (water side) | 3.76 | 3.76 | 56.87% | 10.00% | 50.00% | 20 | $0.59 | $461.00 |
| 1 | 1 | 200 | 210 | Optimize Chilled Water and Condenser Water Settings | 3.76 | 3.76 | 50.00% | 5.00% | 33.00% | 10 | $0.20 | $1.38 |
| 1 | 1 | 200 | 211 | Decrease Cooling Tower Approach Temperature, 300 Tons, 6 Deg F | 3.76 | 3.38 | 100.00% | 7.50% | 67.00% | 15 | $0.11 | $2.15 |
| 1 | 1 | 200 | 212 | Two-Speed Cooling Tower, 300 Tons | 3.76 | 3.38 | 90.00% | 14.00% | 50.00% | 15 | $0.01 | $2.15 |
| 1 | 1 | 200 | 213 | VSD Cooling Tower, 300 Tons | 3.76 | 3.38 | 90.00% | 18.00% | 50.00% | 15 | $0.07 | $2.15 |
| 1 | 1 | 200 | 214 | Primary/Secondary De-coupled Chilled Water System | 3.76 | 3.38 | 80.00% | 12.00% | 50.00% | 15 | $0.45 | $2.15 |
| 1 | 1 | 200 | 215 | HE Chiller, 0.51 kW/ton, 300 Tons | 3.76 | 3.38 |  | 21.54% |  | 15 | $0.18 | $2.15 |
| 1 | 1 | 200 | 216 | VSD Chiller, 0.47 kW/ton, 300 Tons | 3.76 | 3.38 |  | 27.69% |  | 15 | $0.60 | $2.15 |
| 1 | 1 | 250 | 250 | Base DX Packaged System, EER=10.3, 10 tons | 6.51 | 6.51 | 100.00% | 0.00% | 100.00% | 15 | $2.36 | $2.36 |
| 1 | 1 | 250 | 251 | DX Tune-Up / Diagnostics | 6.51 | 6.51 | 90.00% | 10.00% | 100.00% | 3 | $0.23 | $2.36 |
| 1 | 1 | 250 | 252 | Hi-Eff DX Packaged System, 10 tons, EER=11.3 | 6.51 | 5.63 |  | 8.85% |  | 15 | $0.29 | $2.36 |
| 1 | 1 | 250 | 253 | High Efficiency Windows (Low-E Glass or Multiple Glazed) | 6.51 | 6.51 | 99.43% | 5.00% | 75.00% | 30 | $0.15 | $69.11 |
| 1 | 1 | 250 | 254 | Installation of Direct of Indirect Evaporative Cooling, Evaporative Pre-Cooling, and Absorption Cooling | 6.51 | 6.51 | 95.00% | 10.00% | 25.00% | 10 | $0.87 | $2.36 |
| 1 | 1 | 250 | 256 | Duct Insulation | 6.51 | 6.51 | 25.00% | 3.00% | 25.00% | 20 | $0.02 | $35.72 |
| 1 | 1 | 250 | 257 | Duct Repair and Sealing | 6.51 | 6.51 | 50.00% | 1.00% | 25.00% | 20 | $0.04 | $197.00 |
| 1 | 1 | 250 | 258 | Installation of Automated Building Ventilation Control ( Via Occupancy Sensors, CO2 Sensors, Etc.) | 6.51 | 6.51 | 100.00% | 10.00% | 50.00% | 10 | $0.29 | $2.36 |
| 1 | 1 | 250 | 259 | Roof / Ceiling Insulation | 6.51 | 6.51 | 8.70% | 3.00% | 50.00% | 20 | $0.33 | $523.02 |
| 1 | 1 | 250 | 260 | Cool Roofs (Reflective and Spray Evaporative) | 6.51 | 6.51 | 100.00% | 1.81% | 50.00% | 10 | $0.24 | $394.00 |
| 1 | 1 | 250 | 261 | Clock / Programmable Thermostat | 6.51 | 6.51 | 58.45% | 10.00% | 100.00% | 10 | $0.06 | $2.36 |
| 1 | 1 | 250 | 262 | Installation of Air Side Economizers | 6.51 | 6.51 | 30.37% | 15.00% | 100.00% | 10 | $0.59 | $788.00 |
| 1 | 1 | 280 | 280 | Base Air-Cooled HP Package, 5 tons, SEER=10 | 6.51 | 5.86 | 100.00% | 0.00% | 100.00% | 15 | $2.15 | $2.15 |
| 1 | 1 | 280 | 281 | Air-Cooled HP Package, 5 tons, SEER=11 | 6.51 | 5.86 |  | 9.09% |  | 15 | $0.11 | $2.15 |
| 1 | 1 | 280 | 282 | Air-Cooled HP Package, 5 tons, SEER=12 | 6.51 | 5.86 |  | 16.67% |  | 15 | $0.71 | $2.15 |
| 1 | 1 | 280 | 283 | DX Tune-Up / Diagnostics | 6.51 | 6.51 | 90.00% | 10.00% | 100.00% | 3 | $0.23 | $2.36 |
| 1 | 1 | 280 | 284 | High Efficiency Windows (Low-E Glass or Multiple Glazed) | 6.51 | 6.51 | 99.43% | 5.00% | 75.00% | 30 | $0.15 | $69.11 |
| 1 | 1 | 280 | 285 | Installation of Direct of Indirect Evaporative Cooling, Evaporative Pre-Cooling, and Absorption Cooling | 6.51 | 6.51 | 95.00% | 10.00% | 25.00% | 10 | $0.87 | $2.36 |
| 1 | 1 | 280 | 286 | Duct Insulation | 6.51 | 6.51 | 25.00% | 3.00% | 25.00% | 20 | $0.02 | $35.72 |
| 1 | 1 | 280 | 287 | Duct Repair and Sealing | 6.51 | 6.51 | 50.00% | 1.00% | 25.00% | 20 | $0.04 | $197.00 |
| 1 | 1 | 280 | 288 | Installation of Automated Building Ventilation Control ( Via Occupancy Sensors, CO2 Sensors, Etc.) | 6.51 | 6.51 | 100.00% | 10.00% | 50.00% | 10 | $0.29 | $2.36 |
| 1 | 1 | 280 | 289 | Roof / Ceiling Insulation | 6.51 | 6.51 | 8.70% | 3.00% | 50.00% | 20 | $0.33 | $523.02 |

## Table B.3: Commercial Electric

| Segment | Building | Base Number | Measure Number | Measure Name | Stock Usage | Base Usage | Incomplete Factor | Energy Savings | Feasibility Factor | Measure Life | Full Per Unit Cost | Full Base Measure Cost |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 1 | 280 | 290 | Cool Roofs (Reflective and Spray Evaporative) | 6.51 | 6.51 | 100.00% | 1.81% | 50.00% | 10 | $0.24 | $394.00 |
| 1 | 1 | 280 | 291 | Clock / Programmable Thermostat | 6.51 | 6.51 | 58.45% | 10.00% | 100.00% | 10 | $0.06 | $2.36 |
| 1 | 1 | 280 | 292 | Installation of Air Side Economizers | 6.51 | 6.51 | 30.37% | 15.00% | 100.00% | 10 | $0.59 | $788.00 |
| 1 | 1 | 400 | 400 | Base Fan Motor, 5hp, 1800rpm, 87.5% (ODP) | 2.25 | 2.25 | | 0.00% | | 15 | $0.18 | $0.18 |
| 1 | 1 | 400 | 401 | Energy Efficient Fan & Pump Motors (ODP) | 2.25 | 2.25 | | 1.50% | | 15 | $0.04 | $0.18 |
| 1 | 1 | 400 | 402 | VSD, ASD Fan & Pump Applications | 2.25 | 2.25 | | 30.00% | | 15 | $0.21 | $0.18 |
| 1 | 1 | 610 | 610 | Base Office Equipment | 1.59 | 1.59 | 100.00% | 0.00% | 100.00% | 4 | $1.46 | $4.29 |
| 1 | 1 | 610 | 611 | ENERGY STAR or Better Office Equipment: Computer | 1.59 | 1.59 | 65.00% | 24.69% | 100.00% | 4 | $0.18 | $4.29 |
| 1 | 1 | 610 | 621 | ENERGY STAR or Better Office Equipment: Monitors | 1.59 | 1.59 | 71.00% | 21.94% | 100.00% | 4 | $0.09 | $4.29 |
| 1 | 1 | 610 | 623 | Smart Networks | 1.59 | 1.59 | 40.00% | 9.14% | 90.00% | 4 | $0.01 | $4.29 |
| 1 | 1 | 610 | 631 | ENERGY STAR or Better Office Equipment: Copiers | 1.59 | 1.59 | 65.00% | 4.84% | 100.00% | 4 | $0.03 | $0.40 |
| 1 | 1 | 610 | 641 | ENERGY STAR or Better Office Equipment: Printers | 1.59 | 1.59 | 65.00% | 8.01% | 100.00% | 4 | $0.10 | $1.21 |
| 1 | 1 | 700 | 700 | Base Water Heating | 0.30 | 0.30 | 100.00% | 0.00% | 100.00% | 15 | $4.65 | $4.65 |
| 1 | 1 | 700 | 701 | Demand controlled circulating systems | 0.30 | 0.30 | 93.16% | 5.00% | 50.00% | 15 | $0.91 | $4.65 |
| 1 | 1 | 700 | 702 | Heat Pump Water Heater | 0.30 | 0.30 | 100.00% | 30.00% | 75.00% | 15 | $0.58 | $4.65 |
| 1 | 1 | 700 | 703 | High-Efficiency Water Heater (electric) | 0.30 | 0.30 | | 5.40% | | 15 | $0.17 | $4.65 |
| 1 | 1 | 700 | 704 | Hot Water (SHW) Pipe Insulation | 0.30 | 0.30 | 39.27% | 5.00% | 50.00% | 15 | $0.00 | $0.98 |
| 1 | 1 | 800 | 800 | Base Heating | 0.79 | 0.79 | 100.00% | 0.00% | 100.00% | 20 | $2.40 | $2.40 |
| 1 | 1 | 800 | 802 | Roof / Ceiling Insulation | 0.79 | 0.79 | 12.95% | 10.00% | 50.00% | 20 | $0.33 | $1.59 |
| 1 | 1 | 800 | 803 | Duct Insulation | 0.79 | 0.79 | 58.50% | 2.00% | 25.00% | 20 | $0.02 | $1.59 |
| 1 | 1 | 800 | 804 | Duct Repair and Sealing | 0.79 | 0.79 | 50.00% | 2.00% | 25.00% | 20 | $0.01 | $1.59 |
| 1 | 1 | 800 | 805 | Clock / Programmable Thermostat | 0.79 | 0.79 | 58.45% | 30.00% | 100.00% | 10 | $0.15 | $2.40 |
| 1 | 1 | 800 | 812 | Installation of Automated Building Ventilation Control ( Via Occupancy Sensors, CO2 Sensors, Etc.) | 0.79 | 0.79 | 100.00% | 5.00% | 50.00% | 15 | $0.28 | $2.40 |
| 1 | 2 | 110 | 110 | Base Fluorescent Fixture, 4' 4L T12, 34W, 2EEMAG | 5.89 | 5.89 | 100.00% | 0.00% | 100.00% | 16 | $1.68 | $1.68 |
| 1 | 2 | 110 | 111 | 4' 4L T8 Premium, EB | 5.89 | 5.30 | 100.00% | 25.00% | 16.67% | 25 | $0.55 | $1.68 |
| 1 | 2 | 110 | 112 | 4' 2L T8 Premium, EB, reflector | 5.89 | 5.30 | 100.00% | 62.50% | 16.67% | 25 | $0.83 | $1.68 |
| 1 | 2 | 110 | 113 | Occupancy Sensor, 4-4' Fluorescent Fixtures | 5.89 | 5.30 | 100.00% | 30.00% | 10.00% | 14 | $0.58 | $1.68 |
| 1 | 2 | 110 | 114 | Continuous Dimming, 5-4' Fluorescent Fixtures | 5.89 | 5.30 | 100.00% | 75.00% | 50.00% | 18 | $4.37 | $1.68 |
| 1 | 2 | 110 | 115 | 4' 2L T5HO, EB | 5.89 | 5.30 | 100.00% | 18.75% | 16.67% | 25 | $0.32 | $1.68 |
| 1 | 2 | 110 | 116 | 4' 4L T8, EB | 5.89 | 5.30 | 100.00% | 22.22% | 16.67% | 25 | $0.23 | $1.68 |
| 1 | 2 | 110 | 117 | 4' 3L T8, EB | 5.89 | 5.30 | 100.00% | 38.20% | 16.67% | 25 | $0.11 | $1.68 |
| 1 | 2 | 110 | 118 | 4' 3L T8 Premium, EB | 5.89 | 5.30 | 100.00% | 42.36% | 16.67% | 25 | $0.35 | $1.68 |
| 1 | 2 | 120 | 120 | Base Fluorescent Fixture, 4' 2L T12, 34W, 1EEMAG | 5.89 | 5.89 | 100.00% | 0.00% | 100.00% | 16 | $3.17 | $3.17 |
| 1 | 2 | 120 | 121 | 4' 2L T8 Premium, EB | 5.89 | 5.30 | 100.00% | 25.00% | 33.33% | 25 | $0.88 | $3.17 |
| 1 | 2 | 120 | 122 | 4' 1L T8 Premium, EB, reflector | 5.89 | 5.30 | 100.00% | 61.11% | 33.33% | 25 | $1.80 | $3.17 |
| 1 | 2 | 120 | 123 | Occupancy Sensor, 8-4' Fluorescent Fixtures | 5.89 | 5.30 | 100.00% | 30.00% | 10.00% | 14 | $0.52 | $3.17 |
| 1 | 2 | 120 | 124 | Continuous Dimming, 10-4' Fluorescent Fixtures | 5.89 | 5.30 | 100.00% | 75.00% | 50.00% | 18 | $4.35 | $3.17 |
| 1 | 2 | 120 | 125 | 4' 1L T5HO, EB | 5.89 | 5.30 | 100.00% | 13.90% | 33.33% | 25 | $0.67 | $3.17 |
| 1 | 2 | 130 | 130 | Base Fluorescent Fixture, 8' 2L T12, 60W, 1EEMAG | 5.89 | 5.89 | 100.00% | 0.00% | 100.00% | 16 | $2.23 | $2.23 |
| 1 | 2 | 130 | 131 | 8' 2L T12, 60W, EB | 5.89 | 5.30 | 95.41% | 10.57% | 25.00% | 25 | $0.21 | $2.23 |
| 1 | 2 | 130 | 132 | 8' 1L T12, 60W, EB, reflector | 5.89 | 5.30 | 100.00% | 55.30% | 25.00% | 25 | $0.96 | $2.23 |
| 1 | 2 | 130 | 133 | Occupancy Sensor, 4-8' Fluorescent Fixtures | 5.89 | 5.30 | 100.00% | 30.00% | 10.00% | 14 | $0.67 | $2.23 |
| 1 | 2 | 130 | 134 | Continuous Dimming, 5-8' Fluorescent Fixtures | 5.89 | 5.30 | 100.00% | 75.00% | 20.00% | 18 | $5.02 | $2.23 |

## Table B.3: Commercial Electric

| Segment | Building | Base Number | Measure Number | Measure Name | Stock Usage | Base Usage | Incomplete Factor | Energy Savings | Feasibility Factor | Measure Life | Full Per Unit Cost | Full Base Measure Cost |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 2 | 130 | 135 | 8' 2L T8, EB | 5.89 | 5.30 | 100.00% | 52.80% | 50.00% | 25 | $0.44 | $2.23 |
| 1 | 2 | 140 | 140 | Base Incandescent Flood, 75W | 5.89 | 5.89 | 100.00% | 0.00% | 100.00% | 1 | $4.55 | $4.55 |
| 1 | 2 | 140 | 141 | CFL Screw-in, Modular 18W | 5.89 | 5.30 | 75.00% | 65.30% | 50.00% | 7 | $2.80 | $4.55 |
| 1 | 2 | 150 | 150 | Base Incandescent Flood, 150W PAR | 5.89 | 5.89 | 100.00% | 0.00% | 100.00% | 1 | $1.88 | $1.88 |
| 1 | 2 | 150 | 151 | Halogen PAR Flood, 90W | 5.89 | 5.89 | 99.28% | 40.00% | 10.00% | 1 | $0.19 | $1.88 |
| 1 | 2 | 150 | 152 | Metal Halide, 50W | 5.89 | 5.89 | 91.60% | 52.00% | 45.00% | 8 | $10.05 | $1.88 |
| 1 | 2 | 150 | 153 | HPS, 50W | 5.89 | 5.89 | 91.60% | 56.00% | 45.00% | 8 | $5.13 | $1.88 |
| 1 | 2 | 160 | 160 | Base 4' 3L T12, 34W, 1EEMAG | 5.89 | 5.89 | 100.00% | 0.00% | 100.00% | 10 | $1.35 | $1.35 |
| 1 | 2 | 160 | 161 | 4' 3L T8, EB | 5.89 | 5.30 | 100.00% | 22.61% | 75.00% | 25 | $0.11 | $1.35 |
| 1 | 2 | 160 | 162 | 4' 3L T8 Premium, EB | 5.89 | 5.30 | 100.00% | 22.61% | 75.00% | 25 | $0.31 | $1.35 |
| 1 | 2 | 160 | 163 | 4' 2L T8 Premium, EB, reflector | 5.89 | 5.30 | 100.00% | 53.04% | 40.00% | 25 | $0.70 | $1.35 |
| 1 | 2 | 160 | 164 | 4' 1L T5HO, EB | 5.89 | 5.30 | 100.00% | 46.09% | 75.00% | 25 | $0.12 | $1.35 |
| 1 | 2 | 180 | 180 | Base Fluorescent Fixture 4' 4L T8, 1EB | 4.71 | 4.71 | 100.00% | 0.00% | 100.00% | 25 | $1.88 | $1.88 |
| 1 | 2 | 180 | 181 | 4' 4L T8 Premium, EB | 4.71 | 4.24 | 100.00% | 3.60% | 100.00% | 25 | $0.34 | $1.88 |
| 1 | 2 | 180 | 182 | Occupancy Sensor, 4-4' Fluorescent Fixtures | 4.71 | 4.24 | 100.00% | 30.00% | 10.00% | 14 | $0.58 | $1.88 |
| 1 | 2 | 185 | 185 | Base Fluorescent Fixture 4' 3L T8, 1EB | 4.71 | 4.00 | 100.00% | 0.00% | 100.00% | 25 | $3.59 | $3.59 |
| 1 | 2 | 185 | 186 | 4' 3L T8 Premium, EB | 4.71 | 4.24 | 100.00% | 6.70% | 100.00% | 25 | $0.49 | $3.59 |
| 1 | 2 | 190 | 190 | Base Fluorescent Fixture 4' 2L T8, 1EB | 4.71 | 4.00 | 100.00% | 0.00% | 100.00% | 25 | $3.38 | $3.38 |
| 1 | 2 | 190 | 191 | 4' 2L T8 Premium, EB | 4.71 | 4.24 | 100.00% | 8.50% | 100.00% | 25 | $0.30 | $3.38 |
| 1 | 2 | 190 | 192 | Occupancy Sensor, 8-4' Fluorescent Fixtures | 4.71 | 4.24 | 100.00% | 30.00% | 10.00% | 14 | $0.52 | $3.38 |
| 1 | 2 | 200 | 200 | Base Centrifugal Chiller, 0.65 kW/ton, 300 tons | 1.22 | 1.22 | 100.00% | 0.00% | 100.00% | 20 | $1.15 | $1.15 |
| 1 | 2 | 200 | 201 | Chiller Tune-Up / Diagnostics | 1.22 | 1.22 | 90.00% | 5.00% | 100.00% | 5 | $0.09 | $1.15 |
| 1 | 2 | 200 | 202 | Installation of Automated Building Ventilation Control ( Via Occupancy Sensors, CO2 Sensors, Etc.) | 1.22 | 1.22 | 100.00% | 10.00% | 50.00% | 10 | $0.24 | $1.15 |
| 1 | 2 | 200 | 203 | Roof / Ceiling Insulation | 1.22 | 1.22 | 100.00% | 3.00% | 50.00% | 20 | $0.47 | $443.39 |
| 1 | 2 | 200 | 204 | Cool Roofs (Reflective and Spray Evaporative) | 1.22 | 1.22 | 100.00% | 6.92% | 90.00% | 10 | $0.47 | $461.00 |
| 1 | 2 | 200 | 205 | EMS Optimization | 1.22 | 1.22 | 75.00% | 1.00% | 100.00% | 5 | $0.00 | $0.00 |
| 1 | 2 | 200 | 206 | High Efficiency Windows (Low-E Glass or Multiple Glazed) | 1.22 | 1.22 | 100.00% | 10.32% | 75.00% | 30 | $0.03 | $21.21 |
| 1 | 2 | 200 | 207 | Installation of Energy Management Systems | 1.22 | 1.22 | 100.00% | 10.00% | 50.00% | 10 | $0.15 | $1.15 |
| 1 | 2 | 200 | 208 | Insulation of Pipes | 1.22 | 1.22 | 50.00% | 1.00% | 50.00% | 20 | $0.03 | $2.94 |
| 1 | 2 | 200 | 209 | Installation of Chiller Economizers (water side) | 1.22 | 1.22 | 100.00% | 10.00% | 50.00% | 20 | $0.59 | $461.00 |
| 1 | 2 | 200 | 210 | Optimize Chilled Water and Condenser Water Settings | 1.22 | 1.22 | 50.00% | 5.00% | 33.00% | 10 | $0.17 | $1.15 |
| 1 | 2 | 200 | 211 | Decrease Cooling Tower Approach Temperature, 300 Tons, 6 Deg F | 1.22 | 1.10 | 100.00% | 7.50% | 67.00% | 15 | $0.09 | $1.79 |
| 1 | 2 | 200 | 212 | Two-Speed Cooling Tower, 300 Tons | 1.22 | 1.10 | 90.00% | 14.00% | 50.00% | 15 | $0.01 | $1.79 |
| 1 | 2 | 200 | 213 | VSD Cooling Tower, 300 Tons | 1.22 | 1.10 | 90.00% | 18.00% | 50.00% | 15 | $0.06 | $1.79 |
| 1 | 2 | 200 | 214 | Primary/Secondary De-coupled Chilled Water System | 1.22 | 1.10 | 80.00% | 12.00% | 50.00% | 15 | $0.38 | $1.79 |
| 1 | 2 | 200 | 215 | HE Chiller, 0.51 kW/ton, 300 Tons | 1.22 | 1.10 |  | 21.54% |  | 15 | $0.15 | $1.79 |
| 1 | 2 | 200 | 216 | VSD Chiller, 0.47 kW/ton, 300 Tons | 1.22 | 1.10 |  | 27.69% |  | 15 | $0.50 | $1.79 |
| 1 | 2 | 250 | 250 | Base DX Packaged System, EER=10.3, 10 tons | 2.11 | 2.11 | 100.00% | 0.00% | 100.00% | 15 | $1.97 | $1.97 |
| 1 | 2 | 250 | 251 | DX Tune-Up / Diagnostics | 2.11 | 2.11 | 90.00% | 10.00% | 100.00% | 3 | $0.20 | $1.97 |
| 1 | 2 | 250 | 252 | Hi-Eff DX Packaged System, 10 tons, EER=11.3 | 2.11 | 1.82 |  | 8.85% |  | 15 | $0.24 | $1.97 |
| 1 | 2 | 250 | 253 | High Efficiency Windows (Low-E Glass or Multiple Glazed) | 2.11 | 2.11 | 100.00% | 5.00% | 75.00% | 30 | $0.08 | $36.25 |

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## Table B.3: Commercial Electric

| Segment | Building | Base Number | Measure Number | Measure Name | Stock Usage | Base Usage | Incomplete Factor | Energy Savings | Feasibility Factor | Measure Life | Full Per Unit Cost | Full Base Measure Cost |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 2 | 250 | 254 | Installation of Direct of Indirect Evaporative Cooling, Evaporative Pre-Cooling, and Absorption Cooling | 2.11 | 2.11 | 95.00% | 10.00% | 25.00% | 10 | $0.73 | $1.97 |
| 1 | 2 | 250 | 256 | Duct Insulation | 2.11 | 2.11 | 25.00% | 3.00% | 25.00% | 20 | $0.03 | $62.52 |
| 1 | 2 | 250 | 257 | Duct Repair and Sealing | 2.11 | 2.11 | 50.00% | 1.00% | 25.00% | 20 | $0.04 | $197.00 |
| 1 | 2 | 250 | 258 | Installation of Automated Building Ventilation Control ( Via Occupancy Sensors, CO2 Sensors, Etc.) | 2.11 | 2.11 | 100.00% | 10.00% | 50.00% | 10 | $0.24 | $1.97 |
| 1 | 2 | 250 | 259 | Roof / Ceiling Insulation | 2.11 | 2.11 | 100.00% | 3.00% | 50.00% | 20 | $0.47 | $757.89 |
| 1 | 2 | 250 | 260 | Cool Roofs (Reflective and Spray Evaporative) | 2.11 | 2.11 | 100.00% | 6.92% | 50.00% | 10 | $0.47 | $788.00 |
| 1 | 2 | 250 | 261 | Clock / Programmable Thermostat | 2.11 | 2.11 | 50.00% | 10.00% | 100.00% | 10 | $0.05 | $1.97 |
| 1 | 2 | 250 | 262 | Installation of Air Side Economizers | 2.11 | 2.11 | 92.26% | 15.00% | 100.00% | 10 | $0.59 | $788.00 |
| 1 | 2 | 280 | 280 | Base Air-Cooled HP Package, 5 tons, SEER=10 | 2.11 | 1.90 | 100.00% | 0.00% | 100.00% | 15 | $1.79 | $1.79 |
| 1 | 2 | 280 | 281 | Air-Cooled HP Package, 5 tons, SEER=11 | 2.11 | 1.90 | | 9.09% | | 15 | $0.09 | $1.79 |
| 1 | 2 | 280 | 282 | Air-Cooled HP Package, 5 tons, SEER=12 | 2.11 | 1.90 | | 16.67% | | 15 | $0.59 | $1.79 |
| 1 | 2 | 280 | 283 | DX Tune-Up / Diagnostics | 2.11 | 2.11 | 90.00% | 10.00% | 100.00% | 3 | $0.20 | $1.97 |
| 1 | 2 | 280 | 284 | High Efficiency Windows (Low-E Glass or Multiple Glazed) | 2.11 | 2.11 | 100.00% | 5.00% | 75.00% | 30 | $0.08 | $36.25 |
| 1 | 2 | 280 | 285 | Installation of Direct of Indirect Evaporative Cooling, Evaporative Pre-Cooling, and Absorption Cooling | 2.11 | 2.11 | 95.00% | 10.00% | 25.00% | 10 | $0.73 | $1.97 |
| 1 | 2 | 280 | 286 | Duct Insulation | 2.11 | 2.11 | 25.00% | 3.00% | 25.00% | 20 | $0.03 | $62.52 |
| 1 | 2 | 280 | 287 | Duct Repair and Sealing | 2.11 | 2.11 | 50.00% | 1.00% | 25.00% | 20 | $0.04 | $197.00 |
| 1 | 2 | 280 | 288 | Installation of Automated Building Ventilation Control ( Via Occupancy Sensors, CO2 Sensors, Etc.) | 2.11 | 2.11 | 100.00% | 10.00% | 50.00% | 10 | $0.24 | $1.97 |
| 1 | 2 | 280 | 289 | Roof / Ceiling Insulation | 2.11 | 2.11 | 100.00% | 3.00% | 50.00% | 20 | $0.47 | $757.89 |
| 1 | 2 | 280 | 290 | Cool Roofs (Reflective and Spray Evaporative) | 2.11 | 2.11 | 100.00% | 6.92% | 50.00% | 10 | $0.47 | $788.00 |
| 1 | 2 | 280 | 291 | Clock / Programmable Thermostat | 2.11 | 2.11 | 50.00% | 10.00% | 100.00% | 10 | $0.05 | $1.97 |
| 1 | 2 | 280 | 292 | Installation of Air Side Economizers | 2.11 | 2.11 | 92.26% | 15.00% | 100.00% | 10 | $0.59 | $788.00 |
| 1 | 2 | 400 | 400 | Base Fan Motor, 5hp, 1800rpm, 87.5% (ODP) | 0.67 | 0.67 | | 0.00% | | 15 | $0.39 | $0.39 |
| 1 | 2 | 400 | 401 | Energy Efficient Fan & Pump Motors (ODP) | 0.67 | 0.67 | | 1.50% | | 15 | $0.08 | $0.39 |
| 1 | 2 | 400 | 402 | VSD, ASD Fan & Pump Applications | 0.67 | 0.67 | | 30.00% | | 15 | $0.45 | $0.39 |
| 1 | 2 | 610 | 610 | Base Office Equipment | 0.15 | 0.15 | 100.00% | 0.00% | 100.00% | 4 | $0.12 | $0.34 |
| 1 | 2 | 610 | 611 | ENERGY STAR or Better Office Equipment: Computer | 0.15 | 0.15 | 65.00% | 17.18% | 100.00% | 4 | $0.01 | $0.34 |
| 1 | 2 | 610 | 621 | ENERGY STAR or Better Office Equipment: Monitors | 0.15 | 0.15 | 71.00% | 15.26% | 100.00% | 4 | $0.01 | $0.34 |
| 1 | 2 | 610 | 623 | Smart Networks | 0.15 | 0.15 | 40.00% | 6.36% | 90.00% | 4 | $0.00 | $0.34 |
| 1 | 2 | 610 | 631 | ENERGY STAR or Better Office Equipment: Copiers | 0.15 | 0.15 | 65.00% | 9.55% | 100.00% | 4 | $0.01 | $0.06 |
| 1 | 2 | 610 | 641 | ENERGY STAR or Better Office Equipment: Printers | 0.15 | 0.15 | 65.00% | 14.55% | 100.00% | 4 | $0.02 | $0.24 |
| 1 | 2 | 700 | 700 | Base Water Heating | 0.44 | 0.44 | 100.00% | 0.00% | 100.00% | 15 | $20.00 | $20.00 |
| 1 | 2 | 700 | 701 | Demand controlled circulating systems | 0.44 | 0.44 | 100.00% | 5.00% | 50.00% | 15 | $3.90 | $20.00 |
| 1 | 2 | 700 | 702 | Heat Pump Water Heater | 0.44 | 0.44 | 100.00% | 30.00% | 75.00% | 15 | $2.49 | $20.00 |
| 1 | 2 | 700 | 703 | High-Efficiency Water Heater (electric) | 0.44 | 0.44 | | 5.40% | | 15 | $0.72 | $20.00 |
| 1 | 2 | 700 | 704 | Hot Water (SHW) Pipe Insulation | 0.44 | 0.44 | 100.00% | 5.00% | 50.00% | 15 | $0.03 | $6.38 |
| 1 | 2 | 800 | 800 | Base Heating | 0.93 | 0.93 | 100.00% | 0.00% | 100.00% | 20 | $2.40 | $2.40 |
| 1 | 2 | 800 | 802 | Roof / Ceiling Insulation | 0.93 | 0.93 | 55.72% | 10.00% | 50.00% | 20 | $0.47 | $2.31 |
| 1 | 2 | 800 | 803 | Duct Insulation | 0.93 | 0.93 | 84.90% | 2.00% | 25.00% | 20 | $0.01 | $2.31 |
| 1 | 2 | 800 | 804 | Duct Repair and Sealing | 0.93 | 0.93 | 50.00% | 2.00% | 25.00% | 20 | $0.00 | $2.31 |
| 1 | 2 | 800 | 805 | Clock / Programmable Thermostat | 0.93 | 0.93 | 50.00% | 30.00% | 100.00% | 10 | $0.15 | $2.40 |

## Table B.3: Commercial Electric

| Segment | Building | Base Number | Measure Number | Measure Name | Stock Usage | Base Usage | Incomplete Factor | Energy Savings | Feasibility Factor | Measure Life | Full Per Unit Cost | Full Base Measure Cost |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 2 | 800 | 812 | Installation of Automated Building Ventilation Control ( Via Occupancy Sensors, CO2 Sensors, Etc.) | 0.93 | 0.93 | 100.00% | 5.00% | 50.00% | 15 | $0.28 | $2.40 |
| 1 | 3 | 100 | 100 | Base Cooking | 52.39 | 52.39 | | 0.00% | | 15 | $1.93 | $1.93 |
| 1 | 3 | 100 | 101 | High-Efficiency Convection Oven | 52.39 | 52.39 | | 20.00% | | 15 | $1.62 | $1.93 |
| 1 | 3 | 110 | 110 | Base Fluorescent Fixture, 4' 4L T12, 34W, 2EEMAG | 8.74 | 8.74 | 100.00% | 0.00% | 100.00% | 14 | $1.54 | $1.54 |
| 1 | 3 | 110 | 111 | 4' 4L T8 Premium, EB | 8.74 | 7.86 | 100.00% | 25.00% | 16.67% | 22 | $0.51 | $1.54 |
| 1 | 3 | 110 | 112 | 4' 2L T8 Premium, EB, reflector | 8.74 | 7.86 | 100.00% | 62.50% | 16.67% | 22 | $0.76 | $1.54 |
| 1 | 3 | 110 | 113 | Occupancy Sensor, 4-4' Fluorescent Fixtures | 8.74 | 7.86 | 95.72% | 30.00% | 10.00% | 13 | $0.53 | $1.54 |
| 1 | 3 | 110 | 114 | Continuous Dimming, 5-4' Fluorescent Fixtures | 8.74 | 7.86 | 100.00% | 75.00% | 12.00% | 16 | $4.01 | $1.54 |
| 1 | 3 | 110 | 115 | 4' 2L T5HO, EB | 8.74 | 7.86 | 100.00% | 18.75% | 16.67% | 22 | $0.29 | $1.54 |
| 1 | 3 | 110 | 116 | 4' 4L T8, EB | 8.74 | 7.86 | 100.00% | 22.22% | 16.67% | 22 | $0.21 | $1.54 |
| 1 | 3 | 110 | 117 | 4' 3L T8, EB | 8.74 | 7.86 | 100.00% | 38.20% | 16.67% | 22 | $0.10 | $1.54 |
| 1 | 3 | 110 | 118 | 4' 3L T8 Premium, EB | 8.74 | 7.86 | 100.00% | 42.36% | 16.67% | 22 | $0.32 | $1.54 |
| 1 | 3 | 120 | 120 | Base Fluorescent Fixture, 4' 2L T12, 34W, 1EEMAG | 8.74 | 8.74 | 100.00% | 0.00% | 100.00% | 14 | $2.83 | $2.83 |
| 1 | 3 | 120 | 121 | 4' 2L T8 Premium, EB | 8.74 | 7.86 | 100.00% | 25.00% | 33.33% | 22 | $0.79 | $2.83 |
| 1 | 3 | 120 | 122 | 4' 1L T8 Premium, EB, reflector | 8.74 | 7.86 | 100.00% | 61.11% | 33.33% | 22 | $1.60 | $2.83 |
| 1 | 3 | 120 | 123 | Occupancy Sensor, 8-4' Fluorescent Fixtures | 8.74 | 7.86 | 95.72% | 30.00% | 10.00% | 13 | $0.46 | $2.83 |
| 1 | 3 | 120 | 124 | Continuous Dimming, 10-4' Fluorescent Fixtures | 8.74 | 7.86 | 100.00% | 75.00% | 12.00% | 16 | $3.89 | $2.83 |
| 1 | 3 | 120 | 125 | 4' 1L T5HO, EB | 8.74 | 7.86 | 100.00% | 13.90% | 33.33% | 22 | $0.60 | $2.83 |
| 1 | 3 | 130 | 130 | Base Fluorescent Fixture, 8' 2L T12, 60W, 1EEMAG | 8.74 | 8.74 | 100.00% | 0.00% | 100.00% | 14 | $1.94 | $1.94 |
| 1 | 3 | 130 | 131 | 8' 2L T12, 60W, EB | 8.74 | 7.86 | 68.10% | 10.57% | 25.00% | 22 | $0.18 | $1.94 |
| 1 | 3 | 130 | 132 | 8' 1L T12, 60W, EB, reflector | 8.74 | 7.86 | 100.00% | 55.30% | 25.00% | 22 | $0.84 | $1.94 |
| 1 | 3 | 130 | 133 | Occupancy Sensor, 4-8' Fluorescent Fixtures | 8.74 | 7.86 | 95.72% | 30.00% | 10.00% | 13 | $0.58 | $1.94 |
| 1 | 3 | 130 | 134 | Continuous Dimming, 5-8' Fluorescent Fixtures | 8.74 | 7.86 | 100.00% | 75.00% | 12.00% | 16 | $4.37 | $1.94 |
| 1 | 3 | 130 | 135 | 8' 2L T8, EB | 8.74 | 7.86 | 100.00% | 52.80% | 50.00% | 22 | $0.38 | $1.94 |
| 1 | 3 | 140 | 140 | Base Incandescent Flood, 75W | 8.74 | 8.74 | 100.00% | 0.00% | 100.00% | 1 | $3.78 | $3.78 |
| 1 | 3 | 140 | 141 | CFL Screw-in, Modular 18W | 8.74 | 7.86 | 89.06% | 65.30% | 50.00% | 6 | $2.33 | $3.78 |
| 1 | 3 | 150 | 150 | Base Incandescent Flood, 150W PAR | 8.74 | 8.74 | 100.00% | 0.00% | 100.00% | 1 | $1.86 | $1.86 |
| 1 | 3 | 150 | 151 | Halogen PAR Flood, 90W | 8.74 | 8.74 | 100.00% | 40.00% | 10.00% | 1 | $0.19 | $1.86 |
| 1 | 3 | 150 | 152 | Metal Halide, 50W | 8.74 | 8.74 | 90.41% | 52.00% | 45.00% | 8 | $9.99 | $1.86 |
| 1 | 3 | 150 | 153 | HPS, 50W | 8.74 | 8.74 | 90.41% | 56.00% | 45.00% | 8 | $5.10 | $1.86 |
| 1 | 3 | 160 | 160 | Base 4' 3L T12, 34W, 1EEMAG | 8.74 | 8.74 | 100.00% | 0.00% | 100.00% | 10 | $0.43 | $0.43 |
| 1 | 3 | 160 | 161 | 4' 3L T8, EB | 8.74 | 7.86 | 100.00% | 22.61% | 75.00% | 22 | $0.04 | $0.43 |
| 1 | 3 | 160 | 162 | 4' 3L T8 Premium, EB | 8.74 | 7.86 | 100.00% | 22.61% | 75.00% | 22 | $0.10 | $0.43 |
| 1 | 3 | 160 | 163 | 4' 2L T8 Premium, EB, reflector | 8.74 | 7.86 | 100.00% | 53.04% | 40.00% | 22 | $0.22 | $0.43 |
| 1 | 3 | 160 | 164 | 4' 1L T5HO, EB | 8.74 | 7.86 | 100.00% | 46.09% | 75.00% | 22 | $0.04 | $0.43 |
| 1 | 3 | 180 | 180 | Base Fluorescent Fixture 4' 4L T8, 1EB | 6.99 | 6.99 | 100.00% | 0.00% | 100.00% | 22 | $1.73 | $1.73 |
| 1 | 3 | 180 | 181 | 4' 4L T8 Premium, EB | 6.99 | 6.29 | 100.00% | 3.60% | 100.00% | 22 | $0.31 | $1.73 |
| 1 | 3 | 180 | 182 | Occupancy Sensor, 4-4' Fluorescent Fixtures | 6.99 | 6.29 | 95.72% | 30.00% | 10.00% | 13 | $0.53 | $1.73 |
| 1 | 3 | 185 | 185 | Base Fluorescent Fixture 4' 3L T8, 1EB | 6.99 | 5.94 | 100.00% | 0.00% | 100.00% | 22 | $3.21 | $3.21 |
| 1 | 3 | 185 | 186 | 4' 3L T8 Premium, EB | 6.99 | 6.29 | 100.00% | 6.70% | 100.00% | 22 | $0.43 | $3.21 |
| 1 | 3 | 190 | 190 | Base Fluorescent Fixture 4' 2L T8, 1EB | 6.99 | 5.94 | 100.00% | 0.00% | 100.00% | 22 | $3.02 | $3.02 |
| 1 | 3 | 190 | 191 | 4' 2L T8 Premium, EB | 6.99 | 6.29 | 100.00% | 8.50% | 100.00% | 22 | $0.27 | $3.02 |
| 1 | 3 | 190 | 192 | Occupancy Sensor, 8-4' Fluorescent Fixtures | 6.99 | 6.29 | 95.72% | 30.00% | 10.00% | 13 | $0.46 | $3.02 |

# Table B.3: Commercial Electric

| Segment | Building | Base Number | Measure Number | Measure Name | Stock Usage | Base Usage | Incomplete Factor | Energy Savings | Feasibility Factor | Measure Life | Full Per Unit Cost | Full Base Measure Cost |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 3 | 200 | 200 | Base Centrifugal Chiller, 0.65 kW/ton, 300 tons | 5.20 | 5.20 | 100.00% | 0.00% | 100.00% | 20 | $0.88 | $0.88 |
| 1 | 3 | 200 | 201 | Chiller Tune-Up / Diagnostics | 5.20 | 5.20 | 90.00% | 5.00% | 100.00% | 5 | $0.07 | $0.88 |
| 1 | 3 | 200 | 202 | Installation of Automated Building Ventilation Control ( Via Occupancy Sensors, CO2 Sensors, Etc.) | 5.20 | 5.20 | 100.00% | 10.00% | 50.00% | 10 | $0.18 | $0.88 |
| 1 | 3 | 200 | 203 | Roof / Ceiling Insulation | 5.20 | 5.20 | 100.00% | 3.00% | 50.00% | 20 | $0.45 | $421.73 |
| 1 | 3 | 200 | 204 | Cool Roofs (Reflective and Spray Evaporative) | 5.20 | 5.20 | 100.00% | 4.30% | 90.00% | 10 | $0.47 | $461.00 |
| 1 | 3 | 200 | 205 | EMS Optimization | 5.20 | 5.20 | 75.00% | 1.00% | 100.00% | 5 | $0.00 | $0.00 |
| 1 | 3 | 200 | 206 | High Efficiency Windows (Low-E Glass or Multiple Glazed) | 5.20 | 5.20 | 100.00% | 5.40% | 50.00% | 30 | $0.02 | $13.11 |
| 1 | 3 | 200 | 207 | Installation of Energy Management Systems | 5.20 | 5.20 | 100.00% | 10.00% | 50.00% | 10 | $0.11 | $0.88 |
| 1 | 3 | 200 | 208 | Insulation of Pipes | 5.20 | 5.20 | 50.00% | 1.00% | 50.00% | 20 | $0.02 | $2.73 |
| 1 | 3 | 200 | 209 | Installation of Chiller Economizers (water side) | 5.20 | 5.20 | 100.00% | 10.00% | 50.00% | 20 | $0.59 | $461.00 |
| 1 | 3 | 200 | 210 | Optimize Chilled Water and Condenser Water Settings | 5.20 | 5.20 | 50.00% | 5.00% | 33.00% | 10 | $0.13 | $0.88 |
| 1 | 3 | 200 | 211 | Decrease Cooling Tower Approach Temperature, 300 Tons, 6 Deg F | 5.20 | 4.68 | 100.00% | 7.50% | 67.00% | 15 | $0.07 | $1.36 |
| 1 | 3 | 200 | 212 | Two-Speed Cooling Tower, 300 Tons | 5.20 | 4.68 | 90.00% | 14.00% | 50.00% | 15 | $0.01 | $1.36 |
| 1 | 3 | 200 | 213 | VSD Cooling Tower, 300 Tons | 5.20 | 4.68 | 90.00% | 18.00% | 50.00% | 15 | $0.05 | $1.36 |
| 1 | 3 | 200 | 214 | Primary/Secondary De-coupled Chilled Water System | 5.20 | 4.68 | 80.00% | 12.00% | 50.00% | 15 | $0.29 | $1.36 |
| 1 | 3 | 200 | 215 | HE Chiller, 0.51 kW/ton, 300 Tons | 5.20 | 4.68 | | 21.54% | | 15 | $0.11 | $1.36 |
| 1 | 3 | 200 | 216 | VSD Chiller, 0.47 kW/ton, 300 Tons | 5.20 | 4.68 | | 27.69% | | 15 | $0.38 | $1.36 |
| 1 | 3 | 250 | 250 | Base DX Packaged System, EER=10.3, 10 tons | 9.00 | 9.00 | 100.00% | 0.00% | 100.00% | 15 | $1.50 | $1.50 |
| 1 | 3 | 250 | 251 | DX Tune-Up / Diagnostics | 9.00 | 9.00 | 90.00% | 10.00% | 100.00% | 3 | $0.15 | $1.50 |
| 1 | 3 | 250 | 252 | Hi-Eff DX Packaged System, 10 tons, EER=11.3 | 9.00 | 7.78 | | 8.85% | | 15 | $0.18 | $1.50 |
| 1 | 3 | 250 | 253 | High Efficiency Windows (Low-E Glass or Multiple Glazed) | 9.00 | 9.00 | 100.00% | 5.00% | 50.00% | 30 | $0.05 | $22.41 |
| 1 | 3 | 250 | 254 | Installation of Direct of Indirect Evaporative Cooling, Evaporative Pre-Cooling, and Absorption Cooling | 9.00 | 9.00 | 95.00% | 10.00% | 25.00% | 10 | $0.55 | $1.50 |
| 1 | 3 | 250 | 256 | Duct Insulation | 9.00 | 9.00 | 25.00% | 3.00% | 25.00% | 20 | $0.01 | $24.50 |
| 1 | 3 | 250 | 257 | Duct Repair and Sealing | 9.00 | 9.00 | 50.00% | 1.00% | 25.00% | 20 | $0.04 | $197.00 |
| 1 | 3 | 250 | 258 | Installation of Automated Building Ventilation Control ( Via Occupancy Sensors, CO2 Sensors, Etc.) | 9.00 | 9.00 | 100.00% | 10.00% | 50.00% | 10 | $0.18 | $1.50 |
| 1 | 3 | 250 | 259 | Roof / Ceiling Insulation | 9.00 | 9.00 | 100.00% | 3.00% | 50.00% | 20 | $0.45 | $720.87 |
| 1 | 3 | 250 | 260 | Cool Roofs (Reflective and Spray Evaporative) | 9.00 | 9.00 | 100.00% | 4.30% | 50.00% | 10 | $0.47 | $788.00 |
| 1 | 3 | 250 | 261 | Clock / Programmable Thermostat | 9.00 | 9.00 | 80.40% | 10.00% | 100.00% | 10 | $0.04 | $1.50 |
| 1 | 3 | 250 | 262 | Installation of Air Side Economizers | 9.00 | 9.00 | 55.37% | 15.00% | 100.00% | 10 | $0.59 | $788.00 |
| 1 | 3 | 280 | 280 | Base Air-Cooled HP Package, 5 tons, SEER=10 | 9.00 | 8.10 | 100.00% | 0.00% | 100.00% | 15 | $1.36 | $1.36 |
| 1 | 3 | 280 | 281 | Air-Cooled HP Package, 5 tons, SEER=11 | 9.00 | 8.10 | | 9.09% | | 15 | $0.07 | $1.36 |
| 1 | 3 | 280 | 282 | Air-Cooled HP Package, 5 tons, SEER=12 | 9.00 | 8.10 | | 16.67% | | 15 | $0.45 | $1.36 |
| 1 | 3 | 280 | 283 | DX Tune-Up / Diagnostics | 9.00 | 9.00 | 90.00% | 10.00% | 100.00% | 3 | $0.15 | $1.50 |
| 1 | 3 | 280 | 284 | High Efficiency Windows (Low-E Glass or Multiple Glazed) | 9.00 | 9.00 | 100.00% | 5.00% | 50.00% | 30 | $0.05 | $22.41 |
| 1 | 3 | 280 | 285 | Installation of Direct of Indirect Evaporative Cooling, Evaporative Pre-Cooling, and Absorption Cooling | 9.00 | 9.00 | 95.00% | 10.00% | 25.00% | 10 | $0.55 | $1.50 |
| 1 | 3 | 280 | 286 | Duct Insulation | 9.00 | 9.00 | 25.00% | 3.00% | 25.00% | 20 | $0.01 | $24.50 |
| 1 | 3 | 280 | 287 | Duct Repair and Sealing | 9.00 | 9.00 | 50.00% | 1.00% | 50.00% | 20 | $0.04 | $197.00 |
| 1 | 3 | 280 | 288 | Installation of Automated Building Ventilation Control ( Via Occupancy Sensors, CO2 Sensors, Etc.) | 9.00 | 9.00 | 100.00% | 10.00% | 50.00% | 10 | $0.18 | $1.50 |
| 1 | 3 | 280 | 289 | Roof / Ceiling Insulation | 9.00 | 9.00 | 100.00% | 3.00% | 50.00% | 20 | $0.45 | $720.87 |

## Table B.3: Commercial Electric

| Segment | Building | Base Number | Measure Number | Measure Name | Stock Usage | Base Usage | Incomplete Factor | Energy Savings | Feasibility Factor | Measure Life | Full Per Unit Cost | Full Base Measure Cost |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 3 | 280 | 290 | Cool Roofs (Reflective and Spray Evaporative) | 9.00 | 9.00 | 100.00% | 4.30% | 50.00% | 10 | $0.47 | $788.00 |
| 1 | 3 | 280 | 291 | Clock / Programmable Thermostat | 9.00 | 9.00 | 80.40% | 10.00% | 100.00% | 10 | $0.04 | $1.50 |
| 1 | 3 | 280 | 292 | Installation of Air Side Economizers | 9.00 | 9.00 | 55.37% | 15.00% | 100.00% | 10 | $0.59 | $788.00 |
| 1 | 3 | 400 | 400 | Base Fan Motor, 5hp, 1800rpm, 87.5% (ODP) | 3.96 | 3.96 | | 0.00% | | 15 | $0.07 | $0.07 |
| 1 | 3 | 400 | 401 | Energy Efficient Fan & Pump Motors (ODP) | 3.96 | 3.96 | | 1.50% | | 15 | $0.01 | $0.07 |
| 1 | 3 | 400 | 402 | VSD, ASD Fan & Pump Applications | 3.96 | 3.96 | | 30.00% | | 15 | $0.08 | $0.07 |
| 1 | 3 | 500 | 500 | Base Refrigeration System | 5.80 | 5.80 | 100.00% | 0.00% | 100.00% | 10 | $2.00 | $2.00 |
| 1 | 3 | 500 | 501 | High Efficiency Case Fans | 5.80 | 5.80 | 95.00% | 11.98% | 100.00% | 16 | $1.16 | $2.00 |
| 1 | 3 | 500 | 502 | Strip Curtains for Walk-Ins | 5.80 | 5.80 | 30.00% | 4.02% | 100.00% | 4 | $0.05 | $2.00 |
| 1 | 3 | 500 | 503 | Night Covers for Display Cases | 5.80 | 5.80 | 95.00% | 5.80% | 50.00% | 5 | $0.01 | $2.00 |
| 1 | 3 | 500 | 504 | Reduced Speed or Cycling of Evaporator Fans | 5.80 | 5.80 | 80.00% | 0.55% | 100.00% | 5 | $0.09 | $2.00 |
| 1 | 3 | 500 | 505 | High-Efficiency Compressors | 5.80 | 5.80 | 81.00% | 6.83% | 100.00% | 10 | $0.09 | $2.00 |
| 1 | 3 | 500 | 506 | Compressor VSD retrofit | 5.80 | 5.80 | 95.00% | 6.20% | 50.00% | 10 | $0.41 | $2.00 |
| 1 | 3 | 500 | 507 | Installation of Floating Condenser Head Pressure Controls | 5.80 | 5.80 | 44.37% | 6.83% | 100.00% | 14 | $0.12 | $2.00 |
| 1 | 3 | 500 | 508 | Refrigeration Commissioning | 5.80 | 5.80 | 50.00% | 5.00% | 100.00% | 3 | $0.06 | $2.00 |
| 1 | 3 | 500 | 509 | Demand Control Defrost - Hot Gas | 5.80 | 5.80 | 69.57% | 2.51% | 100.00% | 10 | $0.07 | $2.00 |
| 1 | 3 | 500 | 510 | Demand Control Defrost - Electric | 5.80 | 5.80 | 47.98% | 7.76% | 100.00% | 10 | $0.04 | $2.00 |
| 1 | 3 | 500 | 511 | Anti-Sweat (Humidistat) Controls | 5.80 | 5.80 | 47.98% | 4.99% | 100.00% | 12 | $0.02 | $2.00 |
| 1 | 3 | 610 | 610 | Base Office Equipment | 0.23 | 0.23 | 100.00% | 0.00% | 100.00% | 4 | $0.24 | $0.71 |
| 1 | 3 | 610 | 611 | ENERGY STAR or Better Office Equipment: Computer | 0.23 | 0.23 | 65.00% | 18.39% | 100.00% | 4 | $0.03 | $0.71 |
| 1 | 3 | 610 | 621 | ENERGY STAR or Better Office Equipment: Monitors | 0.23 | 0.23 | 71.00% | 16.34% | 100.00% | 4 | $0.02 | $0.71 |
| 1 | 3 | 610 | 623 | Smart Networks | 0.23 | 0.23 | 40.00% | 6.81% | 90.00% | 4 | $0.00 | $0.71 |
| 1 | 3 | 610 | 631 | ENERGY STAR or Better Office Equipment: Copiers | 0.23 | 0.23 | 65.00% | 7.82% | 100.00% | 4 | $0.01 | $0.13 |
| 1 | 3 | 610 | 641 | ENERGY STAR or Better Office Equipment: Printers | 0.23 | 0.23 | 65.00% | 14.96% | 100.00% | 4 | $0.04 | $0.42 |
| 1 | 3 | 700 | 700 | Base Water Heating | 3.05 | 3.05 | 100.00% | 0.00% | 100.00% | 15 | $14.52 | $14.52 |
| 1 | 3 | 700 | 701 | Demand controlled circulating systems | 3.05 | 3.05 | 100.00% | 5.00% | 50.00% | 15 | $2.83 | $14.52 |
| 1 | 3 | 700 | 702 | Heat Pump Water Heater | 3.05 | 3.05 | 100.00% | 30.00% | 75.00% | 15 | $1.80 | $14.52 |
| 1 | 3 | 700 | 703 | High-Efficiency Water Heater (electric) | 3.05 | 3.05 | | 5.40% | | 15 | $0.52 | $14.52 |
| 1 | 3 | 700 | 704 | Hot Water (SHW) Pipe Insulation | 3.05 | 3.05 | 100.00% | 5.00% | 50.00% | 15 | $0.02 | $5.91 |
| 1 | 3 | 800 | 800 | Base Heating | 7.23 | 7.23 | 100.00% | 0.00% | 100.00% | 20 | $2.40 | $2.40 |
| 1 | 3 | 800 | 802 | Roof / Ceiling Insulation | 7.23 | 7.23 | 67.01% | 10.00% | 50.00% | 20 | $0.45 | $2.20 |
| 1 | 3 | 800 | 803 | Duct Insulation | 7.23 | 7.23 | 56.80% | 2.00% | 25.00% | 20 | $0.03 | $2.20 |
| 1 | 3 | 800 | 804 | Duct Repair and Sealing | 7.23 | 7.23 | 50.00% | 2.00% | 25.00% | 20 | $0.01 | $2.20 |
| 1 | 3 | 800 | 805 | Clock / Programmable Thermostat | 7.23 | 7.23 | 46.20% | 30.00% | 100.00% | 10 | $0.15 | $2.40 |
| 1 | 3 | 800 | 812 | Installation of Automated Building Ventilation Control ( Via Occupancy Sensors, CO2 Sensors, Etc.) | 7.23 | 7.23 | 100.00% | 5.00% | 50.00% | 15 | $0.28 | $2.40 |
| 1 | 4 | 100 | 100 | Base Cooking | 5.16 | 5.16 | | 0.00% | | 15 | $0.52 | $0.52 |
| 1 | 4 | 100 | 101 | High-Efficiency Convection Oven | 5.16 | 5.16 | | 20.00% | | 15 | $0.44 | $0.52 |
| 1 | 4 | 110 | 110 | Base Fluorescent Fixture, 4' 4L T12, 34W, 2EEMAG | 12.76 | 12.76 | 100.00% | 0.00% | 100.00% | 7 | $1.50 | $1.50 |
| 1 | 4 | 110 | 111 | 4' 4L T8 Premium, EB | 12.76 | 11.49 | 100.00% | 25.00% | 16.67% | 12 | $0.49 | $1.50 |
| 1 | 4 | 110 | 112 | 4' 2L T8 Premium, EB, reflector | 12.76 | 11.49 | 100.00% | 62.50% | 16.67% | 12 | $0.74 | $1.50 |
| 1 | 4 | 110 | 113 | Occupancy Sensor, 4-4' Fluorescent Fixtures | 12.76 | 11.49 | 100.00% | 30.00% | 10.00% | 7 | $0.52 | $1.50 |
| 1 | 4 | 110 | 114 | Continuous Dimming, 5-4' Fluorescent Fixtures | 12.76 | 11.49 | 100.00% | 75.00% | 26.00% | 8 | $3.90 | $1.50 |
| 1 | 4 | 110 | 115 | 4' 2L T5HO, EB | 12.76 | 11.49 | 100.00% | 18.75% | 16.67% | 12 | $0.29 | $1.50 |

## Table B.3: Commercial Electric

| Segment | Building | Base Number | Measure Number | Measure Name | Stock Usage | Base Usage | Incomplete Factor | Energy Savings | Feasibility Factor | Measure Life | Full Per Unit Cost | Full Base Measure Cost |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 4 | 110 | 116 | 4' 4L T8, EB | 12.76 | 11.49 | 100.00% | 22.22% | 16.67% | 12 | $0.20 | $1.50 |
| 1 | 4 | 110 | 117 | 4' 3L T8, EB | 12.76 | 11.49 | 100.00% | 38.20% | 16.67% | 12 | $0.10 | $1.50 |
| 1 | 4 | 110 | 118 | 4' 3L T8 Premium, EB | 12.76 | 11.49 | 100.00% | 42.36% | 16.67% | 12 | $0.31 | $1.50 |
| 1 | 4 | 120 | 120 | Base Fluorescent Fixture, 4' 2L T12, 34W, 1EEMAG | 12.76 | 12.76 | 100.00% | 0.00% | 100.00% | 7 | $2.73 | $2.73 |
| 1 | 4 | 120 | 121 | 4' 2L T8 Premium, EB | 12.76 | 11.49 | 100.00% | 25.00% | 33.33% | 12 | $0.76 | $2.73 |
| 1 | 4 | 120 | 122 | 4' 1L T8 Premium, EB, reflector | 12.76 | 11.49 | 100.00% | 61.11% | 33.33% | 12 | $1.55 | $2.73 |
| 1 | 4 | 120 | 123 | Occupancy Sensor, 8-4' Fluorescent Fixtures | 12.76 | 11.49 | 100.00% | 30.00% | 10.00% | 7 | $0.45 | $2.73 |
| 1 | 4 | 120 | 124 | Continuous Dimming, 10-4' Fluorescent Fixtures | 12.76 | 11.49 | 100.00% | 75.00% | 26.00% | 8 | $3.75 | $2.73 |
| 1 | 4 | 120 | 125 | 4' 1L T5HO, EB | 12.76 | 11.49 | 100.00% | 13.90% | 33.33% | 12 | $0.58 | $2.73 |
| 1 | 4 | 130 | 130 | Base Fluorescent Fixture, 8' 2L T12, 60W, 1EEMAG | 12.76 | 12.76 | 100.00% | 0.00% | 100.00% | 7 | $1.88 | $1.88 |
| 1 | 4 | 130 | 131 | 8' 2L T12, 60W, EB | 12.76 | 11.49 | 54.24% | 10.57% | 25.00% | 12 | $0.18 | $1.88 |
| 1 | 4 | 130 | 132 | 8' 1L T12, 60W, EB, reflector | 12.76 | 11.49 | 100.00% | 55.30% | 25.00% | 12 | $0.82 | $1.88 |
| 1 | 4 | 130 | 133 | Occupancy Sensor, 4-8' Fluorescent Fixtures | 12.76 | 11.49 | 100.00% | 30.00% | 10.00% | 7 | $0.56 | $1.88 |
| 1 | 4 | 130 | 134 | Continuous Dimming, 5-8' Fluorescent Fixtures | 12.76 | 11.49 | 100.00% | 75.00% | 26.00% | 8 | $4.24 | $1.88 |
| 1 | 4 | 130 | 135 | 8' 2L T8, EB | 12.76 | 11.49 | 100.00% | 52.80% | 50.00% | 12 | $0.37 | $1.88 |
| 1 | 4 | 140 | 140 | Base Incandescent Flood, 75W | 12.76 | 12.76 | 100.00% | 0.00% | 100.00% | 1 | $3.83 | $3.83 |
| 1 | 4 | 140 | 141 | CFL Screw-in, Modular 18W | 12.76 | 11.49 | 95.37% | 65.30% | 90.00% | 3 | $2.36 | $3.83 |
| 1 | 4 | 150 | 150 | Base Incandescent Flood, 150W PAR | 12.76 | 12.76 | 100.00% | 0.00% | 100.00% | 1 | $3.29 | $3.29 |
| 1 | 4 | 150 | 151 | Halogen PAR Flood, 90W | 12.76 | 12.76 | 99.55% | 40.00% | 10.00% | 1 | $0.33 | $3.29 |
| 1 | 4 | 150 | 152 | Metal Halide, 50W | 12.76 | 12.76 | 94.33% | 52.00% | 45.00% | 4 | $17.62 | $3.29 |
| 1 | 4 | 150 | 153 | HPS, 50W | 12.76 | 12.76 | 94.33% | 56.00% | 45.00% | 4 | $8.99 | $3.29 |
| 1 | 4 | 160 | 160 | Base 4' 3L T12, 34W, 1EEMAG | 12.76 | 12.76 | 100.00% | 0.00% | 100.00% | 10 | $0.67 | $0.67 |
| 1 | 4 | 160 | 161 | 4' 3L T8, EB | 12.76 | 11.49 | 100.00% | 22.61% | 75.00% | 12 | $0.06 | $0.67 |
| 1 | 4 | 160 | 162 | 4' 3L T8 Premium, EB | 12.76 | 11.49 | 100.00% | 22.61% | 75.00% | 12 | $0.16 | $0.67 |
| 1 | 4 | 160 | 163 | 4' 2L T8 Premium, EB, reflector | 12.76 | 11.49 | 100.00% | 53.04% | 40.00% | 12 | $0.35 | $0.67 |
| 1 | 4 | 160 | 164 | 4' 1L T5HO, EB | 12.76 | 11.49 | 100.00% | 46.09% | 75.00% | 12 | $0.06 | $0.67 |
| 1 | 4 | 180 | 180 | Base Fluorescent Fixture 4' 4L T8, 1EB | 10.21 | 10.21 | 100.00% | 0.00% | 100.00% | 12 | $1.68 | $1.68 |
| 1 | 4 | 180 | 181 | 4' 4L T8 Premium, EB | 10.21 | 9.19 | 100.00% | 3.60% | 100.00% | 12 | $0.30 | $1.68 |
| 1 | 4 | 180 | 182 | Occupancy Sensor, 4-4' Fluorescent Fixtures | 10.21 | 9.19 | 100.00% | 30.00% | 10.00% | 7 | $0.52 | $1.68 |
| 1 | 4 | 185 | 185 | Base Fluorescent Fixture 4' 3L T8, 1EB | 10.21 | 8.68 | 100.00% | 0.00% | 100.00% | 12 | $3.09 | $3.09 |
| 1 | 4 | 185 | 186 | 4' 3L T8 Premium, EB | 10.21 | 9.19 | 100.00% | 6.70% | 100.00% | 12 | $0.42 | $3.09 |
| 1 | 4 | 190 | 190 | Base Fluorescent Fixture 4' 2L T8, 1EB | 10.21 | 8.68 | 100.00% | 0.00% | 100.00% | 12 | $2.91 | $2.91 |
| 1 | 4 | 190 | 191 | 4' 2L T8 Premium, EB | 10.21 | 9.19 | 100.00% | 8.50% | 100.00% | 12 | $0.26 | $2.91 |
| 1 | 4 | 190 | 192 | Occupancy Sensor, 8-4' Fluorescent Fixtures | 10.21 | 9.19 | 100.00% | 30.00% | 10.00% | 7 | $0.45 | $2.91 |
| 1 | 4 | 200 | 200 | Base Centrifugal Chiller, 0.65 kW/ton, 300 tons | 6.72 | 6.72 | 100.00% | 0.00% | 100.00% | 20 | $1.50 | $1.50 |
| 1 | 4 | 200 | 201 | Chiller Tune-Up / Diagnostics | 6.72 | 6.72 | 90.00% | 5.00% | 100.00% | 5 | $0.12 | $1.50 |
| 1 | 4 | 200 | 202 | Installation of Automated Building Ventilation Control ( Via Occupancy Sensors, CO2 Sensors, Etc.) | 6.72 | 6.72 | 100.00% | 10.00% | 50.00% | 10 | $0.32 | $1.50 |
| 1 | 4 | 200 | 203 | Roof / Ceiling Insulation | 6.72 | 6.72 | 20.00% | 3.00% | 50.00% | 20 | $0.48 | $452.64 |
| 1 | 4 | 200 | 204 | Cool Roofs (Reflective and Spray Evaporative) | 6.72 | 6.72 | 100.00% | 4.30% | 90.00% | 10 | $0.47 | $461.00 |
| 1 | 4 | 200 | 205 | EMS Optimization | 6.72 | 6.72 | 75.00% | 1.00% | 100.00% | 5 | $0.00 | $0.00 |
| 1 | 4 | 200 | 206 | High Efficiency Windows (Low-E Glass or Multiple Glazed) | 6.72 | 6.72 | 100.00% | 5.40% | 75.00% | 30 | $0.03 | $18.85 |
| 1 | 4 | 200 | 207 | Installation of Energy Management Systems | 6.72 | 6.72 | 100.00% | 10.00% | 50.00% | 10 | $0.20 | $1.50 |
| 1 | 4 | 200 | 208 | Insulation of Pipes | 6.72 | 6.72 | 50.00% | 1.00% | 50.00% | 20 | $0.01 | $1.07 |

## Table B.3: Commercial Electric

| Segment | Building | Base Number | Measure Number | Measure Name | Stock Usage | Base Usage | Incomplete Factor | Energy Savings | Feasibility Factor | Measure Life | Full Per Unit Cost | Full Base Measure Cost |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 4 | 200 | 209 | Installation of Chiller Economizers (water side) | 6.72 | 6.72 | 100.00% | 10.00% | 50.00% | 20 | $0.59 | $461.00 |
| 1 | 4 | 200 | 210 | Optimize Chilled Water and Condenser Water Settings | 6.72 | 6.72 | 50.00% | 5.00% | 33.00% | 10 | $0.21 | $1.50 |
| 1 | 4 | 200 | 211 | Decrease Cooling Tower Approach Temperature, 300 Tons, 6 Deg F | 6.72 | 6.04 | 100.00% | 7.50% | 67.00% | 15 | $0.11 | $2.33 |
| 1 | 4 | 200 | 212 | Two-Speed Cooling Tower, 300 Tons | 6.72 | 6.04 | 90.00% | 14.00% | 50.00% | 15 | $0.01 | $2.33 |
| 1 | 4 | 200 | 213 | VSD Cooling Tower, 300 Tons | 6.72 | 6.04 | 90.00% | 18.00% | 50.00% | 15 | $0.08 | $2.33 |
| 1 | 4 | 200 | 214 | Primary/Secondary De-coupled Chilled Water System | 6.72 | 6.04 | 80.00% | 12.00% | 50.00% | 15 | $0.49 | $2.33 |
| 1 | 4 | 200 | 215 | HE Chiller, 0.51 kW/ton, 300 Tons | 6.72 | 6.04 | | 21.54% | | 15 | $0.20 | $2.33 |
| 1 | 4 | 200 | 216 | VSD Chiller, 0.47 kW/ton, 300 Tons | 6.72 | 6.04 | | 27.69% | | 15 | $0.65 | $2.33 |
| 1 | 4 | 250 | 250 | Base DX Packaged System, EER=10.3, 10 tons | 11.63 | 11.63 | 100.00% | 0.00% | 100.00% | 15 | $2.56 | $2.56 |
| 1 | 4 | 250 | 251 | DX Tune-Up / Diagnostics | 11.63 | 11.63 | 90.00% | 10.00% | 100.00% | 3 | $0.25 | $2.56 |
| 1 | 4 | 250 | 252 | Hi-Eff DX Packaged System, 10 tons, EER=11.3 | 11.63 | 10.05 | | 8.85% | | 15 | $0.31 | $2.56 |
| 1 | 4 | 250 | 253 | High Efficiency Windows (Low-E Glass or Multiple Glazed) | 11.63 | 11.63 | 100.00% | 5.00% | 75.00% | 30 | $0.07 | $32.23 |
| 1 | 4 | 250 | 254 | Installation of Direct of Indirect Evaporative Cooling, Evaporative Pre-Cooling, and Absorption Cooling | 11.63 | 11.63 | 95.00% | 10.00% | 25.00% | 10 | $0.94 | $2.56 |
| 1 | 4 | 250 | 256 | Duct Insulation | 11.63 | 11.63 | 25.00% | 3.00% | 25.00% | 20 | $0.01 | $26.16 |
| 1 | 4 | 250 | 257 | Duct Repair and Sealing | 11.63 | 11.63 | 50.00% | 1.00% | 25.00% | 20 | $0.04 | $197.00 |
| 1 | 4 | 250 | 258 | Installation of Automated Building Ventilation Control ( Via Occupancy Sensors, CO2 Sensors, Etc.) | 11.63 | 11.63 | 100.00% | 10.00% | 50.00% | 10 | $0.32 | $2.56 |
| 1 | 4 | 250 | 259 | Roof / Ceiling Insulation | 11.63 | 11.63 | 20.00% | 3.00% | 50.00% | 20 | $0.48 | $773.71 |
| 1 | 4 | 250 | 260 | Cool Roofs (Reflective and Spray Evaporative) | 11.63 | 11.63 | 100.00% | 4.30% | 50.00% | 10 | $0.47 | $788.00 |
| 1 | 4 | 250 | 261 | Clock / Programmable Thermostat | 11.63 | 11.63 | 84.68% | 10.00% | 100.00% | 10 | $0.07 | $2.56 |
| 1 | 4 | 250 | 262 | Installation of Air Side Economizers | 11.63 | 11.63 | 98.59% | 15.00% | 100.00% | 10 | $0.59 | $788.00 |
| 1 | 4 | 280 | 280 | Base Air-Cooled HP Package, 5 tons, SEER=10 | 11.63 | 10.47 | 100.00% | 0.00% | 100.00% | 15 | $2.33 | $2.33 |
| 1 | 4 | 280 | 281 | Air-Cooled HP Package, 5 tons, SEER=11 | 11.63 | 10.47 | | 9.09% | | 15 | $0.11 | $2.33 |
| 1 | 4 | 280 | 282 | Air-Cooled HP Package, 5 tons, SEER=12 | 11.63 | 10.47 | | 16.67% | | 15 | $0.76 | $2.33 |
| 1 | 4 | 280 | 283 | DX Tune-Up / Diagnostics | 11.63 | 11.63 | 90.00% | 10.00% | 100.00% | 3 | $0.25 | $2.56 |
| 1 | 4 | 280 | 284 | High Efficiency Windows (Low-E Glass or Multiple Glazed) | 11.63 | 11.63 | 100.00% | 5.00% | 75.00% | 30 | $0.07 | $32.23 |
| 1 | 4 | 280 | 285 | Installation of Direct of Indirect Evaporative Cooling, Evaporative Pre-Cooling, and Absorption Cooling | 11.63 | 11.63 | 95.00% | 10.00% | 25.00% | 10 | $0.94 | $2.56 |
| 1 | 4 | 280 | 286 | Duct Insulation | 11.63 | 11.63 | 25.00% | 3.00% | 25.00% | 20 | $0.01 | $26.16 |
| 1 | 4 | 280 | 287 | Duct Repair and Sealing | 11.63 | 11.63 | 50.00% | 1.00% | 25.00% | 20 | $0.04 | $197.00 |
| 1 | 4 | 280 | 288 | Installation of Automated Building Ventilation Control ( Via Occupancy Sensors, CO2 Sensors, Etc.) | 11.63 | 11.63 | 100.00% | 10.00% | 50.00% | 10 | $0.32 | $2.56 |
| 1 | 4 | 280 | 289 | Roof / Ceiling Insulation | 11.63 | 11.63 | 20.00% | 3.00% | 50.00% | 20 | $0.48 | $773.71 |
| 1 | 4 | 280 | 290 | Cool Roofs (Reflective and Spray Evaporative) | 11.63 | 11.63 | 100.00% | 4.30% | 50.00% | 10 | $0.47 | $788.00 |
| 1 | 4 | 280 | 291 | Clock / Programmable Thermostat | 11.63 | 11.63 | 84.68% | 10.00% | 100.00% | 10 | $0.07 | $2.56 |
| 1 | 4 | 280 | 292 | Installation of Air Side Economizers | 11.63 | 11.63 | 98.59% | 15.00% | 100.00% | 10 | $0.59 | $788.00 |
| 1 | 4 | 400 | 400 | Base Fan Motor, 5hp, 1800rpm, 87.5% (ODP) | 5.40 | 5.40 | | 0.00% | | 15 | $0.23 | $0.23 |
| 1 | 4 | 400 | 401 | Energy Efficient Fan & Pump Motors (ODP) | 5.40 | 5.40 | | 1.50% | | 15 | $0.05 | $0.23 |
| 1 | 4 | 400 | 402 | VSD, ASD Fan & Pump Applications | 5.40 | 5.40 | | 30.00% | | 15 | $0.26 | $0.23 |
| 1 | 4 | 500 | 500 | Base Refrigeration System | 24.18 | 24.18 | 100.00% | 0.00% | 100.00% | 10 | $2.00 | $2.00 |
| 1 | 4 | 500 | 501 | High Efficiency Case Fans | 24.18 | 24.18 | 95.00% | 11.98% | 100.00% | 16 | $1.16 | $2.00 |
| 1 | 4 | 500 | 502 | Strip Curtains for Walk-Ins | 24.18 | 24.18 | 30.00% | 4.02% | 100.00% | 4 | $0.05 | $2.00 |
| 1 | 4 | 500 | 503 | Night Covers for Display Cases | 24.18 | 24.18 | 95.00% | 5.80% | 50.00% | 5 | $0.01 | $2.00 |

## Table B.3: Commercial Electric

| Segment | Building | Base Number | Measure Number | Measure Name | Stock Usage | Base Usage | Incomplete Factor | Energy Savings | Feasibility Factor | Measure Life | Full Per Unit Cost | Full Base Measure Cost |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 4 | 500 | 504 | Reduced Speed or Cycling of Evaporator Fans | 24.18 | 24.18 | 80.00% | 0.55% | 100.00% | 5 | $0.09 | $2.00 |
| 1 | 4 | 500 | 505 | High-Efficiency Compressors | 24.18 | 24.18 | 81.00% | 6.83% | 100.00% | 10 | $0.09 | $2.00 |
| 1 | 4 | 500 | 506 | Compressor VSD retrofit | 24.18 | 24.18 | 95.00% | 6.20% | 50.00% | 10 | $0.41 | $2.00 |
| 1 | 4 | 500 | 507 | Installation of Floating Condenser Head Pressure Controls | 24.18 | 24.18 | 44.37% | 6.83% | 100.00% | 14 | $0.12 | $2.00 |
| 1 | 4 | 500 | 508 | Refrigeration Commissioning | 24.18 | 24.18 | 50.00% | 5.00% | 100.00% | 3 | $0.06 | $2.00 |
| 1 | 4 | 500 | 509 | Demand Control Defrost - Hot Gas | 24.18 | 24.18 | 69.57% | 2.51% | 100.00% | 10 | $0.07 | $2.00 |
| 1 | 4 | 500 | 510 | Demand Control Defrost - Electric | 24.18 | 24.18 | 47.98% | 7.76% | 100.00% | 10 | $0.04 | $2.00 |
| 1 | 4 | 500 | 511 | Anti-Sweat (Humidistat) Controls | 24.18 | 24.18 | 47.98% | 4.99% | 100.00% | 12 | $0.02 | $2.00 |
| 1 | 4 | 610 | 610 | Base Office Equipment | 0.41 | 0.41 | 100.00% | 0.00% | 100.00% | 4 | $0.09 | $0.28 |
| 1 | 4 | 610 | 611 | ENERGY STAR or Better Office Equipment: Computer | 0.41 | 0.41 | 65.00% | 17.86% | 100.00% | 4 | $0.01 | $0.28 |
| 1 | 4 | 610 | 621 | ENERGY STAR or Better Office Equipment: Monitors | 0.41 | 0.41 | 71.00% | 15.87% | 100.00% | 4 | $0.01 | $0.28 |
| 1 | 4 | 610 | 623 | Smart Networks | 0.41 | 0.41 | 40.00% | 6.61% | 90.00% | 4 | $0.00 | $0.28 |
| 1 | 4 | 610 | 631 | ENERGY STAR or Better Office Equipment: Copiers | 0.41 | 0.41 | 65.00% | 9.74% | 100.00% | 4 | $0.01 | $0.15 |
| 1 | 4 | 610 | 641 | ENERGY STAR or Better Office Equipment: Printers | 0.41 | 0.41 | 65.00% | 13.04% | 100.00% | 4 | $0.01 | $0.14 |
| 1 | 4 | 700 | 700 | Base Water Heating | 3.05 | 3.05 | 100.00% | 0.00% | 100.00% | 15 | $6.77 | $6.77 |
| 1 | 4 | 700 | 701 | Demand controlled circulating systems | 3.05 | 3.05 | 100.00% | 5.00% | 50.00% | 15 | $1.32 | $6.77 |
| 1 | 4 | 700 | 702 | Heat Pump Water Heater | 3.05 | 3.05 | 100.00% | 30.00% | 75.00% | 15 | $0.84 | $6.77 |
| 1 | 4 | 700 | 703 | High-Efficiency Water Heater (electric) | 3.05 | 3.05 | | 5.40% | | 15 | $0.24 | $6.77 |
| 1 | 4 | 700 | 704 | Hot Water (SHW) Pipe Insulation | 3.05 | 3.05 | 100.00% | 5.00% | 50.00% | 15 | $0.01 | $2.32 |
| 1 | 4 | 800 | 800 | Base Heating | 1.37 | 1.37 | 100.00% | 0.00% | 100.00% | 20 | $2.40 | $2.40 |
| 1 | 4 | 800 | 802 | Roof / Ceiling Insulation | 1.37 | 1.37 | 85.03% | 10.00% | 50.00% | 20 | $0.48 | $2.36 |
| 1 | 4 | 800 | 803 | Duct Insulation | 1.37 | 1.37 | 71.50% | 2.00% | 25.00% | 20 | $0.01 | $2.36 |
| 1 | 4 | 800 | 804 | Duct Repair and Sealing | 1.37 | 1.37 | 50.00% | 2.00% | 25.00% | 20 | $0.01 | $2.36 |
| 1 | 4 | 800 | 805 | Clock / Programmable Thermostat | 1.37 | 1.37 | 50.00% | 30.00% | 100.00% | 10 | $0.15 | $2.40 |
| 1 | 4 | 800 | 812 | Installation of Automated Building Ventilation Control ( Via Occupancy Sensors, CO2 Sensors, Etc.) | 1.37 | 1.37 | 100.00% | 5.00% | 50.00% | 15 | $0.28 | $2.40 |
| 1 | 5 | 110 | 110 | Base Fluorescent Fixture, 4' 4L T12, 34W, 2EEMAG | 2.94 | 2.94 | 100.00% | 0.00% | 100.00% | 14 | $0.75 | $0.75 |
| 1 | 5 | 110 | 111 | 4' 4L T8 Premium, EB | 2.94 | 2.65 | 100.00% | 25.00% | 16.67% | 22 | $0.25 | $0.75 |
| 1 | 5 | 110 | 112 | 4' 2L T8 Premium, EB, reflector | 2.94 | 2.65 | 100.00% | 62.50% | 16.67% | 22 | $0.37 | $0.75 |
| 1 | 5 | 110 | 113 | Occupancy Sensor, 4-4' Fluorescent Fixtures | 2.94 | 2.65 | 97.95% | 30.00% | 20.00% | 12 | $0.26 | $0.75 |
| 1 | 5 | 110 | 114 | Continuous Dimming, 5-4' Fluorescent Fixtures | 2.94 | 2.65 | 100.00% | 75.00% | 40.00% | 16 | $1.95 | $0.75 |
| 1 | 5 | 110 | 115 | 4' 2L T5HO, EB | 2.94 | 2.65 | 100.00% | 18.75% | 16.67% | 22 | $0.14 | $0.75 |
| 1 | 5 | 110 | 116 | 4' 4L T8, EB | 2.94 | 2.65 | 100.00% | 22.22% | 16.67% | 22 | $0.10 | $0.75 |
| 1 | 5 | 110 | 117 | 4' 3L T8, EB | 2.94 | 2.65 | 100.00% | 38.20% | 16.67% | 22 | $0.05 | $0.75 |
| 1 | 5 | 110 | 118 | 4' 3L T8 Premium, EB | 2.94 | 2.65 | 100.00% | 42.36% | 16.67% | 22 | $0.16 | $0.75 |
| 1 | 5 | 120 | 120 | Base Fluorescent Fixture, 4' 2L T12, 34W, 1EEMAG | 2.94 | 2.94 | 100.00% | 0.00% | 100.00% | 14 | $1.40 | $1.40 |
| 1 | 5 | 120 | 121 | 4' 2L T8 Premium, EB | 2.94 | 2.65 | 100.00% | 25.00% | 33.33% | 22 | $0.39 | $1.40 |
| 1 | 5 | 120 | 122 | 4' 1L T8 Premium, EB, reflector | 2.94 | 2.65 | 100.00% | 61.11% | 33.33% | 22 | $0.80 | $1.40 |
| 1 | 5 | 120 | 123 | Occupancy Sensor, 8-4' Fluorescent Fixtures | 2.94 | 2.65 | 97.95% | 30.00% | 20.00% | 12 | $0.23 | $1.40 |
| 1 | 5 | 120 | 124 | Continuous Dimming, 10-4' Fluorescent Fixtures | 2.94 | 2.65 | 100.00% | 75.00% | 40.00% | 16 | $1.93 | $1.40 |
| 1 | 5 | 120 | 125 | 4' 1L T5HO, EB | 2.94 | 2.65 | 100.00% | 13.90% | 33.33% | 22 | $0.30 | $1.40 |
| 1 | 5 | 130 | 130 | Base Fluorescent Fixture, 8' 2L T12, 60W, 1EEMAG | 2.94 | 2.94 | 100.00% | 0.00% | 100.00% | 14 | $1.06 | $1.06 |
| 1 | 5 | 130 | 131 | 8' 2L T12, 60W, EB | 2.94 | 2.65 | 84.67% | 10.57% | 25.00% | 22 | $0.10 | $1.06 |
| 1 | 5 | 130 | 132 | 8' 1L T12, 60W, EB, reflector | 2.94 | 2.65 | 100.00% | 55.30% | 25.00% | 22 | $0.46 | $1.06 |

# Table B.3: Commercial Electric

| Segment | Building | Base Number | Measure Number | Measure Name | Stock Usage | Base Usage | Incomplete Factor | Energy Savings | Feasibility Factor | Measure Life | Full Per Unit Cost | Full Base Measure Cost |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 5 | 130 | 133 | Occupancy Sensor, 4-8' Fluorescent Fixtures | 2.94 | 2.65 | 97.95% | 30.00% | 20.00% | 12 | $0.32 | $1.06 |
| 1 | 5 | 130 | 134 | Continuous Dimming, 5-8' Fluorescent Fixtures | 2.94 | 2.65 | 100.00% | 75.00% | 40.00% | 16 | $2.39 | $1.06 |
| 1 | 5 | 130 | 135 | 8' 2L T8, EB | 2.94 | 2.65 | 100.00% | 52.80% | 50.00% | 22 | $0.21 | $1.06 |
| 1 | 5 | 140 | 140 | Base Incandescent Flood, 75W | 2.94 | 2.94 | 100.00% | 0.00% | 100.00% | 1 | $2.17 | $2.17 |
| 1 | 5 | 140 | 141 | CFL Screw-in, Modular 18W | 2.94 | 2.65 | 88.72% | 65.30% | 90.00% | 6 | $1.34 | $2.17 |
| 1 | 5 | 150 | 150 | Base Incandescent Flood, 150W PAR | 2.94 | 2.94 | 100.00% | 0.00% | 100.00% | 1 | $0.99 | $0.99 |
| 1 | 5 | 150 | 151 | Halogen PAR Flood, 90W | 2.94 | 2.94 | 100.00% | 40.00% | 10.00% | 1 | $0.10 | $0.99 |
| 1 | 5 | 150 | 152 | Metal Halide, 50W | 2.94 | 2.94 | 90.21% | 52.00% | 45.00% | 7 | $5.28 | $0.99 |
| 1 | 5 | 150 | 153 | HPS, 50W | 2.94 | 2.94 | 90.21% | 56.00% | 45.00% | 7 | $2.69 | $0.99 |
| 1 | 5 | 160 | 160 | Base 4' 3L T12, 34W, 1EEMAG | 2.94 | 2.94 | 100.00% | 0.00% | 100.00% | 10 | $0.07 | $0.07 |
| 1 | 5 | 160 | 161 | 4' 3L T8, EB | 2.94 | 2.65 | 100.00% | 22.61% | 75.00% | 22 | $0.01 | $0.07 |
| 1 | 5 | 160 | 162 | 4' 3L T8 Premium, EB | 2.94 | 2.65 | 100.00% | 22.61% | 75.00% | 22 | $0.02 | $0.07 |
| 1 | 5 | 160 | 163 | 4' 2L T8 Premium, EB, reflector | 2.94 | 2.65 | 100.00% | 53.04% | 40.00% | 22 | $0.04 | $0.07 |
| 1 | 5 | 160 | 164 | 4' 1L T5HO, EB | 2.94 | 2.65 | 100.00% | 46.09% | 75.00% | 22 | $0.01 | $0.07 |
| 1 | 5 | 180 | 180 | Base Fluorescent Fixture 4' 4L T8, 1EB | 2.36 | 2.36 | 100.00% | 0.00% | 100.00% | 22 | $0.84 | $0.84 |
| 1 | 5 | 180 | 181 | 4' 4L T8 Premium, EB | 2.36 | 2.12 | 100.00% | 3.60% | 100.00% | 22 | $0.15 | $0.84 |
| 1 | 5 | 180 | 182 | Occupancy Sensor, 4-4' Fluorescent Fixtures | 2.36 | 2.12 | 97.95% | 30.00% | 20.00% | 12 | $0.26 | $0.84 |
| 1 | 5 | 185 | 185 | Base Fluorescent Fixture 4' 3L T8, 1EB | 2.36 | 2.00 | 100.00% | 0.00% | 100.00% | 22 | $1.59 | $1.59 |
| 1 | 5 | 185 | 186 | 4' 3L T8 Premium, EB | 2.36 | 2.12 | 100.00% | 6.70% | 100.00% | 22 | $0.22 | $1.59 |
| 1 | 5 | 190 | 190 | Base Fluorescent Fixture 4' 2L T8, 1EB | 2.36 | 2.00 | 100.00% | 0.00% | 100.00% | 22 | $1.50 | $1.50 |
| 1 | 5 | 190 | 191 | 4' 2L T8 Premium, EB | 2.36 | 2.12 | 100.00% | 8.50% | 100.00% | 22 | $0.13 | $1.50 |
| 1 | 5 | 190 | 192 | Occupancy Sensor, 8-4' Fluorescent Fixtures | 2.36 | 2.12 | 97.95% | 30.00% | 20.00% | 12 | $0.23 | $1.50 |
| 1 | 5 | 200 | 200 | Base Centrifugal Chiller, 0.65 kW/ton, 300 tons | 1.59 | 1.59 | 100.00% | 0.00% | 100.00% | 20 | $0.41 | $0.41 |
| 1 | 5 | 200 | 201 | Chiller Tune-Up / Diagnostics | 1.59 | 1.59 | 90.00% | 5.00% | 100.00% | 5 | $0.03 | $0.41 |
| 1 | 5 | 200 | 202 | Installation of Automated Building Ventilation Control ( Via Occupancy Sensors, CO2 Sensors, Etc.) | 1.59 | 1.59 | 100.00% | 10.00% | 50.00% | 10 | $0.09 | $0.41 |
| 1 | 5 | 200 | 203 | Roof / Ceiling Insulation | 1.59 | 1.59 | 20.00% | 3.00% | 50.00% | 20 | $0.45 | $426.61 |
| 1 | 5 | 200 | 204 | Cool Roofs (Reflective and Spray Evaporative) | 1.59 | 1.59 | 100.00% | 4.30% | 90.00% | 10 | $0.47 | $461.00 |
| 1 | 5 | 200 | 205 | EMS Optimization | 1.59 | 1.59 | 75.00% | 1.00% | 100.00% | 5 | $0.00 | $0.00 |
| 1 | 5 | 200 | 206 | High Efficiency Windows (Low-E Glass or Multiple Glazed) | 1.59 | 1.59 | 100.00% | 5.40% | 75.00% | 30 | $0.01 | $7.87 |
| 1 | 5 | 200 | 207 | Installation of Energy Management Systems | 1.59 | 1.59 | 80.00% | 10.00% | 50.00% | 10 | $0.05 | $0.41 |
| 1 | 5 | 200 | 208 | Insulation of Pipes | 1.59 | 1.59 | 50.00% | 1.00% | 50.00% | 20 | $0.00 | $0.19 |
| 1 | 5 | 200 | 209 | Installation of Chiller Economizers (water side) | 1.59 | 1.59 | 100.00% | 10.00% | 50.00% | 20 | $0.59 | $461.00 |
| 1 | 5 | 200 | 210 | Optimize Chilled Water and Condenser Water Settings | 1.59 | 1.59 | 50.00% | 5.00% | 33.00% | 10 | $0.06 | $0.41 |
| 1 | 5 | 200 | 211 | Decrease Cooling Tower Approach Temperature, 300 Tons, 6 Deg F | 1.59 | 1.43 | 100.00% | 7.50% | 67.00% | 15 | $0.03 | $0.64 |
| 1 | 5 | 200 | 212 | Two-Speed Cooling Tower, 300 Tons | 1.59 | 1.43 | 90.00% | 14.00% | 50.00% | 15 | $0.00 | $0.64 |
| 1 | 5 | 200 | 213 | VSD Cooling Tower, 300 Tons | 1.59 | 1.43 | 90.00% | 18.00% | 50.00% | 15 | $0.02 | $0.64 |
| 1 | 5 | 200 | 214 | Primary/Secondary De-coupled Chilled Water System | 1.59 | 1.43 | 80.00% | 12.00% | 50.00% | 15 | $0.14 | $0.64 |
| 1 | 5 | 200 | 215 | HE Chiller, 0.51 kW/ton, 300 Tons | 1.59 | 1.43 | | 21.54% | | 15 | $0.05 | $0.64 |
| 1 | 5 | 200 | 216 | VSD Chiller, 0.47 kW/ton, 300 Tons | 1.59 | 1.43 | | 27.69% | | 15 | $0.18 | $0.64 |
| 1 | 5 | 250 | 250 | Base DX Packaged System, EER=10.3, 10 tons | 2.75 | 2.75 | 100.00% | 0.00% | 100.00% | 15 | $0.71 | $0.71 |
| 1 | 5 | 250 | 251 | DX Tune-Up / Diagnostics | 2.75 | 2.75 | 90.00% | 10.00% | 100.00% | 3 | $0.07 | $0.71 |
| 1 | 5 | 250 | 252 | Hi-Eff DX Packaged System, 10 tons, EER=11.3 | 2.75 | 2.38 | | 8.85% | | 15 | $0.09 | $0.71 |

## Table B.3: Commercial Electric

| Segment | Building | Base Number | Measure Number | Measure Name | Stock Usage | Base Usage | Incomplete Factor | Energy Savings | Feasibility Factor | Measure Life | Full Per Unit Cost | Full Base Measure Cost |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 5 | 250 | 253 | High Efficiency Windows (Low-E Glass or Multiple Glazed) | 2.75 | 2.75 | 100.00% | 5.00% | 75.00% | 30 | $0.03 | $13.45 |
| 1 | 5 | 250 | 254 | Installation of Direct of Indirect Evaporative Cooling, Evaporative Pre-Cooling, and Absorption Cooling | 2.75 | 2.75 | 95.00% | 10.00% | 25.00% | 10 | $0.26 | $0.71 |
| 1 | 5 | 250 | 256 | Duct Insulation | 2.75 | 2.75 | 25.00% | 3.00% | 25.00% | 20 | $0.01 | $12.08 |
| 1 | 5 | 250 | 257 | Duct Repair and Sealing | 2.75 | 2.75 | 50.00% | 1.00% | 25.00% | 20 | $0.04 | $197.00 |
| 1 | 5 | 250 | 258 | Installation of Automated Building Ventilation Control ( Via Occupancy Sensors, CO2 Sensors, Etc.) | 2.75 | 2.75 | 100.00% | 10.00% | 50.00% | 10 | $0.09 | $0.71 |
| 1 | 5 | 250 | 259 | Roof / Ceiling Insulation | 2.75 | 2.75 | 20.00% | 3.00% | 50.00% | 20 | $0.45 | $729.22 |
| 1 | 5 | 250 | 260 | Cool Roofs (Reflective and Spray Evaporative) | 2.75 | 2.75 | 100.00% | 4.30% | 50.00% | 10 | $0.47 | $788.00 |
| 1 | 5 | 250 | 261 | Clock / Programmable Thermostat | 2.75 | 2.75 | 46.56% | 10.00% | 100.00% | 10 | $0.02 | $0.71 |
| 1 | 5 | 250 | 262 | Installation of Air Side Economizers | 2.75 | 2.75 | 53.45% | 15.00% | 100.00% | 10 | $0.59 | $788.00 |
| 1 | 5 | 280 | 280 | Base Air-Cooled HP Package, 5 tons, SEER=10 | 2.75 | 2.47 | 100.00% | 0.00% | 100.00% | 15 | $0.64 | $0.64 |
| 1 | 5 | 280 | 281 | Air-Cooled HP Package, 5 tons, SEER=11 | 2.75 | 2.47 |  | 9.09% |  | 15 | $0.03 | $0.64 |
| 1 | 5 | 280 | 282 | Air-Cooled HP Package, 5 tons, SEER=12 | 2.75 | 2.47 |  | 16.67% |  | 15 | $0.21 | $0.64 |
| 1 | 5 | 280 | 283 | DX Tune-Up / Diagnostics | 2.75 | 2.75 | 90.00% | 10.00% | 100.00% | 3 | $0.07 | $0.71 |
| 1 | 5 | 280 | 284 | High Efficiency Windows (Low-E Glass or Multiple Glazed) | 2.75 | 2.75 | 100.00% | 5.00% | 75.00% | 30 | $0.03 | $13.45 |
| 1 | 5 | 280 | 285 | Installation of Direct of Indirect Evaporative Cooling, Evaporative Pre-Cooling, and Absorption Cooling | 2.75 | 2.75 | 95.00% | 10.00% | 25.00% | 10 | $0.26 | $0.71 |
| 1 | 5 | 280 | 286 | Duct Insulation | 2.75 | 2.75 | 25.00% | 3.00% | 25.00% | 20 | $0.01 | $12.08 |
| 1 | 5 | 280 | 287 | Duct Repair and Sealing | 2.75 | 2.75 | 50.00% | 1.00% | 25.00% | 20 | $0.04 | $197.00 |
| 1 | 5 | 280 | 288 | Installation of Automated Building Ventilation Control ( Via Occupancy Sensors, CO2 Sensors, Etc.) | 2.75 | 2.75 | 100.00% | 10.00% | 50.00% | 10 | $0.09 | $0.71 |
| 1 | 5 | 280 | 289 | Roof / Ceiling Insulation | 2.75 | 2.75 | 20.00% | 3.00% | 50.00% | 20 | $0.45 | $729.22 |
| 1 | 5 | 280 | 290 | Cool Roofs (Reflective and Spray Evaporative) | 2.75 | 2.75 | 100.00% | 4.30% | 50.00% | 10 | $0.47 | $788.00 |
| 1 | 5 | 280 | 291 | Clock / Programmable Thermostat | 2.75 | 2.75 | 46.56% | 10.00% | 100.00% | 10 | $0.02 | $0.71 |
| 1 | 5 | 280 | 292 | Installation of Air Side Economizers | 2.75 | 2.75 | 53.45% | 15.00% | 100.00% | 10 | $0.59 | $788.00 |
| 1 | 5 | 400 | 400 | Base Fan Motor, 5hp, 1800rpm, 87.5% (ODP) | 1.71 | 1.71 |  | 0.00% |  | 15 | $0.11 | $0.11 |
| 1 | 5 | 400 | 401 | Energy Efficient Fan & Pump Motors (ODP) | 1.71 | 1.71 |  | 1.50% |  | 15 | $0.02 | $0.11 |
| 1 | 5 | 400 | 402 | VSD, ASD Fan & Pump Applications | 1.71 | 1.71 |  | 30.00% |  | 15 | $0.13 | $0.11 |
| 1 | 5 | 610 | 610 | Base Office Equipment | 0.15 | 0.15 | 100.00% | 0.00% | 100.00% | 4 | $0.79 | $2.32 |
| 1 | 5 | 610 | 611 | ENERGY STAR or Better Office Equipment: Computer | 0.15 | 0.15 | 65.00% | 20.96% | 100.00% | 4 | $0.10 | $2.32 |
| 1 | 5 | 610 | 621 | ENERGY STAR or Better Office Equipment: Monitors | 0.15 | 0.15 | 71.00% | 18.62% | 100.00% | 4 | $0.05 | $2.32 |
| 1 | 5 | 610 | 623 | Smart Networks | 0.15 | 0.15 | 40.00% | 7.76% | 90.00% | 4 | $0.00 | $2.32 |
| 1 | 5 | 610 | 631 | ENERGY STAR or Better Office Equipment: Copiers | 0.15 | 0.15 | 65.00% | 7.07% | 100.00% | 4 | $0.02 | $0.25 |
| 1 | 5 | 610 | 641 | ENERGY STAR or Better Office Equipment: Printers | 0.15 | 0.15 | 65.00% | 11.42% | 100.00% | 4 | $0.06 | $0.74 |
| 1 | 5 | 700 | 700 | Base Water Heating | 0.33 | 0.33 | 100.00% | 0.00% | 100.00% | 15 | $0.85 | $0.85 |
| 1 | 5 | 700 | 701 | Demand controlled circulating systems | 0.33 | 0.33 | 100.00% | 5.00% | 50.00% | 15 | $0.17 | $0.85 |
| 1 | 5 | 700 | 702 | Heat Pump Water Heater | 0.33 | 0.33 | 100.00% | 30.00% | 75.00% | 15 | $0.11 | $0.85 |
| 1 | 5 | 700 | 703 | High-Efficiency Water Heater (electric) | 0.33 | 0.33 |  | 5.40% |  | 15 | $0.03 | $0.85 |
| 1 | 5 | 700 | 704 | Hot Water (SHW) Pipe Insulation | 0.33 | 0.33 | 95.22% | 5.00% | 50.00% | 15 | $0.00 | $0.42 |
| 1 | 5 | 800 | 800 | Base Heating | 0.79 | 0.79 | 100.00% | 0.00% | 100.00% | 20 | $2.40 | $2.40 |
| 1 | 5 | 800 | 802 | Roof / Ceiling Insulation | 0.79 | 0.79 | 33.67% | 10.00% | 50.00% | 20 | $0.45 | $2.22 |
| 1 | 5 | 800 | 803 | Duct Insulation | 0.79 | 0.79 | 62.30% | 2.00% | 25.00% | 20 | $0.01 | $2.22 |
| 1 | 5 | 800 | 804 | Duct Repair and Sealing | 0.79 | 0.79 | 50.00% | 2.00% | 25.00% | 20 | $0.00 | $2.22 |

## Table B.3: Commercial Electric

| Segment | Building | Base Number | Measure Number | Measure Name | Stock Usage | Base Usage | Incomplete Factor | Energy Savings | Feasibility Factor | Measure Life | Full Per Unit Cost | Full Base Measure Cost |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 5 | 800 | 805 | Clock / Programmable Thermostat | 0.79 | 0.79 | 41.85% | 30.00% | 100.00% | 10 | $0.15 | $2.40 |
| 1 | 5 | 800 | 812 | Installation of Automated Building Ventilation Control ( Via Occupancy Sensors, CO2 Sensors, Etc.) | 0.79 | 0.79 | 100.00% | 5.00% | 50.00% | 15 | $0.28 | $2.40 |
| 1 | 6 | 100 | 100 | Base Cooking | 0.36 | 0.36 | | 0.00% | | 15 | $0.24 | $0.24 |
| 1 | 6 | 100 | 101 | High-Efficiency Convection Oven | 0.36 | 0.36 | | 20.00% | | 15 | $0.20 | $0.24 |
| 1 | 6 | 110 | 110 | Base Fluorescent Fixture, 4' 4L T12, 34W, 2EEMAG | 2.68 | 2.68 | 100.00% | 0.00% | 100.00% | 22 | $1.35 | $1.35 |
| 1 | 6 | 110 | 111 | 4' 4L T8 Premium, EB | 2.68 | 2.41 | 100.00% | 25.00% | 16.67% | 34 | $0.44 | $1.35 |
| 1 | 6 | 110 | 112 | 4' 2L T8 Premium, EB, reflector | 2.68 | 2.41 | 100.00% | 62.50% | 16.67% | 34 | $0.66 | $1.35 |
| 1 | 6 | 110 | 113 | Occupancy Sensor, 4-4' Fluorescent Fixtures | 2.68 | 2.41 | 94.74% | 30.00% | 50.00% | 20 | $0.47 | $1.35 |
| 1 | 6 | 110 | 114 | Continuous Dimming, 5-4' Fluorescent Fixtures | 2.68 | 2.41 | 100.00% | 75.00% | 30.00% | 24 | $3.52 | $1.35 |
| 1 | 6 | 110 | 115 | 4' 2L T5HO, EB | 2.68 | 2.41 | 100.00% | 18.75% | 16.67% | 34 | $0.26 | $1.35 |
| 1 | 6 | 110 | 116 | 4' 4L T8, EB | 2.68 | 2.41 | 100.00% | 22.22% | 16.67% | 34 | $0.18 | $1.35 |
| 1 | 6 | 110 | 117 | 4' 3L T8, EB | 2.68 | 2.41 | 100.00% | 38.20% | 16.67% | 34 | $0.09 | $1.35 |
| 1 | 6 | 110 | 118 | 4' 3L T8 Premium, EB | 2.68 | 2.41 | 100.00% | 42.36% | 16.67% | 34 | $0.28 | $1.35 |
| 1 | 6 | 120 | 120 | Base Fluorescent Fixture, 4' 2L T12, 34W, 1EEMAG | 2.68 | 2.68 | 100.00% | 0.00% | 100.00% | 22 | $2.46 | $2.46 |
| 1 | 6 | 120 | 121 | 4' 2L T8 Premium, EB | 2.68 | 2.41 | 100.00% | 25.00% | 33.33% | 34 | $0.69 | $2.46 |
| 1 | 6 | 120 | 122 | 4' 1L T8 Premium, EB, reflector | 2.68 | 2.41 | 100.00% | 61.11% | 33.33% | 34 | $1.40 | $2.46 |
| 1 | 6 | 120 | 123 | Occupancy Sensor, 8-4' Fluorescent Fixtures | 2.68 | 2.41 | 94.74% | 30.00% | 50.00% | 20 | $0.40 | $2.46 |
| 1 | 6 | 120 | 124 | Continuous Dimming, 10-4' Fluorescent Fixtures | 2.68 | 2.41 | 100.00% | 75.00% | 30.00% | 24 | $3.38 | $2.46 |
| 1 | 6 | 120 | 125 | 4' 1L T5HO, EB | 2.68 | 2.41 | 100.00% | 13.90% | 33.33% | 34 | $0.52 | $2.46 |
| 1 | 6 | 130 | 130 | Base Fluorescent Fixture, 8' 2L T12, 60W, 1EEMAG | 2.68 | 2.68 | 100.00% | 0.00% | 100.00% | 22 | $1.83 | $1.83 |
| 1 | 6 | 130 | 131 | 8' 2L T12, 60W, EB | 2.68 | 2.41 | 32.87% | 10.57% | 25.00% | 34 | $0.17 | $1.83 |
| 1 | 6 | 130 | 132 | 8' 1L T12, 60W, EB, reflector | 2.68 | 2.41 | 100.00% | 55.30% | 25.00% | 34 | $0.79 | $1.83 |
| 1 | 6 | 130 | 133 | Occupancy Sensor, 4-8' Fluorescent Fixtures | 2.68 | 2.41 | 94.74% | 30.00% | 50.00% | 20 | $0.55 | $1.83 |
| 1 | 6 | 130 | 134 | Continuous Dimming, 5-8' Fluorescent Fixtures | 2.68 | 2.41 | 100.00% | 75.00% | 30.00% | 24 | $4.12 | $1.83 |
| 1 | 6 | 130 | 135 | 8' 2L T8, EB | 2.68 | 2.41 | 100.00% | 52.80% | 50.00% | 34 | $0.36 | $1.83 |
| 1 | 6 | 140 | 140 | Base Incandescent Flood, 75W | 2.68 | 2.68 | 100.00% | 0.00% | 100.00% | 1 | $3.12 | $3.12 |
| 1 | 6 | 140 | 141 | CFL Screw-in, Modular 18W | 2.68 | 2.41 | 88.39% | 65.30% | 90.00% | 10 | $1.92 | $3.12 |
| 1 | 6 | 150 | 150 | Base Incandescent Flood, 150W PAR | 2.68 | 2.68 | 100.00% | 0.00% | 100.00% | 1 | $0.76 | $0.76 |
| 1 | 6 | 150 | 151 | Halogen PAR Flood, 90W | 2.68 | 2.68 | 97.31% | 40.00% | 10.00% | 1 | $0.08 | $0.76 |
| 1 | 6 | 150 | 152 | Metal Halide, 50W | 2.68 | 2.68 | 85.51% | 52.00% | 45.00% | 12 | $4.09 | $0.76 |
| 1 | 6 | 150 | 153 | HPS, 50W | 2.68 | 2.68 | 85.51% | 56.00% | 45.00% | 12 | $2.09 | $0.76 |
| 1 | 6 | 160 | 160 | Base 4' 3L T12, 34W, 1EEMAG | 2.68 | 2.68 | 100.00% | 0.00% | 100.00% | 10 | $0.45 | $0.45 |
| 1 | 6 | 160 | 161 | 4' 3L T8, EB | 2.68 | 2.41 | 100.00% | 22.61% | 75.00% | 34 | $0.04 | $0.45 |
| 1 | 6 | 160 | 162 | 4' 3L T8 Premium, EB | 2.68 | 2.41 | 100.00% | 22.61% | 75.00% | 34 | $0.10 | $0.45 |
| 1 | 6 | 160 | 163 | 4' 2L T8 Premium, EB, reflector | 2.68 | 2.41 | 100.00% | 53.04% | 40.00% | 34 | $0.23 | $0.45 |
| 1 | 6 | 160 | 164 | 4' 1L T5HO, EB | 2.68 | 2.41 | 100.00% | 46.09% | 75.00% | 34 | $0.04 | $0.45 |
| 1 | 6 | 180 | 180 | Base Fluorescent Fixture 4' 4L T8, 1EB | 2.14 | 2.14 | 100.00% | 0.00% | 100.00% | 34 | $1.51 | $1.51 |
| 1 | 6 | 180 | 181 | 4' 4L T8 Premium, EB | 2.14 | 1.93 | 100.00% | 3.60% | 100.00% | 34 | $0.27 | $1.51 |
| 1 | 6 | 180 | 182 | Occupancy Sensor, 4-4' Fluorescent Fixtures | 2.14 | 1.93 | 94.74% | 30.00% | 50.00% | 20 | $0.47 | $1.51 |
| 1 | 6 | 185 | 185 | Base Fluorescent Fixture 4' 3L T8, 1EB | 2.14 | 1.82 | 100.00% | 0.00% | 100.00% | 34 | $2.79 | $2.79 |
| 1 | 6 | 185 | 186 | 4' 3L T8 Premium, EB | 2.14 | 1.93 | 100.00% | 6.70% | 100.00% | 34 | $0.38 | $2.79 |
| 1 | 6 | 190 | 190 | Base Fluorescent Fixture 4' 2L T8, 1EB | 2.14 | 1.82 | 100.00% | 0.00% | 100.00% | 34 | $2.62 | $2.62 |
| 1 | 6 | 190 | 191 | 4' 2L T8 Premium, EB | 2.14 | 1.93 | 100.00% | 8.50% | 100.00% | 34 | $0.24 | $2.62 |

## Table B.3: Commercial Electric

| Segment | Building | Base Number | Measure Number | Measure Name | Stock Usage | Base Usage | Incomplete Factor | Energy Savings | Feasibility Factor | Measure Life | Full Per Unit Cost | Full Base Measure Cost |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 6 | 190 | 192 | Occupancy Sensor, 8-4' Fluorescent Fixtures | 2.14 | 1.93 | 94.74% | 30.00% | 50.00% | 20 | $0.40 | $2.62 |
| 1 | 6 | 200 | 200 | Base Centrifugal Chiller, 0.65 kW/ton, 300 tons | 0.30 | 0.30 | 100.00% | 0.00% | 100.00% | 20 | $1.04 | $1.04 |
| 1 | 6 | 200 | 201 | Chiller Tune-Up / Diagnostics | 0.30 | 0.30 | 90.00% | 5.00% | 100.00% | 5 | $0.08 | $1.04 |
| 1 | 6 | 200 | 202 | Installation of Automated Building Ventilation Control ( Via Occupancy Sensors, CO2 Sensors, Etc.) | 0.30 | 0.30 | 100.00% | 10.00% | 50.00% | 10 | $0.22 | $1.04 |
| 1 | 6 | 200 | 203 | Roof / Ceiling Insulation | 0.30 | 0.30 | 23.44% | 3.00% | 50.00% | 20 | $0.47 | $439.21 |
| 1 | 6 | 200 | 204 | Cool Roofs (Reflective and Spray Evaporative) | 0.30 | 0.30 | 100.00% | 6.14% | 90.00% | 10 | $0.24 | $230.50 |
| 1 | 6 | 200 | 205 | EMS Optimization | 0.30 | 0.30 | 75.00% | 1.00% | 100.00% | 5 | $0.00 | $0.00 |
| 1 | 6 | 200 | 206 | High Efficiency Windows (Low-E Glass or Multiple Glazed) | 0.30 | 0.30 | 66.00% | 3.89% | 75.00% | 30 | $0.02 | $11.17 |
| 1 | 6 | 200 | 207 | Installation of Energy Management Systems | 0.30 | 0.30 | 70.68% | 10.00% | 50.00% | 10 | $0.14 | $1.04 |
| 1 | 6 | 200 | 208 | Insulation of Pipes | 0.30 | 0.30 | 50.00% | 1.00% | 50.00% | 20 | $0.02 | $1.74 |
| 1 | 6 | 200 | 209 | Installation of Chiller Economizers (water side) | 0.30 | 0.30 | 81.26% | 10.00% | 50.00% | 20 | $0.59 | $461.00 |
| 1 | 6 | 200 | 210 | Optimize Chilled Water and Condenser Water Settings | 0.30 | 0.30 | 50.00% | 5.00% | 33.00% | 10 | $0.15 | $1.04 |
| 1 | 6 | 200 | 211 | Decrease Cooling Tower Approach Temperature, 300 Tons, 6 Deg F | 0.30 | 0.27 | 100.00% | 7.50% | 67.00% | 15 | $0.08 | $1.61 |
| 1 | 6 | 200 | 212 | Two-Speed Cooling Tower, 300 Tons | 0.30 | 0.27 | 90.00% | 14.00% | 50.00% | 15 | $0.01 | $1.61 |
| 1 | 6 | 200 | 213 | VSD Cooling Tower, 300 Tons | 0.30 | 0.27 | 90.00% | 18.00% | 50.00% | 15 | $0.05 | $1.61 |
| 1 | 6 | 200 | 214 | Primary/Secondary De-coupled Chilled Water System | 0.30 | 0.27 | 80.00% | 12.00% | 50.00% | 15 | $0.34 | $1.61 |
| 1 | 6 | 200 | 215 | HE Chiller, 0.51 kW/ton, 300 Tons | 0.30 | 0.27 | | 21.54% | | 15 | $0.14 | $1.61 |
| 1 | 6 | 200 | 216 | VSD Chiller, 0.47 kW/ton, 300 Tons | 0.30 | 0.27 | | 27.69% | | 15 | $0.45 | $1.61 |
| 1 | 6 | 250 | 250 | Base DX Packaged System, EER=10.3, 10 tons | 0.52 | 0.52 | 100.00% | 0.00% | 100.00% | 15 | $1.77 | $1.77 |
| 1 | 6 | 250 | 251 | DX Tune-Up / Diagnostics | 0.52 | 0.52 | 90.00% | 10.00% | 100.00% | 3 | $0.18 | $1.77 |
| 1 | 6 | 250 | 252 | Hi-Eff DX Packaged System, 10 tons, EER=11.3 | 0.52 | 0.45 | | 8.85% | | 15 | $0.21 | $1.77 |
| 1 | 6 | 250 | 253 | High Efficiency Windows (Low-E Glass or Multiple Glazed) | 0.52 | 0.52 | 66.00% | 5.00% | 75.00% | 30 | $0.04 | $19.09 |
| 1 | 6 | 250 | 254 | Installation of Direct of Indirect Evaporative Cooling, Evaporative Pre-Cooling, and Absorption Cooling | 0.52 | 0.52 | 95.00% | 10.00% | 25.00% | 10 | $0.65 | $1.77 |
| 1 | 6 | 250 | 256 | Duct Insulation | 0.52 | 0.52 | 25.00% | 3.00% | 25.00% | 20 | $0.01 | $13.37 |
| 1 | 6 | 250 | 257 | Duct Repair and Sealing | 0.52 | 0.52 | 50.00% | 1.00% | 25.00% | 20 | $0.04 | $197.00 |
| 1 | 6 | 250 | 258 | Installation of Automated Building Ventilation Control ( Via Occupancy Sensors, CO2 Sensors, Etc.) | 0.52 | 0.52 | 100.00% | 10.00% | 50.00% | 10 | $0.22 | $1.77 |
| 1 | 6 | 250 | 259 | Roof / Ceiling Insulation | 0.52 | 0.52 | 23.44% | 3.00% | 50.00% | 20 | $0.47 | $750.76 |
| 1 | 6 | 250 | 260 | Cool Roofs (Reflective and Spray Evaporative) | 0.52 | 0.52 | 100.00% | 6.14% | 50.00% | 10 | $0.24 | $394.00 |
| 1 | 6 | 250 | 261 | Clock / Programmable Thermostat | 0.52 | 0.52 | 41.07% | 10.00% | 100.00% | 10 | $0.05 | $1.77 |
| 1 | 6 | 250 | 262 | Installation of Air Side Economizers | 0.52 | 0.52 | 41.07% | 15.00% | 100.00% | 10 | $0.59 | $788.00 |
| 1 | 6 | 280 | 280 | Base Air-Cooled HP Package, 5 tons, SEER=10 | 0.52 | 0.47 | 100.00% | 0.00% | 100.00% | 15 | $1.61 | $1.61 |
| 1 | 6 | 280 | 281 | Air-Cooled HP Package, 5 tons, SEER=11 | 0.52 | 0.47 | | 9.09% | | 15 | $0.08 | $1.61 |
| 1 | 6 | 280 | 282 | Air-Cooled HP Package, 5 tons, SEER=12 | 0.52 | 0.47 | | 16.67% | | 15 | $0.53 | $1.61 |
| 1 | 6 | 280 | 283 | DX Tune-Up / Diagnostics | 0.52 | 0.52 | 90.00% | 10.00% | 100.00% | 3 | $0.18 | $1.77 |
| 1 | 6 | 280 | 284 | High Efficiency Windows (Low-E Glass or Multiple Glazed) | 0.52 | 0.52 | 66.00% | 5.00% | 75.00% | 30 | $0.04 | $19.09 |
| 1 | 6 | 280 | 285 | Installation of Direct of Indirect Evaporative Cooling, Evaporative Pre-Cooling, and Absorption Cooling | 0.52 | 0.52 | 95.00% | 10.00% | 25.00% | 10 | $0.65 | $1.77 |
| 1 | 6 | 280 | 286 | Duct Insulation | 0.52 | 0.52 | 25.00% | 3.00% | 25.00% | 20 | $0.01 | $13.37 |
| 1 | 6 | 280 | 287 | Duct Repair and Sealing | 0.52 | 0.52 | 50.00% | 1.00% | 25.00% | 20 | $0.04 | $197.00 |
| 1 | 6 | 280 | 288 | Installation of Automated Building Ventilation Control ( Via Occupancy Sensors, CO2 Sensors, Etc.) | 0.52 | 0.52 | 100.00% | 10.00% | 50.00% | 10 | $0.22 | $1.77 |

# Table B.3: Commercial Electric

| Segment | Building | Base Number | Measure Number | Measure Name | Stock Usage | Base Usage | Incomplete Factor | Energy Savings | Feasibility Factor | Measure Life | Full Per Unit Cost | Full Base Measure Cost |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 6 | 280 | 289 | Roof / Ceiling Insulation | 0.52 | 0.52 | 23.44% | 3.00% | 50.00% | 20 | $0.47 | $750.76 |
| 1 | 6 | 280 | 290 | Cool Roofs (Reflective and Spray Evaporative) | 0.52 | 0.52 | 100.00% | 6.14% | 50.00% | 10 | $0.24 | $394.00 |
| 1 | 6 | 280 | 291 | Clock / Programmable Thermostat | 0.52 | 0.52 | 41.07% | 10.00% | 100.00% | 10 | $0.05 | $1.77 |
| 1 | 6 | 280 | 292 | Installation of Air Side Economizers | 0.52 | 0.52 | 41.07% | 15.00% | 100.00% | 10 | $0.59 | $788.00 |
| 1 | 6 | 400 | 400 | Base Fan Motor, 5hp, 1800rpm, 87.5% (ODP) | 0.75 | 0.75 | | 0.00% | | 15 | $0.09 | $0.09 |
| 1 | 6 | 400 | 401 | Energy Efficient Fan & Pump Motors (ODP) | 0.75 | 0.75 | | 1.50% | | 15 | $0.02 | $0.09 |
| 1 | 6 | 400 | 402 | VSD, ASD Fan & Pump Applications | 0.75 | 0.75 | | 30.00% | | 15 | $0.10 | $0.09 |
| 1 | 6 | 610 | 610 | Base Office Equipment | 0.11 | 0.11 | 100.00% | 0.00% | 100.00% | 4 | $0.93 | $2.72 |
| 1 | 6 | 610 | 611 | ENERGY STAR or Better Office Equipment: Computer | 0.11 | 0.11 | 65.00% | 19.52% | 100.00% | 4 | $0.12 | $2.72 |
| 1 | 6 | 610 | 621 | ENERGY STAR or Better Office Equipment: Monitors | 0.11 | 0.11 | 71.00% | 17.34% | 100.00% | 4 | $0.06 | $2.72 |
| 1 | 6 | 610 | 623 | Smart Networks | 0.11 | 0.11 | 40.00% | 7.22% | 90.00% | 4 | $0.00 | $2.72 |
| 1 | 6 | 610 | 631 | ENERGY STAR or Better Office Equipment: Copiers | 0.11 | 0.11 | 65.00% | 8.96% | 100.00% | 4 | $0.01 | $0.17 |
| 1 | 6 | 610 | 641 | ENERGY STAR or Better Office Equipment: Printers | 0.11 | 0.11 | 65.00% | 11.20% | 100.00% | 4 | $0.06 | $0.75 |
| 1 | 6 | 700 | 700 | Base Water Heating | 0.64 | 0.64 | 100.00% | 0.00% | 100.00% | 15 | $20.37 | $20.37 |
| 1 | 6 | 700 | 701 | Demand controlled circulating systems | 0.64 | 0.64 | 100.00% | 5.00% | 50.00% | 15 | $3.97 | $20.37 |
| 1 | 6 | 700 | 702 | Heat Pump Water Heater | 0.64 | 0.64 | 87.24% | 30.00% | 75.00% | 15 | $2.53 | $20.37 |
| 1 | 6 | 700 | 703 | High-Efficiency Water Heater (electric) | 0.64 | 0.64 | | 5.40% | | 15 | $0.73 | $20.37 |
| 1 | 6 | 700 | 704 | Hot Water (SHW) Pipe Insulation | 0.64 | 0.64 | 9.88% | 5.00% | 50.00% | 15 | $0.02 | $3.77 |
| 1 | 6 | 800 | 800 | Base Heating | 9.71 | 9.71 | 100.00% | 0.00% | 100.00% | 20 | $2.40 | $2.40 |
| 1 | 6 | 800 | 802 | Roof / Ceiling Insulation | 9.71 | 9.71 | 44.94% | 10.00% | 50.00% | 20 | $0.47 | $2.29 |
| 1 | 6 | 800 | 803 | Duct Insulation | 9.71 | 9.71 | 71.80% | 2.00% | 25.00% | 20 | $0.01 | $2.29 |
| 1 | 6 | 800 | 804 | Duct Repair and Sealing | 9.71 | 9.71 | 50.00% | 2.00% | 25.00% | 20 | $0.00 | $2.29 |
| 1 | 6 | 800 | 805 | Clock / Programmable Thermostat | 9.71 | 9.71 | 41.07% | 30.00% | 100.00% | 10 | $0.15 | $2.40 |
| 1 | 6 | 800 | 812 | Installation of Automated Building Ventilation Control ( Via Occupancy Sensors, CO2 Sensors, Etc.) | 9.71 | 9.71 | 100.00% | 5.00% | 50.00% | 15 | $0.28 | $2.40 |
| 1 | 7 | 110 | 110 | Base Fluorescent Fixture, 4' 4L T12, 34W, 2EEMAG | 5.29 | 5.29 | 100.00% | 0.00% | 100.00% | 21 | $1.27 | $1.27 |
| 1 | 7 | 110 | 111 | 4' 4L T8 Premium, EB | 5.29 | 4.77 | 100.00% | 25.00% | 16.67% | 32 | $0.42 | $1.27 |
| 1 | 7 | 110 | 112 | 4' 2L T8 Premium, EB, reflector | 5.29 | 4.77 | 100.00% | 62.50% | 16.67% | 32 | $0.62 | $1.27 |
| 1 | 7 | 110 | 113 | Occupancy Sensor, 4-4' Fluorescent Fixtures | 5.29 | 4.77 | 90.00% | 30.00% | 50.00% | 19 | $0.44 | $1.27 |
| 1 | 7 | 110 | 114 | Continuous Dimming, 5-4' Fluorescent Fixtures | 5.29 | 4.77 | 100.00% | 75.00% | 30.00% | 23 | $3.30 | $1.27 |
| 1 | 7 | 110 | 115 | 4' 2L T5HO, EB | 5.29 | 4.77 | 100.00% | 18.75% | 16.67% | 32 | $0.24 | $1.27 |
| 1 | 7 | 110 | 116 | 4' 4L T8, EB | 5.29 | 4.77 | 100.00% | 22.22% | 16.67% | 32 | $0.17 | $1.27 |
| 1 | 7 | 110 | 117 | 4' 3L T8, EB | 5.29 | 4.77 | 100.00% | 38.20% | 16.67% | 32 | $0.08 | $1.27 |
| 1 | 7 | 110 | 118 | 4' 3L T8 Premium, EB | 5.29 | 4.77 | 100.00% | 42.36% | 16.67% | 32 | $0.27 | $1.27 |
| 1 | 7 | 120 | 120 | Base Fluorescent Fixture, 4' 2L T12, 34W, 1EEMAG | 5.29 | 5.29 | 100.00% | 0.00% | 100.00% | 21 | $2.34 | $2.34 |
| 1 | 7 | 120 | 121 | 4' 2L T8 Premium, EB | 5.29 | 4.77 | 100.00% | 25.00% | 33.33% | 32 | $0.65 | $2.34 |
| 1 | 7 | 120 | 122 | 4' 1L T8 Premium, EB, reflector | 5.29 | 4.77 | 100.00% | 61.11% | 33.33% | 32 | $1.32 | $2.34 |
| 1 | 7 | 120 | 123 | Occupancy Sensor, 8-4' Fluorescent Fixtures | 5.29 | 4.77 | 90.00% | 30.00% | 50.00% | 19 | $0.38 | $2.34 |
| 1 | 7 | 120 | 124 | Continuous Dimming, 10-4' Fluorescent Fixtures | 5.29 | 4.77 | 100.00% | 75.00% | 30.00% | 23 | $3.21 | $2.34 |
| 1 | 7 | 120 | 125 | 4' 1L T5HO, EB | 5.29 | 4.77 | 100.00% | 13.90% | 33.33% | 32 | $0.49 | $2.34 |
| 1 | 7 | 130 | 130 | Base Fluorescent Fixture, 8' 2L T12, 60W, 1EEMAG | 5.29 | 5.29 | 100.00% | 0.00% | 100.00% | 21 | $1.64 | $1.64 |
| 1 | 7 | 130 | 131 | 8' 2L T12, 60W, EB | 5.29 | 4.77 | 50.00% | 10.57% | 25.00% | 32 | $0.16 | $1.64 |
| 1 | 7 | 130 | 132 | 8' 1L T12, 60W, EB, reflector | 5.29 | 4.77 | 100.00% | 55.30% | 25.00% | 32 | $0.71 | $1.64 |
| 1 | 7 | 130 | 133 | Occupancy Sensor, 4-8' Fluorescent Fixtures | 5.29 | 4.77 | 90.00% | 30.00% | 50.00% | 19 | $0.49 | $1.64 |

# Table B.3: Commercial Electric

| Segment | Building | Base Number | Measure Number | Measure Name | Stock Usage | Base Usage | Incomplete Factor | Energy Savings | Feasibility Factor | Measure Life | Full Per Unit Cost | Full Base Measure Cost |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 7 | 130 | 134 | Continuous Dimming, 5-8' Fluorescent Fixtures | 5.29 | 4.77 | 100.00% | 75.00% | 30.00% | 23 | $3.70 | $1.64 |
| 1 | 7 | 130 | 135 | 8' 2L T8, EB | 5.29 | 4.77 | 100.00% | 52.80% | 50.00% | 32 | $0.32 | $1.64 |
| 1 | 7 | 140 | 140 | Base Incandescent Flood, 75W | 5.29 | 5.29 | 100.00% | 0.00% | 100.00% | 1 | $3.09 | $3.09 |
| 1 | 7 | 140 | 141 | CFL Screw-in, Modular 18W | 5.29 | 4.77 | 85.00% | 65.30% | 90.00% | 9 | $1.90 | $3.09 |
| 1 | 7 | 150 | 150 | Base Incandescent Flood, 150W PAR | 5.29 | 5.29 | 100.00% | 0.00% | 100.00% | 1 | $1.40 | $1.40 |
| 1 | 7 | 150 | 151 | Halogen PAR Flood, 90W | 5.29 | 5.29 | 95.00% | 40.00% | 10.00% | 1 | $0.14 | $1.40 |
| 1 | 7 | 150 | 152 | Metal Halide, 50W | 5.29 | 5.29 | 90.00% | 52.00% | 45.00% | 11 | $7.51 | $1.40 |
| 1 | 7 | 150 | 153 | HPS, 50W | 5.29 | 5.29 | 90.00% | 56.00% | 45.00% | 11 | $3.83 | $1.40 |
| 1 | 7 | 160 | 160 | Base 4' 3L T12, 34W, 1EEMAG | 5.29 | 5.29 | 100.00% | 0.00% | 100.00% | 10 | $0.09 | $0.09 |
| 1 | 7 | 160 | 161 | 4' 3L T8, EB | 5.29 | 4.77 | 100.00% | 22.61% | 75.00% | 32 | $0.01 | $0.09 |
| 1 | 7 | 160 | 162 | 4' 3L T8 Premium, EB | 5.29 | 4.77 | 100.00% | 22.61% | 75.00% | 32 | $0.02 | $0.09 |
| 1 | 7 | 160 | 163 | 4' 2L T8 Premium, EB, reflector | 5.29 | 4.77 | 100.00% | 53.04% | 40.00% | 32 | $0.05 | $0.09 |
| 1 | 7 | 160 | 164 | 4' 1L T5HO, EB | 5.29 | 4.77 | 100.00% | 46.09% | 75.00% | 32 | $0.01 | $0.09 |
| 1 | 7 | 180 | 180 | Base Fluorescent Fixture 4' 4L T8, 1EB | 4.24 | 4.24 | 100.00% | 0.00% | 100.00% | 32 | $1.42 | $1.42 |
| 1 | 7 | 180 | 181 | 4' 4L T8 Premium, EB | 4.24 | 3.81 | 100.00% | 3.60% | 100.00% | 32 | $0.25 | $1.42 |
| 1 | 7 | 180 | 182 | Occupancy Sensor, 4-4' Fluorescent Fixtures | 4.24 | 3.81 | 90.00% | 30.00% | 50.00% | 19 | $0.44 | $1.42 |
| 1 | 7 | 185 | 185 | Base Fluorescent Fixture 4' 3L T8, 1EB | 4.24 | 3.60 | 100.00% | 0.00% | 100.00% | 32 | $2.65 | $2.65 |
| 1 | 7 | 185 | 186 | 4' 3L T8 Premium, EB | 4.24 | 3.81 | 100.00% | 6.70% | 100.00% | 32 | $0.36 | $2.65 |
| 1 | 7 | 190 | 190 | Base Fluorescent Fixture 4' 2L T8, 1EB | 4.24 | 3.60 | 100.00% | 0.00% | 100.00% | 32 | $2.49 | $2.49 |
| 1 | 7 | 190 | 191 | 4' 2L T8 Premium, EB | 4.24 | 3.81 | 100.00% | 8.50% | 100.00% | 32 | $0.22 | $2.49 |
| 1 | 7 | 190 | 192 | Occupancy Sensor, 8-4' Fluorescent Fixtures | 4.24 | 3.81 | 90.00% | 30.00% | 50.00% | 19 | $0.38 | $2.49 |
| 1 | 7 | 200 | 200 | Base Centrifugal Chiller, 0.65 kW/ton, 300 tons | 3.76 | 3.76 | 100.00% | 0.00% | 100.00% | 20 | $2.07 | $2.07 |
| 1 | 7 | 200 | 201 | Chiller Tune-Up / Diagnostics | 3.76 | 3.76 | 90.00% | 5.00% | 100.00% | 5 | $0.17 | $2.07 |
| 1 | 7 | 200 | 202 | Installation of Automated Building Ventilation Control ( Via Occupancy Sensors, CO2 Sensors, Etc.) | 3.76 | 3.76 | 100.00% | 10.00% | 50.00% | 10 | $0.44 | $2.07 |
| 1 | 7 | 200 | 203 | Roof / Ceiling Insulation | 3.76 | 3.76 | 20.00% | 3.00% | 50.00% | 20 | $0.30 | $277.59 |
| 1 | 7 | 200 | 204 | Cool Roofs (Reflective and Spray Evaporative) | 3.76 | 3.76 | 100.00% | 1.35% | 90.00% | 10 | $0.20 | $199.77 |
| 1 | 7 | 200 | 205 | EMS Optimization | 3.76 | 3.76 | 75.00% | 1.00% | 100.00% | 5 | $0.00 | $0.00 |
| 1 | 7 | 200 | 206 | High Efficiency Windows (Low-E Glass or Multiple Glazed) | 3.76 | 3.76 | 66.00% | 3.96% | 75.00% | 30 | $0.04 | $28.82 |
| 1 | 7 | 200 | 207 | Installation of Energy Management Systems | 3.76 | 3.76 | 50.00% | 10.00% | 50.00% | 10 | $0.27 | $2.07 |
| 1 | 7 | 200 | 208 | Insulation of Pipes | 3.76 | 3.76 | 50.00% | 1.00% | 50.00% | 20 | $0.03 | $2.92 |
| 1 | 7 | 200 | 209 | Installation of Chiller Economizers (water side) | 3.76 | 3.76 | 100.00% | 10.00% | 50.00% | 20 | $0.59 | $461.00 |
| 1 | 7 | 200 | 210 | Optimize Chilled Water and Condenser Water Settings | 3.76 | 3.76 | 50.00% | 5.00% | 33.00% | 10 | $0.30 | $2.07 |
| 1 | 7 | 200 | 211 | Decrease Cooling Tower Approach Temperature, 300 Tons, 6 Deg F | 3.76 | 3.38 | 100.00% | 7.50% | 67.00% | 15 | $0.16 | $3.22 |
| 1 | 7 | 200 | 212 | Two-Speed Cooling Tower, 300 Tons | 3.76 | 3.38 | 90.00% | 14.00% | 50.00% | 15 | $0.01 | $3.22 |
| 1 | 7 | 200 | 213 | VSD Cooling Tower, 300 Tons | 3.76 | 3.38 | 90.00% | 18.00% | 50.00% | 15 | $0.11 | $3.22 |
| 1 | 7 | 200 | 214 | Primary/Secondary De-coupled Chilled Water System | 3.76 | 3.38 | 80.00% | 12.00% | 50.00% | 15 | $0.68 | $3.22 |
| 1 | 7 | 200 | 215 | HE Chiller, 0.51 kW/ton, 300 Tons | 3.76 | 3.38 | | 21.54% | | 15 | $0.27 | $3.22 |
| 1 | 7 | 200 | 216 | VSD Chiller, 0.47 kW/ton, 300 Tons | 3.76 | 3.38 | | 27.69% | | 15 | $0.90 | $3.22 |
| 1 | 7 | 250 | 250 | Base DX Packaged System, EER=10.3, 10 tons | 6.51 | 6.51 | 100.00% | 0.00% | 100.00% | 15 | $3.55 | $3.55 |
| 1 | 7 | 250 | 251 | DX Tune-Up / Diagnostics | 6.51 | 6.51 | 90.00% | 10.00% | 100.00% | 3 | $0.35 | $3.55 |
| 1 | 7 | 250 | 252 | Hi-Eff DX Packaged System, 10 tons, EER=11.3 | 6.51 | 5.63 | | 8.85% | | 15 | $0.43 | $3.55 |
| 1 | 7 | 250 | 253 | High Efficiency Windows (Low-E Glass or Multiple Glazed) | 6.51 | 6.51 | 66.00% | 5.00% | 75.00% | 30 | $0.11 | $49.27 |

## Table B.3: Commercial Electric

| Segment | Building | Base Number | Measure Number | Measure Name | Stock Usage | Base Usage | Incomplete Factor | Energy Savings | Feasibility Factor | Measure Life | Full Per Unit Cost | Full Base Measure Cost |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 7 | 250 | 254 | Installation of Direct of Indirect Evaporative Cooling, Evaporative Pre-Cooling, and Absorption Cooling | 6.51 | 6.51 | 95.00% | 10.00% | 25.00% | 10 | $1.31 | $3.55 |
| 1 | 7 | 250 | 256 | Duct Insulation | 6.51 | 6.51 | 25.00% | 3.00% | 25.00% | 20 | $0.01 | $11.43 |
| 1 | 7 | 250 | 257 | Duct Repair and Sealing | 6.51 | 6.51 | 50.00% | 1.00% | 25.00% | 20 | $0.04 | $197.00 |
| 1 | 7 | 250 | 258 | Installation of Automated Building Ventilation Control ( Via Occupancy Sensors, CO2 Sensors, Etc.) | 6.51 | 6.51 | 100.00% | 10.00% | 50.00% | 10 | $0.44 | $3.55 |
| 1 | 7 | 250 | 259 | Roof / Ceiling Insulation | 6.51 | 6.51 | 20.00% | 3.00% | 50.00% | 20 | $0.30 | $474.49 |
| 1 | 7 | 250 | 260 | Cool Roofs (Reflective and Spray Evaporative) | 6.51 | 6.51 | 100.00% | 1.35% | 50.00% | 10 | $0.20 | $341.47 |
| 1 | 7 | 250 | 261 | Clock / Programmable Thermostat | 6.51 | 6.51 | 30.00% | 10.00% | 100.00% | 10 | $0.09 | $3.55 |
| 1 | 7 | 250 | 262 | Installation of Air Side Economizers | 6.51 | 6.51 | 100.00% | 15.00% | 100.00% | 10 | $0.59 | $788.00 |
| 1 | 7 | 280 | 280 | Base Air-Cooled HP Package, 5 tons, SEER=10 | 6.51 | 5.86 | 100.00% | 0.00% | 100.00% | 15 | $3.22 | $3.22 |
| 1 | 7 | 280 | 281 | Air-Cooled HP Package, 5 tons, SEER=11 | 6.51 | 5.86 | | 9.09% | | 15 | $0.16 | $3.22 |
| 1 | 7 | 280 | 282 | Air-Cooled HP Package, 5 tons, SEER=12 | 6.51 | 5.86 | | 16.67% | | 15 | $1.06 | $3.22 |
| 1 | 7 | 280 | 283 | DX Tune-Up / Diagnostics | 6.51 | 6.51 | 90.00% | 10.00% | 100.00% | 3 | $0.35 | $3.55 |
| 1 | 7 | 280 | 284 | High Efficiency Windows (Low-E Glass or Multiple Glazed) | 6.51 | 6.51 | 66.00% | 5.00% | 75.00% | 30 | $0.11 | $49.27 |
| 1 | 7 | 280 | 285 | Installation of Direct of Indirect Evaporative Cooling, Evaporative Pre-Cooling, and Absorption Cooling | 6.51 | 6.51 | 95.00% | 10.00% | 25.00% | 10 | $1.31 | $3.55 |
| 1 | 7 | 280 | 286 | Duct Insulation | 6.51 | 6.51 | 25.00% | 3.00% | 25.00% | 20 | $0.01 | $11.43 |
| 1 | 7 | 280 | 287 | Duct Repair and Sealing | 6.51 | 6.51 | 50.00% | 1.00% | 25.00% | 20 | $0.04 | $197.00 |
| 1 | 7 | 280 | 288 | Installation of Automated Building Ventilation Control ( Via Occupancy Sensors, CO2 Sensors, Etc.) | 6.51 | 6.51 | 100.00% | 10.00% | 50.00% | 10 | $0.44 | $3.55 |
| 1 | 7 | 280 | 289 | Roof / Ceiling Insulation | 6.51 | 6.51 | 20.00% | 3.00% | 50.00% | 20 | $0.30 | $474.49 |
| 1 | 7 | 280 | 290 | Cool Roofs (Reflective and Spray Evaporative) | 6.51 | 6.51 | 100.00% | 1.35% | 50.00% | 10 | $0.20 | $341.47 |
| 1 | 7 | 280 | 291 | Clock / Programmable Thermostat | 6.51 | 6.51 | 30.00% | 10.00% | 100.00% | 10 | $0.09 | $3.55 |
| 1 | 7 | 280 | 292 | Installation of Air Side Economizers | 6.51 | 6.51 | 100.00% | 15.00% | 100.00% | 10 | $0.59 | $788.00 |
| 1 | 7 | 400 | 400 | Base Fan Motor, 5hp, 1800rpm, 87.5% (ODP) | 0.98 | 0.98 | | 0.00% | | 15 | $0.11 | $0.11 |
| 1 | 7 | 400 | 401 | Energy Efficient Fan & Pump Motors (ODP) | 0.98 | 0.98 | | 1.50% | | 15 | $0.02 | $0.11 |
| 1 | 7 | 400 | 402 | VSD, ASD Fan & Pump Applications | 0.98 | 0.98 | | 30.00% | | 15 | $0.13 | $0.11 |
| 1 | 7 | 610 | 610 | Base Office Equipment | 0.32 | 0.32 | 100.00% | 0.00% | 100.00% | 4 | $0.25 | $0.74 |
| 1 | 7 | 610 | 611 | ENERGY STAR or Better Office Equipment: Computer | 0.32 | 0.32 | 65.00% | 21.55% | 100.00% | 4 | $0.03 | $0.74 |
| 1 | 7 | 610 | 621 | ENERGY STAR or Better Office Equipment: Monitors | 0.32 | 0.32 | 71.00% | 19.15% | 100.00% | 4 | $0.02 | $0.74 |
| 1 | 7 | 610 | 623 | Smart Networks | 0.32 | 0.32 | 40.00% | 7.98% | 90.00% | 4 | $0.00 | $0.74 |
| 1 | 7 | 610 | 631 | ENERGY STAR or Better Office Equipment: Copiers | 0.32 | 0.32 | 65.00% | 6.25% | 100.00% | 4 | $0.00 | $0.04 |
| 1 | 7 | 610 | 641 | ENERGY STAR or Better Office Equipment: Printers | 0.32 | 0.32 | 65.00% | 11.58% | 100.00% | 4 | $0.02 | $0.22 |
| 1 | 7 | 700 | 700 | Base Water Heating | 0.64 | 0.64 | 100.00% | 0.00% | 100.00% | 15 | $36.19 | $36.19 |
| 1 | 7 | 700 | 701 | Demand controlled circulating systems | 0.64 | 0.64 | 100.00% | 5.00% | 50.00% | 15 | $7.06 | $36.19 |
| 1 | 7 | 700 | 702 | Heat Pump Water Heater | 0.64 | 0.64 | 100.00% | 30.00% | 75.00% | 15 | $4.50 | $36.19 |
| 1 | 7 | 700 | 703 | High-Efficiency Water Heater (electric) | 0.64 | 0.64 | | 5.40% | | 15 | $1.30 | $36.19 |
| 1 | 7 | 700 | 704 | Hot Water (SHW) Pipe Insulation | 0.64 | 0.64 | 80.00% | 5.00% | 50.00% | 15 | $0.03 | $6.34 |
| 1 | 7 | 800 | 800 | Base Heating | 0.79 | 0.79 | 100.00% | 0.00% | 100.00% | 20 | $2.40 | $2.40 |
| 1 | 7 | 800 | 802 | Roof / Ceiling Insulation | 0.79 | 0.79 | 40.00% | 10.00% | 50.00% | 20 | $0.30 | $1.45 |
| 1 | 7 | 800 | 803 | Duct Insulation | 0.79 | 0.79 | 73.80% | 2.00% | 25.00% | 20 | $0.01 | $1.45 |
| 1 | 7 | 800 | 804 | Duct Repair and Sealing | 0.79 | 0.79 | 50.00% | 2.00% | 25.00% | 20 | $0.00 | $1.45 |
| 1 | 7 | 800 | 805 | Clock / Programmable Thermostat | 0.79 | 0.79 | 70.00% | 30.00% | 100.00% | 10 | $0.15 | $2.40 |

## Table B.3: Commercial Electric

| Segment | Building | Base Number | Measure Number | Measure Name | Stock Usage | Base Usage | Incomplete Factor | Energy Savings | Feasibility Factor | Measure Life | Full Per Unit Cost | Full Base Measure Cost |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 7 | 800 | 812 | Installation of Automated Building Ventilation Control ( Via Occupancy Sensors, CO2 Sensors, Etc.) | 0.79 | 0.79 | 100.00% | 5.00% | 50.00% | 15 | $0.28 | $2.40 |
| 1 | 8 | 110 | 110 | Base Fluorescent Fixture, 4' 4L T12, 34W, 2EEMAG | 10.77 | 10.77 | 100.00% | 0.00% | 100.00% | 8 | $1.48 | $1.48 |
| 1 | 8 | 110 | 111 | 4' 4L T8 Premium, EB | 10.77 | 9.69 | 100.00% | 25.00% | 16.67% | 12 | $0.48 | $1.48 |
| 1 | 8 | 110 | 112 | 4' 2L T8 Premium, EB, reflector | 10.77 | 9.69 | 100.00% | 62.50% | 16.67% | 12 | $0.72 | $1.48 |
| 1 | 8 | 110 | 113 | Occupancy Sensor, 4-4' Fluorescent Fixtures | 10.77 | 9.69 | 90.00% | 30.00% | 50.00% | 7 | $0.51 | $1.48 |
| 1 | 8 | 110 | 114 | Continuous Dimming, 5-4' Fluorescent Fixtures | 10.77 | 9.69 | 100.00% | 75.00% | 10.00% | 8 | $3.84 | $1.48 |
| 1 | 8 | 110 | 115 | 4' 2L T5HO, EB | 10.77 | 9.69 | 100.00% | 18.75% | 16.67% | 12 | $0.28 | $1.48 |
| 1 | 8 | 110 | 116 | 4' 4L T8, EB | 10.77 | 9.69 | 100.00% | 22.22% | 16.67% | 12 | $0.20 | $1.48 |
| 1 | 8 | 110 | 117 | 4' 3L T8, EB | 10.77 | 9.69 | 100.00% | 38.20% | 16.67% | 12 | $0.09 | $1.48 |
| 1 | 8 | 110 | 118 | 4' 3L T8 Premium, EB | 10.77 | 9.69 | 100.00% | 42.36% | 16.67% | 12 | $0.31 | $1.48 |
| 1 | 8 | 120 | 120 | Base Fluorescent Fixture, 4' 2L T12, 34W, 1EEMAG | 10.77 | 10.77 | 100.00% | 0.00% | 100.00% | 8 | $2.72 | $2.72 |
| 1 | 8 | 120 | 121 | 4' 2L T8 Premium, EB | 10.77 | 9.69 | 100.00% | 25.00% | 33.33% | 12 | $0.76 | $2.72 |
| 1 | 8 | 120 | 122 | 4' 1L T8 Premium, EB, reflector | 10.77 | 9.69 | 100.00% | 61.11% | 33.33% | 12 | $1.54 | $2.72 |
| 1 | 8 | 120 | 123 | Occupancy Sensor, 8-4' Fluorescent Fixtures | 10.77 | 9.69 | 90.00% | 30.00% | 50.00% | 7 | $0.44 | $2.72 |
| 1 | 8 | 120 | 124 | Continuous Dimming, 10-4' Fluorescent Fixtures | 10.77 | 9.69 | 100.00% | 75.00% | 10.00% | 8 | $3.74 | $2.72 |
| 1 | 8 | 120 | 125 | 4' 1L T5HO, EB | 10.77 | 9.69 | 100.00% | 13.90% | 33.33% | 12 | $0.58 | $2.72 |
| 1 | 8 | 130 | 130 | Base Fluorescent Fixture, 8' 2L T12, 60W, 1EEMAG | 10.77 | 10.77 | 100.00% | 0.00% | 100.00% | 8 | $1.77 | $1.77 |
| 1 | 8 | 130 | 131 | 8' 2L T12, 60W, EB | 10.77 | 9.69 | 50.00% | 10.57% | 25.00% | 12 | $0.17 | $1.77 |
| 1 | 8 | 130 | 132 | 8' 1L T12, 60W, EB, reflector | 10.77 | 9.69 | 100.00% | 55.30% | 25.00% | 12 | $0.77 | $1.77 |
| 1 | 8 | 130 | 133 | Occupancy Sensor, 4-8' Fluorescent Fixtures | 10.77 | 9.69 | 90.00% | 30.00% | 50.00% | 7 | $0.53 | $1.77 |
| 1 | 8 | 130 | 134 | Continuous Dimming, 5-8' Fluorescent Fixtures | 10.77 | 9.69 | 100.00% | 75.00% | 10.00% | 8 | $3.99 | $1.77 |
| 1 | 8 | 130 | 135 | 8' 2L T8, EB | 10.77 | 9.69 | 100.00% | 52.80% | 50.00% | 12 | $0.35 | $1.77 |
| 1 | 8 | 140 | 140 | Base Incandescent Flood, 75W | 10.77 | 10.77 | 100.00% | 0.00% | 100.00% | 1 | $3.72 | $3.72 |
| 1 | 8 | 140 | 141 | CFL Screw-in, Modular 18W | 10.77 | 9.69 | 85.00% | 65.30% | 90.00% | 3 | $2.29 | $3.72 |
| 1 | 8 | 150 | 150 | Base Incandescent Flood, 150W PAR | 10.77 | 10.77 | 100.00% | 0.00% | 100.00% | 1 | $1.04 | $1.04 |
| 1 | 8 | 150 | 151 | Halogen PAR Flood, 90W | 10.77 | 10.77 | 95.00% | 40.00% | 10.00% | 1 | $0.10 | $1.04 |
| 1 | 8 | 150 | 152 | Metal Halide, 50W | 10.77 | 10.77 | 90.00% | 52.00% | 45.00% | 4 | $5.59 | $1.04 |
| 1 | 8 | 150 | 153 | HPS, 50W | 10.77 | 10.77 | 90.00% | 56.00% | 45.00% | 4 | $2.85 | $1.04 |
| 1 | 8 | 160 | 160 | Base 4' 3L T12, 34W, 1EEMAG | 10.77 | 10.77 | 100.00% | 0.00% | 100.00% | 10 | $0.14 | $0.14 |
| 1 | 8 | 160 | 161 | 4' 3L T8, EB | 10.77 | 9.69 | 100.00% | 22.61% | 75.00% | 12 | $0.01 | $0.14 |
| 1 | 8 | 160 | 162 | 4' 3L T8 Premium, EB | 10.77 | 9.69 | 100.00% | 22.61% | 75.00% | 12 | $0.03 | $0.14 |
| 1 | 8 | 160 | 163 | 4' 2L T8 Premium, EB, reflector | 10.77 | 9.69 | 100.00% | 53.04% | 40.00% | 12 | $0.07 | $0.14 |
| 1 | 8 | 160 | 164 | 4' 1L T5HO, EB | 10.77 | 9.69 | 100.00% | 46.09% | 75.00% | 12 | $0.01 | $0.14 |
| 1 | 8 | 180 | 180 | Base Fluorescent Fixture 4' 4L T8, 1EB | 8.62 | 8.62 | 100.00% | 0.00% | 100.00% | 12 | $1.65 | $1.65 |
| 1 | 8 | 180 | 181 | 4' 4L T8 Premium, EB | 8.62 | 7.75 | 100.00% | 3.60% | 100.00% | 12 | $0.30 | $1.65 |
| 1 | 8 | 180 | 182 | Occupancy Sensor, 4-4' Fluorescent Fixtures | 8.62 | 7.75 | 90.00% | 30.00% | 50.00% | 7 | $0.51 | $1.65 |
| 1 | 8 | 185 | 185 | Base Fluorescent Fixture 4' 3L T8, 1EB | 8.62 | 7.32 | 100.00% | 0.00% | 100.00% | 12 | $3.08 | $3.08 |
| 1 | 8 | 185 | 186 | 4' 3L T8 Premium, EB | 8.62 | 7.75 | 100.00% | 6.70% | 100.00% | 12 | $0.42 | $3.08 |
| 1 | 8 | 190 | 190 | Base Fluorescent Fixture 4' 2L T8, 1EB | 8.62 | 7.32 | 100.00% | 0.00% | 100.00% | 12 | $2.90 | $2.90 |
| 1 | 8 | 190 | 191 | 4' 2L T8 Premium, EB | 8.62 | 7.75 | 100.00% | 8.50% | 100.00% | 12 | $0.26 | $2.90 |
| 1 | 8 | 190 | 192 | Occupancy Sensor, 8-4' Fluorescent Fixtures | 8.62 | 7.75 | 90.00% | 30.00% | 50.00% | 7 | $0.44 | $2.90 |
| 1 | 8 | 200 | 200 | Base Centrifugal Chiller, 0.65 kW/ton, 300 tons | 8.98 | 8.98 | 100.00% | 0.00% | 100.00% | 20 | $2.07 | $2.07 |
| 1 | 8 | 200 | 201 | Chiller Tune-Up / Diagnostics | 8.98 | 8.98 | 90.00% | 5.00% | 100.00% | 5 | $0.17 | $2.07 |

## Table B.3: Commercial Electric

| Segment | Building | Base Number | Measure Number | Measure Name | Stock Usage | Base Usage | Incomplete Factor | Energy Savings | Feasibility Factor | Measure Life | Full Per Unit Cost | Full Base Measure Cost |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 8 | 200 | 202 | Installation of Automated Building Ventilation Control ( Via Occupancy Sensors, CO2 Sensors, Etc.) | 8.98 | 8.98 | 100.00% | 10.00% | 50.00% | 10 | $0.44 | $2.07 |
| 1 | 8 | 200 | 203 | Roof / Ceiling Insulation | 8.98 | 8.98 | 20.00% | 3.00% | 50.00% | 20 | $0.43 | $402.37 |
| 1 | 8 | 200 | 204 | Cool Roofs (Reflective and Spray Evaporative) | 8.98 | 8.98 | 100.00% | 0.64% | 90.00% | 10 | $0.16 | $153.67 |
| 1 | 8 | 200 | 205 | EMS Optimization | 8.98 | 8.98 | 75.00% | 1.00% | 100.00% | 5 | $0.00 | $0.00 |
| 1 | 8 | 200 | 206 | High Efficiency Windows (Low-E Glass or Multiple Glazed) | 8.98 | 8.98 | 66.00% | 1.17% | 75.00% | 30 | $0.01 | $9.28 |
| 1 | 8 | 200 | 207 | Installation of Energy Management Systems | 8.98 | 8.98 | 75.00% | 10.00% | 50.00% | 10 | $0.27 | $2.07 |
| 1 | 8 | 200 | 208 | Insulation of Pipes | 8.98 | 8.98 | 50.00% | 1.00% | 50.00% | 20 | $0.01 | $1.08 |
| 1 | 8 | 200 | 209 | Installation of Chiller Economizers (water side) | 8.98 | 8.98 | 100.00% | 10.00% | 50.00% | 20 | $0.59 | $461.00 |
| 1 | 8 | 200 | 210 | Optimize Chilled Water and Condenser Water Settings | 8.98 | 8.98 | 50.00% | 5.00% | 33.00% | 10 | $0.30 | $2.07 |
| 1 | 8 | 200 | 211 | Decrease Cooling Tower Approach Temperature, 300 Tons, 6 Deg F | 8.98 | 8.08 | 100.00% | 7.50% | 67.00% | 15 | $0.16 | $3.22 |
| 1 | 8 | 200 | 212 | Two-Speed Cooling Tower, 300 Tons | 8.98 | 8.08 | 90.00% | 14.00% | 50.00% | 15 | $0.01 | $3.22 |
| 1 | 8 | 200 | 213 | VSD Cooling Tower, 300 Tons | 8.98 | 8.08 | 90.00% | 18.00% | 50.00% | 15 | $0.11 | $3.22 |
| 1 | 8 | 200 | 214 | Primary/Secondary De-coupled Chilled Water System | 8.98 | 8.08 | 80.00% | 12.00% | 50.00% | 15 | $0.68 | $3.22 |
| 1 | 8 | 200 | 215 | HE Chiller, 0.51 kW/ton, 300 Tons | 8.98 | 8.08 |  | 21.54% |  | 15 | $0.27 | $3.22 |
| 1 | 8 | 200 | 216 | VSD Chiller, 0.47 kW/ton, 300 Tons | 8.98 | 8.08 |  | 27.69% |  | 15 | $0.90 | $3.22 |
| 1 | 8 | 250 | 250 | Base DX Packaged System, EER=10.3, 10 tons | 15.55 | 15.55 | 100.00% | 0.00% | 100.00% | 15 | $3.55 | $3.55 |
| 1 | 8 | 250 | 251 | DX Tune-Up / Diagnostics | 15.55 | 15.55 | 90.00% | 10.00% | 100.00% | 3 | $0.35 | $3.55 |
| 1 | 8 | 250 | 252 | Hi-Eff DX Packaged System, 10 tons, EER=11.3 | 15.55 | 13.44 |  | 8.85% |  | 15 | $0.43 | $3.55 |
| 1 | 8 | 250 | 253 | High Efficiency Windows (Low-E Glass or Multiple Glazed) | 15.55 | 15.55 | 66.00% | 5.00% | 75.00% | 30 | $0.03 | $15.85 |
| 1 | 8 | 250 | 254 | Installation of Direct of Indirect Evaporative Cooling, Evaporative Pre-Cooling, and Absorption Cooling | 15.55 | 15.55 | 95.00% | 10.00% | 25.00% | 10 | $1.31 | $3.55 |
| 1 | 8 | 250 | 256 | Duct Insulation | 15.55 | 15.55 | 25.00% | 3.00% | 25.00% | 20 | $0.01 | $11.22 |
| 1 | 8 | 250 | 257 | Duct Repair and Sealing | 15.55 | 15.55 | 50.00% | 1.00% | 25.00% | 20 | $0.04 | $197.00 |
| 1 | 8 | 250 | 258 | Installation of Automated Building Ventilation Control ( Via Occupancy Sensors, CO2 Sensors, Etc.) | 15.55 | 15.55 | 100.00% | 10.00% | 50.00% | 10 | $0.44 | $3.55 |
| 1 | 8 | 250 | 259 | Roof / Ceiling Insulation | 15.55 | 15.55 | 20.00% | 3.00% | 50.00% | 20 | $0.43 | $687.78 |
| 1 | 8 | 250 | 260 | Cool Roofs (Reflective and Spray Evaporative) | 15.55 | 15.55 | 100.00% | 0.64% | 50.00% | 10 | $0.16 | $262.67 |
| 1 | 8 | 250 | 261 | Clock / Programmable Thermostat | 15.55 | 15.55 | 60.00% | 10.00% | 100.00% | 10 | $0.09 | $3.55 |
| 1 | 8 | 250 | 262 | Installation of Air Side Economizers | 15.55 | 15.55 | 40.00% | 15.00% | 100.00% | 10 | $0.59 | $788.00 |
| 1 | 8 | 280 | 280 | Base Air-Cooled HP Package, 5 tons, SEER=10 | 15.55 | 13.99 | 100.00% | 0.00% | 100.00% | 15 | $3.22 | $3.22 |
| 1 | 8 | 280 | 281 | Air-Cooled HP Package, 5 tons, SEER=11 | 15.55 | 13.99 |  | 9.09% |  | 15 | $0.16 | $3.22 |
| 1 | 8 | 280 | 282 | Air-Cooled HP Package, 5 tons, SEER=12 | 15.55 | 13.99 |  | 16.67% |  | 15 | $1.06 | $3.22 |
| 1 | 8 | 280 | 283 | DX Tune-Up / Diagnostics | 15.55 | 15.55 | 90.00% | 10.00% | 100.00% | 3 | $0.35 | $3.55 |
| 1 | 8 | 280 | 284 | High Efficiency Windows (Low-E Glass or Multiple Glazed) | 15.55 | 15.55 | 66.00% | 5.00% | 75.00% | 30 | $0.03 | $15.85 |
| 1 | 8 | 280 | 285 | Installation of Direct of Indirect Evaporative Cooling, Evaporative Pre-Cooling, and Absorption Cooling | 15.55 | 15.55 | 95.00% | 10.00% | 25.00% | 10 | $1.31 | $3.55 |
| 1 | 8 | 280 | 286 | Duct Insulation | 15.55 | 15.55 | 25.00% | 3.00% | 25.00% | 20 | $0.01 | $11.22 |
| 1 | 8 | 280 | 287 | Duct Repair and Sealing | 15.55 | 15.55 | 50.00% | 1.00% | 25.00% | 20 | $0.04 | $197.00 |
| 1 | 8 | 280 | 288 | Installation of Automated Building Ventilation Control ( Via Occupancy Sensors, CO2 Sensors, Etc.) | 15.55 | 15.55 | 100.00% | 10.00% | 50.00% | 10 | $0.44 | $3.55 |
| 1 | 8 | 280 | 289 | Roof / Ceiling Insulation | 15.55 | 15.55 | 20.00% | 3.00% | 50.00% | 20 | $0.43 | $687.78 |
| 1 | 8 | 280 | 290 | Cool Roofs (Reflective and Spray Evaporative) | 15.55 | 15.55 | 100.00% | 0.64% | 50.00% | 10 | $0.16 | $262.67 |
| 1 | 8 | 280 | 291 | Clock / Programmable Thermostat | 15.55 | 15.55 | 60.00% | 10.00% | 100.00% | 10 | $0.09 | $3.55 |

# Table B.3: Commercial Electric

| Segment | Building | Base Number | Measure Number | Measure Name | Stock Usage | Base Usage | Incomplete Factor | Energy Savings | Feasibility Factor | Measure Life | Full Per Unit Cost | Full Base Measure Cost |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 8 | 280 | 292 | Installation of Air Side Economizers | 15.55 | 15.55 | 40.00% | 15.00% | 100.00% | 10 | $0.59 | $788.00 |
| 1 | 8 | 400 | 400 | Base Fan Motor, 5hp, 1800rpm, 87.5% (ODP) | 2.67 | 2.67 | | 0.00% | | 15 | $0.13 | $0.13 |
| 1 | 8 | 400 | 401 | Energy Efficient Fan & Pump Motors (ODP) | 2.67 | 2.67 | | 1.50% | | 15 | $0.03 | $0.13 |
| 1 | 8 | 400 | 402 | VSD, ASD Fan & Pump Applications | 2.67 | 2.67 | | 30.00% | | 15 | $0.15 | $0.13 |
| 1 | 8 | 610 | 610 | Base Office Equipment | 0.52 | 0.52 | 100.00% | 0.00% | 100.00% | 4 | $0.89 | $2.62 |
| 1 | 8 | 610 | 611 | ENERGY STAR or Better Office Equipment: Computer | 0.52 | 0.52 | 65.00% | 17.36% | 100.00% | 4 | $0.11 | $2.62 |
| 1 | 8 | 610 | 621 | ENERGY STAR or Better Office Equipment: Monitors | 0.52 | 0.52 | 71.00% | 15.43% | 100.00% | 4 | $0.06 | $2.62 |
| 1 | 8 | 610 | 623 | Smart Networks | 0.52 | 0.52 | 40.00% | 6.43% | 90.00% | 4 | $0.00 | $2.62 |
| 1 | 8 | 610 | 631 | ENERGY STAR or Better Office Equipment: Copiers | 0.52 | 0.52 | 65.00% | 10.21% | 100.00% | 4 | $0.04 | $0.47 |
| 1 | 8 | 610 | 641 | ENERGY STAR or Better Office Equipment: Printers | 0.52 | 0.52 | 65.00% | 13.23% | 100.00% | 4 | $0.11 | $1.30 |
| 1 | 8 | 700 | 700 | Base Water Heating | 1.25 | 1.25 | 100.00% | 0.00% | 100.00% | 15 | $31.82 | $31.82 |
| 1 | 8 | 700 | 701 | Demand controlled circulating systems | 1.25 | 1.25 | 90.00% | 5.00% | 50.00% | 15 | $6.20 | $31.82 |
| 1 | 8 | 700 | 702 | Heat Pump Water Heater | 1.25 | 1.25 | 100.00% | 30.00% | 75.00% | 15 | $3.95 | $31.82 |
| 1 | 8 | 700 | 703 | High-Efficiency Water Heater (electric) | 1.25 | 1.25 | | 5.40% | | 15 | $1.15 | $31.82 |
| 1 | 8 | 700 | 704 | Hot Water (SHW) Pipe Insulation | 1.25 | 1.25 | 80.00% | 5.00% | 50.00% | 15 | $0.01 | $2.33 |
| 1 | 8 | 800 | 800 | Base Heating | 4.58 | 4.58 | 100.00% | 0.00% | 100.00% | 20 | $2.40 | $2.40 |
| 1 | 8 | 800 | 802 | Roof / Ceiling Insulation | 4.58 | 4.58 | 40.00% | 10.00% | 50.00% | 20 | $0.43 | $2.09 |
| 1 | 8 | 800 | 803 | Duct Insulation | 4.58 | 4.58 | 70.30% | 2.00% | 25.00% | 20 | $0.01 | $2.09 |
| 1 | 8 | 800 | 804 | Duct Repair and Sealing | 4.58 | 4.58 | 50.00% | 2.00% | 25.00% | 20 | $0.00 | $2.09 |
| 1 | 8 | 800 | 805 | Clock / Programmable Thermostat | 4.58 | 4.58 | 70.00% | 30.00% | 100.00% | 10 | $0.15 | $2.40 |
| 1 | 8 | 800 | 812 | Installation of Automated Building Ventilation Control ( Via Occupancy Sensors, CO2 Sensors, Etc.) | 4.58 | 4.58 | 100.00% | 5.00% | 50.00% | 15 | $0.28 | $2.40 |
| 1 | 9 | 100 | 100 | Base Cooking | 1.62 | 1.62 | | 0.00% | | 15 | $0.11 | $0.11 |
| 1 | 9 | 100 | 101 | High-Efficiency Convection Oven | 1.62 | 1.62 | | 20.00% | | 15 | $0.09 | $0.11 |
| 1 | 9 | 110 | 110 | Base Fluorescent Fixture, 4' 4L T12, 34W, 2EEMAG | 3.01 | 3.01 | 100.00% | 0.00% | 100.00% | 17 | $0.74 | $0.74 |
| 1 | 9 | 110 | 111 | 4' 4L T8 Premium, EB | 3.01 | 2.71 | 100.00% | 25.00% | 16.67% | 26 | $0.24 | $0.74 |
| 1 | 9 | 110 | 112 | 4' 2L T8 Premium, EB, reflector | 3.01 | 2.71 | 100.00% | 62.50% | 16.67% | 26 | $0.36 | $0.74 |
| 1 | 9 | 110 | 113 | Occupancy Sensor, 4-4' Fluorescent Fixtures | 3.01 | 2.71 | 89.63% | 30.00% | 20.00% | 15 | $0.26 | $0.74 |
| 1 | 9 | 110 | 114 | Continuous Dimming, 5-4' Fluorescent Fixtures | 3.01 | 2.71 | 100.00% | 75.00% | 30.00% | 19 | $1.92 | $0.74 |
| 1 | 9 | 110 | 115 | 4' 2L T5HO, EB | 3.01 | 2.71 | 100.00% | 18.75% | 16.67% | 26 | $0.14 | $0.74 |
| 1 | 9 | 110 | 116 | 4' 4L T8, EB | 3.01 | 2.71 | 100.00% | 22.22% | 16.67% | 26 | $0.10 | $0.74 |
| 1 | 9 | 110 | 117 | 4' 3L T8, EB | 3.01 | 2.71 | 100.00% | 38.20% | 16.67% | 26 | $0.05 | $0.74 |
| 1 | 9 | 110 | 118 | 4' 3L T8 Premium, EB | 3.01 | 2.71 | 100.00% | 42.36% | 16.67% | 26 | $0.15 | $0.74 |
| 1 | 9 | 120 | 120 | Base Fluorescent Fixture, 4' 2L T12, 34W, 1EEMAG | 3.01 | 3.01 | 100.00% | 0.00% | 100.00% | 17 | $1.37 | $1.37 |
| 1 | 9 | 120 | 121 | 4' 2L T8 Premium, EB | 3.01 | 2.71 | 100.00% | 25.00% | 33.33% | 26 | $0.38 | $1.37 |
| 1 | 9 | 120 | 122 | 4' 1L T8 Premium, EB, reflector | 3.01 | 2.71 | 100.00% | 61.11% | 33.33% | 26 | $0.78 | $1.37 |
| 1 | 9 | 120 | 123 | Occupancy Sensor, 8-4' Fluorescent Fixtures | 3.01 | 2.71 | 89.63% | 30.00% | 20.00% | 15 | $0.22 | $1.37 |
| 1 | 9 | 120 | 124 | Continuous Dimming, 10-4' Fluorescent Fixtures | 3.01 | 2.71 | 100.00% | 75.00% | 30.00% | 19 | $1.89 | $1.37 |
| 1 | 9 | 120 | 125 | 4' 1L T5HO, EB | 3.01 | 2.71 | 100.00% | 13.90% | 33.33% | 26 | $0.29 | $1.37 |
| 1 | 9 | 130 | 130 | Base Fluorescent Fixture, 8' 2L T12, 60W, 1EEMAG | 3.01 | 3.01 | 100.00% | 0.00% | 100.00% | 17 | $0.92 | $0.92 |
| 1 | 9 | 130 | 131 | 8' 2L T12, 60W, EB | 3.01 | 2.71 | 79.87% | 10.57% | 25.00% | 26 | $0.09 | $0.92 |
| 1 | 9 | 130 | 132 | 8' 1L T12, 60W, EB, reflector | 3.01 | 2.71 | 100.00% | 55.30% | 25.00% | 26 | $0.40 | $0.92 |
| 1 | 9 | 130 | 133 | Occupancy Sensor, 4-8' Fluorescent Fixtures | 3.01 | 2.71 | 89.63% | 30.00% | 20.00% | 15 | $0.28 | $0.92 |
| 1 | 9 | 130 | 134 | Continuous Dimming, 5-8' Fluorescent Fixtures | 3.01 | 2.71 | 100.00% | 75.00% | 30.00% | 19 | $2.07 | $0.92 |

## Table B.3: Commercial Electric

| Segment | Building | Base Number | Measure Number | Measure Name | Stock Usage | Base Usage | Incomplete Factor | Energy Savings | Feasibility Factor | Measure Life | Full Per Unit Cost | Full Base Measure Cost |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 9 | 130 | 135 | 8' 2L T8, EB | 3.01 | 2.71 | 100.00% | 52.80% | 50.00% | 26 | $0.18 | $0.92 |
| 1 | 9 | 140 | 140 | Base Incandescent Flood, 75W | 3.01 | 3.01 | 100.00% | 0.00% | 100.00% | 1 | $2.01 | $2.01 |
| 1 | 9 | 140 | 141 | CFL Screw-in, Modular 18W | 3.01 | 2.71 | 72.51% | 65.30% | 70.00% | 8 | $1.24 | $2.01 |
| 1 | 9 | 150 | 150 | Base Incandescent Flood, 150W PAR | 3.01 | 3.01 | 100.00% | 0.00% | 100.00% | 1 | $0.73 | $0.73 |
| 1 | 9 | 150 | 151 | Halogen PAR Flood, 90W | 3.01 | 3.01 | 98.98% | 40.00% | 10.00% | 1 | $0.07 | $0.73 |
| 1 | 9 | 150 | 152 | Metal Halide, 50W | 3.01 | 3.01 | 92.23% | 52.00% | 45.00% | 9 | $3.88 | $0.73 |
| 1 | 9 | 150 | 153 | HPS, 50W | 3.01 | 3.01 | 92.23% | 56.00% | 45.00% | 9 | $1.98 | $0.73 |
| 1 | 9 | 160 | 160 | Base 4' 3L T12, 34W, 1EEMAG | 3.01 | 3.01 | 100.00% | 0.00% | 100.00% | 10 | $0.22 | $0.22 |
| 1 | 9 | 160 | 161 | 4' 3L T8, EB | 3.01 | 2.71 | 100.00% | 22.61% | 75.00% | 26 | $0.02 | $0.22 |
| 1 | 9 | 160 | 162 | 4' 3L T8 Premium, EB | 3.01 | 2.71 | 100.00% | 22.61% | 75.00% | 26 | $0.05 | $0.22 |
| 1 | 9 | 160 | 163 | 4' 2L T8 Premium, EB, reflector | 3.01 | 2.71 | 100.00% | 53.04% | 40.00% | 26 | $0.11 | $0.22 |
| 1 | 9 | 160 | 164 | 4' 1L T5HO, EB | 3.01 | 2.71 | 100.00% | 46.09% | 75.00% | 26 | $0.02 | $0.22 |
| 1 | 9 | 180 | 180 | Base Fluorescent Fixture 4' 4L T8, 1EB | 2.41 | 2.41 | 100.00% | 0.00% | 100.00% | 26 | $0.83 | $0.83 |
| 1 | 9 | 180 | 181 | 4' 4L T8 Premium, EB | 2.41 | 2.17 | 100.00% | 3.60% | 100.00% | 26 | $0.15 | $0.83 |
| 1 | 9 | 180 | 182 | Occupancy Sensor, 4-4' Fluorescent Fixtures | 2.41 | 2.17 | 89.63% | 30.00% | 20.00% | 15 | $0.26 | $0.83 |
| 1 | 9 | 185 | 185 | Base Fluorescent Fixture 4' 3L T8, 1EB | 2.41 | 2.05 | 100.00% | 0.00% | 100.00% | 26 | $1.56 | $1.56 |
| 1 | 9 | 185 | 186 | 4' 3L T8 Premium, EB | 2.41 | 2.17 | 100.00% | 6.70% | 100.00% | 26 | $0.21 | $1.56 |
| 1 | 9 | 190 | 190 | Base Fluorescent Fixture 4' 2L T8, 1EB | 2.41 | 2.05 | 100.00% | 0.00% | 100.00% | 26 | $1.46 | $1.46 |
| 1 | 9 | 190 | 191 | 4' 2L T8 Premium, EB | 2.41 | 2.17 | 100.00% | 8.50% | 100.00% | 26 | $0.13 | $1.46 |
| 1 | 9 | 190 | 192 | Occupancy Sensor, 8-4' Fluorescent Fixtures | 2.41 | 2.17 | 89.63% | 30.00% | 20.00% | 15 | $0.22 | $1.46 |
| 1 | 9 | 200 | 200 | Base Centrifugal Chiller, 0.65 kW/ton, 300 tons | 1.50 | 1.50 | 100.00% | 0.00% | 100.00% | 20 | $2.19 | $2.19 |
| 1 | 9 | 200 | 201 | Chiller Tune-Up / Diagnostics | 1.50 | 1.50 | 90.00% | 5.00% | 100.00% | 5 | $0.18 | $2.19 |
| 1 | 9 | 200 | 202 | Installation of Automated Building Ventilation Control ( Via Occupancy Sensors, CO2 Sensors, Etc.) | 1.50 | 1.50 | 100.00% | 10.00% | 50.00% | 10 | $0.46 | $2.19 |
| 1 | 9 | 200 | 203 | Roof / Ceiling Insulation | 1.50 | 1.50 | 34.57% | 3.00% | 50.00% | 20 | $0.21 | $198.57 |
| 1 | 9 | 200 | 204 | Cool Roofs (Reflective and Spray Evaporative) | 1.50 | 1.50 | 100.00% | 0.39% | 90.00% | 10 | $0.04 | $38.42 |
| 1 | 9 | 200 | 205 | EMS Optimization | 1.50 | 1.50 | 75.00% | 1.00% | 100.00% | 5 | $0.00 | $0.00 |
| 1 | 9 | 200 | 206 | High Efficiency Windows (Low-E Glass or Multiple Glazed) | 1.50 | 1.50 | 92.94% | 7.03% | 75.00% | 30 | $0.06 | $43.56 |
| 1 | 9 | 200 | 207 | Installation of Energy Management Systems | 1.50 | 1.50 | 37.46% | 10.00% | 50.00% | 10 | $0.29 | $2.19 |
| 1 | 9 | 200 | 208 | Insulation of Pipes | 1.50 | 1.50 | 50.00% | 1.00% | 50.00% | 20 | $0.03 | $3.98 |
| 1 | 9 | 200 | 209 | Installation of Chiller Economizers (water side) | 1.50 | 1.50 | 40.07% | 10.00% | 50.00% | 20 | $0.59 | $461.00 |
| 1 | 9 | 200 | 210 | Optimize Chilled Water and Condenser Water Settings | 1.50 | 1.50 | 50.00% | 5.00% | 33.00% | 10 | $0.31 | $2.19 |
| 1 | 9 | 200 | 211 | Decrease Cooling Tower Approach Temperature, 300 Tons, 6 Deg F | 1.50 | 1.35 | 100.00% | 7.50% | 67.00% | 15 | $0.17 | $3.40 |
| 1 | 9 | 200 | 212 | Two-Speed Cooling Tower, 300 Tons | 1.50 | 1.35 | 90.00% | 14.00% | 50.00% | 15 | $0.01 | $3.40 |
| 1 | 9 | 200 | 213 | VSD Cooling Tower, 300 Tons | 1.50 | 1.35 | 90.00% | 18.00% | 50.00% | 15 | $0.11 | $3.40 |
| 1 | 9 | 200 | 214 | Primary/Secondary De-coupled Chilled Water System | 1.50 | 1.35 | 80.00% | 12.00% | 50.00% | 15 | $0.71 | $3.40 |
| 1 | 9 | 200 | 215 | HE Chiller, 0.51 kW/ton, 300 Tons | 1.50 | 1.35 |  | 21.54% |  | 15 | $0.29 | $3.40 |
| 1 | 9 | 200 | 216 | VSD Chiller, 0.47 kW/ton, 300 Tons | 1.50 | 1.35 |  | 27.69% |  | 15 | $0.95 | $3.40 |
| 1 | 9 | 250 | 250 | Base DX Packaged System, EER=10.3, 10 tons | 2.60 | 2.60 | 100.00% | 0.00% | 100.00% | 15 | $3.74 | $3.74 |
| 1 | 9 | 250 | 251 | DX Tune-Up / Diagnostics | 2.60 | 2.60 | 90.00% | 10.00% | 100.00% | 3 | $0.37 | $3.74 |
| 1 | 9 | 250 | 252 | Hi-Eff DX Packaged System, 10 tons, EER=11.3 | 2.60 | 2.24 |  | 8.85% |  | 15 | $0.45 | $3.74 |
| 1 | 9 | 250 | 253 | High Efficiency Windows (Low-E Glass or Multiple Glazed) | 2.60 | 2.60 | 92.94% | 5.00% | 75.00% | 30 | $0.16 | $74.47 |

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## Table B.3: Commercial Electric

| Segment | Building | Base Number | Measure Number | Measure Name | Stock Usage | Base Usage | Incomplete Factor | Energy Savings | Feasibility Factor | Measure Life | Full Per Unit Cost | Full Base Measure Cost |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 9 | 250 | 254 | Installation of Direct of Indirect Evaporative Cooling, Evaporative Pre-Cooling, and Absorption Cooling | 2.60 | 2.60 | 95.00% | 10.00% | 25.00% | 10 | $1.38 | $3.74 |
| 1 | 9 | 250 | 255 | Occupancy Sensor for room HVAC units | 2.60 | 2.60 | 100.00% | 35.00% | 51.00% | 15 | $0.30 | $2.40 |
| 1 | 9 | 250 | 256 | Duct Insulation | 2.60 | 2.60 | 25.00% | 3.00% | 25.00% | 20 | $0.01 | $24.79 |
| 1 | 9 | 250 | 257 | Duct Repair and Sealing | 2.60 | 2.60 | 50.00% | 1.00% | 25.00% | 20 | $0.04 | $197.00 |
| 1 | 9 | 250 | 258 | Installation of Automated Building Ventilation Control ( Via Occupancy Sensors, CO2 Sensors, Etc.) | 2.60 | 2.60 | 100.00% | 10.00% | 50.00% | 10 | $0.46 | $3.74 |
| 1 | 9 | 250 | 259 | Roof / Ceiling Insulation | 2.60 | 2.60 | 34.57% | 3.00% | 50.00% | 20 | $0.21 | $339.41 |
| 1 | 9 | 250 | 260 | Cool Roofs (Reflective and Spray Evaporative) | 2.60 | 2.60 | 100.00% | 0.39% | 50.00% | 10 | $0.04 | $65.67 |
| 1 | 9 | 250 | 261 | Clock / Programmable Thermostat | 2.60 | 2.60 | 80.00% | 10.00% | 100.00% | 10 | $0.10 | $3.74 |
| 1 | 9 | 250 | 262 | Installation of Air Side Economizers | 2.60 | 2.60 | 40.00% | 15.00% | 100.00% | 10 | $0.59 | $788.00 |
| 1 | 9 | 280 | 280 | Base Air-Cooled HP Package, 5 tons, SEER=10 | 2.60 | 2.34 | 100.00% | 0.00% | 100.00% | 15 | $3.40 | $3.40 |
| 1 | 9 | 280 | 281 | Air-Cooled HP Package, 5 tons, SEER=11 | 2.60 | 2.34 |  | 9.09% |  | 15 | $0.17 | $3.40 |
| 1 | 9 | 280 | 282 | Air-Cooled HP Package, 5 tons, SEER=12 | 2.60 | 2.34 |  | 16.67% |  | 15 | $1.12 | $3.40 |
| 1 | 9 | 280 | 283 | DX Tune-Up / Diagnostics | 2.60 | 2.60 | 90.00% | 10.00% | 100.00% | 3 | $0.37 | $3.74 |
| 1 | 9 | 280 | 284 | High Efficiency Windows (Low-E Glass or Multiple Glazed) | 2.60 | 2.60 | 92.94% | 5.00% | 75.00% | 30 | $0.16 | $74.47 |
| 1 | 9 | 280 | 285 | Installation of Direct of Indirect Evaporative Cooling, Evaporative Pre-Cooling, and Absorption Cooling | 2.60 | 2.60 | 95.00% | 10.00% | 25.00% | 10 | $1.38 | $3.74 |
| 1 | 9 | 280 | 286 | Duct Insulation | 2.60 | 2.60 | 25.00% | 3.00% | 25.00% | 20 | $0.01 | $24.79 |
| 1 | 9 | 280 | 287 | Duct Repair and Sealing | 2.60 | 2.60 | 50.00% | 1.00% | 25.00% | 20 | $0.04 | $197.00 |
| 1 | 9 | 280 | 288 | Installation of Automated Building Ventilation Control ( Via Occupancy Sensors, CO2 Sensors, Etc.) | 2.60 | 2.60 | 100.00% | 10.00% | 50.00% | 10 | $0.46 | $3.74 |
| 1 | 9 | 280 | 289 | Roof / Ceiling Insulation | 2.60 | 2.60 | 34.57% | 3.00% | 50.00% | 20 | $0.21 | $339.41 |
| 1 | 9 | 280 | 290 | Cool Roofs (Reflective and Spray Evaporative) | 2.60 | 2.60 | 100.00% | 0.39% | 50.00% | 10 | $0.04 | $65.67 |
| 1 | 9 | 280 | 291 | Clock / Programmable Thermostat | 2.60 | 2.60 | 80.00% | 10.00% | 100.00% | 10 | $0.10 | $3.74 |
| 1 | 9 | 280 | 292 | Installation of Air Side Economizers | 2.60 | 2.60 | 40.00% | 15.00% | 100.00% | 10 | $0.59 | $788.00 |
| 1 | 9 | 400 | 400 | Base Fan Motor, 5hp, 1800rpm, 87.5% (ODP) | 0.60 | 0.60 |  | 0.00% |  | 15 | $0.09 | $0.09 |
| 1 | 9 | 400 | 401 | Energy Efficient Fan & Pump Motors (ODP) | 0.60 | 0.60 |  | 1.50% |  | 15 | $0.02 | $0.09 |
| 1 | 9 | 400 | 402 | VSD, ASD Fan & Pump Applications | 0.60 | 0.60 |  | 30.00% |  | 15 | $0.10 | $0.09 |
| 1 | 9 | 610 | 610 | Base Office Equipment | 0.10 | 0.10 | 100.00% | 0.00% | 100.00% | 4 | $0.08 | $0.23 |
| 1 | 9 | 610 | 611 | ENERGY STAR or Better Office Equipment: Computer | 0.10 | 0.10 | 65.00% | 12.24% | 100.00% | 4 | $0.01 | $0.23 |
| 1 | 9 | 610 | 621 | ENERGY STAR or Better Office Equipment: Monitors | 0.10 | 0.10 | 71.00% | 10.87% | 100.00% | 4 | $0.00 | $0.23 |
| 1 | 9 | 610 | 623 | Smart Networks | 0.10 | 0.10 | 40.00% | 4.53% | 90.00% | 4 | $0.00 | $0.23 |
| 1 | 9 | 610 | 631 | ENERGY STAR or Better Office Equipment: Copiers | 0.10 | 0.10 | 65.00% | 20.18% | 100.00% | 4 | $0.00 | $0.03 |
| 1 | 9 | 610 | 641 | ENERGY STAR or Better Office Equipment: Printers | 0.10 | 0.10 | 65.00% | 7.56% | 100.00% | 4 | $0.01 | $0.12 |
| 1 | 9 | 700 | 700 | Base Water Heating | 1.74 | 1.74 | 100.00% | 0.00% | 100.00% | 15 | $27.95 | $27.95 |
| 1 | 9 | 700 | 701 | Demand controlled circulating systems | 1.74 | 1.74 | 100.00% | 5.00% | 50.00% | 15 | $5.45 | $27.95 |
| 1 | 9 | 700 | 702 | Heat Pump Water Heater | 1.74 | 1.74 | 100.00% | 30.00% | 75.00% | 15 | $3.47 | $27.95 |
| 1 | 9 | 700 | 703 | High-Efficiency Water Heater (electric) | 1.74 | 1.74 |  | 5.40% |  | 15 | $1.01 | $27.95 |
| 1 | 9 | 700 | 704 | Hot Water (SHW) Pipe Insulation | 1.74 | 1.74 | 100.00% | 5.00% | 50.00% | 15 | $0.03 | $8.64 |
| 1 | 9 | 800 | 800 | Base Heating | 4.84 | 4.84 | 100.00% | 0.00% | 100.00% | 20 | $2.40 | $2.40 |
| 1 | 9 | 800 | 801 | Occupancy Sensor for room HVAC units | 4.84 | 4.84 | 100.00% | 35.00% | 51.00% | 15 | $0.20 | $2.40 |
| 1 | 9 | 800 | 802 | Roof / Ceiling Insulation | 4.84 | 4.84 | 62.26% | 10.00% | 50.00% | 20 | $0.21 | $1.03 |
| 1 | 9 | 800 | 803 | Duct Insulation | 4.84 | 4.84 | 79.10% | 2.00% | 25.00% | 20 | $0.01 | $1.03 |

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## Table B.3: Commercial Electric

| Segment | Building | Base Number | Measure Number | Measure Name | Stock Usage | Base Usage | Incomplete Factor | Energy Savings | Feasibility Factor | Measure Life | Full Per Unit Cost | Full Base Measure Cost |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 9 | 800 | 804 | Duct Repair and Sealing | 4.84 | 4.84 | 50.00% | 2.00% | 25.00% | 20 | $0.01 | $1.03 |
| 1 | 9 | 800 | 805 | Clock / Programmable Thermostat | 4.84 | 4.84 | 59.44% | 30.00% | 100.00% | 10 | $0.15 | $2.40 |
| 1 | 9 | 800 | 812 | Installation of Automated Building Ventilation Control ( Via Occupancy Sensors, CO2 Sensors, Etc.) | 4.84 | 4.84 | 100.00% | 5.00% | 50.00% | 15 | $0.28 | $2.40 |
| 1 | 10 | 110 | 110 | Base Fluorescent Fixture, 4' 4L T12, 34W, 2EEMAG | 2.12 | 2.12 | 100.00% | 0.00% | 100.00% | 23 | $1.42 | $1.42 |
| 1 | 10 | 110 | 111 | 4' 4L T8 Premium, EB | 2.12 | 1.91 | 100.00% | 25.00% | 16.67% | 36 | $0.46 | $1.42 |
| 1 | 10 | 110 | 112 | 4' 2L T8 Premium, EB, reflector | 2.12 | 1.91 | 100.00% | 62.50% | 16.67% | 36 | $0.70 | $1.42 |
| 1 | 10 | 110 | 113 | Occupancy Sensor, 4-4' Fluorescent Fixtures | 2.12 | 1.91 | 95.02% | 30.00% | 20.00% | 21 | $0.49 | $1.42 |
| 1 | 10 | 110 | 114 | Continuous Dimming, 5-4' Fluorescent Fixtures | 2.12 | 1.91 | 100.00% | 75.00% | 30.00% | 26 | $3.69 | $1.42 |
| 1 | 10 | 110 | 115 | 4' 2L T5HO, EB | 2.12 | 1.91 | 100.00% | 18.75% | 16.67% | 36 | $0.27 | $1.42 |
| 1 | 10 | 110 | 116 | 4' 4L T8, EB | 2.12 | 1.91 | 100.00% | 22.22% | 16.67% | 36 | $0.19 | $1.42 |
| 1 | 10 | 110 | 117 | 4' 3L T8, EB | 2.12 | 1.91 | 100.00% | 38.20% | 16.67% | 36 | $0.09 | $1.42 |
| 1 | 10 | 110 | 118 | 4' 3L T8 Premium, EB | 2.12 | 1.91 | 100.00% | 42.36% | 16.67% | 36 | $0.30 | $1.42 |
| 1 | 10 | 120 | 120 | Base Fluorescent Fixture, 4' 2L T12, 34W, 1EEMAG | 2.12 | 2.12 | 100.00% | 0.00% | 100.00% | 23 | $2.63 | $2.63 |
| 1 | 10 | 120 | 121 | 4' 2L T8 Premium, EB | 2.12 | 1.91 | 100.00% | 25.00% | 33.33% | 36 | $0.73 | $2.63 |
| 1 | 10 | 120 | 122 | 4' 1L T8 Premium, EB, reflector | 2.12 | 1.91 | 100.00% | 61.11% | 33.33% | 36 | $1.49 | $2.63 |
| 1 | 10 | 120 | 123 | Occupancy Sensor, 8-4' Fluorescent Fixtures | 2.12 | 1.91 | 95.02% | 30.00% | 20.00% | 21 | $0.43 | $2.63 |
| 1 | 10 | 120 | 124 | Continuous Dimming, 10-4' Fluorescent Fixtures | 2.12 | 1.91 | 100.00% | 75.00% | 30.00% | 26 | $3.62 | $2.63 |
| 1 | 10 | 120 | 125 | 4' 1L T5HO, EB | 2.12 | 1.91 | 100.00% | 13.90% | 33.33% | 36 | $0.56 | $2.63 |
| 1 | 10 | 130 | 130 | Base Fluorescent Fixture, 8' 2L T12, 60W, 1EEMAG | 2.12 | 2.12 | 100.00% | 0.00% | 100.00% | 23 | $1.79 | $1.79 |
| 1 | 10 | 130 | 131 | 8' 2L T12, 60W, EB | 2.12 | 1.91 | 46.17% | 10.57% | 25.00% | 36 | $0.17 | $1.79 |
| 1 | 10 | 130 | 132 | 8' 1L T12, 60W, EB, reflector | 2.12 | 1.91 | 100.00% | 55.30% | 25.00% | 36 | $0.77 | $1.79 |
| 1 | 10 | 130 | 133 | Occupancy Sensor, 4-8' Fluorescent Fixtures | 2.12 | 1.91 | 95.02% | 30.00% | 20.00% | 21 | $0.53 | $1.79 |
| 1 | 10 | 130 | 134 | Continuous Dimming, 5-8' Fluorescent Fixtures | 2.12 | 1.91 | 100.00% | 75.00% | 30.00% | 26 | $4.03 | $1.79 |
| 1 | 10 | 130 | 135 | 8' 2L T8, EB | 2.12 | 1.91 | 100.00% | 52.80% | 50.00% | 36 | $0.35 | $1.79 |
| 1 | 10 | 140 | 140 | Base Incandescent Flood, 75W | 2.12 | 2.12 | 100.00% | 0.00% | 100.00% | 1 | $3.96 | $3.96 |
| 1 | 10 | 140 | 141 | CFL Screw-in, Modular 18W | 2.12 | 1.91 | 95.29% | 65.30% | 90.00% | 10 | $2.44 | $3.96 |
| 1 | 10 | 150 | 150 | Base Incandescent Flood, 150W PAR | 2.12 | 2.12 | 100.00% | 0.00% | 100.00% | 1 | $1.92 | $1.92 |
| 1 | 10 | 150 | 151 | Halogen PAR Flood, 90W | 2.12 | 2.12 | 98.69% | 40.00% | 10.00% | 1 | $0.19 | $1.92 |
| 1 | 10 | 150 | 152 | Metal Halide, 50W | 2.12 | 2.12 | 97.99% | 52.00% | 45.00% | 12 | $10.29 | $1.92 |
| 1 | 10 | 150 | 153 | HPS, 50W | 2.12 | 2.12 | 97.99% | 56.00% | 45.00% | 12 | $5.25 | $1.92 |
| 1 | 10 | 160 | 160 | Base 4' 3L T12, 34W, 1EEMAG | 2.12 | 2.12 | 100.00% | 0.00% | 100.00% | 10 | $0.36 | $0.36 |
| 1 | 10 | 160 | 161 | 4' 3L T8, EB | 2.12 | 1.91 | 100.00% | 22.61% | 75.00% | 36 | $0.03 | $0.36 |
| 1 | 10 | 160 | 162 | 4' 3L T8 Premium, EB | 2.12 | 1.91 | 100.00% | 22.61% | 75.00% | 36 | $0.08 | $0.36 |
| 1 | 10 | 160 | 163 | 4' 2L T8 Premium, EB, reflector | 2.12 | 1.91 | 100.00% | 53.04% | 40.00% | 36 | $0.19 | $0.36 |
| 1 | 10 | 160 | 164 | 4' 1L T5HO, EB | 2.12 | 1.91 | 100.00% | 46.09% | 75.00% | 36 | $0.03 | $0.36 |
| 1 | 10 | 180 | 180 | Base Fluorescent Fixture 4' 4L T8, 1EB | 1.70 | 1.70 | 100.00% | 0.00% | 100.00% | 36 | $1.59 | $1.59 |
| 1 | 10 | 180 | 181 | 4' 4L T8 Premium, EB | 1.70 | 1.53 | 100.00% | 3.60% | 100.00% | 36 | $0.28 | $1.59 |
| 1 | 10 | 180 | 182 | Occupancy Sensor, 4-4' Fluorescent Fixtures | 1.70 | 1.53 | 95.02% | 30.00% | 20.00% | 21 | $0.49 | $1.59 |
| 1 | 10 | 185 | 185 | Base Fluorescent Fixture 4' 3L T8, 1EB | 1.70 | 1.44 | 100.00% | 0.00% | 100.00% | 36 | $2.99 | $2.99 |
| 1 | 10 | 185 | 186 | 4' 3L T8 Premium, EB | 1.70 | 1.53 | 100.00% | 6.70% | 100.00% | 36 | $0.41 | $2.99 |
| 1 | 10 | 190 | 190 | Base Fluorescent Fixture 4' 2L T8, 1EB | 1.70 | 1.44 | 100.00% | 0.00% | 100.00% | 36 | $2.81 | $2.81 |
| 1 | 10 | 190 | 191 | 4' 2L T8 Premium, EB | 1.70 | 1.53 | 100.00% | 8.50% | 100.00% | 36 | $0.25 | $2.81 |
| 1 | 10 | 190 | 192 | Occupancy Sensor, 8-4' Fluorescent Fixtures | 1.70 | 1.53 | 95.02% | 30.00% | 20.00% | 21 | $0.43 | $2.81 |

# Table B.3: Commercial Electric

| Segment | Building | Base Number | Measure Number | Measure Name | Stock Usage | Base Usage | Incomplete Factor | Energy Savings | Feasibility Factor | Measure Life | Full Per Unit Cost | Full Base Measure Cost |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 10 | 200 | 200 | Base Centrifugal Chiller, 0.65 kW/ton, 300 tons | 2.54 | 2.54 | 100.00% | 0.00% | 100.00% | 20 | $0.92 | $0.92 |
| 1 | 10 | 200 | 201 | Chiller Tune-Up / Diagnostics | 2.54 | 2.54 | 90.00% | 5.00% | 100.00% | 5 | $0.08 | $0.92 |
| 1 | 10 | 200 | 202 | Installation of Automated Building Ventilation Control ( Via Occupancy Sensors, CO2 Sensors, Etc.) | 2.54 | 2.54 | 100.00% | 10.00% | 50.00% | 10 | $0.19 | $0.92 |
| 1 | 10 | 200 | 203 | Roof / Ceiling Insulation | 2.54 | 2.54 | 40.19% | 3.00% | 50.00% | 20 | $0.44 | $414.96 |
| 1 | 10 | 200 | 204 | Cool Roofs (Reflective and Spray Evaporative) | 2.54 | 2.54 | 100.00% | 12.96% | 90.00% | 10 | $0.47 | $461.00 |
| 1 | 10 | 200 | 205 | EMS Optimization | 2.54 | 2.54 | 75.00% | 1.00% | 100.00% | 5 | $0.00 | $0.00 |
| 1 | 10 | 200 | 206 | High Efficiency Windows (Low-E Glass or Multiple Glazed) | 2.54 | 2.54 | 76.27% | 2.47% | 75.00% | 30 | $0.02 | $13.11 |
| 1 | 10 | 200 | 207 | Installation of Energy Management Systems | 2.54 | 2.54 | 100.00% | 10.00% | 50.00% | 10 | $0.12 | $0.92 |
| 1 | 10 | 200 | 208 | Insulation of Pipes | 2.54 | 2.54 | 50.00% | 1.00% | 50.00% | 20 | $0.01 | $1.08 |
| 1 | 10 | 200 | 209 | Installation of Chiller Economizers (water side) | 2.54 | 2.54 | 76.27% | 10.00% | 50.00% | 20 | $0.59 | $461.00 |
| 1 | 10 | 200 | 210 | Optimize Chilled Water and Condenser Water Settings | 2.54 | 2.54 | 50.00% | 5.00% | 33.00% | 10 | $0.13 | $0.92 |
| 1 | 10 | 200 | 211 | Decrease Cooling Tower Approach Temperature, 300 Tons, 6 Deg F | 2.54 | 2.29 | 100.00% | 7.50% | 67.00% | 15 | $0.07 | $1.43 |
| 1 | 10 | 200 | 212 | Two-Speed Cooling Tower, 300 Tons | 2.54 | 2.29 | 90.00% | 14.00% | 50.00% | 15 | $0.01 | $1.43 |
| 1 | 10 | 200 | 213 | VSD Cooling Tower, 300 Tons | 2.54 | 2.29 | 90.00% | 18.00% | 50.00% | 15 | $0.05 | $1.43 |
| 1 | 10 | 200 | 214 | Primary/Secondary De-coupled Chilled Water System | 2.54 | 2.29 | 80.00% | 12.00% | 50.00% | 15 | $0.30 | $1.43 |
| 1 | 10 | 200 | 215 | HE Chiller, 0.51 kW/ton, 300 Tons | 2.54 | 2.29 | | 21.54% | | 15 | $0.12 | $1.43 |
| 1 | 10 | 200 | 216 | VSD Chiller, 0.47 kW/ton, 300 Tons | 2.54 | 2.29 | | 27.69% | | 15 | $0.40 | $1.43 |
| 1 | 10 | 250 | 250 | Base DX Packaged System, EER=10.3, 10 tons | 4.40 | 4.40 | 100.00% | 0.00% | 100.00% | 15 | $1.58 | $1.58 |
| 1 | 10 | 250 | 251 | DX Tune-Up / Diagnostics | 4.40 | 4.40 | 90.00% | 10.00% | 100.00% | 3 | $0.16 | $1.58 |
| 1 | 10 | 250 | 252 | Hi-Eff DX Packaged System, 10 tons, EER=11.3 | 4.40 | 3.81 | | 8.85% | | 15 | $0.19 | $1.58 |
| 1 | 10 | 250 | 253 | High Efficiency Windows (Low-E Glass or Multiple Glazed) | 4.40 | 4.40 | 76.27% | 5.00% | 75.00% | 30 | $0.05 | $22.41 |
| 1 | 10 | 250 | 254 | Installation of Direct of Indirect Evaporative Cooling, Evaporative Pre-Cooling, and Absorption Cooling | 4.40 | 4.40 | 95.00% | 10.00% | 25.00% | 10 | $0.58 | $1.58 |
| 1 | 10 | 250 | 256 | Duct Insulation | 4.40 | 4.40 | 25.00% | 3.00% | 25.00% | 20 | $0.01 | $24.64 |
| 1 | 10 | 250 | 257 | Duct Repair and Sealing | 4.40 | 4.40 | 50.00% | 1.00% | 25.00% | 20 | $0.04 | $197.00 |
| 1 | 10 | 250 | 258 | Installation of Automated Building Ventilation Control ( Via Occupancy Sensors, CO2 Sensors, Etc.) | 4.40 | 4.40 | 100.00% | 10.00% | 50.00% | 10 | $0.19 | $1.58 |
| 1 | 10 | 250 | 259 | Roof / Ceiling Insulation | 4.40 | 4.40 | 40.19% | 3.00% | 50.00% | 20 | $0.44 | $709.31 |
| 1 | 10 | 250 | 260 | Cool Roofs (Reflective and Spray Evaporative) | 4.40 | 4.40 | 100.00% | 12.96% | 50.00% | 10 | $0.47 | $788.00 |
| 1 | 10 | 250 | 261 | Clock / Programmable Thermostat | 4.40 | 4.40 | 35.94% | 10.00% | 100.00% | 10 | $0.04 | $1.58 |
| 1 | 10 | 250 | 262 | Installation of Air Side Economizers | 4.40 | 4.40 | 79.66% | 15.00% | 100.00% | 10 | $0.59 | $788.00 |
| 1 | 10 | 280 | 280 | Base Air-Cooled HP Package, 5 tons, SEER=10 | 4.40 | 3.96 | 100.00% | 0.00% | 100.00% | 15 | $1.43 | $1.43 |
| 1 | 10 | 280 | 281 | Air-Cooled HP Package, 5 tons, SEER=11 | 4.40 | 3.96 | | 9.09% | | 15 | $0.07 | $1.43 |
| 1 | 10 | 280 | 282 | Air-Cooled HP Package, 5 tons, SEER=12 | 4.40 | 3.96 | | 16.67% | | 15 | $0.47 | $1.43 |
| 1 | 10 | 280 | 283 | DX Tune-Up / Diagnostics | 4.40 | 4.40 | 90.00% | 10.00% | 100.00% | 3 | $0.16 | $1.58 |
| 1 | 10 | 280 | 284 | High Efficiency Windows (Low-E Glass or Multiple Glazed) | 4.40 | 4.40 | 76.27% | 5.00% | 75.00% | 30 | $0.05 | $22.41 |
| 1 | 10 | 280 | 285 | Installation of Direct of Indirect Evaporative Cooling, Evaporative Pre-Cooling, and Absorption Cooling | 4.40 | 4.40 | 95.00% | 10.00% | 25.00% | 10 | $0.58 | $1.58 |
| 1 | 10 | 280 | 286 | Duct Insulation | 4.40 | 4.40 | 25.00% | 3.00% | 25.00% | 20 | $0.01 | $24.64 |
| 1 | 10 | 280 | 287 | Duct Repair and Sealing | 4.40 | 4.40 | 50.00% | 1.00% | 25.00% | 20 | $0.04 | $197.00 |
| 1 | 10 | 280 | 288 | Installation of Automated Building Ventilation Control ( Via Occupancy Sensors, CO2 Sensors, Etc.) | 4.40 | 4.40 | 100.00% | 10.00% | 50.00% | 10 | $0.19 | $1.58 |
| 1 | 10 | 280 | 289 | Roof / Ceiling Insulation | 4.40 | 4.40 | 40.19% | 3.00% | 50.00% | 20 | $0.44 | $709.31 |

## Table B.3: Commercial Electric

| Segment | Building | Base Number | Measure Number | Measure Name | Stock Usage | Base Usage | Incomplete Factor | Energy Savings | Feasibility Factor | Measure Life | Full Per Unit Cost | Full Base Measure Cost |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 10 | 280 | 290 | Cool Roofs (Reflective and Spray Evaporative) | 4.40 | 4.40 | 100.00% | 12.96% | 50.00% | 10 | $0.47 | $788.00 |
| 1 | 10 | 280 | 291 | Clock / Programmable Thermostat | 4.40 | 4.40 | 35.94% | 10.00% | 100.00% | 10 | $0.04 | $1.58 |
| 1 | 10 | 280 | 292 | Installation of Air Side Economizers | 4.40 | 4.40 | 79.66% | 15.00% | 100.00% | 10 | $0.59 | $788.00 |
| 1 | 10 | 400 | 400 | Base Fan Motor, 5hp, 1800rpm, 87.5% (ODP) | 1.89 | 1.89 |  | 0.00% |  | 15 | $0.28 | $0.28 |
| 1 | 10 | 400 | 401 | Energy Efficient Fan & Pump Motors (ODP) | 1.89 | 1.89 |  | 1.50% |  | 15 | $0.06 | $0.28 |
| 1 | 10 | 400 | 402 | VSD, ASD Fan & Pump Applications | 1.89 | 1.89 |  | 30.00% |  | 15 | $0.33 | $0.28 |
| 1 | 10 | 610 | 610 | Base Office Equipment | 0.09 | 0.09 | 100.00% | 0.00% | 100.00% | 4 | $1.16 | $3.42 |
| 1 | 10 | 610 | 611 | ENERGY STAR or Better Office Equipment: Computer | 0.09 | 0.09 | 65.00% | 18.60% | 100.00% | 4 | $0.15 | $3.42 |
| 1 | 10 | 610 | 621 | ENERGY STAR or Better Office Equipment: Monitors | 0.09 | 0.09 | 71.00% | 16.52% | 100.00% | 4 | $0.07 | $3.42 |
| 1 | 10 | 610 | 623 | Smart Networks | 0.09 | 0.09 | 40.00% | 6.88% | 90.00% | 4 | $0.01 | $3.42 |
| 1 | 10 | 610 | 631 | ENERGY STAR or Better Office Equipment: Copiers | 0.09 | 0.09 | 65.00% | 11.44% | 100.00% | 4 | $0.04 | $0.50 |
| 1 | 10 | 610 | 641 | ENERGY STAR or Better Office Equipment: Printers | 0.09 | 0.09 | 65.00% | 9.16% | 100.00% | 4 | $0.11 | $1.24 |
| 1 | 10 | 700 | 700 | Base Water Heating | 2.25 | 2.25 | 100.00% | 0.00% | 100.00% | 15 | $27.30 | $27.30 |
| 1 | 10 | 700 | 701 | Demand controlled circulating systems | 2.25 | 2.25 | 100.00% | 5.00% | 50.00% | 15 | $5.32 | $27.30 |
| 1 | 10 | 700 | 702 | Heat Pump Water Heater | 2.25 | 2.25 | 100.00% | 30.00% | 75.00% | 15 | $3.39 | $27.30 |
| 1 | 10 | 700 | 703 | High-Efficiency Water Heater (electric) | 2.25 | 2.25 |  | 5.40% |  | 15 | $0.98 | $27.30 |
| 1 | 10 | 700 | 704 | Hot Water (SHW) Pipe Insulation | 2.25 | 2.25 | 100.00% | 5.00% | 50.00% | 15 | $0.01 | $2.34 |
| 1 | 10 | 800 | 800 | Base Heating | 4.58 | 4.58 | 100.00% | 0.00% | 100.00% | 20 | $2.40 | $2.40 |
| 1 | 10 | 800 | 802 | Roof / Ceiling Insulation | 4.58 | 4.58 | 13.38% | 10.00% | 50.00% | 20 | $0.44 | $2.16 |
| 1 | 10 | 800 | 803 | Duct Insulation | 4.58 | 4.58 | 83.40% | 2.00% | 25.00% | 20 | $0.01 | $2.16 |
| 1 | 10 | 800 | 804 | Duct Repair and Sealing | 4.58 | 4.58 | 50.00% | 2.00% | 25.00% | 20 | $0.00 | $2.16 |
| 1 | 10 | 800 | 805 | Clock / Programmable Thermostat | 4.58 | 4.58 | 41.75% | 30.00% | 100.00% | 10 | $0.15 | $2.40 |
| 1 | 10 | 800 | 812 | Installation of Automated Building Ventilation Control ( Via Occupancy Sensors, CO2 Sensors, Etc.) | 4.58 | 4.58 | 100.00% | 5.00% | 50.00% | 15 | $0.28 | $2.40 |
| 2 | 1 | 110 | 110 | Base Fluorescent Fixture, 4' 4L T12, 34W, 2EEMAG | 5.29 | 5.29 | 100.00% | 0.00% | 100.00% | 10 | $1.51 | $1.51 |
| 2 | 1 | 110 | 111 | 4' 4L T8 Premium, EB | 5.29 | 4.77 | 100.00% | 25.00% | 16.67% | 16 | $0.50 | $1.51 |
| 2 | 1 | 110 | 112 | 4' 2L T8 Premium, EB, reflector | 5.29 | 4.77 | 100.00% | 62.50% | 16.67% | 16 | $0.74 | $1.51 |
| 2 | 1 | 110 | 113 | Occupancy Sensor, 4-4' Fluorescent Fixtures | 5.29 | 4.77 | 79.56% | 30.00% | 40.00% | 9 | $0.52 | $1.51 |
| 2 | 1 | 110 | 114 | Continuous Dimming, 5-4' Fluorescent Fixtures | 5.29 | 4.77 | 100.00% | 75.00% | 40.00% | 11 | $3.93 | $1.51 |
| 2 | 1 | 110 | 115 | 4' 2L T5HO, EB | 5.29 | 4.77 | 100.00% | 18.75% | 16.67% | 16 | $0.29 | $1.51 |
| 2 | 1 | 110 | 116 | 4' 4L T8, EB | 5.29 | 4.77 | 100.00% | 22.22% | 16.67% | 16 | $0.21 | $1.51 |
| 2 | 1 | 110 | 117 | 4' 3L T8, EB | 5.29 | 4.77 | 100.00% | 38.20% | 16.67% | 16 | $0.10 | $1.51 |
| 2 | 1 | 110 | 118 | 4' 3L T8 Premium, EB | 5.29 | 4.77 | 100.00% | 42.36% | 16.67% | 16 | $0.32 | $1.51 |
| 2 | 1 | 120 | 120 | Base Fluorescent Fixture, 4' 2L T12, 34W, 1EEMAG | 5.29 | 5.29 | 100.00% | 0.00% | 100.00% | 10 | $2.78 | $2.78 |
| 2 | 1 | 120 | 121 | 4' 2L T8 Premium, EB | 5.29 | 4.77 | 100.00% | 25.00% | 33.33% | 16 | $0.77 | $2.78 |
| 2 | 1 | 120 | 122 | 4' 1L T8 Premium, EB, reflector | 5.29 | 4.77 | 100.00% | 61.11% | 33.33% | 16 | $1.58 | $2.78 |
| 2 | 1 | 120 | 123 | Occupancy Sensor, 8-4' Fluorescent Fixtures | 5.29 | 4.77 | 79.56% | 30.00% | 40.00% | 9 | $0.45 | $2.78 |
| 2 | 1 | 120 | 124 | Continuous Dimming, 10-4' Fluorescent Fixtures | 5.29 | 4.77 | 100.00% | 75.00% | 40.00% | 11 | $3.82 | $2.78 |
| 2 | 1 | 120 | 125 | 4' 1L T5HO, EB | 5.29 | 4.77 | 100.00% | 13.90% | 33.33% | 16 | $0.59 | $2.78 |
| 2 | 1 | 130 | 130 | Base Fluorescent Fixture, 8' 2L T12, 60W, 1EEMAG | 5.29 | 5.29 | 100.00% | 0.00% | 100.00% | 10 | $1.82 | $1.82 |
| 2 | 1 | 130 | 131 | 8' 2L T12, 60W, EB | 5.29 | 4.77 | 26.59% | 10.57% | 25.00% | 16 | $0.17 | $1.82 |
| 2 | 1 | 130 | 132 | 8' 1L T12, 60W, EB, reflector | 5.29 | 4.77 | 100.00% | 55.30% | 25.00% | 16 | $0.79 | $1.82 |
| 2 | 1 | 130 | 133 | Occupancy Sensor, 4-8' Fluorescent Fixtures | 5.29 | 4.77 | 79.56% | 30.00% | 60.12% | 9 | $0.54 | $1.82 |
| 2 | 1 | 130 | 134 | Continuous Dimming, 5-8' Fluorescent Fixtures | 5.29 | 4.77 | 100.00% | 75.00% | 40.00% | 11 | $4.09 | $1.82 |

## Table B.3: Commercial Electric

| Segment | Building | Base Number | Measure Number | Measure Name | Stock Usage | Base Usage | Incomplete Factor | Energy Savings | Feasibility Factor | Measure Life | Full Per Unit Cost | Full Base Measure Cost |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2 | 1 | 130 | 135 | 8' 2L T8, EB | 5.29 | 4.77 | 100.00% | 52.80% | 50.00% | 16 | $0.36 | $1.82 |
| 2 | 1 | 140 | 140 | Base Incandescent Flood, 75W | 5.29 | 5.29 | 100.00% | 0.00% | 100.00% | 1 | $3.66 | $3.66 |
| 2 | 1 | 140 | 141 | CFL Screw-in, Modular 18W | 5.29 | 4.77 | 72.49% | 65.30% | 90.00% | 5 | $2.25 | $3.66 |
| 2 | 1 | 150 | 150 | Base Incandescent Flood, 150W PAR | 5.29 | 5.29 | 100.00% | 0.00% | 100.00% | 1 | $1.76 | $1.76 |
| 2 | 1 | 150 | 151 | Halogen PAR Flood, 90W | 5.29 | 5.29 | 100.00% | 40.00% | 10.00% | 1 | $0.18 | $1.76 |
| 2 | 1 | 150 | 152 | Metal Halide, 50W | 5.29 | 5.29 | 93.86% | 52.00% | 45.00% | 6 | $9.40 | $1.76 |
| 2 | 1 | 150 | 153 | HPS, 50W | 5.29 | 5.29 | 93.86% | 56.00% | 45.00% | 6 | $4.80 | $1.76 |
| 2 | 1 | 160 | 160 | Base 4' 3L T12, 34W, 1EEMAG | 5.29 | 5.29 | 100.00% | 0.00% | 100.00% | 10 | $0.55 | $0.55 |
| 2 | 1 | 160 | 161 | 4' 3L T8, EB | 5.29 | 4.77 | 100.00% | 22.61% | 25.00% | 16 | $0.05 | $0.55 |
| 2 | 1 | 160 | 162 | 4' 3L T8 Premium, EB | 5.29 | 4.77 | 100.00% | 22.61% | 25.00% | 16 | $0.13 | $0.55 |
| 2 | 1 | 160 | 163 | 4' 2L T8 Premium, EB, reflector | 5.29 | 4.77 | 100.00% | 53.04% | 25.00% | 16 | $0.28 | $0.55 |
| 2 | 1 | 160 | 164 | 4' 1L T5HO, EB | 5.29 | 4.77 | 100.00% | 46.09% | 25.00% | 16 | $0.05 | $0.55 |
| 2 | 1 | 180 | 180 | Base Fluorescent Fixture 4' 4L T8, 1EB | 4.24 | 4.24 | 100.00% | 0.00% | 100.00% | 16 | $1.69 | $1.69 |
| 2 | 1 | 180 | 181 | 4' 4L T8 Premium, EB | 4.24 | 3.81 | 100.00% | 3.60% | 100.00% | 16 | $0.30 | $1.69 |
| 2 | 1 | 180 | 182 | Occupancy Sensor, 4-4' Fluorescent Fixtures | 4.24 | 3.81 | 79.56% | 30.00% | 40.00% | 9 | $0.52 | $1.69 |
| 2 | 1 | 185 | 185 | Base Fluorescent Fixture 4' 3L T8, 1EB | 4.24 | 4.24 | 100.00% | 0.00% | 100.00% | 16 | $3.15 | $3.15 |
| 2 | 1 | 185 | 186 | 4' 3L T8 Premium, EB | 4.24 | 3.81 | 100.00% | 6.70% | 100.00% | 16 | $0.43 | $3.15 |
| 2 | 1 | 190 | 190 | Base Fluorescent Fixture 4' 2L T8, 1EB | 4.24 | 3.60 | 100.00% | 0.00% | 100.00% | 16 | $2.97 | $2.97 |
| 2 | 1 | 190 | 191 | 4' 2L T8 Premium, EB | 4.24 | 3.81 | 100.00% | 8.50% | 100.00% | 16 | $0.27 | $2.97 |
| 2 | 1 | 190 | 192 | Occupancy Sensor, 8-4' Fluorescent Fixtures | 4.24 | 3.81 | 79.56% | 30.00% | 40.00% | 9 | $0.45 | $2.97 |
| 2 | 1 | 200 | 200 | Base Centrifugal Chiller, 0.65 kW/ton, 300 tons | 3.76 | 3.76 | 100.00% | 0.00% | 100.00% | 20 | $1.38 | $1.38 |
| 2 | 1 | 200 | 201 | Chiller Tune-Up / Diagnostics | 3.76 | 3.76 | 10.00% | 5.00% | 100.00% | 5 | $0.11 | $1.38 |
| 2 | 1 | 200 | 202 | Installation of Automated Building Ventilation Control ( Via Occupancy Sensors, CO2 Sensors, Etc.) | 3.76 | 3.76 | 100.00% | 10.00% | 50.00% | 10 | $0.29 | $1.38 |
| 2 | 1 | 200 | 203 | Roof / Ceiling Insulation | 3.76 | 3.76 | 8.70% | 3.00% | 50.00% | 20 | $0.33 | $305.98 |
| 2 | 1 | 200 | 204 | Cool Roofs (Reflective and Spray Evaporative) | 3.76 | 3.76 | 100.00% | 1.81% | 90.00% | 10 | $0.24 | $230.50 |
| 2 | 1 | 200 | 205 | EMS Optimization | 3.76 | 3.76 | 50.00% | 1.00% | 100.00% | 5 | $0.00 | $0.00 |
| 2 | 1 | 200 | 206 | High Efficiency Windows (Low-E Glass or Multiple Glazed) | 3.76 | 3.76 | 99.43% | 9.26% | 75.00% | 30 | $0.06 | $40.43 |
| 2 | 1 | 200 | 207 | Installation of Energy Management Systems | 3.76 | 3.76 | 19.08% | 10.00% | 50.00% | 10 | $0.18 | $1.38 |
| 2 | 1 | 200 | 208 | Insulation of Pipes | 3.76 | 3.76 | 50.00% | 1.00% | 50.00% | 20 | $0.00 | $0.45 |
| 2 | 1 | 200 | 209 | Installation of Chiller Economizers (water side) | 3.76 | 3.76 | 56.87% | 10.00% | 50.00% | 20 | $0.59 | $461.00 |
| 2 | 1 | 200 | 210 | Optimize Chilled Water and Condenser Water Settings | 3.76 | 3.76 | 50.00% | 5.00% | 33.00% | 10 | $0.20 | $1.38 |
| 2 | 1 | 200 | 211 | Decrease Cooling Tower Approach Temperature, 300 Tons, 6 Deg F | 3.76 | 3.76 | 90.00% | 7.50% | 67.00% | 15 | $0.11 | $2.15 |
| 2 | 1 | 200 | 212 | Two-Speed Cooling Tower, 300 Tons | 3.76 | 3.76 | 90.00% | 14.00% | 50.00% | 15 | $0.01 | $2.15 |
| 2 | 1 | 200 | 213 | VSD Cooling Tower, 300 Tons | 3.76 | 3.76 | 90.00% | 18.00% | 50.00% | 15 | $0.07 | $2.15 |
| 2 | 1 | 200 | 214 | Primary/Secondary De-coupled Chilled Water System | 3.76 | 3.76 | 80.00% | 12.00% | 50.00% | 15 | $0.45 | $2.15 |
| 2 | 1 | 200 | 215 | HE Chiller, 0.51 kW/ton, 300 Tons | 3.76 | 3.76 |  | 21.54% |  | 15 | $0.18 | $2.15 |
| 2 | 1 | 200 | 216 | VSD Chiller, 0.47 kW/ton, 300 Tons | 3.76 | 3.76 |  | 27.69% |  | 15 | $0.60 | $2.15 |
| 2 | 1 | 250 | 250 | Base DX Packaged System, EER=10.3, 10 tons | 6.51 | 6.51 | 100.00% | 0.00% | 100.00% | 15 | $2.36 | $2.36 |
| 2 | 1 | 250 | 251 | DX Tune-Up / Diagnostics | 6.51 | 6.51 | 10.00% | 10.00% | 100.00% | 3 | $0.23 | $2.36 |
| 2 | 1 | 250 | 252 | Hi-Eff DX Packaged System, 10 tons, EER=11.3 | 6.51 | 6.51 |  | 8.85% |  | 15 | $0.29 | $2.36 |
| 2 | 1 | 250 | 253 | High Efficiency Windows (Low-E Glass or Multiple Glazed) | 6.51 | 6.51 | 99.43% | 5.00% | 75.00% | 30 | $0.15 | $69.11 |

## Table B.3: Commercial Electric

| Segment | Building | Base Number | Measure Number | Measure Name | Stock Usage | Base Usage | Incomplete Factor | Energy Savings | Feasibility Factor | Measure Life | Full Per Unit Cost | Full Base Measure Cost |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2 | 1 | 250 | 254 | Installation of Direct of Indirect Evaporative Cooling, Evaporative Pre-Cooling, and Absorption Cooling | 6.51 | 6.51 | 95.00% | 10.00% | 25.00% | 10 | $0.87 | $2.36 |
| 2 | 1 | 250 | 258 | Installation of Automated Building Ventilation Control ( Via Occupancy Sensors, CO2 Sensors, Etc.) | 6.51 | 6.51 | 100.00% | 10.00% | 50.00% | 10 | $0.29 | $2.36 |
| 2 | 1 | 250 | 259 | Roof / Ceiling Insulation | 6.51 | 6.51 | 8.70% | 3.00% | 50.00% | 20 | $0.33 | $523.02 |
| 2 | 1 | 250 | 260 | Cool Roofs (Reflective and Spray Evaporative) | 6.51 | 6.51 | 100.00% | 1.81% | 50.00% | 10 | $0.24 | $394.00 |
| 2 | 1 | 250 | 261 | Clock / Programmable Thermostat | 6.51 | 6.51 | 29.22% | 10.00% | 100.00% | 10 | $0.06 | $2.36 |
| 2 | 1 | 250 | 262 | Installation of Air Side Economizers | 6.51 | 6.51 | 30.37% | 15.00% | 100.00% | 10 | $0.59 | $788.00 |
| 2 | 1 | 280 | 280 | Base Air-Cooled HP Package, 5 tons, SEER=10 | 6.51 | 6.51 | 100.00% | 0.00% | 100.00% | 15 | $2.15 | $2.15 |
| 2 | 1 | 280 | 281 | Air-Cooled HP Package, 5 tons, SEER=11 | 6.51 | 6.51 | | 9.09% | | 15 | $0.11 | $2.15 |
| 2 | 1 | 280 | 282 | Air-Cooled HP Package, 5 tons, SEER=12 | 6.51 | 6.51 | | 16.67% | | 15 | $0.71 | $2.15 |
| 2 | 1 | 280 | 283 | DX Tune-Up / Diagnostics | 6.51 | 6.51 | 10.00% | 10.00% | 100.00% | 3 | $0.23 | $2.36 |
| 2 | 1 | 280 | 284 | High Efficiency Windows (Low-E Glass or Multiple Glazed) | 6.51 | 6.51 | 99.43% | 5.00% | 75.00% | 30 | $0.15 | $69.11 |
| 2 | 1 | 280 | 285 | Installation of Direct of Indirect Evaporative Cooling, Evaporative Pre-Cooling, and Absorption Cooling | 6.51 | 6.51 | 95.00% | 10.00% | 25.00% | 10 | $0.87 | $2.36 |
| 2 | 1 | 280 | 288 | Installation of Automated Building Ventilation Control ( Via Occupancy Sensors, CO2 Sensors, Etc.) | 6.51 | 6.51 | 100.00% | 10.00% | 50.00% | 10 | $0.29 | $2.36 |
| 2 | 1 | 280 | 289 | Roof / Ceiling Insulation | 6.51 | 6.51 | 8.70% | 3.00% | 50.00% | 20 | $0.33 | $523.02 |
| 2 | 1 | 280 | 290 | Cool Roofs (Reflective and Spray Evaporative) | 6.51 | 6.51 | 100.00% | 1.81% | 50.00% | 10 | $0.24 | $394.00 |
| 2 | 1 | 280 | 291 | Clock / Programmable Thermostat | 6.51 | 6.51 | 29.22% | 10.00% | 100.00% | 10 | $0.06 | $2.36 |
| 2 | 1 | 280 | 292 | Installation of Air Side Economizers | 6.51 | 6.51 | 30.37% | 15.00% | 100.00% | 10 | $0.59 | $788.00 |
| 2 | 1 | 400 | 400 | Base Fan Motor, 5hp, 1800rpm, 87.5% (ODP) | 2.25 | 2.25 | | 0.00% | | 15 | $0.18 | $0.18 |
| 2 | 1 | 400 | 401 | Energy Efficient Fan & Pump Motors (ODP) | 2.25 | 2.25 | | 1.50% | | 15 | $0.04 | $0.18 |
| 2 | 1 | 400 | 402 | VSD, ASD Fan & Pump Applications | 2.25 | 2.25 | | 30.00% | | 15 | $0.21 | $0.18 |
| 2 | 1 | 610 | 610 | Base Office Equipment | 1.59 | 1.59 | 100.00% | 0.00% | 100.00% | 4 | $1.46 | $4.29 |
| 2 | 1 | 610 | 611 | ENERGY STAR or Better Office Equipment: Computer | 1.59 | 1.59 | 65.00% | 24.69% | 100.00% | 4 | $0.18 | $4.29 |
| 2 | 1 | 610 | 621 | ENERGY STAR or Better Office Equipment: Monitors | 1.59 | 1.59 | 71.00% | 21.94% | 100.00% | 4 | $0.09 | $4.29 |
| 2 | 1 | 610 | 623 | Smart Networks | 1.59 | 1.59 | 40.00% | 9.14% | 90.00% | 4 | $0.01 | $4.29 |
| 2 | 1 | 610 | 631 | ENERGY STAR or Better Office Equipment: Copiers | 1.59 | 1.59 | 33.00% | 4.84% | 100.00% | 4 | $0.03 | $0.40 |
| 2 | 1 | 610 | 641 | ENERGY STAR or Better Office Equipment: Printers | 1.59 | 1.59 | 99.00% | 8.01% | 100.00% | 4 | $0.10 | $1.21 |
| 2 | 1 | 700 | 700 | Base Water Heating | 0.30 | 0.30 | 100.00% | 0.00% | 100.00% | 15 | $4.65 | $4.65 |
| 2 | 1 | 700 | 701 | Demand controlled circulating systems | 0.30 | 0.30 | 93.16% | 5.00% | 50.00% | 15 | $0.91 | $4.65 |
| 2 | 1 | 700 | 702 | Heat Pump Water Heater | 0.30 | 0.30 | 100.00% | 30.00% | 75.00% | 15 | $0.58 | $4.65 |
| 2 | 1 | 700 | 703 | High-Efficiency Water Heater (electric) | 0.30 | 0.30 | | 5.40% | | 15 | $0.17 | $4.65 |
| 2 | 1 | 700 | 704 | Hot Water (SHW) Pipe Insulation | 0.30 | 0.30 | 39.27% | 5.00% | 50.00% | 15 | $0.00 | $0.98 |
| 2 | 1 | 800 | 800 | Base Heating | 0.79 | 0.79 | 100.00% | 0.00% | 100.00% | 20 | $2.40 | $2.40 |
| 2 | 1 | 800 | 802 | Roof / Ceiling Insulation | 0.79 | 0.79 | 12.95% | 10.00% | 50.00% | 20 | $0.33 | $1.59 |
| 2 | 1 | 800 | 805 | Clock / Programmable Thermostat | 0.79 | 0.79 | 29.22% | 30.00% | 100.00% | 10 | $0.15 | $2.40 |
| 2 | 1 | 800 | 812 | Installation of Automated Building Ventilation Control ( Via Occupancy Sensors, CO2 Sensors, Etc.) | 0.79 | 0.79 | 100.00% | 5.00% | 50.00% | 15 | $0.28 | $2.40 |
| 2 | 2 | 110 | 110 | Base Fluorescent Fixture, 4' 4L T12, 34W, 2EEMAG | 5.89 | 5.89 | 100.00% | 0.00% | 100.00% | 16 | $1.68 | $1.68 |
| 2 | 2 | 110 | 111 | 4' 4L T8 Premium, EB | 5.89 | 5.30 | 100.00% | 25.00% | 16.67% | 25 | $0.55 | $1.68 |
| 2 | 2 | 110 | 112 | 4' 2L T8 Premium, EB, reflector | 5.89 | 5.30 | 100.00% | 62.50% | 16.67% | 25 | $0.83 | $1.68 |
| 2 | 2 | 110 | 113 | Occupancy Sensor, 4-4' Fluorescent Fixtures | 5.89 | 5.30 | 100.00% | 30.00% | 10.00% | 14 | $0.58 | $1.68 |
| 2 | 2 | 110 | 114 | Continuous Dimming, 5-4' Fluorescent Fixtures | 5.89 | 5.30 | 100.00% | 75.00% | 50.00% | 18 | $4.37 | $1.68 |

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## Table B.3: Commercial Electric

| Segment | Building | Base Number | Measure Number | Measure Name | Stock Usage | Base Usage | Incomplete Factor | Energy Savings | Feasibility Factor | Measure Life | Full Per Unit Cost | Full Base Measure Cost |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2 | 2 | 110 | 115 | 4' 2L T5HO, EB | 5.89 | 5.30 | 100.00% | 18.75% | 16.67% | 25 | $0.32 | $1.68 |
| 2 | 2 | 110 | 116 | 4' 4L T8, EB | 5.89 | 5.30 | 100.00% | 22.22% | 16.67% | 25 | $0.23 | $1.68 |
| 2 | 2 | 110 | 117 | 4' 3L T8, EB | 5.89 | 5.30 | 100.00% | 38.20% | 16.67% | 25 | $0.11 | $1.68 |
| 2 | 2 | 110 | 118 | 4' 3L T8 Premium, EB | 5.89 | 5.30 | 100.00% | 42.36% | 16.67% | 25 | $0.35 | $1.68 |
| 2 | 2 | 120 | 120 | Base Fluorescent Fixture, 4' 2L T12, 34W, 1EEMAG | 5.89 | 5.89 | 100.00% | 0.00% | 100.00% | 16 | $3.17 | $3.17 |
| 2 | 2 | 120 | 121 | 4' 2L T8 Premium, EB | 5.89 | 5.30 | 100.00% | 25.00% | 33.33% | 25 | $0.88 | $3.17 |
| 2 | 2 | 120 | 122 | 4' 1L T8 Premium, EB, reflector | 5.89 | 5.30 | 100.00% | 61.11% | 33.33% | 25 | $1.80 | $3.17 |
| 2 | 2 | 120 | 123 | Occupancy Sensor, 8-4' Fluorescent Fixtures | 5.89 | 5.30 | 100.00% | 30.00% | 10.00% | 14 | $0.52 | $3.17 |
| 2 | 2 | 120 | 124 | Continuous Dimming, 10-4' Fluorescent Fixtures | 5.89 | 5.30 | 100.00% | 75.00% | 50.00% | 18 | $4.35 | $3.17 |
| 2 | 2 | 120 | 125 | 4' 1L T5HO, EB | 5.89 | 5.30 | 100.00% | 13.90% | 33.33% | 25 | $0.67 | $3.17 |
| 2 | 2 | 130 | 130 | Base Fluorescent Fixture, 8' 2L T12, 60W, 1EEMAG | 5.89 | 5.89 | 100.00% | 0.00% | 100.00% | 16 | $2.23 | $2.23 |
| 2 | 2 | 130 | 131 | 8' 2L T12, 60W, EB | 5.89 | 5.30 | 95.41% | 10.57% | 25.00% | 25 | $0.21 | $2.23 |
| 2 | 2 | 130 | 132 | 8' 1L T12, 60W, EB, reflector | 5.89 | 5.30 | 100.00% | 55.30% | 25.00% | 25 | $0.96 | $2.23 |
| 2 | 2 | 130 | 133 | Occupancy Sensor, 4-8' Fluorescent Fixtures | 5.89 | 5.30 | 100.00% | 30.00% | 10.00% | 14 | $0.67 | $2.23 |
| 2 | 2 | 130 | 134 | Continuous Dimming, 5-8' Fluorescent Fixtures | 5.89 | 5.30 | 100.00% | 75.00% | 20.00% | 18 | $5.02 | $2.23 |
| 2 | 2 | 130 | 135 | 8' 2L T8, EB | 5.89 | 5.30 | 100.00% | 52.80% | 50.00% | 25 | $0.44 | $2.23 |
| 2 | 2 | 140 | 140 | Base Incandescent Flood, 75W | 5.89 | 5.89 | 100.00% | 0.00% | 100.00% | 1 | $4.55 | $4.55 |
| 2 | 2 | 140 | 141 | CFL Screw-in, Modular 18W | 5.89 | 5.30 | 75.00% | 65.30% | 50.00% | 7 | $2.80 | $4.55 |
| 2 | 2 | 150 | 150 | Base Incandescent Flood, 150W PAR | 5.89 | 5.89 | 100.00% | 0.00% | 100.00% | 1 | $1.88 | $1.88 |
| 2 | 2 | 150 | 151 | Halogen PAR Flood, 90W | 5.89 | 5.89 | 99.28% | 40.00% | 10.00% | 1 | $0.19 | $1.88 |
| 2 | 2 | 150 | 152 | Metal Halide, 50W | 5.89 | 5.89 | 91.60% | 52.00% | 45.00% | 8 | $10.05 | $1.88 |
| 2 | 2 | 150 | 153 | HPS, 50W | 5.89 | 5.89 | 91.60% | 56.00% | 45.00% | 8 | $5.13 | $1.88 |
| 2 | 2 | 160 | 160 | Base 4' 3L T12, 34W, 1EEMAG | 5.89 | 5.89 | 100.00% | 0.00% | 100.00% | 10 | $1.35 | $1.35 |
| 2 | 2 | 160 | 161 | 4' 3L T8, EB | 5.89 | 5.30 | 100.00% | 22.61% | 25.00% | 25 | $0.11 | $1.35 |
| 2 | 2 | 160 | 162 | 4' 3L T8 Premium, EB | 5.89 | 5.30 | 100.00% | 22.61% | 25.00% | 25 | $0.31 | $1.35 |
| 2 | 2 | 160 | 163 | 4' 2L T8 Premium, EB, reflector | 5.89 | 5.30 | 100.00% | 53.04% | 25.00% | 25 | $0.70 | $1.35 |
| 2 | 2 | 160 | 164 | 4' 1L T5HO, EB | 5.89 | 5.30 | 100.00% | 46.09% | 25.00% | 25 | $0.12 | $1.35 |
| 2 | 2 | 180 | 180 | Base Fluorescent Fixture 4' 4L T8, 1EB | 4.71 | 4.71 | 100.00% | 0.00% | 100.00% | 25 | $1.88 | $1.88 |
| 2 | 2 | 180 | 181 | 4' 4L T8 Premium, EB | 4.71 | 4.24 | 100.00% | 3.60% | 100.00% | 25 | $0.34 | $1.88 |
| 2 | 2 | 180 | 182 | Occupancy Sensor, 4-4' Fluorescent Fixtures | 4.71 | 4.24 | 100.00% | 30.00% | 10.00% | 14 | $0.58 | $1.88 |
| 2 | 2 | 185 | 185 | Base Fluorescent Fixture 4' 3L T8, 1EB | 4.71 | 4.71 | 100.00% | 0.00% | 100.00% | 25 | $3.59 | $3.59 |
| 2 | 2 | 185 | 186 | 4' 3L T8 Premium, EB | 4.71 | 4.24 | 100.00% | 6.70% | 100.00% | 25 | $0.49 | $3.59 |
| 2 | 2 | 190 | 190 | Base Fluorescent Fixture 4' 2L T8, 1EB | 4.71 | 4.00 | 100.00% | 0.00% | 100.00% | 25 | $3.38 | $3.38 |
| 2 | 2 | 190 | 191 | 4' 2L T8 Premium, EB | 4.71 | 4.24 | 100.00% | 8.50% | 100.00% | 25 | $0.30 | $3.38 |
| 2 | 2 | 190 | 192 | Occupancy Sensor, 8-4' Fluorescent Fixtures | 4.71 | 4.24 | 100.00% | 30.00% | 10.00% | 14 | $0.52 | $3.38 |
| 2 | 2 | 200 | 200 | Base Centrifugal Chiller, 0.65 kW/ton, 300 tons | 1.22 | 1.22 | 100.00% | 0.00% | 100.00% | 20 | $1.15 | $1.15 |
| 2 | 2 | 200 | 201 | Chiller Tune-Up / Diagnostics | 1.22 | 1.22 | 10.00% | 5.00% | 100.00% | 5 | $0.09 | $1.15 |
| 2 | 2 | 200 | 202 | Installation of Automated Building Ventilation Control ( Via Occupancy Sensors, CO2 Sensors, Etc.) | 1.22 | 1.22 | 100.00% | 10.00% | 50.00% | 10 | $0.24 | $1.15 |
| 2 | 2 | 200 | 203 | Roof / Ceiling Insulation | 1.22 | 1.22 | 100.00% | 3.00% | 50.00% | 20 | $0.47 | $443.39 |
| 2 | 2 | 200 | 204 | Cool Roofs (Reflective and Spray Evaporative) | 1.22 | 1.22 | 100.00% | 6.92% | 90.00% | 10 | $0.47 | $461.00 |
| 2 | 2 | 200 | 205 | EMS Optimization | 1.22 | 1.22 | 50.00% | 1.00% | 100.00% | 5 | $0.00 | $0.00 |
| 2 | 2 | 200 | 206 | High Efficiency Windows (Low-E Glass or Multiple Glazed) | 1.22 | 1.22 | 100.00% | 10.32% | 75.00% | 30 | $0.03 | $21.21 |
| 2 | 2 | 200 | 207 | Installation of Energy Management Systems | 1.22 | 1.22 | 100.00% | 10.00% | 50.00% | 10 | $0.15 | $1.15 |

## Table B.3: Commercial Electric

| Segment | Building | Base Number | Measure Number | Measure Name | Stock Usage | Base Usage | Incomplete Factor | Energy Savings | Feasibility Factor | Measure Life | Full Per Unit Cost | Full Base Measure Cost |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2 | 2 | 200 | 208 | Insulation of Pipes | 1.22 | 1.22 | 50.00% | 1.00% | 50.00% | 20 | $0.03 | $2.94 |
| 2 | 2 | 200 | 209 | Installation of Chiller Economizers (water side) | 1.22 | 1.22 | 100.00% | 10.00% | 50.00% | 20 | $0.59 | $461.00 |
| 2 | 2 | 200 | 210 | Optimize Chilled Water and Condenser Water Settings | 1.22 | 1.22 | 50.00% | 5.00% | 33.00% | 10 | $0.17 | $1.15 |
| 2 | 2 | 200 | 211 | Decrease Cooling Tower Approach Temperature, 300 Tons, 6 Deg F | 1.22 | 1.22 | 90.00% | 7.50% | 67.00% | 15 | $0.09 | $1.79 |
| 2 | 2 | 200 | 212 | Two-Speed Cooling Tower, 300 Tons | 1.22 | 1.22 | 90.00% | 14.00% | 50.00% | 15 | $0.01 | $1.79 |
| 2 | 2 | 200 | 213 | VSD Cooling Tower, 300 Tons | 1.22 | 1.22 | 90.00% | 18.00% | 50.00% | 15 | $0.06 | $1.79 |
| 2 | 2 | 200 | 214 | Primary/Secondary De-coupled Chilled Water System | 1.22 | 1.22 | 80.00% | 12.00% | 50.00% | 15 | $0.38 | $1.79 |
| 2 | 2 | 200 | 215 | HE Chiller, 0.51 kW/ton, 300 Tons | 1.22 | 1.22 |  | 21.54% |  | 15 | $0.15 | $1.79 |
| 2 | 2 | 200 | 216 | VSD Chiller, 0.47 kW/ton, 300 Tons | 1.22 | 1.22 |  | 27.69% |  | 15 | $0.50 | $1.79 |
| 2 | 2 | 250 | 250 | Base DX Packaged System, EER=10.3, 10 tons | 2.11 | 2.11 | 100.00% | 0.00% | 100.00% | 15 | $1.97 | $1.97 |
| 2 | 2 | 250 | 251 | DX Tune-Up / Diagnostics | 2.11 | 2.11 | 10.00% | 10.00% | 100.00% | 3 | $0.20 | $1.97 |
| 2 | 2 | 250 | 252 | Hi-Eff DX Packaged System, 10 tons, EER=11.3 | 2.11 | 2.11 |  | 8.85% |  | 15 | $0.24 | $1.97 |
| 2 | 2 | 250 | 253 | High Efficiency Windows (Low-E Glass or Multiple Glazed) | 2.11 | 2.11 | 100.00% | 5.00% | 75.00% | 30 | $0.08 | $36.25 |
| 2 | 2 | 250 | 254 | Installation of Direct of Indirect Evaporative Cooling, Evaporative Pre-Cooling, and Absorption Cooling | 2.11 | 2.11 | 95.00% | 10.00% | 25.00% | 10 | $0.73 | $1.97 |
| 2 | 2 | 250 | 258 | Installation of Automated Building Ventilation Control ( Via Occupancy Sensors, CO2 Sensors, Etc.) | 2.11 | 2.11 | 100.00% | 10.00% | 50.00% | 10 | $0.24 | $1.97 |
| 2 | 2 | 250 | 259 | Roof / Ceiling Insulation | 2.11 | 2.11 | 100.00% | 3.00% | 50.00% | 20 | $0.47 | $757.89 |
| 2 | 2 | 250 | 260 | Cool Roofs (Reflective and Spray Evaporative) | 2.11 | 2.11 | 100.00% | 6.92% | 50.00% | 10 | $0.47 | $788.00 |
| 2 | 2 | 250 | 261 | Clock / Programmable Thermostat | 2.11 | 2.11 | 25.00% | 10.00% | 100.00% | 10 | $0.05 | $1.97 |
| 2 | 2 | 250 | 262 | Installation of Air Side Economizers | 2.11 | 2.11 | 92.26% | 15.00% | 100.00% | 10 | $0.59 | $788.00 |
| 2 | 2 | 280 | 280 | Base Air-Cooled HP Package, 5 tons, SEER=10 | 2.11 | 2.11 | 100.00% | 0.00% | 100.00% | 15 | $1.79 | $1.79 |
| 2 | 2 | 280 | 281 | Air-Cooled HP Package, 5 tons, SEER=11 | 2.11 | 2.11 |  | 9.09% |  | 15 | $0.09 | $1.79 |
| 2 | 2 | 280 | 282 | Air-Cooled HP Package, 5 tons, SEER=12 | 2.11 | 2.11 |  | 16.67% |  | 15 | $0.59 | $1.79 |
| 2 | 2 | 280 | 283 | DX Tune-Up / Diagnostics | 2.11 | 2.11 | 10.00% | 10.00% | 100.00% | 3 | $0.20 | $1.97 |
| 2 | 2 | 280 | 284 | High Efficiency Windows (Low-E Glass or Multiple Glazed) | 2.11 | 2.11 | 100.00% | 5.00% | 75.00% | 30 | $0.08 | $36.25 |
| 2 | 2 | 280 | 285 | Installation of Direct of Indirect Evaporative Cooling, Evaporative Pre-Cooling, and Absorption Cooling | 2.11 | 2.11 | 95.00% | 10.00% | 25.00% | 10 | $0.73 | $1.97 |
| 2 | 2 | 280 | 288 | Installation of Automated Building Ventilation Control ( Via Occupancy Sensors, CO2 Sensors, Etc.) | 2.11 | 2.11 | 100.00% | 10.00% | 50.00% | 10 | $0.24 | $1.97 |
| 2 | 2 | 280 | 289 | Roof / Ceiling Insulation | 2.11 | 2.11 | 100.00% | 3.00% | 50.00% | 20 | $0.47 | $757.89 |
| 2 | 2 | 280 | 290 | Cool Roofs (Reflective and Spray Evaporative) | 2.11 | 2.11 | 100.00% | 6.92% | 50.00% | 10 | $0.47 | $788.00 |
| 2 | 2 | 280 | 291 | Clock / Programmable Thermostat | 2.11 | 2.11 | 25.00% | 10.00% | 100.00% | 10 | $0.05 | $1.97 |
| 2 | 2 | 280 | 292 | Installation of Air Side Economizers | 2.11 | 2.11 | 92.26% | 15.00% | 100.00% | 10 | $0.59 | $788.00 |
| 2 | 2 | 400 | 400 | Base Fan Motor, 5hp, 1800rpm, 87.5% (ODP) | 0.67 | 0.67 |  | 0.00% |  | 15 | $0.39 | $0.39 |
| 2 | 2 | 400 | 401 | Energy Efficient Fan & Pump Motors (ODP) | 0.67 | 0.67 |  | 1.50% |  | 15 | $0.08 | $0.39 |
| 2 | 2 | 400 | 402 | VSD, ASD Fan & Pump Applications | 0.67 | 0.67 |  | 30.00% |  | 15 | $0.45 | $0.39 |
| 2 | 2 | 610 | 610 | Base Office Equipment | 0.15 | 0.15 | 100.00% | 0.00% | 100.00% | 4 | $0.12 | $0.34 |
| 2 | 2 | 610 | 611 | ENERGY STAR or Better Office Equipment: Computer | 0.15 | 0.15 | 65.00% | 17.18% | 100.00% | 4 | $0.01 | $0.34 |
| 2 | 2 | 610 | 621 | ENERGY STAR or Better Office Equipment: Monitors | 0.15 | 0.15 | 71.00% | 15.26% | 100.00% | 4 | $0.01 | $0.34 |
| 2 | 2 | 610 | 623 | Smart Networks | 0.15 | 0.15 | 40.00% | 6.36% | 90.00% | 4 | $0.00 | $0.34 |
| 2 | 2 | 610 | 631 | ENERGY STAR or Better Office Equipment: Copiers | 0.15 | 0.15 | 33.00% | 9.55% | 100.00% | 4 | $0.01 | $0.06 |
| 2 | 2 | 610 | 641 | ENERGY STAR or Better Office Equipment: Printers | 0.15 | 0.15 | 99.00% | 14.55% | 100.00% | 4 | $0.02 | $0.24 |
| 2 | 2 | 700 | 700 | Base Water Heating | 0.44 | 0.44 | 100.00% | 0.00% | 100.00% | 15 | $20.00 | $20.00 |

Exhibit No. ___(EMM-6)
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# Table B.3: Commercial Electric

| Segment | Building | Base Number | Measure Number | Measure Name | Stock Usage | Base Usage | Incomplete Factor | Energy Savings | Feasibility Factor | Measure Life | Full Per Unit Cost | Full Base Measure Cost |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2 | 2 | 700 | 701 | Demand controlled circulating systems | 0.44 | 0.44 | 100.00% | 5.00% | 50.00% | 15 | $3.90 | $20.00 |
| 2 | 2 | 700 | 702 | Heat Pump Water Heater | 0.44 | 0.44 | 100.00% | 30.00% | 75.00% | 15 | $2.49 | $20.00 |
| 2 | 2 | 700 | 703 | High-Efficiency Water Heater (electric) | 0.44 | 0.44 | | 5.40% | | 15 | $0.72 | $20.00 |
| 2 | 2 | 700 | 704 | Hot Water (SHW) Pipe Insulation | 0.44 | 0.44 | 100.00% | 5.00% | 50.00% | 15 | $0.03 | $6.38 |
| 2 | 2 | 800 | 800 | Base Heating | 0.93 | 0.93 | 100.00% | 0.00% | 100.00% | 20 | $2.40 | $2.40 |
| 2 | 2 | 800 | 802 | Roof / Ceiling Insulation | 0.93 | 0.93 | 55.72% | 10.00% | 50.00% | 20 | $0.47 | $2.31 |
| 2 | 2 | 800 | 805 | Clock / Programmable Thermostat | 0.93 | 0.93 | 25.00% | 30.00% | 100.00% | 10 | $0.15 | $2.40 |
| 2 | 2 | 800 | 812 | Installation of Automated Building Ventilation Control ( Via Occupancy Sensors, CO2 Sensors, Etc.) | 0.93 | 0.93 | 100.00% | 5.00% | 50.00% | 15 | $0.28 | $2.40 |
| 2 | 3 | 100 | 100 | Base Cooking | 52.39 | 52.39 | | 0.00% | | 15 | $1.93 | $1.93 |
| 2 | 3 | 100 | 101 | High-Efficiency Convection Oven | 52.39 | 52.39 | | 20.00% | | 15 | $1.62 | $1.93 |
| 2 | 3 | 110 | 110 | Base Fluorescent Fixture, 4' 4L T12, 34W, 2EEMAG | 8.74 | 8.74 | 100.00% | 0.00% | 100.00% | 14 | $1.54 | $1.54 |
| 2 | 3 | 110 | 111 | 4' 4L T8 Premium, EB | 8.74 | 7.86 | 100.00% | 25.00% | 16.67% | 22 | $0.51 | $1.54 |
| 2 | 3 | 110 | 112 | 4' 2L T8 Premium, EB, reflector | 8.74 | 7.86 | 100.00% | 62.50% | 16.67% | 22 | $0.76 | $1.54 |
| 2 | 3 | 110 | 113 | Occupancy Sensor, 4-4' Fluorescent Fixtures | 8.74 | 7.86 | 95.72% | 30.00% | 10.00% | 13 | $0.53 | $1.54 |
| 2 | 3 | 110 | 114 | Continuous Dimming, 5-4' Fluorescent Fixtures | 8.74 | 7.86 | 100.00% | 75.00% | 12.00% | 16 | $4.01 | $1.54 |
| 2 | 3 | 110 | 115 | 4' 2L T5HO, EB | 8.74 | 7.86 | 100.00% | 18.75% | 16.67% | 22 | $0.29 | $1.54 |
| 2 | 3 | 110 | 116 | 4' 4L T8, EB | 8.74 | 7.86 | 100.00% | 22.22% | 16.67% | 22 | $0.21 | $1.54 |
| 2 | 3 | 110 | 117 | 4' 3L T8, EB | 8.74 | 7.86 | 100.00% | 38.20% | 16.67% | 22 | $0.10 | $1.54 |
| 2 | 3 | 110 | 118 | 4' 3L T8 Premium, EB | 8.74 | 7.86 | 100.00% | 42.36% | 16.67% | 22 | $0.32 | $1.54 |
| 2 | 3 | 120 | 120 | Base Fluorescent Fixture, 4' 2L T12, 34W, 1EEMAG | 8.74 | 8.74 | 100.00% | 0.00% | 100.00% | 14 | $2.83 | $2.83 |
| 2 | 3 | 120 | 121 | 4' 2L T8 Premium, EB | 8.74 | 7.86 | 100.00% | 25.00% | 33.33% | 22 | $0.79 | $2.83 |
| 2 | 3 | 120 | 122 | 4' 1L T8 Premium, EB, reflector | 8.74 | 7.86 | 100.00% | 61.11% | 33.33% | 22 | $1.60 | $2.83 |
| 2 | 3 | 120 | 123 | Occupancy Sensor, 8-4' Fluorescent Fixtures | 8.74 | 7.86 | 95.72% | 30.00% | 10.00% | 13 | $0.46 | $2.83 |
| 2 | 3 | 120 | 124 | Continuous Dimming, 10-4' Fluorescent Fixtures | 8.74 | 7.86 | 100.00% | 75.00% | 12.00% | 16 | $3.89 | $2.83 |
| 2 | 3 | 120 | 125 | 4' 1L T5HO, EB | 8.74 | 7.86 | 100.00% | 13.90% | 33.33% | 22 | $0.60 | $2.83 |
| 2 | 3 | 130 | 130 | Base Fluorescent Fixture, 8' 2L T12, 60W, 1EEMAG | 8.74 | 8.74 | 100.00% | 0.00% | 100.00% | 14 | $1.94 | $1.94 |
| 2 | 3 | 130 | 131 | 8' 2L T12, 60W, EB | 8.74 | 7.86 | 68.10% | 10.57% | 25.00% | 22 | $0.18 | $1.94 |
| 2 | 3 | 130 | 132 | 8' 1L T12, 60W, EB, reflector | 8.74 | 7.86 | 100.00% | 55.30% | 25.00% | 22 | $0.84 | $1.94 |
| 2 | 3 | 130 | 133 | Occupancy Sensor, 4-8' Fluorescent Fixtures | 8.74 | 7.86 | 95.72% | 30.00% | 10.00% | 13 | $0.58 | $1.94 |
| 2 | 3 | 130 | 134 | Continuous Dimming, 5-8' Fluorescent Fixtures | 8.74 | 7.86 | 100.00% | 75.00% | 12.00% | 16 | $4.37 | $1.94 |
| 2 | 3 | 130 | 135 | 8' 2L T8, EB | 8.74 | 7.86 | 100.00% | 52.80% | 50.00% | 22 | $0.38 | $1.94 |
| 2 | 3 | 140 | 140 | Base Incandescent Flood, 75W | 8.74 | 8.74 | 100.00% | 0.00% | 100.00% | 1 | $3.78 | $3.78 |
| 2 | 3 | 140 | 141 | CFL Screw-in, Modular 18W | 8.74 | 7.86 | 89.06% | 65.30% | 50.00% | 6 | $2.33 | $3.78 |
| 2 | 3 | 150 | 150 | Base Incandescent Flood, 150W PAR | 8.74 | 8.74 | 100.00% | 0.00% | 100.00% | 1 | $1.86 | $1.86 |
| 2 | 3 | 150 | 151 | Halogen PAR Flood, 90W | 8.74 | 8.74 | 100.00% | 40.00% | 10.00% | 1 | $0.19 | $1.86 |
| 2 | 3 | 150 | 152 | Metal Halide, 50W | 8.74 | 8.74 | 90.41% | 52.00% | 45.00% | 8 | $9.99 | $1.86 |
| 2 | 3 | 150 | 153 | HPS, 50W | 8.74 | 8.74 | 90.41% | 56.00% | 45.00% | 8 | $5.10 | $1.86 |
| 2 | 3 | 160 | 160 | Base 4' 3L T12, 34W, 1EEMAG | 8.74 | 8.74 | 100.00% | 0.00% | 100.00% | 10 | $0.43 | $0.43 |
| 2 | 3 | 160 | 161 | 4' 3L T8, EB | 8.74 | 7.86 | 100.00% | 22.61% | 25.00% | 22 | $0.04 | $0.43 |
| 2 | 3 | 160 | 162 | 4' 3L T8 Premium, EB | 8.74 | 7.86 | 100.00% | 22.61% | 25.00% | 22 | $0.10 | $0.43 |
| 2 | 3 | 160 | 163 | 4' 2L T8 Premium, EB, reflector | 8.74 | 7.86 | 100.00% | 53.04% | 25.00% | 22 | $0.22 | $0.43 |
| 2 | 3 | 160 | 164 | 4' 1L T5HO, EB | 8.74 | 7.86 | 100.00% | 46.09% | 25.00% | 22 | $0.04 | $0.43 |
| 2 | 3 | 180 | 180 | Base Fluorescent Fixture 4' 4L T8, 1EB | 6.99 | 6.99 | 100.00% | 0.00% | 100.00% | 22 | $1.73 | $1.73 |

## Table B.3: Commercial Electric

| Segment | Building | Base Number | Measure Number | Measure Name | Stock Usage | Base Usage | Incomplete Factor | Energy Savings | Feasibility Factor | Measure Life | Full Per Unit Cost | Full Base Measure Cost |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2 | 3 | 180 | 181 | 4' 4L T8 Premium, EB | 6.99 | 6.29 | 100.00% | 3.60% | 100.00% | 22 | $0.31 | $1.73 |
| 2 | 3 | 180 | 182 | Occupancy Sensor, 4-4' Fluorescent Fixtures | 6.99 | 6.29 | 95.72% | 30.00% | 10.00% | 13 | $0.53 | $1.73 |
| 2 | 3 | 185 | 185 | Base Fluorescent Fixture 4' 3L T8, 1EB | 6.99 | 6.99 | 100.00% | 0.00% | 100.00% | 22 | $3.21 | $3.21 |
| 2 | 3 | 185 | 186 | 4' 3L T8 Premium, EB | 6.99 | 6.29 | 100.00% | 6.70% | 100.00% | 22 | $0.43 | $3.21 |
| 2 | 3 | 190 | 190 | Base Fluorescent Fixture 4' 2L T8, 1EB | 6.99 | 5.94 | 100.00% | 0.00% | 100.00% | 22 | $3.02 | $3.02 |
| 2 | 3 | 190 | 191 | 4' 2L T8 Premium, EB | 6.99 | 6.29 | 100.00% | 8.50% | 100.00% | 22 | $0.27 | $3.02 |
| 2 | 3 | 190 | 192 | Occupancy Sensor, 8-4' Fluorescent Fixtures | 6.99 | 6.29 | 95.72% | 30.00% | 10.00% | 13 | $0.46 | $3.02 |
| 2 | 3 | 200 | 200 | Base Centrifugal Chiller, 0.65 kW/ton, 300 tons | 5.20 | 5.20 | 100.00% | 0.00% | 100.00% | 20 | $0.88 | $0.88 |
| 2 | 3 | 200 | 201 | Chiller Tune-Up / Diagnostics | 5.20 | 5.20 | 10.00% | 5.00% | 100.00% | 5 | $0.07 | $0.88 |
| 2 | 3 | 200 | 202 | Installation of Automated Building Ventilation Control ( Via Occupancy Sensors, CO2 Sensors, Etc.) | 5.20 | 5.20 | 100.00% | 10.00% | 50.00% | 10 | $0.18 | $0.88 |
| 2 | 3 | 200 | 203 | Roof / Ceiling Insulation | 5.20 | 5.20 | 100.00% | 3.00% | 50.00% | 20 | $0.45 | $421.73 |
| 2 | 3 | 200 | 204 | Cool Roofs (Reflective and Spray Evaporative) | 5.20 | 5.20 | 100.00% | 4.30% | 90.00% | 10 | $0.47 | $461.00 |
| 2 | 3 | 200 | 205 | EMS Optimization | 5.20 | 5.20 | 50.00% | 1.00% | 100.00% | 5 | $0.00 | $0.00 |
| 2 | 3 | 200 | 206 | High Efficiency Windows (Low-E Glass or Multiple Glazed) | 5.20 | 5.20 | 100.00% | 5.40% | 50.00% | 30 | $0.02 | $13.11 |
| 2 | 3 | 200 | 207 | Installation of Energy Management Systems | 5.20 | 5.20 | 100.00% | 10.00% | 50.00% | 10 | $0.11 | $0.88 |
| 2 | 3 | 200 | 208 | Insulation of Pipes | 5.20 | 5.20 | 50.00% | 1.00% | 50.00% | 20 | $0.02 | $2.73 |
| 2 | 3 | 200 | 209 | Installation of Chiller Economizers (water side) | 5.20 | 5.20 | 100.00% | 10.00% | 50.00% | 20 | $0.59 | $461.00 |
| 2 | 3 | 200 | 210 | Optimize Chilled Water and Condenser Water Settings | 5.20 | 5.20 | 50.00% | 5.00% | 33.00% | 10 | $0.13 | $0.88 |
| 2 | 3 | 200 | 211 | Decrease Cooling Tower Approach Temperature, 300 Tons, 6 Deg F | 5.20 | 5.20 | 90.00% | 7.50% | 67.00% | 15 | $0.07 | $1.36 |
| 2 | 3 | 200 | 212 | Two-Speed Cooling Tower, 300 Tons | 5.20 | 5.20 | 90.00% | 14.00% | 50.00% | 15 | $0.01 | $1.36 |
| 2 | 3 | 200 | 213 | VSD Cooling Tower, 300 Tons | 5.20 | 5.20 | 90.00% | 18.00% | 50.00% | 15 | $0.05 | $1.36 |
| 2 | 3 | 200 | 214 | Primary/Secondary De-coupled Chilled Water System | 5.20 | 5.20 | 80.00% | 12.00% | 50.00% | 15 | $0.29 | $1.36 |
| 2 | 3 | 200 | 215 | HE Chiller, 0.51 kW/ton, 300 Tons | 5.20 | 5.20 | | 21.54% | | 15 | $0.11 | $1.36 |
| 2 | 3 | 200 | 216 | VSD Chiller, 0.47 kW/ton, 300 Tons | 5.20 | 5.20 | | 27.69% | | 15 | $0.38 | $1.36 |
| 2 | 3 | 250 | 250 | Base DX Packaged System, EER=10.3, 10 tons | 9.00 | 9.00 | 100.00% | 0.00% | 100.00% | 15 | $1.50 | $1.50 |
| 2 | 3 | 250 | 251 | DX Tune-Up / Diagnostics | 9.00 | 9.00 | 10.00% | 10.00% | 100.00% | 3 | $0.15 | $1.50 |
| 2 | 3 | 250 | 252 | Hi-Eff DX Packaged System, 10 tons, EER=11.3 | 9.00 | 9.00 | | 8.85% | | 15 | $0.18 | $1.50 |
| 2 | 3 | 250 | 253 | High Efficiency Windows (Low-E Glass or Multiple Glazed) | 9.00 | 9.00 | 100.00% | 5.00% | 50.00% | 30 | $0.05 | $22.41 |
| 2 | 3 | 250 | 254 | Installation of Direct of Indirect Evaporative Cooling, Evaporative Pre-Cooling, and Absorption Cooling | 9.00 | 9.00 | 95.00% | 10.00% | 25.00% | 10 | $0.55 | $1.50 |
| 2 | 3 | 250 | 258 | Installation of Automated Building Ventilation Control ( Via Occupancy Sensors, CO2 Sensors, Etc.) | 9.00 | 9.00 | 100.00% | 10.00% | 50.00% | 10 | $0.18 | $1.50 |
| 2 | 3 | 250 | 259 | Roof / Ceiling Insulation | 9.00 | 9.00 | 100.00% | 3.00% | 50.00% | 20 | $0.45 | $720.87 |
| 2 | 3 | 250 | 260 | Cool Roofs (Reflective and Spray Evaporative) | 9.00 | 9.00 | 100.00% | 4.30% | 50.00% | 10 | $0.47 | $788.00 |
| 2 | 3 | 250 | 261 | Clock / Programmable Thermostat | 9.00 | 9.00 | 40.20% | 10.00% | 100.00% | 10 | $0.04 | $1.50 |
| 2 | 3 | 250 | 262 | Installation of Air Side Economizers | 9.00 | 9.00 | 55.37% | 15.00% | 100.00% | 10 | $0.59 | $788.00 |
| 2 | 3 | 280 | 280 | Base Air-Cooled HP Package, 5 tons, SEER=10 | 9.00 | 9.00 | 100.00% | 0.00% | 100.00% | 15 | $1.36 | $1.36 |
| 2 | 3 | 280 | 281 | Air-Cooled HP Package, 5 tons, SEER=11 | 9.00 | 9.00 | | 9.09% | | 15 | $0.07 | $1.36 |
| 2 | 3 | 280 | 282 | Air-Cooled HP Package, 5 tons, SEER=12 | 9.00 | 9.00 | | 16.67% | | 15 | $0.45 | $1.36 |
| 2 | 3 | 280 | 283 | DX Tune-Up / Diagnostics | 9.00 | 9.00 | 10.00% | 10.00% | 100.00% | 3 | $0.15 | $1.50 |
| 2 | 3 | 280 | 284 | High Efficiency Windows (Low-E Glass or Multiple Glazed) | 9.00 | 9.00 | 100.00% | 5.00% | 50.00% | 30 | $0.05 | $22.41 |
| 2 | 3 | 280 | 285 | Installation of Direct of Indirect Evaporative Cooling, Evaporative Pre-Cooling, and Absorption Cooling | 9.00 | 9.00 | 95.00% | 10.00% | 25.00% | 10 | $0.55 | $1.50 |

# Table B.3: Commercial Electric

| Segment | Building | Base Number | Measure Number | Measure Name | Stock Usage | Base Usage | Incomplete Factor | Energy Savings | Feasibility Factor | Measure Life | Full Per Unit Cost | Full Base Measure Cost |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2 | 3 | 280 | 288 | Installation of Automated Building Ventilation Control ( Via Occupancy Sensors, CO2 Sensors, Etc.) | 9.00 | 9.00 | 100.00% | 10.00% | 50.00% | 10 | $0.18 | $1.50 |
| 2 | 3 | 280 | 289 | Roof / Ceiling Insulation | 9.00 | 9.00 | 100.00% | 3.00% | 50.00% | 20 | $0.45 | $720.87 |
| 2 | 3 | 280 | 290 | Cool Roofs (Reflective and Spray Evaporative) | 9.00 | 9.00 | 100.00% | 4.30% | 50.00% | 10 | $0.47 | $788.00 |
| 2 | 3 | 280 | 291 | Clock / Programmable Thermostat | 9.00 | 9.00 | 40.20% | 10.00% | 100.00% | 10 | $0.04 | $1.50 |
| 2 | 3 | 280 | 292 | Installation of Air Side Economizers | 9.00 | 9.00 | 55.37% | 15.00% | 100.00% | 10 | $0.59 | $788.00 |
| 2 | 3 | 400 | 400 | Base Fan Motor, 5hp, 1800rpm, 87.5% (ODP) | 3.96 | 3.96 | | 0.00% | | 15 | $0.07 | $0.07 |
| 2 | 3 | 400 | 401 | Energy Efficient Fan & Pump Motors (ODP) | 3.96 | 3.96 | | 1.50% | | 15 | $0.01 | $0.07 |
| 2 | 3 | 400 | 402 | VSD, ASD Fan & Pump Applications | 3.96 | 3.96 | | 30.00% | | 15 | $0.08 | $0.07 |
| 2 | 3 | 500 | 500 | Base Refrigeration System | 5.80 | 5.80 | 100.00% | 0.00% | 100.00% | 10 | $2.00 | $2.00 |
| 2 | 3 | 500 | 501 | High Efficiency Case Fans | 5.80 | 5.80 | 95.00% | 11.98% | 100.00% | 16 | $1.16 | $2.00 |
| 2 | 3 | 500 | 502 | Strip Curtains for Walk-Ins | 5.80 | 5.80 | 30.00% | 4.02% | 100.00% | 4 | $0.05 | $2.00 |
| 2 | 3 | 500 | 503 | Night Covers for Display Cases | 5.80 | 5.80 | 95.00% | 5.80% | 50.00% | 5 | $0.01 | $2.00 |
| 2 | 3 | 500 | 504 | Reduced Speed or Cycling of Evaporator Fans | 5.80 | 5.80 | 80.00% | 0.55% | 100.00% | 5 | $0.09 | $2.00 |
| 2 | 3 | 500 | 505 | High-Efficiency Compressors | 5.80 | 5.80 | 81.00% | 6.83% | 100.00% | 10 | $0.09 | $2.00 |
| 2 | 3 | 500 | 506 | Compressor VSD retrofit | 5.80 | 5.80 | 95.00% | 6.20% | 50.00% | 10 | $0.41 | $2.00 |
| 2 | 3 | 500 | 507 | Installation of Floating Condenser Head Pressure Controls | 5.80 | 5.80 | 44.37% | 6.83% | 100.00% | 14 | $0.12 | $2.00 |
| 2 | 3 | 500 | 508 | Refrigeration Commissioning | 5.80 | 5.80 | 50.00% | 5.00% | 100.00% | 3 | $0.06 | $2.00 |
| 2 | 3 | 500 | 509 | Demand Control Defrost - Hot Gas | 5.80 | 5.80 | 69.57% | 2.51% | 100.00% | 10 | $0.07 | $2.00 |
| 2 | 3 | 500 | 510 | Demand Control Defrost - Electric | 5.80 | 5.80 | 47.98% | 7.76% | 100.00% | 10 | $0.04 | $2.00 |
| 2 | 3 | 500 | 511 | Anti-Sweat (Humidistat) Controls | 5.80 | 5.80 | 47.98% | 4.99% | 100.00% | 12 | $0.02 | $2.00 |
| 2 | 3 | 610 | 610 | Base Office Equipment | 0.23 | 0.23 | 100.00% | 0.00% | 100.00% | 4 | $0.24 | $0.71 |
| 2 | 3 | 610 | 611 | ENERGY STAR or Better Office Equipment: Computer | 0.23 | 0.23 | 65.00% | 18.39% | 100.00% | 4 | $0.03 | $0.71 |
| 2 | 3 | 610 | 621 | ENERGY STAR or Better Office Equipment: Monitors | 0.23 | 0.23 | 71.00% | 16.34% | 100.00% | 4 | $0.02 | $0.71 |
| 2 | 3 | 610 | 623 | Smart Networks | 0.23 | 0.23 | 40.00% | 6.81% | 90.00% | 4 | $0.00 | $0.71 |
| 2 | 3 | 610 | 631 | ENERGY STAR or Better Office Equipment: Copiers | 0.23 | 0.23 | 33.00% | 7.82% | 100.00% | 4 | $0.01 | $0.13 |
| 2 | 3 | 610 | 641 | ENERGY STAR or Better Office Equipment: Printers | 0.23 | 0.23 | 99.00% | 14.96% | 100.00% | 4 | $0.04 | $0.42 |
| 2 | 3 | 700 | 700 | Base Water Heating | 3.05 | 3.05 | 100.00% | 0.00% | 100.00% | 15 | $14.52 | $14.52 |
| 2 | 3 | 700 | 701 | Demand controlled circulating systems | 3.05 | 3.05 | 100.00% | 5.00% | 50.00% | 15 | $2.83 | $14.52 |
| 2 | 3 | 700 | 702 | Heat Pump Water Heater | 3.05 | 3.05 | 100.00% | 30.00% | 75.00% | 15 | $1.80 | $14.52 |
| 2 | 3 | 700 | 703 | High-Efficiency Water Heater (electric) | 3.05 | 3.05 | | 5.40% | | 15 | $0.52 | $14.52 |
| 2 | 3 | 700 | 704 | Hot Water (SHW) Pipe Insulation | 3.05 | 3.05 | 100.00% | 5.00% | 50.00% | 15 | $0.02 | $5.91 |
| 2 | 3 | 800 | 800 | Base Heating | 7.23 | 7.23 | 100.00% | 0.00% | 100.00% | 20 | $2.40 | $2.40 |
| 2 | 3 | 800 | 802 | Roof / Ceiling Insulation | 7.23 | 7.23 | 67.01% | 10.00% | 50.00% | 20 | $0.45 | $2.20 |
| 2 | 3 | 800 | 805 | Clock / Programmable Thermostat | 7.23 | 7.23 | 23.10% | 30.00% | 100.00% | 10 | $0.15 | $2.40 |
| 2 | 3 | 800 | 812 | Installation of Automated Building Ventilation Control ( Via Occupancy Sensors, CO2 Sensors, Etc.) | 7.23 | 7.23 | 100.00% | 5.00% | 50.00% | 15 | $0.28 | $2.40 |
| 2 | 4 | 100 | 100 | Base Cooking | 5.16 | 5.16 | | 0.00% | | 15 | $0.52 | $0.52 |
| 2 | 4 | 100 | 101 | High-Efficiency Convection Oven | 5.16 | 5.16 | | 20.00% | | 15 | $0.44 | $0.52 |
| 2 | 4 | 110 | 110 | Base Fluorescent Fixture, 4' 4L T12, 34W, 2EEMAG | 12.76 | 12.76 | 100.00% | 0.00% | 100.00% | 7 | $1.50 | $1.50 |
| 2 | 4 | 110 | 111 | 4' 4L T8 Premium, EB | 12.76 | 11.49 | 100.00% | 25.00% | 16.67% | 12 | $0.49 | $1.50 |
| 2 | 4 | 110 | 112 | 4' 2L T8 Premium, EB, reflector | 12.76 | 11.49 | 100.00% | 62.50% | 16.67% | 12 | $0.74 | $1.50 |
| 2 | 4 | 110 | 113 | Occupancy Sensor, 4-4' Fluorescent Fixtures | 12.76 | 11.49 | 100.00% | 30.00% | 10.00% | 7 | $0.52 | $1.50 |
| 2 | 4 | 110 | 114 | Continuous Dimming, 5-4' Fluorescent Fixtures | 12.76 | 11.49 | 100.00% | 75.00% | 26.00% | 8 | $3.90 | $1.50 |

## Table B.3: Commercial Electric

| Segment | Building | Base Number | Measure Number | Measure Name | Stock Usage | Base Usage | Incomplete Factor | Energy Savings | Feasibility Factor | Measure Life | Full Per Unit Cost | Full Base Measure Cost |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2 | 4 | 110 | 115 | 4' 2L T5HO, EB | 12.76 | 11.49 | 100.00% | 18.75% | 16.67% | 12 | $0.29 | $1.50 |
| 2 | 4 | 110 | 116 | 4' 4L T8, EB | 12.76 | 11.49 | 100.00% | 22.22% | 16.67% | 12 | $0.20 | $1.50 |
| 2 | 4 | 110 | 117 | 4' 3L T8, EB | 12.76 | 11.49 | 100.00% | 38.20% | 16.67% | 12 | $0.10 | $1.50 |
| 2 | 4 | 110 | 118 | 4' 3L T8 Premium, EB | 12.76 | 11.49 | 100.00% | 42.36% | 16.67% | 12 | $0.31 | $1.50 |
| 2 | 4 | 120 | 120 | Base Fluorescent Fixture, 4' 2L T12, 34W, 1EEMAG | 12.76 | 12.76 | 100.00% | 0.00% | 100.00% | 7 | $2.73 | $2.73 |
| 2 | 4 | 120 | 121 | 4' 2L T8 Premium, EB | 12.76 | 11.49 | 100.00% | 25.00% | 33.33% | 12 | $0.76 | $2.73 |
| 2 | 4 | 120 | 122 | 4' 1L T8 Premium, EB, reflector | 12.76 | 11.49 | 100.00% | 61.11% | 33.33% | 12 | $1.55 | $2.73 |
| 2 | 4 | 120 | 123 | Occupancy Sensor, 8-4' Fluorescent Fixtures | 12.76 | 11.49 | 100.00% | 30.00% | 10.00% | 7 | $0.45 | $2.73 |
| 2 | 4 | 120 | 124 | Continuous Dimming, 10-4' Fluorescent Fixtures | 12.76 | 11.49 | 100.00% | 75.00% | 26.00% | 8 | $3.75 | $2.73 |
| 2 | 4 | 120 | 125 | 4' 1L T5HO, EB | 12.76 | 11.49 | 100.00% | 13.90% | 33.33% | 12 | $0.58 | $2.73 |
| 2 | 4 | 130 | 130 | Base Fluorescent Fixture, 8' 2L T12, 60W, 1EEMAG | 12.76 | 12.76 | 100.00% | 0.00% | 100.00% | 7 | $1.88 | $1.88 |
| 2 | 4 | 130 | 131 | 8' 2L T12, 60W, EB | 12.76 | 11.49 | 54.24% | 10.57% | 25.00% | 12 | $0.18 | $1.88 |
| 2 | 4 | 130 | 132 | 8' 1L T12, 60W, EB, reflector | 12.76 | 11.49 | 100.00% | 55.30% | 25.00% | 12 | $0.82 | $1.88 |
| 2 | 4 | 130 | 133 | Occupancy Sensor, 4-8' Fluorescent Fixtures | 12.76 | 11.49 | 100.00% | 30.00% | 10.00% | 7 | $0.56 | $1.88 |
| 2 | 4 | 130 | 134 | Continuous Dimming, 5-8' Fluorescent Fixtures | 12.76 | 11.49 | 100.00% | 75.00% | 26.00% | 8 | $4.24 | $1.88 |
| 2 | 4 | 130 | 135 | 8' 2L T8, EB | 12.76 | 11.49 | 100.00% | 52.80% | 50.00% | 12 | $0.37 | $1.88 |
| 2 | 4 | 140 | 140 | Base Incandescent Flood, 75W | 12.76 | 12.76 | 100.00% | 0.00% | 100.00% | 1 | $3.83 | $3.83 |
| 2 | 4 | 140 | 141 | CFL Screw-in, Modular 18W | 12.76 | 11.49 | 95.37% | 65.30% | 90.00% | 3 | $2.36 | $3.83 |
| 2 | 4 | 150 | 150 | Base Incandescent Flood, 150W PAR | 12.76 | 12.76 | 100.00% | 0.00% | 100.00% | 1 | $3.29 | $3.29 |
| 2 | 4 | 150 | 151 | Halogen PAR Flood, 90W | 12.76 | 12.76 | 99.55% | 40.00% | 10.00% | 1 | $0.33 | $3.29 |
| 2 | 4 | 150 | 152 | Metal Halide, 50W | 12.76 | 12.76 | 94.33% | 52.00% | 45.00% | 4 | $17.62 | $3.29 |
| 2 | 4 | 150 | 153 | HPS, 50W | 12.76 | 12.76 | 94.33% | 56.00% | 45.00% | 4 | $8.99 | $3.29 |
| 2 | 4 | 160 | 160 | Base 4' 3L T12, 34W, 1EEMAG | 12.76 | 12.76 | 100.00% | 0.00% | 100.00% | 10 | $0.67 | $0.67 |
| 2 | 4 | 160 | 161 | 4' 3L T8, EB | 12.76 | 11.49 | 100.00% | 22.61% | 25.00% | 12 | $0.06 | $0.67 |
| 2 | 4 | 160 | 162 | 4' 3L T8 Premium, EB | 12.76 | 11.49 | 100.00% | 22.61% | 25.00% | 12 | $0.16 | $0.67 |
| 2 | 4 | 160 | 163 | 4' 2L T8 Premium, EB, reflector | 12.76 | 11.49 | 100.00% | 53.04% | 25.00% | 12 | $0.35 | $0.67 |
| 2 | 4 | 160 | 164 | 4' 1L T5HO, EB | 12.76 | 11.49 | 100.00% | 46.09% | 25.00% | 12 | $0.06 | $0.67 |
| 2 | 4 | 180 | 180 | Base Fluorescent Fixture 4' 4L T8, 1EB | 10.21 | 10.21 | 100.00% | 0.00% | 100.00% | 12 | $1.68 | $1.68 |
| 2 | 4 | 180 | 181 | 4' 4L T8 Premium, EB | 10.21 | 9.19 | 100.00% | 3.60% | 100.00% | 12 | $0.30 | $1.68 |
| 2 | 4 | 180 | 182 | Occupancy Sensor, 4-4' Fluorescent Fixtures | 10.21 | 9.19 | 100.00% | 30.00% | 10.00% | 7 | $0.52 | $1.68 |
| 2 | 4 | 185 | 185 | Base Fluorescent Fixture 4' 3L T8, 1EB | 10.21 | 10.21 | 100.00% | 0.00% | 100.00% | 12 | $3.09 | $3.09 |
| 2 | 4 | 185 | 186 | 4' 3L T8 Premium, EB | 10.21 | 9.19 | 100.00% | 6.70% | 100.00% | 12 | $0.42 | $3.09 |
| 2 | 4 | 190 | 190 | Base Fluorescent Fixture 4' 2L T8, 1EB | 10.21 | 8.68 | 100.00% | 0.00% | 100.00% | 12 | $2.91 | $2.91 |
| 2 | 4 | 190 | 191 | 4' 2L T8 Premium, EB | 10.21 | 9.19 | 100.00% | 8.50% | 100.00% | 12 | $0.26 | $2.91 |
| 2 | 4 | 190 | 192 | Occupancy Sensor, 8-4' Fluorescent Fixtures | 10.21 | 9.19 | 100.00% | 30.00% | 10.00% | 7 | $0.45 | $2.91 |
| 2 | 4 | 200 | 200 | Base Centrifugal Chiller, 0.65 kW/ton, 300 tons | 6.72 | 6.72 | 100.00% | 0.00% | 100.00% | 20 | $1.50 | $1.50 |
| 2 | 4 | 200 | 201 | Chiller Tune-Up / Diagnostics | 6.72 | 6.72 | 10.00% | 5.00% | 100.00% | 5 | $0.12 | $1.50 |
| 2 | 4 | 200 | 202 | Installation of Automated Building Ventilation Control ( Via Occupancy Sensors, CO2 Sensors, Etc.) | 6.72 | 6.72 | 100.00% | 10.00% | 50.00% | 10 | $0.32 | $1.50 |
| 2 | 4 | 200 | 203 | Roof / Ceiling Insulation | 6.72 | 6.72 | 20.00% | 3.00% | 50.00% | 20 | $0.48 | $452.64 |
| 2 | 4 | 200 | 204 | Cool Roofs (Reflective and Spray Evaporative) | 6.72 | 6.72 | 100.00% | 4.30% | 90.00% | 10 | $0.47 | $461.00 |
| 2 | 4 | 200 | 205 | EMS Optimization | 6.72 | 6.72 | 50.00% | 1.00% | 100.00% | 5 | $0.00 | $0.00 |
| 2 | 4 | 200 | 206 | High Efficiency Windows (Low-E Glass or Multiple Glazed) | 6.72 | 6.72 | 100.00% | 5.40% | 75.00% | 30 | $0.03 | $18.85 |
| 2 | 4 | 200 | 207 | Installation of Energy Management Systems | 6.72 | 6.72 | 100.00% | 10.00% | 50.00% | 10 | $0.20 | $1.50 |

## Table B.3: Commercial Electric

| Segment | Building | Base Number | Measure Number | Measure Name | Stock Usage | Base Usage | Incomplete Factor | Energy Savings | Feasibility Factor | Measure Life | Full Per Unit Cost | Full Base Measure Cost |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2 | 4 | 200 | 208 | Insulation of Pipes | 6.72 | 6.72 | 50.00% | 1.00% | 50.00% | 20 | $0.01 | $1.07 |
| 2 | 4 | 200 | 209 | Installation of Chiller Economizers (water side) | 6.72 | 6.72 | 100.00% | 10.00% | 50.00% | 20 | $0.59 | $461.00 |
| 2 | 4 | 200 | 210 | Optimize Chilled Water and Condenser Water Settings | 6.72 | 6.72 | 50.00% | 5.00% | 33.00% | 10 | $0.21 | $1.50 |
| 2 | 4 | 200 | 211 | Decrease Cooling Tower Approach Temperature, 300 Tons, 6 Deg F | 6.72 | 6.72 | 90.00% | 7.50% | 67.00% | 15 | $0.11 | $2.33 |
| 2 | 4 | 200 | 212 | Two-Speed Cooling Tower, 300 Tons | 6.72 | 6.72 | 90.00% | 14.00% | 50.00% | 15 | $0.01 | $2.33 |
| 2 | 4 | 200 | 213 | VSD Cooling Tower, 300 Tons | 6.72 | 6.72 | 90.00% | 18.00% | 50.00% | 15 | $0.08 | $2.33 |
| 2 | 4 | 200 | 214 | Primary/Secondary De-coupled Chilled Water System | 6.72 | 6.72 | 80.00% | 12.00% | 50.00% | 15 | $0.49 | $2.33 |
| 2 | 4 | 200 | 215 | HE Chiller, 0.51 kW/ton, 300 Tons | 6.72 | 6.72 | | 21.54% | | 15 | $0.20 | $2.33 |
| 2 | 4 | 200 | 216 | VSD Chiller, 0.47 kW/ton, 300 Tons | 6.72 | 6.72 | | 27.69% | | 15 | $0.65 | $2.33 |
| 2 | 4 | 250 | 250 | Base DX Packaged System, EER=10.3, 10 tons | 11.63 | 11.63 | 100.00% | 0.00% | 100.00% | 15 | $2.56 | $2.56 |
| 2 | 4 | 250 | 251 | DX Tune-Up / Diagnostics | 11.63 | 11.63 | 10.00% | 10.00% | 100.00% | 3 | $0.25 | $2.56 |
| 2 | 4 | 250 | 252 | Hi-Eff DX Packaged System, 10 tons, EER=11.3 | 11.63 | 11.63 | | 8.85% | | 15 | $0.31 | $2.56 |
| 2 | 4 | 250 | 253 | High Efficiency Windows (Low-E Glass or Multiple Glazed) | 11.63 | 11.63 | 100.00% | 5.00% | 75.00% | 30 | $0.07 | $32.23 |
| 2 | 4 | 250 | 254 | Installation of Direct of Indirect Evaporative Cooling, Evaporative Pre-Cooling, and Absorption Cooling | 11.63 | 11.63 | 95.00% | 10.00% | 25.00% | 10 | $0.94 | $2.56 |
| 2 | 4 | 250 | 258 | Installation of Automated Building Ventilation Control ( Via Occupancy Sensors, CO2 Sensors, Etc.) | 11.63 | 11.63 | 100.00% | 10.00% | 50.00% | 10 | $0.32 | $2.56 |
| 2 | 4 | 250 | 259 | Roof / Ceiling Insulation | 11.63 | 11.63 | 20.00% | 3.00% | 50.00% | 20 | $0.48 | $773.71 |
| 2 | 4 | 250 | 260 | Cool Roofs (Reflective and Spray Evaporative) | 11.63 | 11.63 | 100.00% | 4.30% | 50.00% | 10 | $0.47 | $788.00 |
| 2 | 4 | 250 | 261 | Clock / Programmable Thermostat | 11.63 | 11.63 | 42.34% | 10.00% | 100.00% | 10 | $0.07 | $2.56 |
| 2 | 4 | 250 | 262 | Installation of Air Side Economizers | 11.63 | 11.63 | 98.59% | 15.00% | 100.00% | 10 | $0.59 | $788.00 |
| 2 | 4 | 280 | 280 | Base Air-Cooled HP Package, 5 tons, SEER=10 | 11.63 | 11.63 | 100.00% | 0.00% | 100.00% | 15 | $2.33 | $2.33 |
| 2 | 4 | 280 | 281 | Air-Cooled HP Package, 5 tons, SEER=11 | 11.63 | 11.63 | | 9.09% | | 15 | $0.11 | $2.33 |
| 2 | 4 | 280 | 282 | Air-Cooled HP Package, 5 tons, SEER=12 | 11.63 | 11.63 | | 16.67% | | 15 | $0.76 | $2.33 |
| 2 | 4 | 280 | 283 | DX Tune-Up / Diagnostics | 11.63 | 11.63 | 10.00% | 10.00% | 100.00% | 3 | $0.25 | $2.56 |
| 2 | 4 | 280 | 284 | High Efficiency Windows (Low-E Glass or Multiple Glazed) | 11.63 | 11.63 | 100.00% | 5.00% | 75.00% | 30 | $0.07 | $32.23 |
| 2 | 4 | 280 | 285 | Installation of Direct of Indirect Evaporative Cooling, Evaporative Pre-Cooling, and Absorption Cooling | 11.63 | 11.63 | 95.00% | 10.00% | 25.00% | 10 | $0.94 | $2.56 |
| 2 | 4 | 280 | 288 | Installation of Automated Building Ventilation Control ( Via Occupancy Sensors, CO2 Sensors, Etc.) | 11.63 | 11.63 | 100.00% | 10.00% | 50.00% | 10 | $0.32 | $2.56 |
| 2 | 4 | 280 | 289 | Roof / Ceiling Insulation | 11.63 | 11.63 | 20.00% | 3.00% | 50.00% | 20 | $0.48 | $773.71 |
| 2 | 4 | 280 | 290 | Cool Roofs (Reflective and Spray Evaporative) | 11.63 | 11.63 | 100.00% | 4.30% | 50.00% | 10 | $0.47 | $788.00 |
| 2 | 4 | 280 | 291 | Clock / Programmable Thermostat | 11.63 | 11.63 | 42.34% | 10.00% | 100.00% | 10 | $0.07 | $2.56 |
| 2 | 4 | 280 | 292 | Installation of Air Side Economizers | 11.63 | 11.63 | 98.59% | 15.00% | 100.00% | 10 | $0.59 | $788.00 |
| 2 | 4 | 400 | 400 | Base Fan Motor, 5hp, 1800rpm, 87.5% (ODP) | 5.40 | 5.40 | | 0.00% | | 15 | $0.23 | $0.23 |
| 2 | 4 | 400 | 401 | Energy Efficient Fan & Pump Motors (ODP) | 5.40 | 5.40 | | 1.50% | | 15 | $0.05 | $0.23 |
| 2 | 4 | 400 | 402 | VSD, ASD Fan & Pump Applications | 5.40 | 5.40 | | 30.00% | | 15 | $0.26 | $0.23 |
| 2 | 4 | 500 | 500 | Base Refrigeration System | 24.18 | 24.18 | 100.00% | 0.00% | 100.00% | 10 | $2.00 | $2.00 |
| 2 | 4 | 500 | 501 | High Efficiency Case Fans | 24.18 | 24.18 | 95.00% | 11.98% | 100.00% | 16 | $1.16 | $2.00 |
| 2 | 4 | 500 | 502 | Strip Curtains for Walk-Ins | 24.18 | 24.18 | 30.00% | 4.02% | 100.00% | 4 | $0.05 | $2.00 |
| 2 | 4 | 500 | 503 | Night Covers for Display Cases | 24.18 | 24.18 | 95.00% | 5.80% | 50.00% | 5 | $0.01 | $2.00 |
| 2 | 4 | 500 | 504 | Reduced Speed or Cycling of Evaporator Fans | 24.18 | 24.18 | 80.00% | 0.55% | 100.00% | 5 | $0.09 | $2.00 |
| 2 | 4 | 500 | 505 | High-Efficiency Compressors | 24.18 | 24.18 | 81.00% | 6.83% | 100.00% | 10 | $0.09 | $2.00 |
| 2 | 4 | 500 | 506 | Compressor VSD retrofit | 24.18 | 24.18 | 95.00% | 6.20% | 50.00% | 10 | $0.41 | $2.00 |

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## Table B.3: Commercial Electric

| Segment | Building | Base Number | Measure Number | Measure Name | Stock Usage | Base Usage | Incomplete Factor | Energy Savings | Feasibility Factor | Measure Life | Full Per Unit Cost | Full Base Measure Cost |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2 | 4 | 500 | 507 | Installation of Floating Condenser Head Pressure Controls | 24.18 | 24.18 | 44.37% | 6.83% | 100.00% | 14 | $0.12 | $2.00 |
| 2 | 4 | 500 | 508 | Refrigeration Commissioning | 24.18 | 24.18 | 50.00% | 5.00% | 100.00% | 3 | $0.06 | $2.00 |
| 2 | 4 | 500 | 509 | Demand Control Defrost - Hot Gas | 24.18 | 24.18 | 69.57% | 2.51% | 100.00% | 10 | $0.07 | $2.00 |
| 2 | 4 | 500 | 510 | Demand Control Defrost - Electric | 24.18 | 24.18 | 47.98% | 7.76% | 100.00% | 10 | $0.04 | $2.00 |
| 2 | 4 | 500 | 511 | Anti-Sweat (Humidistat) Controls | 24.18 | 24.18 | 47.98% | 4.99% | 100.00% | 12 | $0.02 | $2.00 |
| 2 | 4 | 610 | 610 | Base Office Equipment | 0.41 | 0.41 | 100.00% | 0.00% | 100.00% | 4 | $0.09 | $0.28 |
| 2 | 4 | 610 | 611 | ENERGY STAR or Better Office Equipment: Computer | 0.41 | 0.41 | 65.00% | 17.86% | 100.00% | 4 | $0.01 | $0.28 |
| 2 | 4 | 610 | 621 | ENERGY STAR or Better Office Equipment: Monitors | 0.41 | 0.41 | 71.00% | 15.87% | 100.00% | 4 | $0.01 | $0.28 |
| 2 | 4 | 610 | 623 | Smart Networks | 0.41 | 0.41 | 40.00% | 6.61% | 90.00% | 4 | $0.00 | $0.28 |
| 2 | 4 | 610 | 631 | ENERGY STAR or Better Office Equipment: Copiers | 0.41 | 0.41 | 33.00% | 9.74% | 100.00% | 4 | $0.01 | $0.15 |
| 2 | 4 | 610 | 641 | ENERGY STAR or Better Office Equipment: Printers | 0.41 | 0.41 | 99.00% | 13.04% | 100.00% | 4 | $0.01 | $0.14 |
| 2 | 4 | 700 | 700 | Base Water Heating | 3.05 | 3.05 | 100.00% | 0.00% | 100.00% | 15 | $6.77 | $6.77 |
| 2 | 4 | 700 | 701 | Demand controlled circulating systems | 3.05 | 3.05 | 100.00% | 5.00% | 50.00% | 15 | $1.32 | $6.77 |
| 2 | 4 | 700 | 702 | Heat Pump Water Heater | 3.05 | 3.05 | 100.00% | 30.00% | 75.00% | 15 | $0.84 | $6.77 |
| 2 | 4 | 700 | 703 | High-Efficiency Water Heater (electric) | 3.05 | 3.05 |  | 5.40% |  | 15 | $0.24 | $6.77 |
| 2 | 4 | 700 | 704 | Hot Water (SHW) Pipe Insulation | 3.05 | 3.05 | 100.00% | 5.00% | 50.00% | 15 | $0.01 | $2.32 |
| 2 | 4 | 800 | 800 | Base Heating | 1.37 | 1.37 | 100.00% | 0.00% | 100.00% | 20 | $2.40 | $2.40 |
| 2 | 4 | 800 | 802 | Roof / Ceiling Insulation | 1.37 | 1.37 | 85.03% | 10.00% | 50.00% | 20 | $0.48 | $2.36 |
| 2 | 4 | 800 | 805 | Clock / Programmable Thermostat | 1.37 | 1.37 | 25.00% | 30.00% | 100.00% | 10 | $0.15 | $2.40 |
| 2 | 4 | 800 | 812 | Installation of Automated Building Ventilation Control ( Via Occupancy Sensors, CO2 Sensors, Etc.) | 1.37 | 1.37 | 100.00% | 5.00% | 50.00% | 15 | $0.28 | $2.40 |
| 2 | 5 | 110 | 110 | Base Fluorescent Fixture, 4' 4L T12, 34W, 2EEMAG | 2.94 | 2.94 | 100.00% | 0.00% | 100.00% | 14 | $0.75 | $0.75 |
| 2 | 5 | 110 | 111 | 4' 4L T8 Premium, EB | 2.94 | 2.65 | 100.00% | 25.00% | 16.67% | 22 | $0.25 | $0.75 |
| 2 | 5 | 110 | 112 | 4' 2L T8 Premium, EB, reflector | 2.94 | 2.65 | 100.00% | 62.50% | 16.67% | 22 | $0.37 | $0.75 |
| 2 | 5 | 110 | 113 | Occupancy Sensor, 4-4' Fluorescent Fixtures | 2.94 | 2.65 | 97.95% | 30.00% | 20.00% | 12 | $0.26 | $0.75 |
| 2 | 5 | 110 | 114 | Continuous Dimming, 5-4' Fluorescent Fixtures | 2.94 | 2.65 | 100.00% | 75.00% | 40.00% | 16 | $1.95 | $0.75 |
| 2 | 5 | 110 | 115 | 4' 2L T5HO, EB | 2.94 | 2.65 | 100.00% | 18.75% | 16.67% | 22 | $0.14 | $0.75 |
| 2 | 5 | 110 | 116 | 4' 4L T8, EB | 2.94 | 2.65 | 100.00% | 22.22% | 16.67% | 22 | $0.10 | $0.75 |
| 2 | 5 | 110 | 117 | 4' 3L T8, EB | 2.94 | 2.65 | 100.00% | 38.20% | 16.67% | 22 | $0.05 | $0.75 |
| 2 | 5 | 110 | 118 | 4' 3L T8 Premium, EB | 2.94 | 2.65 | 100.00% | 42.36% | 16.67% | 22 | $0.16 | $0.75 |
| 2 | 5 | 120 | 120 | Base Fluorescent Fixture, 4' 2L T12, 34W, 1EEMAG | 2.94 | 2.94 | 100.00% | 0.00% | 100.00% | 14 | $1.40 | $1.40 |
| 2 | 5 | 120 | 121 | 4' 2L T8 Premium, EB | 2.94 | 2.65 | 100.00% | 25.00% | 33.33% | 22 | $0.39 | $1.40 |
| 2 | 5 | 120 | 122 | 4' 1L T8 Premium, EB, reflector | 2.94 | 2.65 | 100.00% | 61.11% | 33.33% | 22 | $0.80 | $1.40 |
| 2 | 5 | 120 | 123 | Occupancy Sensor, 8-4' Fluorescent Fixtures | 2.94 | 2.65 | 97.95% | 30.00% | 20.00% | 12 | $0.23 | $1.40 |
| 2 | 5 | 120 | 124 | Continuous Dimming, 10-4' Fluorescent Fixtures | 2.94 | 2.65 | 100.00% | 75.00% | 40.00% | 16 | $1.93 | $1.40 |
| 2 | 5 | 120 | 125 | 4' 1L T5HO, EB | 2.94 | 2.65 | 100.00% | 13.90% | 33.33% | 22 | $0.30 | $1.40 |
| 2 | 5 | 130 | 130 | Base Fluorescent Fixture, 8' 2L T12, 60W, 1EEMAG | 2.94 | 2.94 | 100.00% | 0.00% | 100.00% | 14 | $1.06 | $1.06 |
| 2 | 5 | 130 | 131 | 8' 2L T12, 60W, EB | 2.94 | 2.65 | 84.67% | 10.57% | 25.00% | 22 | $0.10 | $1.06 |
| 2 | 5 | 130 | 132 | 8' 1L T12, 60W, EB, reflector | 2.94 | 2.65 | 100.00% | 55.30% | 25.00% | 22 | $0.46 | $1.06 |
| 2 | 5 | 130 | 133 | Occupancy Sensor, 4-8' Fluorescent Fixtures | 2.94 | 2.65 | 97.95% | 30.00% | 20.00% | 12 | $0.32 | $1.06 |
| 2 | 5 | 130 | 134 | Continuous Dimming, 5-8' Fluorescent Fixtures | 2.94 | 2.65 | 100.00% | 75.00% | 40.00% | 16 | $2.39 | $1.06 |
| 2 | 5 | 130 | 135 | 8' 2L T8, EB | 2.94 | 2.65 | 100.00% | 52.80% | 50.00% | 22 | $0.21 | $1.06 |
| 2 | 5 | 140 | 140 | Base Incandescent Flood, 75W | 2.94 | 2.94 | 100.00% | 0.00% | 100.00% | 1 | $2.17 | $2.17 |
| 2 | 5 | 140 | 141 | CFL Screw-in, Modular 18W | 2.94 | 2.65 | 88.72% | 65.30% | 90.00% | 6 | $1.34 | $2.17 |

## Table B.3: Commercial Electric

| Segment | Building | Base Number | Measure Number | Measure Name | Stock Usage | Base Usage | Incomplete Factor | Energy Savings | Feasibility Factor | Measure Life | Full Per Unit Cost | Full Base Measure Cost |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2 | 5 | 150 | 150 | Base Incandescent Flood, 150W PAR | 2.94 | 2.94 | 100.00% | 0.00% | 100.00% | 1 | $0.99 | $0.99 |
| 2 | 5 | 150 | 151 | Halogen PAR Flood, 90W | 2.94 | 2.94 | 100.00% | 40.00% | 10.00% | 1 | $0.10 | $0.99 |
| 2 | 5 | 150 | 152 | Metal Halide, 50W | 2.94 | 2.94 | 90.21% | 52.00% | 45.00% | 7 | $5.28 | $0.99 |
| 2 | 5 | 150 | 153 | HPS, 50W | 2.94 | 2.94 | 90.21% | 56.00% | 45.00% | 7 | $2.69 | $0.99 |
| 2 | 5 | 160 | 160 | Base 4' 3L T12, 34W, 1EEMAG | 2.94 | 2.94 | 100.00% | 0.00% | 100.00% | 10 | $0.07 | $0.07 |
| 2 | 5 | 160 | 161 | 4' 3L T8, EB | 2.94 | 2.65 | 100.00% | 22.61% | 25.00% | 22 | $0.01 | $0.07 |
| 2 | 5 | 160 | 162 | 4' 3L T8 Premium, EB | 2.94 | 2.65 | 100.00% | 22.61% | 25.00% | 22 | $0.02 | $0.07 |
| 2 | 5 | 160 | 163 | 4' 2L T8 Premium, EB, reflector | 2.94 | 2.65 | 100.00% | 53.04% | 25.00% | 22 | $0.04 | $0.07 |
| 2 | 5 | 160 | 164 | 4' 1L T5HO, EB | 2.94 | 2.65 | 100.00% | 46.09% | 25.00% | 22 | $0.01 | $0.07 |
| 2 | 5 | 180 | 180 | Base Fluorescent Fixture 4' 4L T8, 1EB | 2.36 | 2.36 | 100.00% | 0.00% | 100.00% | 22 | $0.84 | $0.84 |
| 2 | 5 | 180 | 181 | 4' 4L T8 Premium, EB | 2.36 | 2.12 | 100.00% | 3.60% | 100.00% | 22 | $0.15 | $0.84 |
| 2 | 5 | 180 | 182 | Occupancy Sensor, 4-4' Fluorescent Fixtures | 2.36 | 2.12 | 97.95% | 30.00% | 20.00% | 12 | $0.26 | $0.84 |
| 2 | 5 | 185 | 185 | Base Fluorescent Fixture 4' 3L T8, 1EB | 2.36 | 2.36 | 100.00% | 0.00% | 100.00% | 22 | $1.59 | $1.59 |
| 2 | 5 | 185 | 186 | 4' 3L T8 Premium, EB | 2.36 | 2.12 | 100.00% | 6.70% | 100.00% | 22 | $0.22 | $1.59 |
| 2 | 5 | 190 | 190 | Base Fluorescent Fixture 4' 2L T8, 1EB | 2.36 | 2.36 | 100.00% | 0.00% | 100.00% | 22 | $1.50 | $1.50 |
| 2 | 5 | 190 | 191 | 4' 2L T8 Premium, EB | 2.36 | 2.12 | 100.00% | 8.50% | 100.00% | 22 | $0.13 | $1.50 |
| 2 | 5 | 190 | 192 | Occupancy Sensor, 8-4' Fluorescent Fixtures | 2.36 | 2.12 | 97.95% | 30.00% | 20.00% | 12 | $0.23 | $1.50 |
| 2 | 5 | 200 | 200 | Base Centrifugal Chiller, 0.65 kW/ton, 300 tons | 1.59 | 1.59 | 100.00% | 0.00% | 100.00% | 20 | $0.41 | $0.41 |
| 2 | 5 | 200 | 201 | Chiller Tune-Up / Diagnostics | 1.59 | 1.59 | 10.00% | 5.00% | 100.00% | 5 | $0.03 | $0.41 |
| 2 | 5 | 200 | 202 | Installation of Automated Building Ventilation Control ( Via Occupancy Sensors, CO2 Sensors, Etc.) | 1.59 | 1.59 | 100.00% | 10.00% | 50.00% | 10 | $0.09 | $0.41 |
| 2 | 5 | 200 | 203 | Roof / Ceiling Insulation | 1.59 | 1.59 | 20.00% | 3.00% | 50.00% | 20 | $0.45 | $426.61 |
| 2 | 5 | 200 | 204 | Cool Roofs (Reflective and Spray Evaporative) | 1.59 | 1.59 | 100.00% | 4.30% | 90.00% | 10 | $0.47 | $461.00 |
| 2 | 5 | 200 | 205 | EMS Optimization | 1.59 | 1.59 | 50.00% | 1.00% | 100.00% | 5 | $0.00 | $0.00 |
| 2 | 5 | 200 | 206 | High Efficiency Windows (Low-E Glass or Multiple Glazed) | 1.59 | 1.59 | 100.00% | 5.40% | 75.00% | 30 | $0.01 | $7.87 |
| 2 | 5 | 200 | 207 | Installation of Energy Management Systems | 1.59 | 1.59 | 80.00% | 10.00% | 50.00% | 10 | $0.05 | $0.41 |
| 2 | 5 | 200 | 208 | Insulation of Pipes | 1.59 | 1.59 | 50.00% | 1.00% | 50.00% | 20 | $0.00 | $0.19 |
| 2 | 5 | 200 | 209 | Installation of Chiller Economizers (water side) | 1.59 | 1.59 | 100.00% | 10.00% | 50.00% | 20 | $0.59 | $461.00 |
| 2 | 5 | 200 | 210 | Optimize Chilled Water and Condenser Water Settings | 1.59 | 1.59 | 50.00% | 5.00% | 33.00% | 10 | $0.06 | $0.41 |
| 2 | 5 | 200 | 211 | Decrease Cooling Tower Approach Temperature, 300 Tons, 6 Deg F | 1.59 | 1.59 | 90.00% | 7.50% | 67.00% | 15 | $0.03 | $0.64 |
| 2 | 5 | 200 | 212 | Two-Speed Cooling Tower, 300 Tons | 1.59 | 1.59 | 90.00% | 14.00% | 50.00% | 15 | $0.00 | $0.64 |
| 2 | 5 | 200 | 213 | VSD Cooling Tower, 300 Tons | 1.59 | 1.59 | 90.00% | 18.00% | 50.00% | 15 | $0.02 | $0.64 |
| 2 | 5 | 200 | 214 | Primary/Secondary De-coupled Chilled Water System | 1.59 | 1.59 | 80.00% | 12.00% | 50.00% | 15 | $0.14 | $0.64 |
| 2 | 5 | 200 | 215 | HE Chiller, 0.51 kW/ton, 300 Tons | 1.59 | 1.59 | | 21.54% | | 15 | $0.05 | $0.64 |
| 2 | 5 | 200 | 216 | VSD Chiller, 0.47 kW/ton, 300 Tons | 1.59 | 1.59 | | 27.69% | | 15 | $0.18 | $0.64 |
| 2 | 5 | 250 | 250 | Base DX Packaged System, EER=10.3, 10 tons | 2.75 | 2.75 | 100.00% | 0.00% | 100.00% | 15 | $0.71 | $0.71 |
| 2 | 5 | 250 | 251 | DX Tune-Up / Diagnostics | 2.75 | 2.75 | 10.00% | 10.00% | 100.00% | 3 | $0.07 | $0.71 |
| 2 | 5 | 250 | 252 | Hi-Eff DX Packaged System, 10 tons, EER=11.3 | 2.75 | 2.75 | | 8.85% | | 15 | $0.09 | $0.71 |
| 2 | 5 | 250 | 253 | High Efficiency Windows (Low-E Glass or Multiple Glazed) | 2.75 | 2.75 | 100.00% | 5.00% | 75.00% | 30 | $0.03 | $13.45 |
| 2 | 5 | 250 | 254 | Installation of Direct of Indirect Evaporative Cooling, Evaporative Pre-Cooling, and Absorption Cooling | 2.75 | 2.75 | 95.00% | 10.00% | 25.00% | 10 | $0.26 | $0.71 |
| 2 | 5 | 250 | 258 | Installation of Automated Building Ventilation Control ( Via Occupancy Sensors, CO2 Sensors, Etc.) | 2.75 | 2.75 | 100.00% | 10.00% | 50.00% | 10 | $0.09 | $0.71 |

## Table B.3: Commercial Electric

| Segment | Building | Base Number | Measure Number | Measure Name | Stock Usage | Base Usage | Incomplete Factor | Energy Savings | Feasibility Factor | Measure Life | Full Per Unit Cost | Full Base Measure Cost |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2 | 5 | 250 | 259 | Roof / Ceiling Insulation | 2.75 | 2.75 | 20.00% | 3.00% | 50.00% | 20 | $0.45 | $729.22 |
| 2 | 5 | 250 | 260 | Cool Roofs (Reflective and Spray Evaporative) | 2.75 | 2.75 | 100.00% | 4.30% | 50.00% | 10 | $0.47 | $788.00 |
| 2 | 5 | 250 | 261 | Clock / Programmable Thermostat | 2.75 | 2.75 | 23.28% | 10.00% | 100.00% | 10 | $0.02 | $0.71 |
| 2 | 5 | 250 | 262 | Installation of Air Side Economizers | 2.75 | 2.75 | 53.45% | 15.00% | 100.00% | 10 | $0.59 | $788.00 |
| 2 | 5 | 280 | 280 | Base Air-Cooled HP Package, 5 tons, SEER=10 | 2.75 | 2.75 | 100.00% | 0.00% | 100.00% | 15 | $0.64 | $0.64 |
| 2 | 5 | 280 | 281 | Air-Cooled HP Package, 5 tons, SEER=11 | 2.75 | 2.75 | | 9.09% | | 15 | $0.03 | $0.64 |
| 2 | 5 | 280 | 282 | Air-Cooled HP Package, 5 tons, SEER=12 | 2.75 | 2.75 | | 16.67% | | 15 | $0.21 | $0.64 |
| 2 | 5 | 280 | 283 | DX Tune-Up / Diagnostics | 2.75 | 2.75 | 10.00% | 10.00% | 100.00% | 3 | $0.07 | $0.71 |
| 2 | 5 | 280 | 284 | High Efficiency Windows (Low-E Glass or Multiple Glazed) | 2.75 | 2.75 | 100.00% | 5.00% | 75.00% | 30 | $0.03 | $13.45 |
| 2 | 5 | 280 | 285 | Installation of Direct of Indirect Evaporative Cooling, Evaporative Pre-Cooling, and Absorption Cooling | 2.75 | 2.75 | 95.00% | 10.00% | 25.00% | 10 | $0.26 | $0.71 |
| 2 | 5 | 280 | 288 | Installation of Automated Building Ventilation Control ( Via Occupancy Sensors, CO2 Sensors, Etc.) | 2.75 | 2.75 | 100.00% | 10.00% | 50.00% | 10 | $0.09 | $0.71 |
| 2 | 5 | 280 | 289 | Roof / Ceiling Insulation | 2.75 | 2.75 | 20.00% | 3.00% | 50.00% | 20 | $0.45 | $729.22 |
| 2 | 5 | 280 | 290 | Cool Roofs (Reflective and Spray Evaporative) | 2.75 | 2.75 | 100.00% | 4.30% | 50.00% | 10 | $0.47 | $788.00 |
| 2 | 5 | 280 | 291 | Clock / Programmable Thermostat | 2.75 | 2.75 | 23.28% | 10.00% | 100.00% | 10 | $0.02 | $0.71 |
| 2 | 5 | 280 | 292 | Installation of Air Side Economizers | 2.75 | 2.75 | 53.45% | 15.00% | 100.00% | 10 | $0.59 | $788.00 |
| 2 | 5 | 400 | 400 | Base Fan Motor, 5hp, 1800rpm, 87.5% (ODP) | 1.71 | 1.71 | | 0.00% | | 15 | $0.11 | $0.11 |
| 2 | 5 | 400 | 401 | Energy Efficient Fan & Pump Motors (ODP) | 1.71 | 1.71 | | 1.50% | | 15 | $0.02 | $0.11 |
| 2 | 5 | 400 | 402 | VSD, ASD Fan & Pump Applications | 1.71 | 1.71 | | 30.00% | | 15 | $0.13 | $0.11 |
| 2 | 5 | 610 | 610 | Base Office Equipment | 0.15 | 0.15 | 100.00% | 0.00% | 100.00% | 4 | $0.79 | $2.32 |
| 2 | 5 | 610 | 611 | ENERGY STAR or Better Office Equipment: Computer | 0.15 | 0.15 | 65.00% | 20.96% | 100.00% | 4 | $0.10 | $2.32 |
| 2 | 5 | 610 | 621 | ENERGY STAR or Better Office Equipment: Monitors | 0.15 | 0.15 | 71.00% | 18.62% | 100.00% | 4 | $0.05 | $2.32 |
| 2 | 5 | 610 | 623 | Smart Networks | 0.15 | 0.15 | 40.00% | 7.76% | 90.00% | 4 | $0.00 | $2.32 |
| 2 | 5 | 610 | 631 | ENERGY STAR or Better Office Equipment: Copiers | 0.15 | 0.15 | 33.00% | 7.07% | 100.00% | 4 | $0.02 | $0.25 |
| 2 | 5 | 610 | 641 | ENERGY STAR or Better Office Equipment: Printers | 0.15 | 0.15 | 99.00% | 11.42% | 100.00% | 4 | $0.06 | $0.74 |
| 2 | 5 | 700 | 700 | Base Water Heating | 0.33 | 0.33 | 100.00% | 0.00% | 100.00% | 15 | $0.85 | $0.85 |
| 2 | 5 | 700 | 701 | Demand controlled circulating systems | 0.33 | 0.33 | 100.00% | 5.00% | 50.00% | 15 | $0.17 | $0.85 |
| 2 | 5 | 700 | 702 | Heat Pump Water Heater | 0.33 | 0.33 | 100.00% | 30.00% | 75.00% | 15 | $0.11 | $0.85 |
| 2 | 5 | 700 | 703 | High-Efficiency Water Heater (electric) | 0.33 | 0.33 | | 5.40% | | 15 | $0.03 | $0.85 |
| 2 | 5 | 700 | 704 | Hot Water (SHW) Pipe Insulation | 0.33 | 0.33 | 95.22% | 5.00% | 50.00% | 15 | $0.00 | $0.42 |
| 2 | 5 | 800 | 800 | Base Heating | 0.79 | 0.79 | 100.00% | 0.00% | 100.00% | 20 | $2.40 | $2.40 |
| 2 | 5 | 800 | 802 | Roof / Ceiling Insulation | 0.79 | 0.79 | 33.67% | 10.00% | 50.00% | 20 | $0.45 | $2.22 |
| 2 | 5 | 800 | 805 | Clock / Programmable Thermostat | 0.79 | 0.79 | 20.92% | 30.00% | 100.00% | 10 | $0.15 | $2.40 |
| 2 | 5 | 800 | 812 | Installation of Automated Building Ventilation Control ( Via Occupancy Sensors, CO2 Sensors, Etc.) | 0.79 | 0.79 | 100.00% | 5.00% | 50.00% | 15 | $0.28 | $2.40 |
| 2 | 6 | 100 | 100 | Base Cooking | 0.36 | 0.36 | | 0.00% | | 15 | $0.24 | $0.24 |
| 2 | 6 | 100 | 101 | High-Efficiency Convection Oven | 0.36 | 0.36 | | 20.00% | | 15 | $0.20 | $0.24 |
| 2 | 6 | 110 | 110 | Base Fluorescent Fixture, 4' 4L T12, 34W, 2EEMAG | 2.68 | 2.68 | 100.00% | 0.00% | 100.00% | 22 | $1.35 | $1.35 |
| 2 | 6 | 110 | 111 | 4' 4L T8 Premium, EB | 2.68 | 2.41 | 100.00% | 25.00% | 16.67% | 34 | $0.44 | $1.35 |
| 2 | 6 | 110 | 112 | 4' 2L T8 Premium, EB, reflector | 2.68 | 2.41 | 100.00% | 62.50% | 16.67% | 34 | $0.66 | $1.35 |
| 2 | 6 | 110 | 113 | Occupancy Sensor, 4-4' Fluorescent Fixtures | 2.68 | 2.41 | 94.74% | 30.00% | 50.00% | 20 | $0.47 | $1.35 |
| 2 | 6 | 110 | 114 | Continuous Dimming, 5-4' Fluorescent Fixtures | 2.68 | 2.41 | 100.00% | 75.00% | 30.00% | 24 | $3.52 | $1.35 |
| 2 | 6 | 110 | 115 | 4' 2L T5HO, EB | 2.68 | 2.41 | 100.00% | 18.75% | 16.67% | 34 | $0.26 | $1.35 |

## Table B.3: Commercial Electric

| Segment | Building | Base Number | Measure Number | Measure Name | Stock Usage | Base Usage | Incomplete Factor | Energy Savings | Feasibility Factor | Measure Life | Full Per Unit Cost | Full Base Measure Cost |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2 | 6 | 110 | 116 | 4' 4L T8, EB | 2.68 | 2.41 | 100.00% | 22.22% | 16.67% | 34 | $0.18 | $1.35 |
| 2 | 6 | 110 | 117 | 4' 3L T8, EB | 2.68 | 2.41 | 100.00% | 38.20% | 16.67% | 34 | $0.09 | $1.35 |
| 2 | 6 | 110 | 118 | 4' 3L T8 Premium, EB | 2.68 | 2.41 | 100.00% | 42.36% | 16.67% | 34 | $0.28 | $1.35 |
| 2 | 6 | 120 | 120 | Base Fluorescent Fixture, 4' 2L T12, 34W, 1EEMAG | 2.68 | 2.68 | 100.00% | 0.00% | 100.00% | 22 | $2.46 | $2.46 |
| 2 | 6 | 120 | 121 | 4' 2L T8 Premium, EB | 2.68 | 2.41 | 100.00% | 25.00% | 33.33% | 34 | $0.69 | $2.46 |
| 2 | 6 | 120 | 122 | 4' 1L T8 Premium, EB, reflector | 2.68 | 2.41 | 100.00% | 61.11% | 33.33% | 34 | $1.40 | $2.46 |
| 2 | 6 | 120 | 123 | Occupancy Sensor, 8-4' Fluorescent Fixtures | 2.68 | 2.41 | 94.74% | 30.00% | 50.00% | 20 | $0.40 | $2.46 |
| 2 | 6 | 120 | 124 | Continuous Dimming, 10-4' Fluorescent Fixtures | 2.68 | 2.41 | 100.00% | 75.00% | 30.00% | 24 | $3.38 | $2.46 |
| 2 | 6 | 120 | 125 | 4' 1L T5HO, EB | 2.68 | 2.41 | 100.00% | 13.90% | 33.33% | 34 | $0.52 | $2.46 |
| 2 | 6 | 130 | 130 | Base Fluorescent Fixture, 8' 2L T12, 60W, 1EEMAG | 2.68 | 2.68 | 100.00% | 0.00% | 100.00% | 22 | $1.83 | $1.83 |
| 2 | 6 | 130 | 131 | 8' 2L T12, 60W, EB | 2.68 | 2.41 | 32.87% | 10.57% | 25.00% | 34 | $0.17 | $1.83 |
| 2 | 6 | 130 | 132 | 8' 1L T12, 60W, EB, reflector | 2.68 | 2.41 | 100.00% | 55.30% | 25.00% | 34 | $0.79 | $1.83 |
| 2 | 6 | 130 | 133 | Occupancy Sensor, 4-8' Fluorescent Fixtures | 2.68 | 2.41 | 94.74% | 30.00% | 50.00% | 20 | $0.55 | $1.83 |
| 2 | 6 | 130 | 134 | Continuous Dimming, 5-8' Fluorescent Fixtures | 2.68 | 2.41 | 100.00% | 75.00% | 30.00% | 24 | $4.12 | $1.83 |
| 2 | 6 | 130 | 135 | 8' 2L T8, EB | 2.68 | 2.41 | 100.00% | 52.80% | 50.00% | 34 | $0.36 | $1.83 |
| 2 | 6 | 140 | 140 | Base Incandescent Flood, 75W | 2.68 | 2.68 | 100.00% | 0.00% | 100.00% | 1 | $3.12 | $3.12 |
| 2 | 6 | 140 | 141 | CFL Screw-in, Modular 18W | 2.68 | 2.41 | 88.39% | 65.30% | 90.00% | 10 | $1.92 | $3.12 |
| 2 | 6 | 150 | 150 | Base Incandescent Flood, 150W PAR | 2.68 | 2.68 | 100.00% | 0.00% | 100.00% | 1 | $0.76 | $0.76 |
| 2 | 6 | 150 | 151 | Halogen PAR Flood, 90W | 2.68 | 2.68 | 97.31% | 40.00% | 10.00% | 1 | $0.08 | $0.76 |
| 2 | 6 | 150 | 152 | Metal Halide, 50W | 2.68 | 2.68 | 85.51% | 52.00% | 45.00% | 12 | $4.09 | $0.76 |
| 2 | 6 | 150 | 153 | HPS, 50W | 2.68 | 2.68 | 85.51% | 56.00% | 45.00% | 12 | $2.09 | $0.76 |
| 2 | 6 | 160 | 160 | Base 4' 3L T12, 34W, 1EEMAG | 2.68 | 2.68 | 100.00% | 0.00% | 100.00% | 10 | $0.45 | $0.45 |
| 2 | 6 | 160 | 161 | 4' 3L T8, EB | 2.68 | 2.41 | 100.00% | 22.61% | 25.00% | 34 | $0.04 | $0.45 |
| 2 | 6 | 160 | 162 | 4' 3L T8 Premium, EB | 2.68 | 2.41 | 100.00% | 22.61% | 25.00% | 34 | $0.10 | $0.45 |
| 2 | 6 | 160 | 163 | 4' 2L T8 Premium, EB, reflector | 2.68 | 2.41 | 100.00% | 53.04% | 25.00% | 34 | $0.23 | $0.45 |
| 2 | 6 | 160 | 164 | 4' 1L T5HO, EB | 2.68 | 2.41 | 100.00% | 46.09% | 25.00% | 34 | $0.04 | $0.45 |
| 2 | 6 | 180 | 180 | Base Fluorescent Fixture 4' 4L T8, 1EB | 2.14 | 2.14 | 100.00% | 0.00% | 100.00% | 34 | $1.51 | $1.51 |
| 2 | 6 | 180 | 181 | 4' 4L T8 Premium, EB | 2.14 | 1.93 | 100.00% | 3.60% | 100.00% | 34 | $0.27 | $1.51 |
| 2 | 6 | 180 | 182 | Occupancy Sensor, 4-4' Fluorescent Fixtures | 2.14 | 1.93 | 94.74% | 30.00% | 50.00% | 20 | $0.47 | $1.51 |
| 2 | 6 | 185 | 185 | Base Fluorescent Fixture 4' 3L T8, 1EB | 2.14 | 2.14 | 100.00% | 0.00% | 100.00% | 34 | $2.79 | $2.79 |
| 2 | 6 | 185 | 186 | 4' 3L T8 Premium, EB | 2.14 | 1.93 | 100.00% | 6.70% | 100.00% | 34 | $0.38 | $2.79 |
| 2 | 6 | 190 | 190 | Base Fluorescent Fixture 4' 2L T8, 1EB | 2.14 | 2.14 | 100.00% | 0.00% | 100.00% | 34 | $2.62 | $2.62 |
| 2 | 6 | 190 | 191 | 4' 2L T8 Premium, EB | 2.14 | 1.93 | 100.00% | 8.50% | 100.00% | 34 | $0.24 | $2.62 |
| 2 | 6 | 190 | 192 | Occupancy Sensor, 8-4' Fluorescent Fixtures | 2.14 | 1.93 | 94.74% | 30.00% | 50.00% | 20 | $0.40 | $2.62 |
| 2 | 6 | 200 | 200 | Base Centrifugal Chiller, 0.65 kW/ton, 300 tons | 0.30 | 0.30 | 100.00% | 0.00% | 100.00% | 20 | $1.04 | $1.04 |
| 2 | 6 | 200 | 201 | Chiller Tune-Up / Diagnostics | 0.30 | 0.30 | 10.00% | 5.00% | 100.00% | 5 | $0.08 | $1.04 |
| 2 | 6 | 200 | 202 | Installation of Automated Building Ventilation Control ( Via Occupancy Sensors, CO2 Sensors, Etc.) | 0.30 | 0.30 | 100.00% | 10.00% | 50.00% | 10 | $0.22 | $1.04 |
| 2 | 6 | 200 | 203 | Roof / Ceiling Insulation | 0.30 | 0.30 | 23.44% | 3.00% | 50.00% | 20 | $0.47 | $439.21 |
| 2 | 6 | 200 | 204 | Cool Roofs (Reflective and Spray Evaporative) | 0.30 | 0.30 | 100.00% | 6.14% | 90.00% | 10 | $0.24 | $230.50 |
| 2 | 6 | 200 | 205 | EMS Optimization | 0.30 | 0.30 | 50.00% | 1.00% | 100.00% | 5 | $0.00 | $0.00 |
| 2 | 6 | 200 | 206 | High Efficiency Windows (Low-E Glass or Multiple Glazed) | 0.30 | 0.30 | 66.00% | 3.89% | 75.00% | 30 | $0.02 | $11.17 |
| 2 | 6 | 200 | 207 | Installation of Energy Management Systems | 0.30 | 0.30 | 70.68% | 10.00% | 50.00% | 10 | $0.14 | $1.04 |
| 2 | 6 | 200 | 208 | Insulation of Pipes | 0.30 | 0.30 | 50.00% | 1.00% | 50.00% | 20 | $0.02 | $1.74 |

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## Table B.3: Commercial Electric

| Segment | Building | Base Number | Measure Number | Measure Name | Stock Usage | Base Usage | Incomplete Factor | Energy Savings | Feasibility Factor | Measure Life | Full Per Unit Cost | Full Base Measure Cost |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2 | 6 | 200 | 209 | Installation of Chiller Economizers (water side) | 0.30 | 0.30 | 81.26% | 10.00% | 50.00% | 20 | $0.59 | $461.00 |
| 2 | 6 | 200 | 210 | Optimize Chilled Water and Condenser Water Settings | 0.30 | 0.30 | 50.00% | 5.00% | 33.00% | 10 | $0.15 | $1.04 |
| 2 | 6 | 200 | 211 | Decrease Cooling Tower Approach Temperature, 300 Tons, 6 Deg F | 0.30 | 0.30 | 90.00% | 7.50% | 67.00% | 15 | $0.08 | $1.61 |
| 2 | 6 | 200 | 212 | Two-Speed Cooling Tower, 300 Tons | 0.30 | 0.30 | 90.00% | 14.00% | 50.00% | 15 | $0.01 | $1.61 |
| 2 | 6 | 200 | 213 | VSD Cooling Tower, 300 Tons | 0.30 | 0.30 | 90.00% | 18.00% | 50.00% | 15 | $0.05 | $1.61 |
| 2 | 6 | 200 | 214 | Primary/Secondary De-coupled Chilled Water System | 0.30 | 0.30 | 80.00% | 12.00% | 50.00% | 15 | $0.34 | $1.61 |
| 2 | 6 | 200 | 215 | HE Chiller, 0.51 kW/ton, 300 Tons | 0.30 | 0.30 | | 21.54% | | 15 | $0.14 | $1.61 |
| 2 | 6 | 200 | 216 | VSD Chiller, 0.47 kW/ton, 300 Tons | 0.30 | 0.30 | | 27.69% | | 15 | $0.45 | $1.61 |
| 2 | 6 | 250 | 250 | Base DX Packaged System, EER=10.3, 10 tons | 0.52 | 0.52 | 100.00% | 0.00% | 100.00% | 15 | $1.77 | $1.77 |
| 2 | 6 | 250 | 251 | DX Tune-Up / Diagnostics | 0.52 | 0.52 | 10.00% | 10.00% | 100.00% | 3 | $0.18 | $1.77 |
| 2 | 6 | 250 | 252 | Hi-Eff DX Packaged System, 10 tons, EER=11.3 | 0.52 | 0.52 | | 8.85% | | 15 | $0.21 | $1.77 |
| 2 | 6 | 250 | 253 | High Efficiency Windows (Low-E Glass or Multiple Glazed) | 0.52 | 0.52 | 66.00% | 5.00% | 75.00% | 30 | $0.04 | $19.09 |
| 2 | 6 | 250 | 254 | Installation of Direct of Indirect Evaporative Cooling, Evaporative Pre-Cooling, and Absorption Cooling | 0.52 | 0.52 | 95.00% | 10.00% | 25.00% | 10 | $0.65 | $1.77 |
| 2 | 6 | 250 | 258 | Installation of Automated Building Ventilation Control ( Via Occupancy Sensors, CO2 Sensors, Etc.) | 0.52 | 0.52 | 100.00% | 10.00% | 50.00% | 10 | $0.22 | $1.77 |
| 2 | 6 | 250 | 259 | Roof / Ceiling Insulation | 0.52 | 0.52 | 23.44% | 3.00% | 50.00% | 20 | $0.47 | $750.76 |
| 2 | 6 | 250 | 260 | Cool Roofs (Reflective and Spray Evaporative) | 0.52 | 0.52 | 100.00% | 6.14% | 50.00% | 10 | $0.24 | $394.00 |
| 2 | 6 | 250 | 261 | Clock / Programmable Thermostat | 0.52 | 0.52 | 20.54% | 10.00% | 100.00% | 10 | $0.05 | $1.77 |
| 2 | 6 | 250 | 262 | Installation of Air Side Economizers | 0.52 | 0.52 | 41.07% | 15.00% | 100.00% | 10 | $0.59 | $788.00 |
| 2 | 6 | 280 | 280 | Base Air-Cooled HP Package, 5 tons, SEER=10 | 0.52 | 0.52 | 100.00% | 0.00% | 100.00% | 15 | $1.61 | $1.61 |
| 2 | 6 | 280 | 281 | Air-Cooled HP Package, 5 tons, SEER=11 | 0.52 | 0.52 | | 9.09% | | 15 | $0.08 | $1.61 |
| 2 | 6 | 280 | 282 | Air-Cooled HP Package, 5 tons, SEER=12 | 0.52 | 0.52 | | 16.67% | | 15 | $0.53 | $1.61 |
| 2 | 6 | 280 | 283 | DX Tune-Up / Diagnostics | 0.52 | 0.52 | 10.00% | 10.00% | 100.00% | 3 | $0.18 | $1.77 |
| 2 | 6 | 280 | 284 | High Efficiency Windows (Low-E Glass or Multiple Glazed) | 0.52 | 0.52 | 66.00% | 5.00% | 75.00% | 30 | $0.04 | $19.09 |
| 2 | 6 | 280 | 285 | Installation of Direct of Indirect Evaporative Cooling, Evaporative Pre-Cooling, and Absorption Cooling | 0.52 | 0.52 | 95.00% | 10.00% | 25.00% | 10 | $0.65 | $1.77 |
| 2 | 6 | 280 | 288 | Installation of Automated Building Ventilation Control ( Via Occupancy Sensors, CO2 Sensors, Etc.) | 0.52 | 0.52 | 100.00% | 10.00% | 50.00% | 10 | $0.22 | $1.77 |
| 2 | 6 | 280 | 289 | Roof / Ceiling Insulation | 0.52 | 0.52 | 23.44% | 3.00% | 50.00% | 20 | $0.47 | $750.76 |
| 2 | 6 | 280 | 290 | Cool Roofs (Reflective and Spray Evaporative) | 0.52 | 0.52 | 100.00% | 6.14% | 50.00% | 10 | $0.24 | $394.00 |
| 2 | 6 | 280 | 291 | Clock / Programmable Thermostat | 0.52 | 0.52 | 20.54% | 10.00% | 100.00% | 10 | $0.05 | $1.77 |
| 2 | 6 | 280 | 292 | Installation of Air Side Economizers | 0.52 | 0.52 | 41.07% | 15.00% | 100.00% | 10 | $0.59 | $788.00 |
| 2 | 6 | 400 | 400 | Base Fan Motor, 5hp, 1800rpm, 87.5% (ODP) | 0.75 | 0.75 | | 0.00% | | 15 | $0.09 | $0.09 |
| 2 | 6 | 400 | 401 | Energy Efficient Fan & Pump Motors (ODP) | 0.75 | 0.75 | | 1.50% | | 15 | $0.02 | $0.09 |
| 2 | 6 | 400 | 402 | VSD, ASD Fan & Pump Applications | 0.75 | 0.75 | | 30.00% | | 15 | $0.10 | $0.09 |
| 2 | 6 | 610 | 610 | Base Office Equipment | 0.11 | 0.11 | 100.00% | 0.00% | 100.00% | 4 | $0.93 | $2.72 |
| 2 | 6 | 610 | 611 | ENERGY STAR or Better Office Equipment: Computer | 0.11 | 0.11 | 65.00% | 19.52% | 100.00% | 4 | $0.12 | $2.72 |
| 2 | 6 | 610 | 621 | ENERGY STAR or Better Office Equipment: Monitors | 0.11 | 0.11 | 71.00% | 17.34% | 100.00% | 4 | $0.06 | $2.72 |
| 2 | 6 | 610 | 623 | Smart Networks | 0.11 | 0.11 | 40.00% | 7.22% | 90.00% | 4 | $0.00 | $2.72 |
| 2 | 6 | 610 | 631 | ENERGY STAR or Better Office Equipment: Copiers | 0.11 | 0.11 | 33.00% | 8.96% | 100.00% | 4 | $0.01 | $0.17 |
| 2 | 6 | 610 | 641 | ENERGY STAR or Better Office Equipment: Printers | 0.11 | 0.11 | 99.00% | 11.20% | 100.00% | 4 | $0.06 | $0.75 |
| 2 | 6 | 700 | 700 | Base Water Heating | 0.64 | 0.64 | 100.00% | 0.00% | 100.00% | 15 | $20.37 | $20.37 |
| 2 | 6 | 700 | 701 | Demand controlled circulating systems | 0.64 | 0.64 | 100.00% | 5.00% | 50.00% | 15 | $3.97 | $20.37 |

# Table B.3: Commercial Electric

| Segment | Building | Base Number | Measure Number | Measure Name | Stock Usage | Base Usage | Incomplete Factor | Energy Savings | Feasibility Factor | Measure Life | Full Per Unit Cost | Full Base Measure Cost |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2 | 6 | 700 | 702 | Heat Pump Water Heater | 0.64 | 0.64 | 87.24% | 30.00% | 75.00% | 15 | $2.53 | $20.37 |
| 2 | 6 | 700 | 703 | High-Efficiency Water Heater (electric) | 0.64 | 0.64 | | 5.40% | | 15 | $0.73 | $20.37 |
| 2 | 6 | 700 | 704 | Hot Water (SHW) Pipe Insulation | 0.64 | 0.64 | 9.88% | 5.00% | 50.00% | 15 | $0.02 | $3.77 |
| 2 | 6 | 800 | 800 | Base Heating | 9.71 | 9.71 | 100.00% | 0.00% | 100.00% | 20 | $2.40 | $2.40 |
| 2 | 6 | 800 | 802 | Roof / Ceiling Insulation | 9.71 | 9.71 | 44.94% | 10.00% | 50.00% | 20 | $0.47 | $2.29 |
| 2 | 6 | 800 | 805 | Clock / Programmable Thermostat | 9.71 | 9.71 | 20.54% | 30.00% | 100.00% | 10 | $0.15 | $2.40 |
| 2 | 6 | 800 | 812 | Installation of Automated Building Ventilation Control ( Via Occupancy Sensors, CO2 Sensors, Etc.) | 9.71 | 9.71 | 100.00% | 5.00% | 50.00% | 15 | $0.28 | $2.40 |
| 2 | 7 | 110 | 110 | Base Fluorescent Fixture, 4' 4L T12, 34W, 2EEMAG | 5.29 | 5.29 | 100.00% | 0.00% | 100.00% | 21 | $1.27 | $1.27 |
| 2 | 7 | 110 | 111 | 4' 4L T8 Premium, EB | 5.29 | 4.77 | 100.00% | 25.00% | 16.67% | 32 | $0.42 | $1.27 |
| 2 | 7 | 110 | 112 | 4' 2L T8 Premium, EB, reflector | 5.29 | 4.77 | 100.00% | 62.50% | 16.67% | 32 | $0.62 | $1.27 |
| 2 | 7 | 110 | 113 | Occupancy Sensor, 4-4' Fluorescent Fixtures | 5.29 | 4.77 | 90.00% | 30.00% | 50.00% | 19 | $0.44 | $1.27 |
| 2 | 7 | 110 | 114 | Continuous Dimming, 5-4' Fluorescent Fixtures | 5.29 | 4.77 | 100.00% | 75.00% | 30.00% | 23 | $3.30 | $1.27 |
| 2 | 7 | 110 | 115 | 4' 2L T5HO, EB | 5.29 | 4.77 | 100.00% | 18.75% | 16.67% | 32 | $0.24 | $1.27 |
| 2 | 7 | 110 | 116 | 4' 4L T8, EB | 5.29 | 4.77 | 100.00% | 22.22% | 16.67% | 32 | $0.17 | $1.27 |
| 2 | 7 | 110 | 117 | 4' 3L T8, EB | 5.29 | 4.77 | 100.00% | 38.20% | 16.67% | 32 | $0.08 | $1.27 |
| 2 | 7 | 110 | 118 | 4' 3L T8 Premium, EB | 5.29 | 4.77 | 100.00% | 42.36% | 16.67% | 32 | $0.27 | $1.27 |
| 2 | 7 | 120 | 120 | Base Fluorescent Fixture, 4' 2L T12, 34W, 1EEMAG | 5.29 | 5.29 | 100.00% | 0.00% | 100.00% | 21 | $2.34 | $2.34 |
| 2 | 7 | 120 | 121 | 4' 2L T8 Premium, EB | 5.29 | 4.77 | 100.00% | 25.00% | 33.33% | 32 | $0.65 | $2.34 |
| 2 | 7 | 120 | 122 | 4' 1L T8 Premium, EB, reflector | 5.29 | 4.77 | 100.00% | 61.11% | 33.33% | 32 | $1.32 | $2.34 |
| 2 | 7 | 120 | 123 | Occupancy Sensor, 8-4' Fluorescent Fixtures | 5.29 | 4.77 | 90.00% | 30.00% | 50.00% | 19 | $0.38 | $2.34 |
| 2 | 7 | 120 | 124 | Continuous Dimming, 10-4' Fluorescent Fixtures | 5.29 | 4.77 | 100.00% | 75.00% | 30.00% | 23 | $3.21 | $2.34 |
| 2 | 7 | 120 | 125 | 4' 1L T5HO, EB | 5.29 | 4.77 | 100.00% | 13.90% | 33.33% | 32 | $0.49 | $2.34 |
| 2 | 7 | 130 | 130 | Base Fluorescent Fixture, 8' 2L T12, 60W, 1EEMAG | 5.29 | 5.29 | 100.00% | 0.00% | 100.00% | 21 | $1.64 | $1.64 |
| 2 | 7 | 130 | 131 | 8' 2L T12, 60W, EB | 5.29 | 4.77 | 50.00% | 10.57% | 25.00% | 32 | $0.16 | $1.64 |
| 2 | 7 | 130 | 132 | 8' 1L T12, 60W, EB, reflector | 5.29 | 4.77 | 100.00% | 55.30% | 25.00% | 32 | $0.71 | $1.64 |
| 2 | 7 | 130 | 133 | Occupancy Sensor, 4-8' Fluorescent Fixtures | 5.29 | 4.77 | 90.00% | 30.00% | 50.00% | 19 | $0.49 | $1.64 |
| 2 | 7 | 130 | 134 | Continuous Dimming, 5-8' Fluorescent Fixtures | 5.29 | 4.77 | 100.00% | 75.00% | 30.00% | 23 | $3.70 | $1.64 |
| 2 | 7 | 130 | 135 | 8' 2L T8, EB | 5.29 | 4.77 | 100.00% | 52.80% | 50.00% | 32 | $0.32 | $1.64 |
| 2 | 7 | 140 | 140 | Base Incandescent Flood, 75W | 5.29 | 5.29 | 100.00% | 0.00% | 100.00% | 1 | $3.09 | $3.09 |
| 2 | 7 | 140 | 141 | CFL Screw-in, Modular 18W | 5.29 | 4.77 | 85.00% | 65.30% | 90.00% | 9 | $1.90 | $3.09 |
| 2 | 7 | 150 | 150 | Base Incandescent Flood, 150W PAR | 5.29 | 5.29 | 100.00% | 0.00% | 100.00% | 1 | $1.40 | $1.40 |
| 2 | 7 | 150 | 151 | Halogen PAR Flood, 90W | 5.29 | 5.29 | 95.00% | 40.00% | 10.00% | 1 | $0.14 | $1.40 |
| 2 | 7 | 150 | 152 | Metal Halide, 50W | 5.29 | 5.29 | 90.00% | 52.00% | 45.00% | 11 | $7.51 | $1.40 |
| 2 | 7 | 150 | 153 | HPS, 50W | 5.29 | 5.29 | 90.00% | 56.00% | 45.00% | 11 | $3.83 | $1.40 |
| 2 | 7 | 160 | 160 | Base 4' 3L T12, 34W, 1EEMAG | 5.29 | 5.29 | 100.00% | 0.00% | 100.00% | 10 | $0.09 | $0.09 |
| 2 | 7 | 160 | 161 | 4' 3L T8, EB | 5.29 | 4.77 | 100.00% | 22.61% | 25.00% | 32 | $0.01 | $0.09 |
| 2 | 7 | 160 | 162 | 4' 3L T8 Premium, EB | 5.29 | 4.77 | 100.00% | 22.61% | 25.00% | 32 | $0.02 | $0.09 |
| 2 | 7 | 160 | 163 | 4' 2L T8 Premium, EB, reflector | 5.29 | 4.77 | 100.00% | 53.04% | 25.00% | 32 | $0.05 | $0.09 |
| 2 | 7 | 160 | 164 | 4' 1L T5HO, EB | 5.29 | 4.77 | 100.00% | 46.09% | 25.00% | 32 | $0.01 | $0.09 |
| 2 | 7 | 180 | 180 | Base Fluorescent Fixture 4' 4L T8, 1EB | 4.24 | 4.24 | 100.00% | 0.00% | 100.00% | 32 | $1.42 | $1.42 |
| 2 | 7 | 180 | 181 | 4' 4L T8 Premium, EB | 4.24 | 3.81 | 100.00% | 3.60% | 100.00% | 32 | $0.25 | $1.42 |
| 2 | 7 | 180 | 182 | Occupancy Sensor, 4-4' Fluorescent Fixtures | 4.24 | 3.81 | 90.00% | 30.00% | 50.00% | 19 | $0.44 | $1.42 |
| 2 | 7 | 185 | 185 | Base Fluorescent Fixture 4' 3L T8, 1EB | 4.24 | 4.24 | 100.00% | 0.00% | 100.00% | 32 | $2.65 | $2.65 |

## Table B.3: Commercial Electric

| Segment | Building | Base Number | Measure Number | Measure Name | Stock Usage | Base Usage | Incomplete Factor | Energy Savings | Feasibility Factor | Measure Life | Full Per Unit Cost | Full Base Measure Cost |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2 | 7 | 185 | 186 | 4' 3L T8 Premium, EB | 4.24 | 3.81 | 100.00% | 6.70% | 100.00% | 32 | $0.36 | $2.65 |
| 2 | 7 | 190 | 190 | Base Fluorescent Fixture 4' 2L T8, 1EB | 4.24 | 4.24 | 100.00% | 0.00% | 100.00% | 32 | $2.49 | $2.49 |
| 2 | 7 | 190 | 191 | 4' 2L T8 Premium, EB | 4.24 | 3.81 | 100.00% | 8.50% | 100.00% | 32 | $0.22 | $2.49 |
| 2 | 7 | 190 | 192 | Occupancy Sensor, 8-4' Fluorescent Fixtures | 4.24 | 3.81 | 90.00% | 30.00% | 50.00% | 19 | $0.38 | $2.49 |
| 2 | 7 | 200 | 200 | Base Centrifugal Chiller, 0.65 kW/ton, 300 tons | 3.76 | 3.76 | 100.00% | 0.00% | 100.00% | 20 | $2.07 | $2.07 |
| 2 | 7 | 200 | 201 | Chiller Tune-Up / Diagnostics | 3.76 | 3.76 | 10.00% | 5.00% | 100.00% | 5 | $0.17 | $2.07 |
| 2 | 7 | 200 | 202 | Installation of Automated Building Ventilation Control ( Via Occupancy Sensors, CO2 Sensors, Etc.) | 3.76 | 3.76 | 100.00% | 10.00% | 50.00% | 10 | $0.44 | $2.07 |
| 2 | 7 | 200 | 203 | Roof / Ceiling Insulation | 3.76 | 3.76 | 20.00% | 3.00% | 50.00% | 20 | $0.30 | $277.59 |
| 2 | 7 | 200 | 204 | Cool Roofs (Reflective and Spray Evaporative) | 3.76 | 3.76 | 100.00% | 1.35% | 90.00% | 10 | $0.20 | $199.77 |
| 2 | 7 | 200 | 205 | EMS Optimization | 3.76 | 3.76 | 50.00% | 1.00% | 100.00% | 5 | $0.00 | $0.00 |
| 2 | 7 | 200 | 206 | High Efficiency Windows (Low-E Glass or Multiple Glazed) | 3.76 | 3.76 | 66.00% | 3.96% | 75.00% | 30 | $0.04 | $28.82 |
| 2 | 7 | 200 | 207 | Installation of Energy Management Systems | 3.76 | 3.76 | 50.00% | 10.00% | 50.00% | 10 | $0.27 | $2.07 |
| 2 | 7 | 200 | 208 | Insulation of Pipes | 3.76 | 3.76 | 50.00% | 1.00% | 50.00% | 20 | $0.03 | $2.92 |
| 2 | 7 | 200 | 209 | Installation of Chiller Economizers (water side) | 3.76 | 3.76 | 100.00% | 10.00% | 50.00% | 20 | $0.59 | $461.00 |
| 2 | 7 | 200 | 210 | Optimize Chilled Water and Condenser Water Settings | 3.76 | 3.76 | 50.00% | 5.00% | 33.00% | 10 | $0.30 | $2.07 |
| 2 | 7 | 200 | 211 | Decrease Cooling Tower Approach Temperature, 300 Tons, 6 Deg F | 3.76 | 3.76 | 90.00% | 7.50% | 67.00% | 15 | $0.16 | $3.22 |
| 2 | 7 | 200 | 212 | Two-Speed Cooling Tower, 300 Tons | 3.76 | 3.76 | 90.00% | 14.00% | 50.00% | 15 | $0.01 | $3.22 |
| 2 | 7 | 200 | 213 | VSD Cooling Tower, 300 Tons | 3.76 | 3.76 | 90.00% | 18.00% | 50.00% | 15 | $0.11 | $3.22 |
| 2 | 7 | 200 | 214 | Primary/Secondary De-coupled Chilled Water System | 3.76 | 3.76 | 80.00% | 12.00% | 50.00% | 15 | $0.68 | $3.22 |
| 2 | 7 | 200 | 215 | HE Chiller, 0.51 kW/ton, 300 Tons | 3.76 | 3.76 |  | 21.54% |  | 15 | $0.27 | $3.22 |
| 2 | 7 | 200 | 216 | VSD Chiller, 0.47 kW/ton, 300 Tons | 3.76 | 3.76 |  | 27.69% |  | 15 | $0.90 | $3.22 |
| 2 | 7 | 250 | 250 | Base DX Packaged System, EER=10.3, 10 tons | 6.51 | 6.51 | 100.00% | 0.00% | 100.00% | 15 | $3.55 | $3.55 |
| 2 | 7 | 250 | 251 | DX Tune-Up / Diagnostics | 6.51 | 6.51 | 10.00% | 10.00% | 100.00% | 3 | $0.35 | $3.55 |
| 2 | 7 | 250 | 252 | Hi-Eff DX Packaged System, 10 tons, EER=11.3 | 6.51 | 6.51 |  | 8.85% |  | 15 | $0.43 | $3.55 |
| 2 | 7 | 250 | 253 | High Efficiency Windows (Low-E Glass or Multiple Glazed) | 6.51 | 6.51 | 66.00% | 5.00% | 75.00% | 30 | $0.11 | $49.27 |
| 2 | 7 | 250 | 254 | Installation of Direct of Indirect Evaporative Cooling, Evaporative Pre-Cooling, and Absorption Cooling | 6.51 | 6.51 | 95.00% | 10.00% | 25.00% | 10 | $1.31 | $3.55 |
| 2 | 7 | 250 | 258 | Installation of Automated Building Ventilation Control ( Via Occupancy Sensors, CO2 Sensors, Etc.) | 6.51 | 6.51 | 100.00% | 10.00% | 50.00% | 10 | $0.44 | $3.55 |
| 2 | 7 | 250 | 259 | Roof / Ceiling Insulation | 6.51 | 6.51 | 20.00% | 3.00% | 50.00% | 20 | $0.30 | $474.49 |
| 2 | 7 | 250 | 260 | Cool Roofs (Reflective and Spray Evaporative) | 6.51 | 6.51 | 100.00% | 1.35% | 50.00% | 10 | $0.20 | $341.47 |
| 2 | 7 | 250 | 261 | Clock / Programmable Thermostat | 6.51 | 6.51 | 30.00% | 10.00% | 100.00% | 10 | $0.09 | $3.55 |
| 2 | 7 | 250 | 262 | Installation of Air Side Economizers | 6.51 | 6.51 | 100.00% | 15.00% | 100.00% | 10 | $0.59 | $788.00 |
| 2 | 7 | 280 | 280 | Base Air-Cooled HP Package, 5 tons, SEER=10 | 6.51 | 6.51 | 100.00% | 0.00% | 100.00% | 15 | $3.22 | $3.22 |
| 2 | 7 | 280 | 281 | Air-Cooled HP Package, 5 tons, SEER=11 | 6.51 | 6.51 |  | 9.09% |  | 15 | $0.16 | $3.22 |
| 2 | 7 | 280 | 282 | Air-Cooled HP Package, 5 tons, SEER=12 | 6.51 | 6.51 |  | 16.67% |  | 15 | $1.06 | $3.22 |
| 2 | 7 | 280 | 283 | DX Tune-Up / Diagnostics | 6.51 | 6.51 | 10.00% | 10.00% | 100.00% | 3 | $0.35 | $3.55 |
| 2 | 7 | 280 | 284 | High Efficiency Windows (Low-E Glass or Multiple Glazed) | 6.51 | 6.51 | 66.00% | 5.00% | 75.00% | 30 | $0.11 | $49.27 |
| 2 | 7 | 280 | 285 | Installation of Direct of Indirect Evaporative Cooling, Evaporative Pre-Cooling, and Absorption Cooling | 6.51 | 6.51 | 95.00% | 10.00% | 25.00% | 10 | $1.31 | $3.55 |
| 2 | 7 | 280 | 288 | Installation of Automated Building Ventilation Control ( Via Occupancy Sensors, CO2 Sensors, Etc.) | 6.51 | 6.51 | 100.00% | 10.00% | 50.00% | 10 | $0.44 | $3.55 |
| 2 | 7 | 280 | 289 | Roof / Ceiling Insulation | 6.51 | 6.51 | 20.00% | 3.00% | 50.00% | 20 | $0.30 | $474.49 |

## Table B.3: Commercial Electric

| Segment | Building | Base Number | Measure Number | Measure Name | Stock Usage | Base Usage | Incomplete Factor | Energy Savings | Feasibility Factor | Measure Life | Full Per Unit Cost | Full Base Measure Cost |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2 | 7 | 280 | 290 | Cool Roofs (Reflective and Spray Evaporative) | 6.51 | 6.51 | 100.00% | 1.35% | 50.00% | 10 | $0.20 | $341.47 |
| 2 | 7 | 280 | 291 | Clock / Programmable Thermostat | 6.51 | 6.51 | 30.00% | 10.00% | 100.00% | 10 | $0.09 | $3.55 |
| 2 | 7 | 280 | 292 | Installation of Air Side Economizers | 6.51 | 6.51 | 100.00% | 15.00% | 100.00% | 10 | $0.59 | $788.00 |
| 2 | 7 | 400 | 400 | Base Fan Motor, 5hp, 1800rpm, 87.5% (ODP) | 0.98 | 0.98 | | 0.00% | | 15 | $0.11 | $0.11 |
| 2 | 7 | 400 | 401 | Energy Efficient Fan & Pump Motors (ODP) | 0.98 | 0.98 | | 1.50% | | 15 | $0.02 | $0.11 |
| 2 | 7 | 400 | 402 | VSD, ASD Fan & Pump Applications | 0.98 | 0.98 | | 30.00% | | 15 | $0.13 | $0.11 |
| 2 | 7 | 610 | 610 | Base Office Equipment | 0.32 | 0.32 | 100.00% | 0.00% | 100.00% | 4 | $0.25 | $0.74 |
| 2 | 7 | 610 | 611 | ENERGY STAR or Better Office Equipment: Computer | 0.32 | 0.32 | 65.00% | 21.55% | 100.00% | 4 | $0.03 | $0.74 |
| 2 | 7 | 610 | 621 | ENERGY STAR or Better Office Equipment: Monitors | 0.32 | 0.32 | 71.00% | 19.15% | 100.00% | 4 | $0.02 | $0.74 |
| 2 | 7 | 610 | 623 | Smart Networks | 0.32 | 0.32 | 40.00% | 7.98% | 90.00% | 4 | $0.00 | $0.74 |
| 2 | 7 | 610 | 631 | ENERGY STAR or Better Office Equipment: Copiers | 0.32 | 0.32 | 33.00% | 6.25% | 100.00% | 4 | $0.00 | $0.04 |
| 2 | 7 | 610 | 641 | ENERGY STAR or Better Office Equipment: Printers | 0.32 | 0.32 | 99.00% | 11.58% | 100.00% | 4 | $0.02 | $0.22 |
| 2 | 7 | 700 | 700 | Base Water Heating | 0.64 | 0.64 | 100.00% | 0.00% | 100.00% | 15 | $36.19 | $36.19 |
| 2 | 7 | 700 | 701 | Demand controlled circulating systems | 0.64 | 0.64 | 100.00% | 5.00% | 50.00% | 15 | $7.06 | $36.19 |
| 2 | 7 | 700 | 702 | Heat Pump Water Heater | 0.64 | 0.64 | 100.00% | 30.00% | 75.00% | 15 | $4.50 | $36.19 |
| 2 | 7 | 700 | 703 | High-Efficiency Water Heater (electric) | 0.64 | 0.64 | | 5.40% | | 15 | $1.30 | $36.19 |
| 2 | 7 | 700 | 704 | Hot Water (SHW) Pipe Insulation | 0.64 | 0.64 | 80.00% | 5.00% | 50.00% | 15 | $0.03 | $6.34 |
| 2 | 7 | 800 | 800 | Base Heating | 0.79 | 0.79 | 100.00% | 0.00% | 100.00% | 20 | $2.40 | $2.40 |
| 2 | 7 | 800 | 802 | Roof / Ceiling Insulation | 0.79 | 0.79 | 40.00% | 10.00% | 50.00% | 20 | $0.30 | $1.45 |
| 2 | 7 | 800 | 805 | Clock / Programmable Thermostat | 0.79 | 0.79 | 35.00% | 30.00% | 100.00% | 10 | $0.15 | $2.40 |
| 2 | 7 | 800 | 812 | Installation of Automated Building Ventilation Control ( Via Occupancy Sensors, CO2 Sensors, Etc.) | 0.79 | 0.79 | 100.00% | 5.00% | 50.00% | 15 | $0.28 | $2.40 |
| 2 | 8 | 110 | 110 | Base Fluorescent Fixture, 4' 4L T12, 34W, 2EEMAG | 10.77 | 10.77 | 100.00% | 0.00% | 100.00% | 8 | $1.48 | $1.48 |
| 2 | 8 | 110 | 111 | 4' 4L T8 Premium, EB | 10.77 | 9.69 | 100.00% | 25.00% | 16.67% | 12 | $0.48 | $1.48 |
| 2 | 8 | 110 | 112 | 4' 2L T8 Premium, EB, reflector | 10.77 | 9.69 | 100.00% | 62.50% | 16.67% | 12 | $0.72 | $1.48 |
| 2 | 8 | 110 | 113 | Occupancy Sensor, 4-4' Fluorescent Fixtures | 10.77 | 9.69 | 90.00% | 30.00% | 50.00% | 7 | $0.51 | $1.48 |
| 2 | 8 | 110 | 114 | Continuous Dimming, 5-4' Fluorescent Fixtures | 10.77 | 9.69 | 100.00% | 75.00% | 10.00% | 8 | $3.84 | $1.48 |
| 2 | 8 | 110 | 115 | 4' 2L T5HO, EB | 10.77 | 9.69 | 100.00% | 18.75% | 16.67% | 12 | $0.28 | $1.48 |
| 2 | 8 | 110 | 116 | 4' 4L T8, EB | 10.77 | 9.69 | 100.00% | 22.22% | 16.67% | 12 | $0.20 | $1.48 |
| 2 | 8 | 110 | 117 | 4' 3L T8, EB | 10.77 | 9.69 | 100.00% | 38.20% | 16.67% | 12 | $0.09 | $1.48 |
| 2 | 8 | 110 | 118 | 4' 3L T8 Premium, EB | 10.77 | 9.69 | 100.00% | 42.36% | 16.67% | 12 | $0.31 | $1.48 |
| 2 | 8 | 120 | 120 | Base Fluorescent Fixture, 4' 2L T12, 34W, 1EEMAG | 10.77 | 10.77 | 100.00% | 0.00% | 100.00% | 8 | $2.72 | $2.72 |
| 2 | 8 | 120 | 121 | 4' 2L T8 Premium, EB | 10.77 | 9.69 | 100.00% | 25.00% | 33.33% | 12 | $0.76 | $2.72 |
| 2 | 8 | 120 | 122 | 4' 1L T8 Premium, EB, reflector | 10.77 | 9.69 | 100.00% | 61.11% | 33.33% | 12 | $1.54 | $2.72 |
| 2 | 8 | 120 | 123 | Occupancy Sensor, 8-4' Fluorescent Fixtures | 10.77 | 9.69 | 90.00% | 30.00% | 50.00% | 7 | $0.44 | $2.72 |
| 2 | 8 | 120 | 124 | Continuous Dimming, 10-4' Fluorescent Fixtures | 10.77 | 9.69 | 100.00% | 75.00% | 10.00% | 8 | $3.74 | $2.72 |
| 2 | 8 | 120 | 125 | 4' 1L T5HO, EB | 10.77 | 9.69 | 100.00% | 13.90% | 33.33% | 12 | $0.58 | $2.72 |
| 2 | 8 | 130 | 130 | Base Fluorescent Fixture, 8' 2L T12, 60W, 1EEMAG | 10.77 | 10.77 | 100.00% | 0.00% | 100.00% | 8 | $1.77 | $1.77 |
| 2 | 8 | 130 | 131 | 8' 2L T12, 60W, EB | 10.77 | 9.69 | 50.00% | 10.57% | 25.00% | 12 | $0.17 | $1.77 |
| 2 | 8 | 130 | 132 | 8' 1L T12, 60W, EB, reflector | 10.77 | 9.69 | 100.00% | 55.30% | 25.00% | 12 | $0.77 | $1.77 |
| 2 | 8 | 130 | 133 | Occupancy Sensor, 4-8' Fluorescent Fixtures | 10.77 | 9.69 | 90.00% | 30.00% | 50.00% | 7 | $0.53 | $1.77 |
| 2 | 8 | 130 | 134 | Continuous Dimming, 5-8' Fluorescent Fixtures | 10.77 | 9.69 | 100.00% | 75.00% | 10.00% | 8 | $3.99 | $1.77 |
| 2 | 8 | 130 | 135 | 8' 2L T8, EB | 10.77 | 9.69 | 100.00% | 52.80% | 50.00% | 12 | $0.35 | $1.77 |
| 2 | 8 | 140 | 140 | Base Incandescent Flood, 75W | 10.77 | 10.77 | 100.00% | 0.00% | 100.00% | 1 | $3.72 | $3.72 |

## Table B.3: Commercial Electric

| Segment | Building | Base Number | Measure Number | Measure Name | Stock Usage | Base Usage | Incomplete Factor | Energy Savings | Feasibility Factor | Measure Life | Full Per Unit Cost | Full Base Measure Cost |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2 | 8 | 140 | 141 | CFL Screw-in, Modular 18W | 10.77 | 9.69 | 85.00% | 65.30% | 90.00% | 3 | $2.29 | $3.72 |
| 2 | 8 | 150 | 150 | Base Incandescent Flood, 150W PAR | 10.77 | 10.77 | 100.00% | 0.00% | 100.00% | 1 | $1.04 | $1.04 |
| 2 | 8 | 150 | 151 | Halogen PAR Flood, 90W | 10.77 | 10.77 | 95.00% | 40.00% | 10.00% | 1 | $0.10 | $1.04 |
| 2 | 8 | 150 | 152 | Metal Halide, 50W | 10.77 | 10.77 | 90.00% | 52.00% | 45.00% | 4 | $5.59 | $1.04 |
| 2 | 8 | 150 | 153 | HPS, 50W | 10.77 | 10.77 | 90.00% | 56.00% | 45.00% | 4 | $2.85 | $1.04 |
| 2 | 8 | 160 | 160 | Base 4' 3L T12, 34W, 1EEMAG | 10.77 | 10.77 | 100.00% | 0.00% | 100.00% | 10 | $0.14 | $0.14 |
| 2 | 8 | 160 | 161 | 4' 3L T8, EB | 10.77 | 9.69 | 100.00% | 22.61% | 25.00% | 12 | $0.01 | $0.14 |
| 2 | 8 | 160 | 162 | 4' 3L T8 Premium, EB | 10.77 | 9.69 | 100.00% | 22.61% | 25.00% | 12 | $0.03 | $0.14 |
| 2 | 8 | 160 | 163 | 4' 2L T8 Premium, EB, reflector | 10.77 | 9.69 | 100.00% | 53.04% | 25.00% | 12 | $0.07 | $0.14 |
| 2 | 8 | 160 | 164 | 4' 1L T5HO, EB | 10.77 | 9.69 | 100.00% | 46.09% | 25.00% | 12 | $0.01 | $0.14 |
| 2 | 8 | 180 | 180 | Base Fluorescent Fixture 4' 4L T8, 1EB | 8.62 | 8.62 | 100.00% | 0.00% | 100.00% | 12 | $1.65 | $1.65 |
| 2 | 8 | 180 | 181 | 4' 4L T8 Premium, EB | 8.62 | 7.75 | 100.00% | 3.60% | 100.00% | 12 | $0.30 | $1.65 |
| 2 | 8 | 180 | 182 | Occupancy Sensor, 4-4' Fluorescent Fixtures | 8.62 | 7.75 | 90.00% | 30.00% | 50.00% | 7 | $0.51 | $1.65 |
| 2 | 8 | 185 | 185 | Base Fluorescent Fixture 4' 3L T8, 1EB | 8.62 | 8.62 | 100.00% | 0.00% | 100.00% | 12 | $3.08 | $3.08 |
| 2 | 8 | 185 | 186 | 4' 3L T8 Premium, EB | 8.62 | 7.75 | 100.00% | 6.70% | 100.00% | 12 | $0.42 | $3.08 |
| 2 | 8 | 190 | 190 | Base Fluorescent Fixture 4' 2L T8, 1EB | 8.62 | 8.62 | 100.00% | 0.00% | 100.00% | 12 | $2.90 | $2.90 |
| 2 | 8 | 190 | 191 | 4' 2L T8 Premium, EB | 8.62 | 7.75 | 100.00% | 8.50% | 100.00% | 12 | $0.26 | $2.90 |
| 2 | 8 | 190 | 192 | Occupancy Sensor, 8-4' Fluorescent Fixtures | 8.62 | 7.75 | 90.00% | 30.00% | 50.00% | 7 | $0.44 | $2.90 |
| 2 | 8 | 200 | 200 | Base Centrifugal Chiller, 0.65 kW/ton, 300 tons | 8.98 | 8.98 | 100.00% | 0.00% | 100.00% | 20 | $2.07 | $2.07 |
| 2 | 8 | 200 | 201 | Chiller Tune-Up / Diagnostics | 8.98 | 8.98 | 10.00% | 5.00% | 100.00% | 5 | $0.17 | $2.07 |
| 2 | 8 | 200 | 202 | Installation of Automated Building Ventilation Control ( Via Occupancy Sensors, CO2 Sensors, Etc.) | 8.98 | 8.98 | 100.00% | 10.00% | 50.00% | 10 | $0.44 | $2.07 |
| 2 | 8 | 200 | 203 | Roof / Ceiling Insulation | 8.98 | 8.98 | 20.00% | 3.00% | 50.00% | 20 | $0.43 | $402.37 |
| 2 | 8 | 200 | 204 | Cool Roofs (Reflective and Spray Evaporative) | 8.98 | 8.98 | 100.00% | 0.64% | 90.00% | 10 | $0.16 | $153.67 |
| 2 | 8 | 200 | 205 | EMS Optimization | 8.98 | 8.98 | 50.00% | 1.00% | 100.00% | 5 | $0.00 | $0.00 |
| 2 | 8 | 200 | 206 | High Efficiency Windows (Low-E Glass or Multiple Glazed) | 8.98 | 8.98 | 66.00% | 1.17% | 75.00% | 30 | $0.01 | $9.28 |
| 2 | 8 | 200 | 207 | Installation of Energy Management Systems | 8.98 | 8.98 | 75.00% | 10.00% | 50.00% | 10 | $0.27 | $2.07 |
| 2 | 8 | 200 | 208 | Insulation of Pipes | 8.98 | 8.98 | 50.00% | 1.00% | 50.00% | 20 | $0.01 | $1.08 |
| 2 | 8 | 200 | 209 | Installation of Chiller Economizers (water side) | 8.98 | 8.98 | 100.00% | 10.00% | 50.00% | 20 | $0.59 | $461.00 |
| 2 | 8 | 200 | 210 | Optimize Chilled Water and Condenser Water Settings | 8.98 | 8.98 | 50.00% | 5.00% | 33.00% | 10 | $0.30 | $2.07 |
| 2 | 8 | 200 | 211 | Decrease Cooling Tower Approach Temperature, 300 Tons, 6 Deg F | 8.98 | 8.98 | 90.00% | 7.50% | 67.00% | 15 | $0.16 | $3.22 |
| 2 | 8 | 200 | 212 | Two-Speed Cooling Tower, 300 Tons | 8.98 | 8.98 | 90.00% | 14.00% | 50.00% | 15 | $0.01 | $3.22 |
| 2 | 8 | 200 | 213 | VSD Cooling Tower, 300 Tons | 8.98 | 8.98 | 90.00% | 18.00% | 50.00% | 15 | $0.11 | $3.22 |
| 2 | 8 | 200 | 214 | Primary/Secondary De-coupled Chilled Water System | 8.98 | 8.98 | 80.00% | 12.00% | 50.00% | 15 | $0.68 | $3.22 |
| 2 | 8 | 200 | 215 | HE Chiller, 0.51 kW/ton, 300 Tons | 8.98 | 8.98 | | 21.54% | | 15 | $0.27 | $3.22 |
| 2 | 8 | 200 | 216 | VSD Chiller, 0.47 kW/ton, 300 Tons | 8.98 | 8.98 | | 27.69% | | 15 | $0.90 | $3.22 |
| 2 | 8 | 250 | 250 | Base DX Packaged System, EER=10.3, 10 tons | 15.55 | 15.55 | 100.00% | 0.00% | 100.00% | 15 | $3.55 | $3.55 |
| 2 | 8 | 250 | 251 | DX Tune-Up / Diagnostics | 15.55 | 15.55 | 10.00% | 10.00% | 100.00% | 3 | $0.35 | $3.55 |
| 2 | 8 | 250 | 252 | Hi-Eff DX Packaged System, 10 tons, EER=11.3 | 15.55 | 15.55 | | 8.85% | | 15 | $0.43 | $3.55 |
| 2 | 8 | 250 | 253 | High Efficiency Windows (Low-E Glass or Multiple Glazed) | 15.55 | 15.55 | 66.00% | 5.00% | 75.00% | 30 | $0.03 | $15.85 |
| 2 | 8 | 250 | 254 | Installation of Direct of Indirect Evaporative Cooling, Evaporative Pre-Cooling, and Absorption Cooling | 15.55 | 15.55 | 95.00% | 10.00% | 25.00% | 10 | $1.31 | $3.55 |

## Table B.3: Commercial Electric

| Segment | Building | Base Number | Measure Number | Measure Name | Stock Usage | Base Usage | Incomplete Factor | Energy Savings | Feasibility Factor | Measure Life | Full Per Unit Cost | Full Base Measure Cost |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2 | 8 | 250 | 258 | Installation of Automated Building Ventilation Control ( Via Occupancy Sensors, CO2 Sensors, Etc.) | 15.55 | 15.55 | 100.00% | 10.00% | 50.00% | 10 | $0.44 | $3.55 |
| 2 | 8 | 250 | 259 | Roof / Ceiling Insulation | 15.55 | 15.55 | 20.00% | 3.00% | 50.00% | 20 | $0.43 | $687.78 |
| 2 | 8 | 250 | 260 | Cool Roofs (Reflective and Spray Evaporative) | 15.55 | 15.55 | 100.00% | 0.64% | 50.00% | 10 | $0.16 | $262.67 |
| 2 | 8 | 250 | 261 | Clock / Programmable Thermostat | 15.55 | 15.55 | 30.00% | 10.00% | 100.00% | 10 | $0.09 | $3.55 |
| 2 | 8 | 250 | 262 | Installation of Air Side Economizers | 15.55 | 15.55 | 40.00% | 15.00% | 100.00% | 10 | $0.59 | $788.00 |
| 2 | 8 | 280 | 280 | Base Air-Cooled HP Package, 5 tons, SEER=10 | 15.55 | 15.55 | 100.00% | 0.00% | 100.00% | 15 | $3.22 | $3.22 |
| 2 | 8 | 280 | 281 | Air-Cooled HP Package, 5 tons, SEER=11 | 15.55 | 15.55 | | 9.09% | | 15 | $0.16 | $3.22 |
| 2 | 8 | 280 | 282 | Air-Cooled HP Package, 5 tons, SEER=12 | 15.55 | 15.55 | | 16.67% | | 15 | $1.06 | $3.22 |
| 2 | 8 | 280 | 283 | DX Tune-Up / Diagnostics | 15.55 | 15.55 | 10.00% | 10.00% | 100.00% | 3 | $0.35 | $3.55 |
| 2 | 8 | 280 | 284 | High Efficiency Windows (Low-E Glass or Multiple Glazed) | 15.55 | 15.55 | 66.00% | 5.00% | 75.00% | 30 | $0.03 | $15.85 |
| 2 | 8 | 280 | 285 | Installation of Direct of Indirect Evaporative Cooling, Evaporative Pre-Cooling, and Absorption Cooling | 15.55 | 15.55 | 95.00% | 10.00% | 25.00% | 10 | $1.31 | $3.55 |
| 2 | 8 | 280 | 288 | Installation of Automated Building Ventilation Control ( Via Occupancy Sensors, CO2 Sensors, Etc.) | 15.55 | 15.55 | 100.00% | 10.00% | 50.00% | 10 | $0.44 | $3.55 |
| 2 | 8 | 280 | 289 | Roof / Ceiling Insulation | 15.55 | 15.55 | 20.00% | 3.00% | 50.00% | 20 | $0.43 | $687.78 |
| 2 | 8 | 280 | 290 | Cool Roofs (Reflective and Spray Evaporative) | 15.55 | 15.55 | 100.00% | 0.64% | 50.00% | 10 | $0.16 | $262.67 |
| 2 | 8 | 280 | 291 | Clock / Programmable Thermostat | 15.55 | 15.55 | 30.00% | 10.00% | 100.00% | 10 | $0.09 | $3.55 |
| 2 | 8 | 280 | 292 | Installation of Air Side Economizers | 15.55 | 15.55 | 40.00% | 15.00% | 100.00% | 10 | $0.59 | $788.00 |
| 2 | 8 | 400 | 400 | Base Fan Motor, 5hp, 1800rpm, 87.5% (ODP) | 2.67 | 2.67 | | 0.00% | | 15 | $0.13 | $0.13 |
| 2 | 8 | 400 | 401 | Energy Efficient Fan & Pump Motors (ODP) | 2.67 | 2.67 | | 1.50% | | 15 | $0.03 | $0.13 |
| 2 | 8 | 400 | 402 | VSD, ASD Fan & Pump Applications | 2.67 | 2.67 | | 30.00% | | 15 | $0.15 | $0.13 |
| 2 | 8 | 610 | 610 | Base Office Equipment | 0.52 | 0.52 | 100.00% | 0.00% | 100.00% | 4 | $0.89 | $2.62 |
| 2 | 8 | 610 | 611 | ENERGY STAR or Better Office Equipment: Computer | 0.52 | 0.52 | 65.00% | 17.36% | 100.00% | 4 | $0.11 | $2.62 |
| 2 | 8 | 610 | 621 | ENERGY STAR or Better Office Equipment: Monitors | 0.52 | 0.52 | 71.00% | 15.43% | 100.00% | 4 | $0.06 | $2.62 |
| 2 | 8 | 610 | 623 | Smart Networks | 0.52 | 0.52 | 40.00% | 6.43% | 90.00% | 4 | $0.00 | $2.62 |
| 2 | 8 | 610 | 631 | ENERGY STAR or Better Office Equipment: Copiers | 0.52 | 0.52 | 33.00% | 10.21% | 100.00% | 4 | $0.04 | $0.47 |
| 2 | 8 | 610 | 641 | ENERGY STAR or Better Office Equipment: Printers | 0.52 | 0.52 | 99.00% | 13.23% | 100.00% | 4 | $0.11 | $1.30 |
| 2 | 8 | 700 | 700 | Base Water Heating | 1.25 | 1.25 | 100.00% | 0.00% | 100.00% | 15 | $31.82 | $31.82 |
| 2 | 8 | 700 | 701 | Demand controlled circulating systems | 1.25 | 1.25 | 90.00% | 5.00% | 50.00% | 15 | $6.20 | $31.82 |
| 2 | 8 | 700 | 702 | Heat Pump Water Heater | 1.25 | 1.25 | 100.00% | 30.00% | 75.00% | 15 | $3.95 | $31.82 |
| 2 | 8 | 700 | 703 | High-Efficiency Water Heater (electric) | 1.25 | 1.25 | | 5.40% | | 15 | $1.15 | $31.82 |
| 2 | 8 | 700 | 704 | Hot Water (SHW) Pipe Insulation | 1.25 | 1.25 | 80.00% | 5.00% | 50.00% | 15 | $0.01 | $2.33 |
| 2 | 8 | 800 | 800 | Base Heating | 4.58 | 4.58 | 100.00% | 0.00% | 100.00% | 20 | $2.40 | $2.40 |
| 2 | 8 | 800 | 802 | Roof / Ceiling Insulation | 4.58 | 4.58 | 40.00% | 10.00% | 50.00% | 20 | $0.43 | $2.09 |
| 2 | 8 | 800 | 805 | Clock / Programmable Thermostat | 4.58 | 4.58 | 35.00% | 30.00% | 100.00% | 10 | $0.15 | $2.40 |
| 2 | 8 | 800 | 812 | Installation of Automated Building Ventilation Control ( Via Occupancy Sensors, CO2 Sensors, Etc.) | 4.58 | 4.58 | 100.00% | 5.00% | 50.00% | 15 | $0.28 | $2.40 |
| 2 | 9 | 100 | 100 | Base Cooking | 1.62 | 1.62 | | 0.00% | | 15 | $0.11 | $0.11 |
| 2 | 9 | 100 | 101 | High-Efficiency Convection Oven | 1.62 | 1.62 | | 20.00% | | 15 | $0.09 | $0.11 |
| 2 | 9 | 110 | 110 | Base Fluorescent Fixture, 4' 4L T12, 34W, 2EEMAG | 3.01 | 3.01 | 100.00% | 0.00% | 100.00% | 17 | $0.74 | $0.74 |
| 2 | 9 | 110 | 111 | 4' 4L T8 Premium, EB | 3.01 | 2.71 | 100.00% | 25.00% | 16.67% | 26 | $0.24 | $0.74 |
| 2 | 9 | 110 | 112 | 4' 2L T8 Premium, EB, reflector | 3.01 | 2.71 | 100.00% | 62.50% | 16.67% | 26 | $0.36 | $0.74 |
| 2 | 9 | 110 | 113 | Occupancy Sensor, 4-4' Fluorescent Fixtures | 3.01 | 2.71 | 89.63% | 30.00% | 20.00% | 15 | $0.26 | $0.74 |

# Table B.3: Commercial Electric

| Segment | Building | Base Number | Measure Number | Measure Name | Stock Usage | Base Usage | Incomplete Factor | Energy Savings | Feasibility Factor | Measure Life | Full Per Unit Cost | Full Base Measure Cost |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2 | 9 | 110 | 114 | Continuous Dimming, 5-4' Fluorescent Fixtures | 3.01 | 2.71 | 100.00% | 75.00% | 30.00% | 19 | $1.92 | $0.74 |
| 2 | 9 | 110 | 115 | 4' 2L T5HO, EB | 3.01 | 2.71 | 100.00% | 18.75% | 16.67% | 26 | $0.14 | $0.74 |
| 2 | 9 | 110 | 116 | 4' 4L T8, EB | 3.01 | 2.71 | 100.00% | 22.22% | 16.67% | 26 | $0.10 | $0.74 |
| 2 | 9 | 110 | 117 | 4' 3L T8, EB | 3.01 | 2.71 | 100.00% | 38.20% | 16.67% | 26 | $0.05 | $0.74 |
| 2 | 9 | 110 | 118 | 4' 3L T8 Premium, EB | 3.01 | 2.71 | 100.00% | 42.36% | 16.67% | 26 | $0.15 | $0.74 |
| 2 | 9 | 120 | 120 | Base Fluorescent Fixture, 4' 2L T12, 34W, 1EEMAG | 3.01 | 3.01 | 100.00% | 0.00% | 100.00% | 17 | $1.37 | $1.37 |
| 2 | 9 | 120 | 121 | 4' 2L T8 Premium, EB | 3.01 | 2.71 | 100.00% | 25.00% | 33.33% | 26 | $0.38 | $1.37 |
| 2 | 9 | 120 | 122 | 4' 1L T8 Premium, EB, reflector | 3.01 | 2.71 | 100.00% | 61.11% | 33.33% | 26 | $0.78 | $1.37 |
| 2 | 9 | 120 | 123 | Occupancy Sensor, 8-4' Fluorescent Fixtures | 3.01 | 2.71 | 89.63% | 30.00% | 20.00% | 15 | $0.22 | $1.37 |
| 2 | 9 | 120 | 124 | Continuous Dimming, 10-4' Fluorescent Fixtures | 3.01 | 2.71 | 100.00% | 75.00% | 30.00% | 19 | $1.89 | $1.37 |
| 2 | 9 | 120 | 125 | 4' 1L T5HO, EB | 3.01 | 2.71 | 100.00% | 13.90% | 33.33% | 26 | $0.29 | $1.37 |
| 2 | 9 | 130 | 130 | Base Fluorescent Fixture, 8' 2L T12, 60W, 1EEMAG | 3.01 | 3.01 | 100.00% | 0.00% | 100.00% | 17 | $0.92 | $0.92 |
| 2 | 9 | 130 | 131 | 8' 2L T12, 60W, EB | 3.01 | 2.71 | 79.87% | 10.57% | 25.00% | 26 | $0.09 | $0.92 |
| 2 | 9 | 130 | 132 | 8' 1L T12, 60W, EB, reflector | 3.01 | 2.71 | 100.00% | 55.30% | 25.00% | 26 | $0.40 | $0.92 |
| 2 | 9 | 130 | 133 | Occupancy Sensor, 4-8' Fluorescent Fixtures | 3.01 | 2.71 | 89.63% | 30.00% | 20.00% | 15 | $0.28 | $0.92 |
| 2 | 9 | 130 | 134 | Continuous Dimming, 5-8' Fluorescent Fixtures | 3.01 | 2.71 | 100.00% | 75.00% | 30.00% | 19 | $2.07 | $0.92 |
| 2 | 9 | 130 | 135 | 8' 2L T8, EB | 3.01 | 2.71 | 100.00% | 52.80% | 50.00% | 26 | $0.18 | $0.92 |
| 2 | 9 | 140 | 140 | Base Incandescent Flood, 75W | 3.01 | 3.01 | 100.00% | 0.00% | 100.00% | 1 | $2.01 | $2.01 |
| 2 | 9 | 140 | 141 | CFL Screw-in, Modular 18W | 3.01 | 2.71 | 72.51% | 65.30% | 70.00% | 8 | $1.24 | $2.01 |
| 2 | 9 | 150 | 150 | Base Incandescent Flood, 150W PAR | 3.01 | 3.01 | 100.00% | 0.00% | 100.00% | 1 | $0.73 | $0.73 |
| 2 | 9 | 150 | 151 | Halogen PAR Flood, 90W | 3.01 | 3.01 | 98.98% | 40.00% | 10.00% | 1 | $0.07 | $0.73 |
| 2 | 9 | 150 | 152 | Metal Halide, 50W | 3.01 | 3.01 | 92.23% | 52.00% | 45.00% | 9 | $3.88 | $0.73 |
| 2 | 9 | 150 | 153 | HPS, 50W | 3.01 | 3.01 | 92.23% | 56.00% | 45.00% | 9 | $1.98 | $0.73 |
| 2 | 9 | 160 | 160 | Base 4' 3L T12, 34W, 1EEMAG | 3.01 | 3.01 | 100.00% | 0.00% | 100.00% | 10 | $0.22 | $0.22 |
| 2 | 9 | 160 | 161 | 4' 3L T8, EB | 3.01 | 2.71 | 100.00% | 22.61% | 25.00% | 26 | $0.02 | $0.22 |
| 2 | 9 | 160 | 162 | 4' 3L T8 Premium, EB | 3.01 | 2.71 | 100.00% | 22.61% | 25.00% | 26 | $0.05 | $0.22 |
| 2 | 9 | 160 | 163 | 4' 2L T8 Premium, EB, reflector | 3.01 | 2.71 | 100.00% | 53.04% | 25.00% | 26 | $0.11 | $0.22 |
| 2 | 9 | 160 | 164 | 4' 1L T5HO, EB | 3.01 | 2.71 | 100.00% | 46.09% | 25.00% | 26 | $0.02 | $0.22 |
| 2 | 9 | 180 | 180 | Base Fluorescent Fixture 4' 4L T8, 1EB | 2.41 | 2.41 | 100.00% | 0.00% | 100.00% | 26 | $0.83 | $0.83 |
| 2 | 9 | 180 | 181 | 4' 4L T8 Premium, EB | 2.41 | 2.17 | 100.00% | 3.60% | 100.00% | 26 | $0.15 | $0.83 |
| 2 | 9 | 180 | 182 | Occupancy Sensor, 4-4' Fluorescent Fixtures | 2.41 | 2.17 | 89.63% | 30.00% | 20.00% | 15 | $0.26 | $0.83 |
| 2 | 9 | 185 | 185 | Base Fluorescent Fixture 4' 3L T8, 1EB | 2.41 | 2.41 | 100.00% | 0.00% | 100.00% | 26 | $1.56 | $1.56 |
| 2 | 9 | 185 | 186 | 4' 3L T8 Premium, EB | 2.41 | 2.17 | 100.00% | 6.70% | 100.00% | 26 | $0.21 | $1.56 |
| 2 | 9 | 190 | 190 | Base Fluorescent Fixture 4' 2L T8, 1EB | 2.41 | 2.41 | 100.00% | 0.00% | 100.00% | 26 | $1.46 | $1.46 |
| 2 | 9 | 190 | 191 | 4' 2L T8 Premium, EB | 2.41 | 2.17 | 100.00% | 8.50% | 100.00% | 26 | $0.13 | $1.46 |
| 2 | 9 | 190 | 192 | Occupancy Sensor, 8-4' Fluorescent Fixtures | 2.41 | 2.17 | 89.63% | 30.00% | 20.00% | 15 | $0.22 | $1.46 |
| 2 | 9 | 200 | 200 | Base Centrifugal Chiller, 0.65 kW/ton, 300 tons | 1.50 | 1.50 | 100.00% | 0.00% | 100.00% | 20 | $2.19 | $2.19 |
| 2 | 9 | 200 | 201 | Chiller Tune-Up / Diagnostics | 1.50 | 1.50 | 10.00% | 5.00% | 100.00% | 5 | $0.18 | $2.19 |
| 2 | 9 | 200 | 202 | Installation of Automated Building Ventilation Control ( Via Occupancy Sensors, CO2 Sensors, Etc.) | 1.50 | 1.50 | 100.00% | 10.00% | 50.00% | 10 | $0.46 | $2.19 |
| 2 | 9 | 200 | 203 | Roof / Ceiling Insulation | 1.50 | 1.50 | 34.57% | 3.00% | 50.00% | 20 | $0.21 | $198.57 |
| 2 | 9 | 200 | 204 | Cool Roofs (Reflective and Spray Evaporative) | 1.50 | 1.50 | 100.00% | 0.39% | 90.00% | 10 | $0.04 | $38.42 |
| 2 | 9 | 200 | 205 | EMS Optimization | 1.50 | 1.50 | 50.00% | 1.00% | 100.00% | 5 | $0.00 | $0.00 |
| 2 | 9 | 200 | 206 | High Efficiency Windows (Low-E Glass or Multiple Glazed) | 1.50 | 1.50 | 92.94% | 7.03% | 75.00% | 30 | $0.06 | $43.56 |

# Table B.3: Commercial Electric

| Segment | Building | Base Number | Measure Number | Measure Name | Stock Usage | Base Usage | Incomplete Factor | Energy Savings | Feasibility Factor | Measure Life | Full Per Unit Cost | Full Base Measure Cost |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2 | 9 | 200 | 207 | Installation of Energy Management Systems | 1.50 | 1.50 | 37.46% | 10.00% | 50.00% | 10 | $0.29 | $2.19 |
| 2 | 9 | 200 | 208 | Insulation of Pipes | 1.50 | 1.50 | 50.00% | 1.00% | 50.00% | 20 | $0.03 | $3.98 |
| 2 | 9 | 200 | 209 | Installation of Chiller Economizers (water side) | 1.50 | 1.50 | 40.07% | 10.00% | 50.00% | 20 | $0.59 | $461.00 |
| 2 | 9 | 200 | 210 | Optimize Chilled Water and Condenser Water Settings | 1.50 | 1.50 | 50.00% | 5.00% | 33.00% | 10 | $0.31 | $2.19 |
| 2 | 9 | 200 | 211 | Decrease Cooling Tower Approach Temperature, 300 Tons, 6 Deg F | 1.50 | 1.50 | 90.00% | 7.50% | 67.00% | 15 | $0.17 | $3.40 |
| 2 | 9 | 200 | 212 | Two-Speed Cooling Tower, 300 Tons | 1.50 | 1.50 | 90.00% | 14.00% | 50.00% | 15 | $0.01 | $3.40 |
| 2 | 9 | 200 | 213 | VSD Cooling Tower, 300 Tons | 1.50 | 1.50 | 90.00% | 18.00% | 50.00% | 15 | $0.11 | $3.40 |
| 2 | 9 | 200 | 214 | Primary/Secondary De-coupled Chilled Water System | 1.50 | 1.50 | 80.00% | 12.00% | 50.00% | 15 | $0.71 | $3.40 |
| 2 | 9 | 200 | 215 | HE Chiller, 0.51 kW/ton, 300 Tons | 1.50 | 1.50 |  | 21.54% |  | 15 | $0.29 | $3.40 |
| 2 | 9 | 200 | 216 | VSD Chiller, 0.47 kW/ton, 300 Tons | 1.50 | 1.50 |  | 27.69% |  | 15 | $0.95 | $3.40 |
| 2 | 9 | 250 | 250 | Base DX Packaged System, EER=10.3, 10 tons | 2.60 | 2.60 | 100.00% | 0.00% | 100.00% | 15 | $3.74 | $3.74 |
| 2 | 9 | 250 | 251 | DX Tune-Up / Diagnostics | 2.60 | 2.60 | 10.00% | 10.00% | 100.00% | 3 | $0.37 | $3.74 |
| 2 | 9 | 250 | 252 | Hi-Eff DX Packaged System, 10 tons, EER=11.3 | 2.60 | 2.60 |  | 8.85% |  | 15 | $0.45 | $3.74 |
| 2 | 9 | 250 | 253 | High Efficiency Windows (Low-E Glass or Multiple Glazed) | 2.60 | 2.60 | 92.94% | 5.00% | 75.00% | 30 | $0.16 | $74.47 |
| 2 | 9 | 250 | 254 | Installation of Direct of Indirect Evaporative Cooling, Evaporative Pre-Cooling, and Absorption Cooling | 2.60 | 2.60 | 95.00% | 10.00% | 25.00% | 10 | $1.38 | $3.74 |
| 2 | 9 | 250 | 255 | Occupancy Sensor for room HVAC units | 2.60 | 2.60 | 100.00% | 35.00% | 51.00% | 15 | $0.30 | $2.40 |
| 2 | 9 | 250 | 258 | Installation of Automated Building Ventilation Control ( Via Occupancy Sensors, CO2 Sensors, Etc.) | 2.60 | 2.60 | 100.00% | 10.00% | 50.00% | 10 | $0.46 | $3.74 |
| 2 | 9 | 250 | 259 | Roof / Ceiling Insulation | 2.60 | 2.60 | 34.57% | 3.00% | 50.00% | 20 | $0.21 | $339.41 |
| 2 | 9 | 250 | 260 | Cool Roofs (Reflective and Spray Evaporative) | 2.60 | 2.60 | 100.00% | 0.39% | 50.00% | 10 | $0.04 | $65.67 |
| 2 | 9 | 250 | 261 | Clock / Programmable Thermostat | 2.60 | 2.60 | 40.00% | 10.00% | 100.00% | 10 | $0.10 | $3.74 |
| 2 | 9 | 250 | 262 | Installation of Air Side Economizers | 2.60 | 2.60 | 40.00% | 15.00% | 100.00% | 10 | $0.59 | $788.00 |
| 2 | 9 | 280 | 280 | Base Air-Cooled HP Package, 5 tons, SEER=10 | 2.60 | 2.60 | 100.00% | 0.00% | 100.00% | 15 | $3.40 | $3.40 |
| 2 | 9 | 280 | 281 | Air-Cooled HP Package, 5 tons, SEER=11 | 2.60 | 2.60 |  | 9.09% |  | 15 | $0.17 | $3.40 |
| 2 | 9 | 280 | 282 | Air-Cooled HP Package, 5 tons, SEER=12 | 2.60 | 2.60 |  | 16.67% |  | 15 | $1.12 | $3.40 |
| 2 | 9 | 280 | 283 | DX Tune-Up / Diagnostics | 2.60 | 2.60 | 10.00% | 10.00% | 100.00% | 3 | $0.37 | $3.74 |
| 2 | 9 | 280 | 284 | High Efficiency Windows (Low-E Glass or Multiple Glazed) | 2.60 | 2.60 | 92.94% | 5.00% | 75.00% | 30 | $0.16 | $74.47 |
| 2 | 9 | 280 | 285 | Installation of Direct of Indirect Evaporative Cooling, Evaporative Pre-Cooling, and Absorption Cooling | 2.60 | 2.60 | 95.00% | 10.00% | 25.00% | 10 | $1.38 | $3.74 |
| 2 | 9 | 280 | 288 | Installation of Automated Building Ventilation Control ( Via Occupancy Sensors, CO2 Sensors, Etc.) | 2.60 | 2.60 | 100.00% | 10.00% | 50.00% | 10 | $0.46 | $3.74 |
| 2 | 9 | 280 | 289 | Roof / Ceiling Insulation | 2.60 | 2.60 | 34.57% | 3.00% | 50.00% | 20 | $0.21 | $339.41 |
| 2 | 9 | 280 | 290 | Cool Roofs (Reflective and Spray Evaporative) | 2.60 | 2.60 | 100.00% | 0.39% | 50.00% | 10 | $0.04 | $65.67 |
| 2 | 9 | 280 | 291 | Clock / Programmable Thermostat | 2.60 | 2.60 | 40.00% | 10.00% | 100.00% | 10 | $0.10 | $3.74 |
| 2 | 9 | 280 | 292 | Installation of Air Side Economizers | 2.60 | 2.60 | 40.00% | 15.00% | 100.00% | 10 | $0.59 | $788.00 |
| 2 | 9 | 400 | 400 | Base Fan Motor, 5hp, 1800rpm, 87.5% (ODP) | 0.60 | 0.60 |  | 0.00% |  | 15 | $0.09 | $0.09 |
| 2 | 9 | 400 | 401 | Energy Efficient Fan & Pump Motors (ODP) | 0.60 | 0.60 |  | 1.50% |  | 15 | $0.02 | $0.09 |
| 2 | 9 | 400 | 402 | VSD, ASD Fan & Pump Applications | 0.60 | 0.60 |  | 30.00% |  | 15 | $0.10 | $0.09 |
| 2 | 9 | 610 | 610 | Base Office Equipment | 0.10 | 0.10 | 100.00% | 0.00% | 100.00% | 4 | $0.08 | $0.23 |
| 2 | 9 | 610 | 611 | ENERGY STAR or Better Office Equipment: Computer | 0.10 | 0.10 | 65.00% | 12.24% | 100.00% | 4 | $0.01 | $0.23 |
| 2 | 9 | 610 | 621 | ENERGY STAR or Better Office Equipment: Monitors | 0.10 | 0.10 | 71.00% | 10.87% | 100.00% | 4 | $0.00 | $0.23 |
| 2 | 9 | 610 | 623 | Smart Networks | 0.10 | 0.10 | 40.00% | 4.53% | 90.00% | 4 | $0.00 | $0.23 |
| 2 | 9 | 610 | 631 | ENERGY STAR or Better Office Equipment: Copiers | 0.10 | 0.10 | 33.00% | 20.18% | 100.00% | 4 | $0.00 | $0.03 |

## Table B.3: Commercial Electric

| Segment | Building | Base Number | Measure Number | Measure Name | Stock Usage | Base Usage | Incomplete Factor | Energy Savings | Feasibility Factor | Measure Life | Full Per Unit Cost | Full Base Measure Cost |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2 | 9 | 610 | 641 | ENERGY STAR or Better Office Equipment: Printers | 0.10 | 0.10 | 99.00% | 7.56% | 100.00% | 4 | $0.01 | $0.12 |
| 2 | 9 | 700 | 700 | Base Water Heating | 1.74 | 1.74 | 100.00% | 0.00% | 100.00% | 15 | $27.95 | $27.95 |
| 2 | 9 | 700 | 701 | Demand controlled circulating systems | 1.74 | 1.74 | 100.00% | 5.00% | 50.00% | 15 | $5.45 | $27.95 |
| 2 | 9 | 700 | 702 | Heat Pump Water Heater | 1.74 | 1.74 | 100.00% | 30.00% | 75.00% | 15 | $3.47 | $27.95 |
| 2 | 9 | 700 | 703 | High-Efficiency Water Heater (electric) | 1.74 | 1.74 | | 5.40% | | 15 | $1.01 | $27.95 |
| 2 | 9 | 700 | 704 | Hot Water (SHW) Pipe Insulation | 1.74 | 1.74 | 100.00% | 5.00% | 50.00% | 15 | $0.03 | $8.64 |
| 2 | 9 | 800 | 800 | Base Heating | 4.84 | 4.84 | 100.00% | 0.00% | 100.00% | 20 | $2.40 | $2.40 |
| 2 | 9 | 800 | 801 | Occupancy Sensor for room HVAC units | 4.84 | 4.84 | 100.00% | 35.00% | 51.00% | 15 | $0.20 | $2.40 |
| 2 | 9 | 800 | 802 | Roof / Ceiling Insulation | 4.84 | 4.84 | 62.26% | 10.00% | 50.00% | 20 | $0.21 | $1.03 |
| 2 | 9 | 800 | 805 | Clock / Programmable Thermostat | 4.84 | 4.84 | 29.72% | 30.00% | 100.00% | 10 | $0.15 | $2.40 |
| 2 | 9 | 800 | 812 | Installation of Automated Building Ventilation Control ( Via Occupancy Sensors, CO2 Sensors, Etc.) | 4.84 | 4.84 | 100.00% | 5.00% | 50.00% | 15 | $0.28 | $2.40 |
| 2 | 10 | 110 | 110 | Base Fluorescent Fixture, 4' 4L T12, 34W, 2EEMAG | 2.12 | 2.12 | 100.00% | 0.00% | 100.00% | 23 | $1.42 | $1.42 |
| 2 | 10 | 110 | 111 | 4' 4L T8 Premium, EB | 2.12 | 1.91 | 100.00% | 25.00% | 16.67% | 36 | $0.46 | $1.42 |
| 2 | 10 | 110 | 112 | 4' 2L T8 Premium, EB, reflector | 2.12 | 1.91 | 100.00% | 62.50% | 16.67% | 36 | $0.70 | $1.42 |
| 2 | 10 | 110 | 113 | Occupancy Sensor, 4-4' Fluorescent Fixtures | 2.12 | 1.91 | 95.02% | 30.00% | 20.00% | 21 | $0.49 | $1.42 |
| 2 | 10 | 110 | 114 | Continuous Dimming, 5-4' Fluorescent Fixtures | 2.12 | 1.91 | 100.00% | 75.00% | 30.00% | 26 | $3.69 | $1.42 |
| 2 | 10 | 110 | 115 | 4' 2L T5HO, EB | 2.12 | 1.91 | 100.00% | 18.75% | 16.67% | 36 | $0.27 | $1.42 |
| 2 | 10 | 110 | 116 | 4' 4L T8, EB | 2.12 | 1.91 | 100.00% | 22.22% | 16.67% | 36 | $0.19 | $1.42 |
| 2 | 10 | 110 | 117 | 4' 3L T8, EB | 2.12 | 1.91 | 100.00% | 38.20% | 16.67% | 36 | $0.09 | $1.42 |
| 2 | 10 | 110 | 118 | 4' 3L T8 Premium, EB | 2.12 | 1.91 | 100.00% | 42.36% | 16.67% | 36 | $0.30 | $1.42 |
| 2 | 10 | 120 | 120 | Base Fluorescent Fixture, 4' 2L T12, 34W, 1EEMAG | 2.12 | 2.12 | 100.00% | 0.00% | 100.00% | 23 | $2.63 | $2.63 |
| 2 | 10 | 120 | 121 | 4' 2L T8 Premium, EB | 2.12 | 1.91 | 100.00% | 25.00% | 33.33% | 36 | $0.73 | $2.63 |
| 2 | 10 | 120 | 122 | 4' 1L T8 Premium, EB, reflector | 2.12 | 1.91 | 100.00% | 61.11% | 33.33% | 36 | $1.49 | $2.63 |
| 2 | 10 | 120 | 123 | Occupancy Sensor, 8-4' Fluorescent Fixtures | 2.12 | 1.91 | 95.02% | 30.00% | 20.00% | 21 | $0.43 | $2.63 |
| 2 | 10 | 120 | 124 | Continuous Dimming, 10-4' Fluorescent Fixtures | 2.12 | 1.91 | 100.00% | 75.00% | 30.00% | 26 | $3.62 | $2.63 |
| 2 | 10 | 120 | 125 | 4' 1L T5HO, EB | 2.12 | 1.91 | 100.00% | 13.90% | 33.33% | 36 | $0.56 | $2.63 |
| 2 | 10 | 130 | 130 | Base Fluorescent Fixture, 8' 2L T12, 60W, 1EEMAG | 2.12 | 2.12 | 100.00% | 0.00% | 100.00% | 23 | $1.79 | $1.79 |
| 2 | 10 | 130 | 131 | 8' 2L T12, 60W, EB | 2.12 | 1.91 | 46.17% | 10.57% | 25.00% | 36 | $0.17 | $1.79 |
| 2 | 10 | 130 | 132 | 8' 1L T12, 60W, EB, reflector | 2.12 | 1.91 | 100.00% | 55.30% | 25.00% | 36 | $0.77 | $1.79 |
| 2 | 10 | 130 | 133 | Occupancy Sensor, 4-8' Fluorescent Fixtures | 2.12 | 1.91 | 95.02% | 30.00% | 20.00% | 21 | $0.53 | $1.79 |
| 2 | 10 | 130 | 134 | Continuous Dimming, 5-8' Fluorescent Fixtures | 2.12 | 1.91 | 100.00% | 75.00% | 30.00% | 26 | $4.03 | $1.79 |
| 2 | 10 | 130 | 135 | 8' 2L T8, EB | 2.12 | 1.91 | 100.00% | 52.80% | 50.00% | 36 | $0.35 | $1.79 |
| 2 | 10 | 140 | 140 | Base Incandescent Flood, 75W | 2.12 | 2.12 | 100.00% | 0.00% | 100.00% | 1 | $3.96 | $3.96 |
| 2 | 10 | 140 | 141 | CFL Screw-in, Modular 18W | 2.12 | 1.91 | 95.29% | 65.30% | 90.00% | 10 | $2.44 | $3.96 |
| 2 | 10 | 150 | 150 | Base Incandescent Flood, 150W PAR | 2.12 | 2.12 | 100.00% | 0.00% | 100.00% | 1 | $1.92 | $1.92 |
| 2 | 10 | 150 | 151 | Halogen PAR Flood, 90W | 2.12 | 2.12 | 98.69% | 40.00% | 10.00% | 1 | $0.19 | $1.92 |
| 2 | 10 | 150 | 152 | Metal Halide, 50W | 2.12 | 2.12 | 97.99% | 52.00% | 45.00% | 12 | $10.29 | $1.92 |
| 2 | 10 | 150 | 153 | HPS, 50W | 2.12 | 2.12 | 97.99% | 56.00% | 45.00% | 12 | $5.25 | $1.92 |
| 2 | 10 | 160 | 160 | Base 4' 3L T12, 34W, 1EEMAG | 2.12 | 2.12 | 100.00% | 0.00% | 100.00% | 10 | $0.36 | $0.36 |
| 2 | 10 | 160 | 161 | 4' 3L T8, EB | 2.12 | 1.91 | 100.00% | 22.61% | 25.00% | 36 | $0.03 | $0.36 |
| 2 | 10 | 160 | 162 | 4' 3L T8 Premium, EB | 2.12 | 1.91 | 100.00% | 22.61% | 25.00% | 36 | $0.08 | $0.36 |
| 2 | 10 | 160 | 163 | 4' 2L T8 Premium, EB, reflector | 2.12 | 1.91 | 100.00% | 53.04% | 25.00% | 36 | $0.19 | $0.36 |
| 2 | 10 | 160 | 164 | 4' 1L T5HO, EB | 2.12 | 1.91 | 100.00% | 46.09% | 25.00% | 36 | $0.03 | $0.36 |

## Table B.3: Commercial Electric

| Segment | Building | Base Number | Measure Number | Measure Name | Stock Usage | Base Usage | Incomplete Factor | Energy Savings | Feasibility Factor | Measure Life | Full Per Unit Cost | Full Base Measure Cost |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2 | 10 | 180 | 180 | Base Fluorescent Fixture 4' 4L T8, 1EB | 1.70 | 1.70 | 100.00% | 0.00% | 100.00% | 36 | $1.59 | $1.59 |
| 2 | 10 | 180 | 181 | 4' 4L T8 Premium, EB | 1.70 | 1.53 | 100.00% | 3.60% | 100.00% | 36 | $0.28 | $1.59 |
| 2 | 10 | 180 | 182 | Occupancy Sensor, 4-4' Fluorescent Fixtures | 1.70 | 1.53 | 95.02% | 30.00% | 20.00% | 21 | $0.49 | $1.59 |
| 2 | 10 | 185 | 185 | Base Fluorescent Fixture 4' 3L T8, 1EB | 1.70 | 1.70 | 100.00% | 0.00% | 100.00% | 36 | $2.99 | $2.99 |
| 2 | 10 | 185 | 186 | 4' 3L T8 Premium, EB | 1.70 | 1.53 | 100.00% | 6.70% | 100.00% | 36 | $0.41 | $2.99 |
| 2 | 10 | 190 | 190 | Base Fluorescent Fixture 4' 2L T8, 1EB | 1.70 | 1.70 | 100.00% | 0.00% | 100.00% | 36 | $2.81 | $2.81 |
| 2 | 10 | 190 | 191 | 4' 2L T8 Premium, EB | 1.70 | 1.53 | 100.00% | 8.50% | 100.00% | 36 | $0.25 | $2.81 |
| 2 | 10 | 190 | 192 | Occupancy Sensor, 8-4' Fluorescent Fixtures | 1.70 | 1.53 | 95.02% | 30.00% | 20.00% | 21 | $0.43 | $2.81 |
| 2 | 10 | 200 | 200 | Base Centrifugal Chiller, 0.65 kW/ton, 300 tons | 2.54 | 2.54 | 100.00% | 0.00% | 100.00% | 20 | $0.92 | $0.92 |
| 2 | 10 | 200 | 201 | Chiller Tune-Up / Diagnostics | 2.54 | 2.54 | 10.00% | 5.00% | 100.00% | 5 | $0.08 | $0.92 |
| 2 | 10 | 200 | 202 | Installation of Automated Building Ventilation Control ( Via Occupancy Sensors, CO2 Sensors, Etc.) | 2.54 | 2.54 | 100.00% | 10.00% | 50.00% | 10 | $0.19 | $0.92 |
| 2 | 10 | 200 | 203 | Roof / Ceiling Insulation | 2.54 | 2.54 | 40.19% | 3.00% | 50.00% | 20 | $0.44 | $414.96 |
| 2 | 10 | 200 | 204 | Cool Roofs (Reflective and Spray Evaporative) | 2.54 | 2.54 | 100.00% | 12.96% | 90.00% | 10 | $0.47 | $461.00 |
| 2 | 10 | 200 | 205 | EMS Optimization | 2.54 | 2.54 | 50.00% | 1.00% | 100.00% | 5 | $0.00 | $0.00 |
| 2 | 10 | 200 | 206 | High Efficiency Windows (Low-E Glass or Multiple Glazed) | 2.54 | 2.54 | 76.27% | 2.47% | 75.00% | 30 | $0.02 | $13.11 |
| 2 | 10 | 200 | 207 | Installation of Energy Management Systems | 2.54 | 2.54 | 100.00% | 10.00% | 50.00% | 10 | $0.12 | $0.92 |
| 2 | 10 | 200 | 208 | Insulation of Pipes | 2.54 | 2.54 | 50.00% | 1.00% | 50.00% | 20 | $0.01 | $1.08 |
| 2 | 10 | 200 | 209 | Installation of Chiller Economizers (water side) | 2.54 | 2.54 | 76.27% | 10.00% | 50.00% | 20 | $0.59 | $461.00 |
| 2 | 10 | 200 | 210 | Optimize Chilled Water and Condenser Water Settings | 2.54 | 2.54 | 50.00% | 5.00% | 33.00% | 10 | $0.13 | $0.92 |
| 2 | 10 | 200 | 211 | Decrease Cooling Tower Approach Temperature, 300 Tons, 6 Deg F | 2.54 | 2.54 | 90.00% | 7.50% | 67.00% | 15 | $0.07 | $1.43 |
| 2 | 10 | 200 | 212 | Two-Speed Cooling Tower, 300 Tons | 2.54 | 2.54 | 90.00% | 14.00% | 50.00% | 15 | $0.01 | $1.43 |
| 2 | 10 | 200 | 213 | VSD Cooling Tower, 300 Tons | 2.54 | 2.54 | 90.00% | 18.00% | 50.00% | 15 | $0.05 | $1.43 |
| 2 | 10 | 200 | 214 | Primary/Secondary De-coupled Chilled Water System | 2.54 | 2.54 | 80.00% | 12.00% | 50.00% | 15 | $0.30 | $1.43 |
| 2 | 10 | 200 | 215 | HE Chiller, 0.51 kW/ton, 300 Tons | 2.54 | 2.54 | | 21.54% | | 15 | $0.12 | $1.43 |
| 2 | 10 | 200 | 216 | VSD Chiller, 0.47 kW/ton, 300 Tons | 2.54 | 2.54 | | 27.69% | | 15 | $0.40 | $1.43 |
| 2 | 10 | 250 | 250 | Base DX Packaged System, EER=10.3, 10 tons | 4.40 | 4.40 | 100.00% | 0.00% | 100.00% | 15 | $1.58 | $1.58 |
| 2 | 10 | 250 | 251 | DX Tune-Up / Diagnostics | 4.40 | 4.40 | 10.00% | 10.00% | 100.00% | 3 | $0.16 | $1.58 |
| 2 | 10 | 250 | 252 | Hi-Eff DX Packaged System, 10 tons, EER=11.3 | 4.40 | 4.40 | | 8.85% | | 15 | $0.19 | $1.58 |
| 2 | 10 | 250 | 253 | High Efficiency Windows (Low-E Glass or Multiple Glazed) | 4.40 | 4.40 | 76.27% | 5.00% | 75.00% | 30 | $0.05 | $22.41 |
| 2 | 10 | 250 | 254 | Installation of Direct of Indirect Evaporative Cooling, Evaporative Pre-Cooling, and Absorption Cooling | 4.40 | 4.40 | 95.00% | 10.00% | 25.00% | 10 | $0.58 | $1.58 |
| 2 | 10 | 250 | 258 | Installation of Automated Building Ventilation Control ( Via Occupancy Sensors, CO2 Sensors, Etc.) | 4.40 | 4.40 | 100.00% | 10.00% | 50.00% | 10 | $0.19 | $1.58 |
| 2 | 10 | 250 | 259 | Roof / Ceiling Insulation | 4.40 | 4.40 | 40.19% | 3.00% | 50.00% | 20 | $0.44 | $709.31 |
| 2 | 10 | 250 | 260 | Cool Roofs (Reflective and Spray Evaporative) | 4.40 | 4.40 | 100.00% | 12.96% | 50.00% | 10 | $0.42 | $709.31 |
| 2 | 10 | 250 | 261 | Clock / Programmable Thermostat | 4.40 | 4.40 | 17.97% | 10.00% | 100.00% | 10 | $0.04 | $1.58 |
| 2 | 10 | 250 | 262 | Installation of Air Side Economizers | 4.40 | 4.40 | 79.66% | 15.00% | 100.00% | 10 | $0.59 | $788.00 |
| 2 | 10 | 280 | 280 | Base Air-Cooled HP Package, 5 tons, SEER=10 | 4.40 | 4.40 | 100.00% | 0.00% | 100.00% | 15 | $1.43 | $1.43 |
| 2 | 10 | 280 | 281 | Air-Cooled HP Package, 5 tons, SEER=11 | 4.40 | 4.40 | | 9.09% | | 15 | $0.07 | $1.43 |
| 2 | 10 | 280 | 282 | Air-Cooled HP Package, 5 tons, SEER=12 | 4.40 | 4.40 | | 16.67% | | 15 | $0.47 | $1.43 |
| 2 | 10 | 280 | 283 | DX Tune-Up / Diagnostics | 4.40 | 4.40 | 10.00% | 10.00% | 100.00% | 3 | $0.16 | $1.58 |
| 2 | 10 | 280 | 284 | High Efficiency Windows (Low-E Glass or Multiple Glazed) | 4.40 | 4.40 | 76.27% | 5.00% | 75.00% | 30 | $0.05 | $22.41 |

## Table B.3: Commercial Electric

| Segment | Building | Base Number | Measure Number | Measure Name | Stock Usage | Base Usage | Incomplete Factor | Energy Savings | Feasibility Factor | Measure Life | Full Per Unit Cost | Full Base Measure Cost |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2 | 10 | 280 | 285 | Installation of Direct of Indirect Evaporative Cooling, Evaporative Pre-Cooling, and Absorption Cooling | 4.40 | 4.40 | 95.00% | 10.00% | 25.00% | 10 | $0.58 | $1.58 |
| 2 | 10 | 280 | 288 | Installation of Automated Building Ventilation Control ( Via Occupancy Sensors, CO2 Sensors, Etc.) | 4.40 | 4.40 | 100.00% | 10.00% | 50.00% | 10 | $0.19 | $1.58 |
| 2 | 10 | 280 | 289 | Roof / Ceiling Insulation | 4.40 | 4.40 | 40.19% | 3.00% | 50.00% | 20 | $0.44 | $709.31 |
| 2 | 10 | 280 | 290 | Cool Roofs (Reflective and Spray Evaporative) | 4.40 | 4.40 | 100.00% | 12.96% | 50.00% | 10 | $0.42 | $709.31 |
| 2 | 10 | 280 | 291 | Clock / Programmable Thermostat | 4.40 | 4.40 | 17.97% | 10.00% | 100.00% | 10 | $0.04 | $1.58 |
| 2 | 10 | 280 | 292 | Installation of Air Side Economizers | 4.40 | 4.40 | 79.66% | 15.00% | 100.00% | 10 | $0.59 | $788.00 |
| 2 | 10 | 400 | 400 | Base Fan Motor, 5hp, 1800rpm, 87.5% (ODP) | 1.89 | 1.89 | | 0.00% | | 15 | $0.28 | $0.28 |
| 2 | 10 | 400 | 401 | Energy Efficient Fan & Pump Motors (ODP) | 1.89 | 1.89 | | 1.50% | | 15 | $0.06 | $0.28 |
| 2 | 10 | 400 | 402 | VSD, ASD Fan & Pump Applications | 1.89 | 1.89 | | 30.00% | | 15 | $0.33 | $0.28 |
| 2 | 10 | 610 | 610 | Base Office Equipment | 0.09 | 0.09 | 100.00% | 0.00% | 100.00% | 4 | $1.16 | $3.42 |
| 2 | 10 | 610 | 611 | ENERGY STAR or Better Office Equipment: Computer | 0.09 | 0.09 | 65.00% | 18.60% | 100.00% | 4 | $0.15 | $3.42 |
| 2 | 10 | 610 | 621 | ENERGY STAR or Better Office Equipment: Monitors | 0.09 | 0.09 | 71.00% | 16.52% | 100.00% | 4 | $0.07 | $3.42 |
| 2 | 10 | 610 | 623 | Smart Networks | 0.09 | 0.09 | 40.00% | 6.88% | 90.00% | 4 | $0.01 | $3.42 |
| 2 | 10 | 610 | 631 | ENERGY STAR or Better Office Equipment: Copiers | 0.09 | 0.09 | 33.00% | 11.44% | 100.00% | 4 | $0.04 | $0.50 |
| 2 | 10 | 610 | 641 | ENERGY STAR or Better Office Equipment: Printers | 0.09 | 0.09 | 99.00% | 9.16% | 100.00% | 4 | $0.11 | $1.24 |
| 2 | 10 | 700 | 700 | Base Water Heating | 2.25 | 2.25 | 100.00% | 0.00% | 100.00% | 15 | $27.30 | $27.30 |
| 2 | 10 | 700 | 701 | Demand controlled circulating systems | 2.25 | 2.25 | 100.00% | 5.00% | 50.00% | 15 | $5.32 | $27.30 |
| 2 | 10 | 700 | 702 | Heat Pump Water Heater | 2.25 | 2.25 | 100.00% | 30.00% | 75.00% | 15 | $3.39 | $27.30 |
| 2 | 10 | 700 | 703 | High-Efficiency Water Heater (electric) | 2.25 | 2.25 | | 5.40% | | 15 | $0.98 | $27.30 |
| 2 | 10 | 700 | 704 | Hot Water (SHW) Pipe Insulation | 2.25 | 2.25 | 100.00% | 5.00% | 50.00% | 15 | $0.01 | $2.34 |
| 2 | 10 | 800 | 800 | Base Heating | 4.58 | 4.58 | 100.00% | 0.00% | 100.00% | 20 | $2.40 | $2.40 |
| 2 | 10 | 800 | 802 | Roof / Ceiling Insulation | 4.58 | 4.58 | 13.38% | 10.00% | 50.00% | 20 | $0.44 | $2.16 |
| 2 | 10 | 800 | 805 | Clock / Programmable Thermostat | 4.58 | 4.58 | 20.88% | 30.00% | 100.00% | 10 | $0.15 | $2.40 |
| 2 | 10 | 800 | 812 | Installation of Automated Building Ventilation Control ( Via Occupancy Sensors, CO2 Sensors, Etc.) | 4.58 | 4.58 | 100.00% | 5.00% | 50.00% | 15 | $0.28 | $2.40 |

## Table B.4: Commercial Gas

| Segment | Building | Base Number | Measure Number | Measure Name | Stock Usage | Base Usage | Incomplete Factor | Energy Savings | Feasibility Factor | Measure Life | Full Per Unit Cost | Full Base Measure Cost |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 1 | 200 | 200 | Base Heating | 0.18 | 0.18 | 100.00% | 0.00% | 100.00% | 20.0 | $0.2954 | $0.30 |
| 1 | 1 | 200 | 201 | High Efficiency Windows (Multiple Glazed, Low Emissivity) | 0.18 | 0.18 | 98.00% | 36.84% | 75.00% | 60.0 | $0.0596 | $1.75 |
| 1 | 1 | 200 | 202 | Insulation (ceiling) | 0.18 | 0.18 | 12.95% | 5.31% | 50.00% | 20.0 | $0.3252 | $13.27 |
| 1 | 1 | 200 | 203 | Insulation (wall) | 0.18 | 0.18 | 84.12% | 20.00% | 50.00% | 20.0 | $0.3650 | $13.27 |
| 1 | 1 | 200 | 206 | Duct Repair and Sealing | 0.18 | 0.18 | 50.00% | 2.00% | 25.00% | 20.0 | $0.0072 | $0.91 |
| 1 | 1 | 200 | 207 | Duct Insulation | 0.18 | 0.18 | 58.50% | 2.00% | 25.00% | 20.0 | $0.0183 | $0.91 |
| 1 | 1 | 200 | 209 | Insulation of Pipes | 0.18 | 0.18 | 25.00% | 2.00% | 50.00% | 20.0 | $0.0150 | $0.74 |
| 1 | 1 | 200 | 212 | Boiler Tune-Up | 0.18 | 0.18 | 90.00% | 2.00% | 100.00% | 2.0 | $0.0022 | $0.00 |
| 1 | 1 | 200 | 216 | Clock / Programmable Thermostat | 0.18 | 0.18 | 48.81% | 2.00% | 75.00% | 10.0 | $0.0008 | $0.00 |

## Table B.4: Commercial Gas

| Segment | Building | Base Number | Measure Number | Measure Name | Stock Usage | Base Usage | Incomplete Factor | Energy Savings | Feasibility Factor | Measure Life | Full Per Unit Cost | Full Base Measure Cost |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 1 | 200 | 218 | Installation of Energy Management Systems (EMS) | 0.18 | 0.18 | 52.58% | 10.00% | 25.00% | 20.0 | $0.2900 | $20.00 |
| 1 | 1 | 200 | 222 | Installation of Air Side Heat Recovery Systems | 0.18 | 0.18 | 90.00% | 20.00% | 50.00% | 20.0 | $1.0000 | $10.00 |
| 1 | 1 | 200 | 227 | High Efficiency Gas Furnace/Boiler | 0.18 | 0.18 | | 13.20% | | 20.0 | $0.0960 | $0.30 |
| 1 | 1 | 200 | 228 | Stack Heat Exchanger | 0.18 | 0.18 | 84.00% | 4.76% | 50.00% | 20.0 | $0.0093 | $0.00 |
| 1 | 1 | 400 | 400 | Base Water Heating, 100 gal., 88 kBtu, EF=.76 | 0.06 | 0.06 | 100.00% | 0.00% | 100.00% | 15.0 | $0.0381 | $0.04 |
| 1 | 1 | 400 | 401 | Hot Water (SHW) Pipe Insulation | 0.06 | 0.06 | 50.30% | 3.00% | 50.00% | 15.0 | $0.0039 | $0.01 |
| 1 | 1 | 400 | 403 | Water Heater Tank Blanket/Insulation | 0.06 | 0.06 | 88.76% | 15.00% | 95.00% | 15.0 | $0.0055 | $0.00 |
| 1 | 1 | 400 | 404 | Tankless Water Heater | 0.06 | 0.06 | 100.00% | 10.00% | 10.00% | 15.0 | $0.0369 | $0.04 |
| 1 | 1 | 400 | 405 | High-Efficiency Water Heater (gas), 100 gal., 88 kBTU, EF=.80 | 0.06 | 0.06 | 47.10% | 5.00% | 95.00% | 15.0 | $0.0664 | $0.04 |
| 1 | 1 | 400 | 406 | High-Efficiency Water Heater (gas), 100 gal., 120 kBTU, EF=.95 | 0.06 | 0.06 | 47.10% | 20.00% | 95.00% | 15.0 | $0.1036 | $0.04 |
| 1 | 2 | 200 | 200 | Base Heating | 0.12 | 0.12 | 100.00% | 0.00% | 100.00% | 20.0 | $0.3082 | $0.31 |
| 1 | 2 | 200 | 201 | High Efficiency Windows (Multiple Glazed, Low Emissivity) | 0.12 | 0.12 | 99.80% | 25.00% | 75.00% | 60.0 | $0.0193 | $0.57 |
| 1 | 2 | 200 | 202 | Insulation (ceiling) | 0.12 | 0.12 | 75.43% | 16.92% | 50.00% | 20.0 | $0.4483 | $18.30 |
| 1 | 2 | 200 | 203 | Insulation (wall) | 0.12 | 0.12 | 72.21% | 20.00% | 50.00% | 20.0 | $0.5031 | $18.30 |
| 1 | 2 | 200 | 206 | Duct Repair and Sealing | 0.12 | 0.12 | 50.00% | 2.00% | 25.00% | 20.0 | $0.0050 | $0.62 |
| 1 | 2 | 200 | 207 | Duct Insulation | 0.12 | 0.12 | 84.90% | 2.00% | 25.00% | 20.0 | $0.0126 | $0.62 |
| 1 | 2 | 200 | 209 | Insulation of Pipes | 0.12 | 0.12 | 25.00% | 2.00% | 50.00% | 20.0 | $0.0205 | $1.01 |
| 1 | 2 | 200 | 216 | Clock / Programmable Thermostat | 0.12 | 0.12 | 79.02% | 2.00% | 75.00% | 10.0 | $0.0008 | $0.00 |
| 1 | 2 | 200 | 222 | Installation of Air Side Heat Recovery Systems | 0.12 | 0.12 | 90.00% | 20.00% | 50.00% | 20.0 | $1.0000 | $10.00 |
| 1 | 2 | 200 | 227 | High Efficiency Gas Furnace/Boiler | 0.12 | 0.12 | | 13.20% | | 20.0 | $0.1002 | $0.31 |
| 1 | 2 | 200 | 228 | Stack Heat Exchanger | 0.12 | 0.12 | 85.00% | 4.76% | 50.00% | 20.0 | $0.0297 | $0.00 |
| 1 | 2 | 400 | 400 | Base Water Heating, 100 gal., 88 kBtu, EF=.76 | 0.19 | 0.19 | 100.00% | 0.00% | 100.00% | 15.0 | $0.1191 | $0.12 |
| 1 | 2 | 400 | 401 | Hot Water (SHW) Pipe Insulation | 0.19 | 0.19 | 73.40% | 3.00% | 50.00% | 15.0 | $0.0236 | $0.05 |
| 1 | 2 | 400 | 403 | Water Heater Tank Blanket/Insulation | 0.19 | 0.19 | 75.87% | 15.00% | 95.00% | 15.0 | $0.0331 | $0.00 |
| 1 | 2 | 400 | 404 | Tankless Water Heater | 0.19 | 0.19 | 100.00% | 10.00% | 10.00% | 15.0 | $0.1154 | $0.12 |
| 1 | 2 | 400 | 405 | High-Efficiency Water Heater (gas), 100 gal., 88 kBTU, EF=.80 | 0.19 | 0.19 | 57.40% | 5.00% | 95.00% | 15.0 | $0.2076 | $0.12 |
| 1 | 2 | 400 | 406 | High-Efficiency Water Heater (gas), 100 gal., 120 kBTU, EF=.95 | 0.19 | 0.19 | 57.40% | 20.00% | 95.00% | 15.0 | $0.3238 | $0.12 |
| 1 | 3 | 100 | 100 | Base Cooking | 1.72 | 1.72 | 100.00% | 0.00% | 100.00% | 15.0 | $1.9256 | $1.93 |
| 1 | 3 | 100 | 102 | High-Efficiency Convection Oven | 1.72 | 1.72 | | 12.00% | | 15.0 | $1.6175 | $1.93 |
| 1 | 3 | 100 | 103 | Efficient Infrared Griddle | 1.72 | 1.72 | 80.00% | 14.00% | 90.00% | 15.0 | $0.4652 | $1.93 |
| 1 | 3 | 100 | 104 | Infrared Fryer | 1.72 | 1.72 | 80.00% | 30.00% | 90.00% | 15.0 | $0.6608 | $1.93 |
| 1 | 3 | 100 | 105 | Power Burner Oven | 1.72 | 1.72 | 80.00% | 8.00% | 90.00% | 15.0 | $1.9670 | $1.93 |
| 1 | 3 | 100 | 106 | Power Burner Fryer | 1.72 | 1.72 | 80.00% | 8.00% | 90.00% | 15.0 | $0.7873 | $1.93 |
| 1 | 3 | 100 | 107 | Infrared Conveyer Oven | 1.72 | 1.72 | 90.00% | 30.00% | 90.00% | 15.0 | $2.1088 | $1.93 |
| 1 | 3 | 200 | 200 | Base Heating | 0.14 | 0.14 | 100.00% | 0.00% | 100.00% | 20.0 | $0.8148 | $0.81 |
| 1 | 3 | 200 | 201 | High Efficiency Windows (Multiple Glazed, Low Emissivity) | 0.14 | 0.14 | 100.00% | 15.00% | 50.00% | 60.0 | $0.0313 | $0.92 |
| 1 | 3 | 200 | 202 | Insulation (ceiling) | 0.14 | 0.14 | 55.72% | 6.40% | 50.00% | 20.0 | $0.4713 | $19.24 |
| 1 | 3 | 200 | 203 | Insulation (wall) | 0.14 | 0.14 | 93.11% | 20.00% | 50.00% | 20.0 | $0.5290 | $19.24 |
| 1 | 3 | 200 | 206 | Duct Repair and Sealing | 0.14 | 0.14 | 50.00% | 2.00% | 25.00% | 20.0 | $0.0127 | $1.59 |
| 1 | 3 | 200 | 207 | Duct Insulation | 0.14 | 0.14 | 56.80% | 2.00% | 25.00% | 20.0 | $0.0321 | $1.59 |
| 1 | 3 | 200 | 209 | Insulation of Pipes | 0.14 | 0.14 | 25.00% | 2.00% | 50.00% | 20.0 | $0.0316 | $1.56 |
| 1 | 3 | 200 | 216 | Clock / Programmable Thermostat | 0.14 | 0.14 | 50.25% | 2.00% | 75.00% | 10.0 | $0.0008 | $0.00 |
| 1 | 3 | 200 | 222 | Installation of Air Side Heat Recovery Systems | 0.14 | 0.14 | 78.34% | 20.00% | 50.00% | 20.0 | $1.0000 | $10.00 |
| 1 | 3 | 200 | 227 | High Efficiency Gas Furnace/Boiler | 0.14 | 0.14 | | 13.20% | | 20.0 | $0.2648 | $0.81 |

# Table B.4: Commercial Gas

| Segment | Building | Base Number | Measure Number | Measure Name | Stock Usage | Base Usage | Incomplete Factor | Energy Savings | Feasibility Factor | Measure Life | Full Per Unit Cost | Full Base Measure Cost |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 3 | 200 | 228 | Stack Heat Exchanger | 0.14 | 0.14 | 86.00% | 4.76% | 50.00% | 20.0 | $0.1194 | $0.00 |
| 1 | 3 | 400 | 400 | Base Water Heating, 100 gal., 88 kBtu, EF=.76 | 0.54 | 0.54 | 100.00% | 0.00% | 100.00% | 15.0 | $0.1640 | $0.16 |
| 1 | 3 | 400 | 401 | Hot Water (SHW) Pipe Insulation | 0.54 | 0.54 | 74.60% | 3.00% | 50.00% | 15.0 | $0.0255 | $0.05 |
| 1 | 3 | 400 | 403 | Water Heater Tank Blanket/Insulation | 0.54 | 0.54 | 86.30% | 5.00% | 95.00% | 15.0 | $0.0357 | $0.01 |
| 1 | 3 | 400 | 404 | Tankless Water Heater | 0.54 | 0.54 | 100.00% | 10.00% | 10.00% | 15.0 | $0.1590 | $0.16 |
| 1 | 3 | 400 | 405 | High-Efficiency Water Heater (gas), 100 gal., 88 kBTU, EF=.80 | 0.54 | 0.54 | 54.20% | 5.00% | 95.00% | 15.0 | $0.2860 | $0.16 |
| 1 | 3 | 400 | 406 | High-Efficiency Water Heater (gas), 100 gal., 120 kBTU, EF=.95 | 0.54 | 0.54 | 54.20% | 20.00% | 95.00% | 15.0 | $0.4460 | $0.16 |
| 1 | 4 | 100 | 100 | Base Cooking | 0.67 | 0.67 | 100.00% | 0.00% | 100.00% | 15.0 | $0.5229 | $0.52 |
| 1 | 4 | 100 | 102 | High-Efficiency Convection Oven | 0.67 | 0.67 |  | 9.00% |  | 15.0 | $0.4392 | $0.52 |
| 1 | 4 | 100 | 103 | Efficient Infrared Griddle | 0.67 | 0.67 | 80.00% | 3.00% | 75.00% | 15.0 | $0.1263 | $0.52 |
| 1 | 4 | 100 | 104 | Infrared Fryer | 0.67 | 0.67 | 80.00% | 3.00% | 75.00% | 15.0 | $0.1794 | $0.52 |
| 1 | 4 | 100 | 105 | Power Burner Oven | 0.67 | 0.67 | 80.00% | 4.26% | 75.00% | 15.0 | $0.5341 | $0.52 |
| 1 | 4 | 100 | 106 | Power Burner Fryer | 0.67 | 0.67 | 80.00% | 4.26% | 75.00% | 15.0 | $0.2138 | $0.52 |
| 1 | 4 | 100 | 107 | Infrared Conveyer Oven | 0.67 | 0.67 | 90.00% | 3.00% | 75.00% | 15.0 | $0.5726 | $0.52 |
| 1 | 4 | 200 | 200 | Base Heating | 0.20 | 0.20 | 100.00% | 0.00% | 100.00% | 20.0 | $0.3388 | $0.34 |
| 1 | 4 | 200 | 201 | High Efficiency Windows (Multiple Glazed, Low Emissivity) | 0.20 | 0.20 | 100.00% | 6.35% | 75.00% | 60.0 | $0.0278 | $0.82 |
| 1 | 4 | 200 | 202 | Insulation (ceiling) | 0.20 | 0.20 | 85.03% | 11.27% | 50.00% | 20.0 | $0.4811 | $19.64 |
| 1 | 4 | 200 | 203 | Insulation (wall) | 0.20 | 0.20 | 85.03% | 20.00% | 50.00% | 20.0 | $0.5400 | $19.64 |
| 1 | 4 | 200 | 206 | Duct Repair and Sealing | 0.20 | 0.20 | 50.00% | 2.00% | 25.00% | 20.0 | $0.0053 | $0.66 |
| 1 | 4 | 200 | 207 | Duct Insulation | 0.20 | 0.20 | 71.50% | 2.00% | 25.00% | 20.0 | $0.0134 | $0.66 |
| 1 | 4 | 200 | 209 | Insulation of Pipes | 0.20 | 0.20 | 25.00% | 2.00% | 50.00% | 20.0 | $0.0236 | $1.17 |
| 1 | 4 | 200 | 216 | Clock / Programmable Thermostat | 0.20 | 0.20 | 78.37% | 2.00% | 75.00% | 10.0 | $0.0008 | $0.00 |
| 1 | 4 | 200 | 222 | Installation of Air Side Heat Recovery Systems | 0.20 | 0.20 | 76.40% | 20.00% | 50.00% | 20.0 | $1.0000 | $10.00 |
| 1 | 4 | 200 | 227 | High Efficiency Gas Furnace/Boiler | 0.20 | 0.20 |  | 13.20% |  | 20.0 | $0.1101 | $0.34 |
| 1 | 4 | 200 | 228 | Stack Heat Exchanger | 0.20 | 0.20 | 87.00% | 4.76% | 50.00% | 20.0 | $0.0941 | $0.00 |
| 1 | 4 | 400 | 400 | Base Water Heating, 100 gal., 88 kBtu, EF=.76 | 0.09 | 0.09 | 100.00% | 0.00% | 100.00% | 15.0 | $0.0555 | $0.06 |
| 1 | 4 | 400 | 401 | Hot Water (SHW) Pipe Insulation | 0.09 | 0.09 | 69.50% | 3.00% | 50.00% | 15.0 | $0.0093 | $0.02 |
| 1 | 4 | 400 | 403 | Water Heater Tank Blanket/Insulation | 0.09 | 0.09 | 100.00% | 10.00% | 95.00% | 15.0 | $0.0130 | $0.00 |
| 1 | 4 | 400 | 404 | Tankless Water Heater | 0.09 | 0.09 | 100.00% | 10.00% | 10.00% | 15.0 | $0.0538 | $0.06 |
| 1 | 4 | 400 | 405 | High-Efficiency Water Heater (gas), 100 gal., 88 kBTU, EF=.80 | 0.09 | 0.09 | 69.30% | 5.00% | 95.00% | 15.0 | $0.0968 | $0.06 |
| 1 | 4 | 400 | 406 | High-Efficiency Water Heater (gas), 100 gal., 120 kBTU, EF=.95 | 0.09 | 0.09 | 69.30% | 20.00% | 95.00% | 15.0 | $0.1509 | $0.06 |
| 1 | 5 | 200 | 200 | Base Heating | 0.12 | 0.12 | 100.00% | 0.00% | 100.00% | 20.0 | $0.2472 | $0.25 |
| 1 | 5 | 200 | 201 | High Efficiency Windows (Multiple Glazed, Low Emissivity) | 0.12 | 0.12 | 100.00% | 1.00% | 75.00% | 60.0 | $0.0116 | $0.34 |
| 1 | 5 | 200 | 202 | Insulation (ceiling) | 0.12 | 0.12 | 33.67% | 30.92% | 50.00% | 20.0 | $0.4534 | $18.51 |
| 1 | 5 | 200 | 203 | Insulation (wall) | 0.12 | 0.12 | 44.52% | 20.00% | 50.00% | 20.0 | $0.5090 | $18.51 |
| 1 | 5 | 200 | 206 | Duct Repair and Sealing | 0.12 | 0.12 | 50.00% | 2.00% | 25.00% | 20.0 | $0.0024 | $0.31 |
| 1 | 5 | 200 | 207 | Duct Insulation | 0.12 | 0.12 | 62.30% | 2.00% | 25.00% | 20.0 | $0.0062 | $0.31 |
| 1 | 5 | 200 | 209 | Insulation of Pipes | 0.12 | 0.12 | 25.00% | 2.00% | 50.00% | 20.0 | $0.0112 | $0.56 |
| 1 | 5 | 200 | 216 | Clock / Programmable Thermostat | 0.12 | 0.12 | 38.41% | 2.00% | 75.00% | 10.0 | $0.0008 | $0.00 |
| 1 | 5 | 200 | 222 | Installation of Air Side Heat Recovery Systems | 0.12 | 0.12 | 69.04% | 20.00% | 50.00% | 20.0 | $1.0000 | $10.00 |
| 1 | 5 | 200 | 227 | High Efficiency Gas Furnace/Boiler | 0.12 | 0.12 |  | 13.20% |  | 20.0 | $0.0804 | $0.25 |
| 1 | 5 | 200 | 228 | Stack Heat Exchanger | 0.12 | 0.12 | 84.00% | 4.76% | 50.00% | 20.0 | $0.0100 | $0.00 |
| 1 | 5 | 400 | 400 | Base Water Heating, 100 gal., 88 kBtu, EF=.76 | 0.01 | 0.01 | 100.00% | 0.00% | 100.00% | 15.0 | $0.0070 | $0.01 |
| 1 | 5 | 400 | 401 | Hot Water (SHW) Pipe Insulation | 0.01 | 0.01 | 75.80% | 3.00% | 50.00% | 15.0 | $0.0017 | $0.00 |

## Table B.4: Commercial Gas

| Segment | Building | Base Number | Measure Number | Measure Name | Stock Usage | Base Usage | Incomplete Factor | Energy Savings | Feasibility Factor | Measure Life | Full Per Unit Cost | Full Base Measure Cost |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 5 | 400 | 403 | Water Heater Tank Blanket/Insulation | 0.01 | 0.01 | 100.00% | 15.00% | 95.00% | 15.0 | $0.0023 | $0.00 |
| 1 | 5 | 400 | 404 | Tankless Water Heater | 0.01 | 0.01 | 100.00% | 10.00% | 10.00% | 15.0 | $0.0068 | $0.01 |
| 1 | 5 | 400 | 405 | High-Efficiency Water Heater (gas), 100 gal., 88 kBTU, EF=.80 | 0.01 | 0.01 | 53.90% | 5.00% | 95.00% | 15.0 | $0.0122 | $0.01 |
| 1 | 5 | 400 | 406 | High-Efficiency Water Heater (gas), 100 gal., 120 kBTU, EF=.95 | 0.01 | 0.01 | 53.90% | 20.00% | 95.00% | 15.0 | $0.0190 | $0.01 |
| 1 | 6 | 100 | 100 | Base Cooking | 0.03 | 0.03 | 100.00% | 0.00% | 100.00% | 15.0 | $0.2401 | $0.24 |
| 1 | 6 | 100 | 102 | High-Efficiency Convection Oven | 0.03 | 0.03 | | 14.00% | | 15.0 | $0.2017 | $0.24 |
| 1 | 6 | 100 | 103 | Efficient Infrared Griddle | 0.03 | 0.03 | 80.00% | 3.00% | 75.00% | 15.0 | $0.0580 | $0.24 |
| 1 | 6 | 100 | 104 | Infrared Fryer | 0.03 | 0.03 | 80.00% | 15.00% | 75.00% | 15.0 | $0.0824 | $0.24 |
| 1 | 6 | 100 | 105 | Power Burner Oven | 0.03 | 0.03 | 80.00% | 4.26% | 75.00% | 15.0 | $0.2453 | $0.24 |
| 1 | 6 | 100 | 106 | Power Burner Fryer | 0.03 | 0.03 | 80.00% | 4.26% | 75.00% | 15.0 | $0.0982 | $0.24 |
| 1 | 6 | 100 | 107 | Infrared Conveyer Oven | 0.03 | 0.03 | 90.00% | 5.00% | 75.00% | 15.0 | $0.2629 | $0.24 |
| 1 | 6 | 200 | 200 | Base Heating | 0.18 | 0.18 | 100.00% | 0.00% | 100.00% | 20.0 | $1.2048 | $1.20 |
| 1 | 6 | 200 | 201 | High Efficiency Windows (Multiple Glazed, Low Emissivity) | 0.18 | 0.18 | 99.20% | 15.00% | 75.00% | 60.0 | $0.0165 | $0.48 |
| 1 | 6 | 200 | 202 | Insulation (ceiling) | 0.18 | 0.18 | 44.94% | 11.04% | 50.00% | 20.0 | $0.4668 | $19.05 |
| 1 | 6 | 200 | 203 | Insulation (wall) | 0.18 | 0.18 | 47.86% | 20.00% | 50.00% | 20.0 | $0.5240 | $19.05 |
| 1 | 6 | 200 | 206 | Duct Repair and Sealing | 0.18 | 0.18 | 50.00% | 2.00% | 25.00% | 20.0 | $0.0027 | $0.34 |
| 1 | 6 | 200 | 207 | Duct Insulation | 0.18 | 0.18 | 71.80% | 2.00% | 25.00% | 20.0 | $0.0069 | $0.34 |
| 1 | 6 | 200 | 209 | Insulation of Pipes | 0.18 | 0.18 | 25.00% | 2.00% | 50.00% | 20.0 | $0.0119 | $0.59 |
| 1 | 6 | 200 | 212 | Boiler Tune-Up | 0.18 | 0.18 | 90.00% | 2.00% | 100.00% | 2.0 | $0.0064 | $0.00 |
| 1 | 6 | 200 | 216 | Clock / Programmable Thermostat | 0.18 | 0.18 | 49.43% | 2.00% | 75.00% | 10.0 | $0.0008 | $0.00 |
| 1 | 6 | 200 | 218 | Installation of Energy Management Systems (EMS) | 0.18 | 0.18 | 9.59% | 10.00% | 25.00% | 20.0 | $0.2900 | $20.00 |
| 1 | 6 | 200 | 222 | Installation of Air Side Heat Recovery Systems | 0.18 | 0.18 | 58.48% | 20.00% | 50.00% | 20.0 | $1.0000 | $10.00 |
| 1 | 6 | 200 | 227 | High Efficiency Gas Furnace/Boiler | 0.18 | 0.18 | | 13.20% | | 20.0 | $0.3916 | $1.20 |
| 1 | 6 | 200 | 228 | Stack Heat Exchanger | 0.18 | 0.18 | 84.00% | 4.76% | 50.00% | 20.0 | $0.0274 | $0.00 |
| 1 | 6 | 300 | 300 | Base Pool Heating | 0.17 | 0.17 | 100.00% | 0.00% | 100.00% | 10.0 | $0.1459 | $0.15 |
| 1 | 6 | 300 | 301 | Installation of Solar Pool/Spa Heating Systems | 0.17 | 0.17 | 100.00% | 15.80% | 100.00% | 10.0 | $0.3050 | $0.10 |
| 1 | 6 | 300 | 302 | Installation of Swimming Pool / Spa Covers | 0.17 | 0.17 | 29.00% | 35.00% | 90.00% | 5.0 | $0.0068 | $0.15 |
| 1 | 6 | 400 | 400 | Base Water Heating, 100 gal., 88 kBtu, EF=.76 | 0.18 | 0.18 | 100.00% | 0.00% | 100.00% | 15.0 | $0.1670 | $0.17 |
| 1 | 6 | 400 | 401 | Hot Water (SHW) Pipe Insulation | 0.18 | 0.18 | 25.10% | 3.00% | 50.00% | 15.0 | $0.0151 | $0.03 |
| 1 | 6 | 400 | 403 | Water Heater Tank Blanket/Insulation | 0.18 | 0.18 | 100.00% | 10.00% | 95.00% | 15.0 | $0.0211 | $0.00 |
| 1 | 6 | 400 | 404 | Tankless Water Heater | 0.18 | 0.18 | 100.00% | 10.00% | 10.00% | 15.0 | $0.1619 | $0.17 |
| 1 | 6 | 400 | 405 | High-Efficiency Water Heater (gas), 100 gal., 88 kBTU, EF=.80 | 0.18 | 0.18 | | 5.00% | | 15.0 | $0.2913 | $0.17 |
| 1 | 6 | 400 | 406 | High-Efficiency Water Heater (gas), 100 gal., 120 kBTU, EF=.95 | 0.18 | 0.18 | | 20.00% | | 15.0 | $0.4543 | $0.17 |
| 1 | 7 | 100 | 100 | Base Cooking | 0.03 | 0.03 | 100.00% | 0.00% | 100.00% | 15.0 | $0.1365 | $0.14 |
| 1 | 7 | 100 | 102 | High-Efficiency Convection Oven | 0.03 | 0.03 | | 5.00% | | 15.0 | $0.1147 | $0.14 |
| 1 | 7 | 100 | 103 | Efficient Infrared Griddle | 0.03 | 0.03 | 80.00% | 4.00% | 75.00% | 15.0 | $0.0330 | $0.14 |
| 1 | 7 | 100 | 104 | Infrared Fryer | 0.03 | 0.03 | 80.00% | 15.00% | 75.00% | 15.0 | $0.0468 | $0.14 |
| 1 | 7 | 100 | 105 | Power Burner Oven | 0.03 | 0.03 | 80.00% | 4.26% | 75.00% | 15.0 | $0.1394 | $0.14 |
| 1 | 7 | 100 | 106 | Power Burner Fryer | 0.03 | 0.03 | 80.00% | 4.26% | 75.00% | 15.0 | $0.0558 | $0.14 |
| 1 | 7 | 100 | 107 | Infrared Conveyer Oven | 0.03 | 0.03 | 90.00% | 15.00% | 75.00% | 15.0 | $0.1495 | $0.14 |
| 1 | 7 | 200 | 200 | Base Heating | 0.26 | 0.26 | 100.00% | 0.00% | 100.00% | 20.0 | $0.4557 | $0.46 |
| 1 | 7 | 200 | 201 | High Efficiency Windows (Multiple Glazed, Low Emissivity) | 0.26 | 0.26 | 99.00% | 15.00% | 75.00% | 60.0 | $0.0425 | $1.25 |
| 1 | 7 | 200 | 202 | Insulation (ceiling) | 0.26 | 0.26 | 18.79% | 10.00% | 50.00% | 20.0 | $0.2951 | $12.04 |
| 1 | 7 | 200 | 203 | Insulation (wall) | 0.26 | 0.26 | 18.79% | 20.00% | 50.00% | 20.0 | $0.3312 | $12.04 |

# Table B.4: Commercial Gas

| Segment | Building | Base Number | Measure Number | Measure Name | Stock Usage | Base Usage | Incomplete Factor | Energy Savings | Feasibility Factor | Measure Life | Full Per Unit Cost | Full Base Measure Cost |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 7 | 200 | 206 | Duct Repair and Sealing | 0.26 | 0.26 | 50.00% | 2.00% | 25.00% | 20.0 | $0.0023 | $0.29 |
| 1 | 7 | 200 | 207 | Duct Insulation | 0.26 | 0.26 | 73.80% | 2.00% | 25.00% | 20.0 | $0.0059 | $0.29 |
| 1 | 7 | 200 | 209 | Insulation of Pipes | 0.26 | 0.26 | 25.00% | 2.00% | 50.00% | 20.0 | $0.0044 | $0.22 |
| 1 | 7 | 200 | 212 | Boiler Tune-Up | 0.26 | 0.26 | 90.00% | 2.00% | 100.00% | 2.0 | $0.0015 | $0.00 |
| 1 | 7 | 200 | 216 | Clock / Programmable Thermostat | 0.26 | 0.26 | 49.00% | 2.00% | 75.00% | 10.0 | $0.0008 | $0.00 |
| 1 | 7 | 200 | 218 | Installation of Energy Management Systems (EMS) | 0.26 | 0.26 | 23.20% | 10.00% | 25.00% | 20.0 | $0.2900 | $20.00 |
| 1 | 7 | 200 | 222 | Installation of Air Side Heat Recovery Systems | 0.26 | 0.26 | 90.00% | 20.00% | 50.00% | 20.0 | $1.0000 | $10.00 |
| 1 | 7 | 200 | 227 | High Efficiency Gas Furnace/Boiler | 0.26 | 0.26 | | 13.20% | | 20.0 | $0.1481 | $0.46 |
| 1 | 7 | 200 | 228 | Stack Heat Exchanger | 0.26 | 0.26 | 81.00% | 4.71% | 50.00% | 20.0 | $0.0065 | $0.00 |
| 1 | 7 | 300 | 300 | Base Pool Heating | 0.14 | 0.14 | 100.00% | 0.00% | 100.00% | 10.0 | $0.1152 | $0.12 |
| 1 | 7 | 300 | 301 | Installation of Solar Pool/Spa Heating Systems | 0.14 | 0.14 | 100.00% | 15.80% | 100.00% | 10.0 | $0.1969 | $0.07 |
| 1 | 7 | 300 | 302 | Installation of Swimming Pool / Spa Covers | 0.14 | 0.14 | 25.00% | 35.00% | 90.00% | 5.0 | $0.0054 | $0.12 |
| 1 | 7 | 400 | 400 | Base Water Heating, 100 gal., 88 kBtu, EF=.76 | 0.48 | 0.48 | 100.00% | 0.00% | 100.00% | 15.0 | $0.2968 | $0.30 |
| 1 | 7 | 400 | 401 | Hot Water (SHW) Pipe Insulation | 0.48 | 0.48 | 2.00% | 3.00% | 50.00% | 15.0 | $0.0254 | $0.05 |
| 1 | 7 | 400 | 403 | Water Heater Tank Blanket/Insulation | 0.48 | 0.48 | 50.00% | 5.00% | 95.00% | 15.0 | $0.0355 | $0.01 |
| 1 | 7 | 400 | 404 | Tankless Water Heater | 0.48 | 0.48 | 100.00% | 10.00% | 10.00% | 15.0 | $0.2877 | $0.30 |
| 1 | 7 | 400 | 405 | High-Efficiency Water Heater (gas), 100 gal., 88 kBTU, EF=.80 | 0.48 | 0.48 | | 5.00% | | 15.0 | $0.5176 | $0.30 |
| 1 | 7 | 400 | 406 | High-Efficiency Water Heater (gas), 100 gal., 120 kBTU, EF=.95 | 0.48 | 0.48 | | 20.00% | | 15.0 | $0.8071 | $0.30 |
| 1 | 8 | 100 | 100 | Base Cooking | 0.09 | 0.09 | 100.00% | 0.00% | 100.00% | 15.0 | $0.0914 | $0.09 |
| 1 | 8 | 100 | 102 | High-Efficiency Convection Oven | 0.09 | 0.09 | | 7.00% | | 15.0 | $0.0768 | $0.09 |
| 1 | 8 | 100 | 103 | Efficient Infrared Griddle | 0.09 | 0.09 | 80.00% | 3.00% | 75.00% | 15.0 | $0.0221 | $0.09 |
| 1 | 8 | 100 | 104 | Infrared Fryer | 0.09 | 0.09 | 80.00% | 15.00% | 75.00% | 15.0 | $0.0314 | $0.09 |
| 1 | 8 | 100 | 105 | Power Burner Oven | 0.09 | 0.09 | 80.00% | 4.26% | 75.00% | 15.0 | $0.0934 | $0.09 |
| 1 | 8 | 100 | 106 | Power Burner Fryer | 0.09 | 0.09 | 80.00% | 4.26% | 75.00% | 15.0 | $0.0374 | $0.09 |
| 1 | 8 | 100 | 107 | Infrared Conveyer Oven | 0.09 | 0.09 | 90.00% | 15.00% | 75.00% | 15.0 | $0.1001 | $0.09 |
| 1 | 8 | 200 | 200 | Base Heating | 0.47 | 0.47 | 100.00% | 0.00% | 100.00% | 20.0 | $0.4000 | $0.40 |
| 1 | 8 | 200 | 201 | High Efficiency Windows (Multiple Glazed, Low Emissivity) | 0.47 | 0.47 | 99.30% | 15.00% | 75.00% | 60.0 | $0.0137 | $0.40 |
| 1 | 8 | 200 | 202 | Insulation (ceiling) | 0.47 | 0.47 | 21.53% | 10.00% | 50.00% | 20.0 | $0.4277 | $17.46 |
| 1 | 8 | 200 | 203 | Insulation (wall) | 0.47 | 0.47 | 21.53% | 20.00% | 50.00% | 20.0 | $0.4800 | $17.46 |
| 1 | 8 | 200 | 206 | Duct Repair and Sealing | 0.47 | 0.47 | 50.00% | 2.00% | 25.00% | 20.0 | $0.0023 | $0.28 |
| 1 | 8 | 200 | 207 | Duct Insulation | 0.47 | 0.47 | 70.30% | 2.00% | 25.00% | 20.0 | $0.0058 | $0.28 |
| 1 | 8 | 200 | 209 | Insulation of Pipes | 0.47 | 0.47 | 25.00% | 2.00% | 50.00% | 20.0 | $0.0175 | $0.87 |
| 1 | 8 | 200 | 212 | Boiler Tune-Up | 0.47 | 0.47 | 90.00% | 2.00% | 100.00% | 2.0 | $0.0034 | $0.00 |
| 1 | 8 | 200 | 216 | Clock / Programmable Thermostat | 0.47 | 0.47 | 49.00% | 2.00% | 75.00% | 10.0 | $0.0008 | $0.00 |
| 1 | 8 | 200 | 218 | Installation of Energy Management Systems (EMS) | 0.47 | 0.47 | 74.60% | 10.00% | 25.00% | 20.0 | $0.2900 | $20.00 |
| 1 | 8 | 200 | 222 | Installation of Air Side Heat Recovery Systems | 0.47 | 0.47 | 90.00% | 20.00% | 50.00% | 20.0 | $1.0000 | $10.00 |
| 1 | 8 | 200 | 227 | High Efficiency Gas Furnace/Boiler | 0.47 | 0.47 | | 13.20% | | 20.0 | $0.1300 | $0.40 |
| 1 | 8 | 200 | 228 | Stack Heat Exchanger | 0.47 | 0.47 | 79.00% | 4.69% | 50.00% | 20.0 | $0.0145 | $0.00 |
| 1 | 8 | 300 | 300 | Base Pool Heating | 0.03 | 0.03 | 100.00% | 0.00% | 100.00% | 10.0 | $0.0243 | $0.02 |
| 1 | 8 | 300 | 301 | Installation of Solar Pool/Spa Heating Systems | 0.03 | 0.03 | 100.00% | 15.80% | 100.00% | 10.0 | $0.0235 | $0.01 |
| 1 | 8 | 300 | 302 | Installation of Swimming Pool / Spa Covers | 0.03 | 0.03 | 50.00% | 35.00% | 90.00% | 5.0 | $0.0011 | $0.02 |
| 1 | 8 | 400 | 400 | Base Water Heating, 100 gal., 88 kBtu, EF=.76 | 0.71 | 0.71 | 100.00% | 0.00% | 100.00% | 15.0 | $0.2609 | $0.26 |
| 1 | 8 | 400 | 401 | Hot Water (SHW) Pipe Insulation | 0.71 | 0.71 | 32.50% | 3.00% | 50.00% | 15.0 | $0.0093 | $0.02 |
| 1 | 8 | 400 | 403 | Water Heater Tank Blanket/Insulation | 0.71 | 0.71 | 50.00% | 5.00% | 95.00% | 15.0 | $0.0448 | $0.01 |

## Table B.4: Commercial Gas

| Segment | Building | Base Number | Measure Number | Measure Name | Stock Usage | Base Usage | Incomplete Factor | Energy Savings | Feasibility Factor | Measure Life | Full Per Unit Cost | Full Base Measure Cost |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 8 | 400 | 404 | Tankless Water Heater | 0.71 | 0.71 | 91.80% | 10.00% | 10.00% | 15.0 | $0.2529 | $0.26 |
| 1 | 8 | 400 | 405 | High-Efficiency Water Heater (gas), 100 gal., 88 kBTU, EF=.80 | 0.71 | 0.71 | | 5.00% | | 15.0 | $0.4550 | $0.26 |
| 1 | 8 | 400 | 406 | High-Efficiency Water Heater (gas), 100 gal., 120 kBTU, EF=.95 | 0.71 | 0.71 | | 20.00% | | 15.0 | $0.7095 | $0.26 |
| 1 | 9 | 100 | 100 | Base Cooking | 0.11 | 0.11 | 100.00% | 0.00% | 100.00% | 15.0 | $0.1070 | $0.11 |
| 1 | 9 | 100 | 102 | High-Efficiency Convection Oven | 0.11 | 0.11 | | 6.00% | | 15.0 | $0.0899 | $0.11 |
| 1 | 9 | 100 | 103 | Efficient Infrared Griddle | 0.11 | 0.11 | 80.00% | 3.00% | 75.00% | 15.0 | $0.0259 | $0.11 |
| 1 | 9 | 100 | 104 | Infrared Fryer | 0.11 | 0.11 | 80.00% | 15.00% | 75.00% | 15.0 | $0.0367 | $0.11 |
| 1 | 9 | 100 | 105 | Power Burner Oven | 0.11 | 0.11 | 80.00% | 4.26% | 75.00% | 15.0 | $0.1093 | $0.11 |
| 1 | 9 | 100 | 106 | Power Burner Fryer | 0.11 | 0.11 | 80.00% | 4.26% | 75.00% | 15.0 | $0.0438 | $0.11 |
| 1 | 9 | 100 | 107 | Infrared Conveyer Oven | 0.11 | 0.11 | 90.00% | 5.00% | 75.00% | 15.0 | $0.1172 | $0.11 |
| 1 | 9 | 200 | 200 | Base Heating | 0.08 | 0.08 | 100.00% | 0.00% | 100.00% | 20.0 | $0.2971 | $0.30 |
| 1 | 9 | 200 | 201 | High Efficiency Windows (Multiple Glazed, Low Emissivity) | 0.08 | 0.08 | 97.50% | 30.00% | 75.00% | 60.0 | $0.0643 | $1.89 |
| 1 | 9 | 200 | 202 | Insulation (ceiling) | 0.08 | 0.08 | 62.26% | 10.00% | 50.00% | 20.0 | $0.2111 | $8.61 |
| 1 | 9 | 200 | 203 | Insulation (wall) | 0.08 | 0.08 | 100.00% | 20.00% | 50.00% | 20.0 | $0.2369 | $8.61 |
| 1 | 9 | 200 | 206 | Duct Repair and Sealing | 0.08 | 0.08 | 50.00% | 2.00% | 25.00% | 20.0 | $0.0050 | $0.63 |
| 1 | 9 | 200 | 207 | Duct Insulation | 0.08 | 0.08 | 79.10% | 2.00% | 25.00% | 20.0 | $0.0127 | $0.63 |
| 1 | 9 | 200 | 209 | Insulation of Pipes | 0.08 | 0.08 | 25.00% | 2.00% | 50.00% | 20.0 | $0.0099 | $0.49 |
| 1 | 9 | 200 | 212 | Boiler Tune-Up | 0.08 | 0.08 | 90.00% | 2.00% | 100.00% | 2.0 | $0.0029 | $0.00 |
| 1 | 9 | 200 | 213 | Occupancy Sensor for room HVAC units | 0.08 | 0.08 | 100.00% | 35.00% | 51.00% | 15.0 | $0.0440 | $8.61 |
| 1 | 9 | 200 | 216 | Clock / Programmable Thermostat | 0.08 | 0.08 | 33.66% | 2.00% | 75.00% | 10.0 | $0.0008 | $0.00 |
| 1 | 9 | 200 | 218 | Installation of Energy Management Systems (EMS) | 0.08 | 0.08 | 57.28% | 10.00% | 25.00% | 20.0 | $0.2900 | $20.00 |
| 1 | 9 | 200 | 222 | Installation of Air Side Heat Recovery Systems | 0.08 | 0.08 | 49.56% | 20.00% | 50.00% | 20.0 | $1.0000 | $10.00 |
| 1 | 9 | 200 | 227 | High Efficiency Gas Furnace/Boiler | 0.08 | 0.08 | | 13.20% | | 20.0 | $0.0965 | $0.30 |
| 1 | 9 | 200 | 228 | Stack Heat Exchanger | 0.08 | 0.08 | 85.00% | 4.63% | 50.00% | 20.0 | $0.0123 | $0.00 |
| 1 | 9 | 300 | 300 | Base Pool Heating | 0.11 | 0.11 | 100.00% | 0.00% | 100.00% | 10.0 | $0.0946 | $0.09 |
| 1 | 9 | 300 | 301 | Installation of Solar Pool/Spa Heating Systems | 0.11 | 0.11 | 100.00% | 15.80% | 100.00% | 10.0 | $0.0728 | $0.02 |
| 1 | 9 | 300 | 302 | Installation of Swimming Pool / Spa Covers | 0.11 | 0.11 | 80.00% | 35.00% | 90.00% | 5.0 | $0.0044 | $0.09 |
| 1 | 9 | 400 | 400 | Base Water Heating, 100 gal., 88 kBtu, EF=.76 | 0.37 | 0.37 | 100.00% | 0.00% | 100.00% | 15.0 | $0.2292 | $0.23 |
| 1 | 9 | 400 | 401 | Hot Water (SHW) Pipe Insulation | 0.37 | 0.37 | 49.00% | 3.00% | 50.00% | 15.0 | $0.0346 | $0.07 |
| 1 | 9 | 400 | 403 | Water Heater Tank Blanket/Insulation | 0.37 | 0.37 | 97.77% | 5.00% | 95.00% | 15.0 | $0.0484 | $0.01 |
| 1 | 9 | 400 | 404 | Tankless Water Heater | 0.37 | 0.37 | 100.00% | 10.00% | 10.00% | 15.0 | $0.2222 | $0.23 |
| 1 | 9 | 400 | 405 | High-Efficiency Water Heater (gas), 100 gal., 88 kBTU, EF=.80 | 0.37 | 0.37 | | 5.00% | | 15.0 | $0.3996 | $0.23 |
| 1 | 9 | 400 | 406 | High-Efficiency Water Heater (gas), 100 gal., 120 kBTU, EF=.95 | 0.37 | 0.37 | | 20.00% | | 15.0 | $0.6232 | $0.23 |
| 1 | 10 | 200 | 200 | Base Heating | 0.23 | 0.23 | 100.00% | 0.00% | 100.00% | 20.0 | $0.5056 | $0.51 |
| 1 | 10 | 200 | 201 | High Efficiency Windows (Multiple Glazed, Low Emissivity) | 0.23 | 0.23 | 98.90% | 6.40% | 75.00% | 60.0 | $0.0193 | $0.57 |
| 1 | 10 | 200 | 202 | Insulation (ceiling) | 0.23 | 0.23 | 14.47% | 10.00% | 50.00% | 20.0 | $0.4411 | $18.00 |
| 1 | 10 | 200 | 203 | Insulation (wall) | 0.23 | 0.23 | 63.74% | 20.00% | 50.00% | 20.0 | $0.4951 | $18.00 |
| 1 | 10 | 200 | 206 | Duct Repair and Sealing | 0.23 | 0.23 | 50.00% | 2.00% | 25.00% | 20.0 | $0.0050 | $0.63 |
| 1 | 10 | 200 | 207 | Duct Insulation | 0.23 | 0.23 | 83.40% | 2.00% | 25.00% | 20.0 | $0.0127 | $0.63 |
| 1 | 10 | 200 | 209 | Insulation of Pipes | 0.23 | 0.23 | 25.00% | 2.00% | 50.00% | 20.0 | $0.0237 | $1.17 |
| 1 | 10 | 200 | 212 | Boiler Tune-Up | 0.23 | 0.23 | 90.00% | 2.00% | 100.00% | 2.0 | $0.0043 | $0.00 |
| 1 | 10 | 200 | 216 | Clock / Programmable Thermostat | 0.23 | 0.23 | 41.94% | 2.00% | 75.00% | 10.0 | $0.0008 | $0.00 |
| 1 | 10 | 200 | 218 | Installation of Energy Management Systems (EMS) | 0.23 | 0.23 | 17.11% | 10.00% | 25.00% | 20.0 | $0.2900 | $20.00 |
| 1 | 10 | 200 | 222 | Installation of Air Side Heat Recovery Systems | 0.23 | 0.23 | 50.00% | 20.00% | 50.00% | 20.0 | $1.0000 | $10.00 |

## Table B.4: Commercial Gas

| Segment | Building | Base Number | Measure Number | Measure Name | Stock Usage | Base Usage | Incomplete Factor | Energy Savings | Feasibility Factor | Measure Life | Full Per Unit Cost | Full Base Measure Cost |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 10 | 200 | 227 | High Efficiency Gas Furnace/Boiler | 0.23 | 0.23 | | 13.20% | | 20.0 | $0.1643 | $0.51 |
| 1 | 10 | 200 | 228 | Stack Heat Exchanger | 0.23 | 0.23 | 84.00% | 5.00% | 50.00% | 20.0 | $0.0186 | $0.00 |
| 1 | 10 | 400 | 400 | Base Water Heating, 100 gal., 88 kBtu, EF=.76 | 0.37 | 0.37 | 100.00% | 0.00% | 100.00% | 15.0 | $0.2239 | $0.22 |
| 1 | 10 | 400 | 401 | Hot Water (SHW) Pipe Insulation | 0.37 | 0.37 | 58.80% | 3.00% | 50.00% | 15.0 | $0.0094 | $0.02 |
| 1 | 10 | 400 | 403 | Water Heater Tank Blanket/Insulation | 0.37 | 0.37 | 39.91% | 10.00% | 95.00% | 15.0 | $0.0131 | $0.00 |
| 1 | 10 | 400 | 404 | Tankless Water Heater | 0.37 | 0.37 | 100.00% | 10.00% | 10.00% | 15.0 | $0.2170 | $0.22 |
| 1 | 10 | 400 | 405 | High-Efficiency Water Heater (gas), 100 gal., 88 kBTU, EF=.80 | 0.37 | 0.37 | | 5.00% | | 15.0 | $0.3904 | $0.22 |
| 1 | 10 | 400 | 406 | High-Efficiency Water Heater (gas), 100 gal., 120 kBTU, EF=.95 | 0.37 | 0.37 | | 20.00% | | 15.0 | $0.6088 | $0.22 |
| 2 | 1 | 200 | 200 | Base Heating | 0.18 | 0.18 | 100.00% | 0.00% | 100.00% | 20.0 | $0.2807 | $0.30 |
| 2 | 1 | 200 | 201 | High Efficiency Windows (Multiple Glazed, Low Emissivity) | 0.18 | 0.18 | 98.00% | 20.00% | 75.00% | 60.0 | $0.0570 | $1.75 |
| 2 | 1 | 200 | 202 | Insulation (ceiling) | 0.18 | 0.18 | 12.95% | 5.31% | 75.00% | 20.0 | $0.3120 | $13.27 |
| 2 | 1 | 200 | 203 | Insulation (wall) | 0.18 | 0.18 | 84.12% | 10.00% | 50.00% | 20.0 | $0.3518 | $13.27 |
| 2 | 1 | 200 | 209 | Insulation of Pipes | 0.18 | 0.18 | 25.00% | 1.00% | 100.00% | 20.0 | $0.0137 | $0.74 |
| 2 | 1 | 200 | 212 | Boiler Tune-Up | 0.18 | 0.18 | 10.00% | 1.00% | 100.00% | 2.0 | $0.0018 | $0.00 |
| 2 | 1 | 200 | 216 | Clock / Programmable Thermostat | 0.18 | 0.18 | 48.81% | 0.50% | 75.00% | 10.0 | $0.0005 | $0.00 |
| 2 | 1 | 200 | 218 | Installation of Energy Management Systems (EMS) | 0.18 | 0.18 | 52.58% | 7.00% | 25.00% | 20.0 | $0.2500 | $20.00 |
| 2 | 1 | 200 | 222 | Installation of Air Side Heat Recovery Systems | 0.18 | 0.18 | 80.00% | 15.00% | 75.00% | 20.0 | $0.9300 | $10.00 |
| 2 | 1 | 200 | 227 | High Efficiency Gas Furnace/Boiler | 0.18 | 0.18 | | 13.20% | | 20.0 | $0.0960 | $0.30 |
| 2 | 1 | 200 | 228 | Stack Heat Exchanger | 0.18 | 0.18 | 84.00% | 4.00% | 50.00% | 20.0 | $0.0083 | $0.00 |
| 2 | 1 | 400 | 400 | Base Water Heating, 100 gal., 88 kBtu, EF=.76 | 0.06 | 0.06 | 100.00% | 0.00% | 100.00% | 15.0 | $0.0362 | $0.04 |
| 2 | 1 | 400 | 401 | Hot Water (SHW) Pipe Insulation | 0.06 | 0.06 | 50.30% | 2.00% | 50.00% | 15.0 | $0.0037 | $0.01 |
| 2 | 1 | 400 | 403 | Water Heater Tank Blanket/Insulation | 0.06 | 0.06 | 88.76% | 12.00% | 95.00% | 15.0 | $0.0046 | $0.00 |
| 2 | 1 | 400 | 404 | Tankless Water Heater | 0.06 | 0.06 | 100.00% | 8.00% | 10.00% | 15.0 | $0.0351 | $0.04 |
| 2 | 1 | 400 | 405 | High-Efficiency Water Heater (gas), 100 gal., 88 kBTU, EF=.80 | 0.06 | 0.06 | | 5.00% | | 15.0 | $0.0632 | $0.04 |
| 2 | 1 | 400 | 406 | High-Efficiency Water Heater (gas), 100 gal., 120 kBTU, EF=.95 | 0.06 | 0.06 | | 20.00% | | 15.0 | $0.0985 | $0.04 |
| 2 | 2 | 200 | 200 | Base Heating | 0.12 | 0.12 | 100.00% | 0.00% | 100.00% | 20.0 | $0.2928 | $0.31 |
| 2 | 2 | 200 | 201 | High Efficiency Windows (Multiple Glazed, Low Emissivity) | 0.12 | 0.12 | 99.80% | 10.22% | 75.00% | 60.0 | $0.0185 | $0.57 |
| 2 | 2 | 200 | 202 | Insulation (ceiling) | 0.12 | 0.12 | 75.43% | 8.00% | 50.00% | 20.0 | $0.4300 | $18.30 |
| 2 | 2 | 200 | 203 | Insulation (wall) | 0.12 | 0.12 | 72.21% | 10.00% | 50.00% | 20.0 | $0.4849 | $18.30 |
| 2 | 2 | 200 | 209 | Insulation of Pipes | 0.12 | 0.12 | 25.00% | 1.00% | 100.00% | 20.0 | $0.0188 | $1.01 |
| 2 | 2 | 200 | 216 | Clock / Programmable Thermostat | 0.12 | 0.12 | 79.02% | 0.50% | 75.00% | 10.0 | $0.0005 | $0.00 |
| 2 | 2 | 200 | 222 | Installation of Air Side Heat Recovery Systems | 0.12 | 0.12 | 80.00% | 15.00% | 50.00% | 20.0 | $0.9300 | $10.00 |
| 2 | 2 | 200 | 227 | High Efficiency Gas Furnace/Boiler | 0.12 | 0.12 | | 13.20% | | 20.0 | $0.1002 | $0.31 |
| 2 | 2 | 200 | 228 | Stack Heat Exchanger | 0.12 | 0.12 | 85.00% | 4.00% | 50.00% | 20.0 | $0.0265 | $0.00 |
| 2 | 2 | 400 | 400 | Base Water Heating, 100 gal., 88 kBtu, EF=.76 | 0.19 | 0.19 | 100.00% | 0.00% | 100.00% | 15.0 | $0.1133 | $0.12 |
| 2 | 2 | 400 | 401 | Hot Water (SHW) Pipe Insulation | 0.19 | 0.19 | 73.40% | 2.00% | 50.00% | 15.0 | $0.0222 | $0.05 |
| 2 | 2 | 400 | 403 | Water Heater Tank Blanket/Insulation | 0.19 | 0.19 | 75.87% | 12.00% | 95.00% | 15.0 | $0.0281 | $0.00 |
| 2 | 2 | 400 | 404 | Tankless Water Heater | 0.19 | 0.19 | 100.00% | 8.00% | 10.00% | 15.0 | $0.1096 | $0.12 |
| 2 | 2 | 400 | 405 | High-Efficiency Water Heater (gas), 100 gal., 88 kBTU, EF=.80 | 0.19 | 0.19 | | 5.00% | | 15.0 | $0.1975 | $0.12 |
| 2 | 2 | 400 | 406 | High-Efficiency Water Heater (gas), 100 gal., 120 kBTU, EF=.95 | 0.19 | 0.19 | | 20.00% | | 15.0 | $0.3078 | $0.12 |
| 2 | 3 | 100 | 100 | Base Cooking | 1.72 | 1.72 | 100.00% | 0.00% | 100.00% | 15.0 | $1.9256 | $1.93 |
| 2 | 3 | 100 | 102 | High-Efficiency Convection Oven | 1.72 | 1.72 | | 6.00% | | 15.0 | $1.6175 | $1.93 |
| 2 | 3 | 100 | 103 | Efficient Infrared Griddle | 1.72 | 1.72 | 80.00% | 7.00% | 80.00% | 15.0 | $0.4652 | $1.93 |
| 2 | 3 | 100 | 104 | Infrared Fryer | 1.72 | 1.72 | 80.00% | 15.00% | 80.00% | 15.0 | $0.6608 | $1.93 |

Exhibit No. ___(EMM-6)
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## Table B.4: Commercial Gas

| Segment | Building | Base Number | Measure Number | Measure Name | Stock Usage | Base Usage | Incomplete Factor | Energy Savings | Feasibility Factor | Measure Life | Full Per Unit Cost | Full Base Measure Cost |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2 | 3 | 100 | 105 | Power Burner Oven | 1.72 | 1.72 | 80.00% | 4.26% | 80.00% | 15.0 | $1.9670 | $1.93 |
| 2 | 3 | 100 | 106 | Power Burner Fryer | 1.72 | 1.72 | 80.00% | 4.26% | 80.00% | 15.0 | $0.7873 | $1.93 |
| 2 | 3 | 100 | 107 | Infrared Conveyer Oven | 1.72 | 1.72 | 90.00% | 15.00% | 80.00% | 15.0 | $2.1088 | $1.93 |
| 2 | 3 | 200 | 200 | Base Heating | 0.14 | 0.14 | 100.00% | 0.00% | 100.00% | 20.0 | $0.7740 | $0.81 |
| 2 | 3 | 200 | 201 | High Efficiency Windows (Multiple Glazed, Low Emissivity) | 0.14 | 0.14 | 100.00% | 2.78% | 50.00% | 60.0 | $0.0299 | $0.92 |
| 2 | 3 | 200 | 202 | Insulation (ceiling) | 0.14 | 0.14 | 55.72% | 6.40% | 50.00% | 20.0 | $0.4520 | $19.24 |
| 2 | 3 | 200 | 203 | Insulation (wall) | 0.14 | 0.14 | 93.11% | 10.00% | 50.00% | 20.0 | $0.5098 | $19.24 |
| 2 | 3 | 200 | 209 | Insulation of Pipes | 0.14 | 0.14 | 25.00% | 1.00% | 100.00% | 20.0 | $0.0289 | $1.56 |
| 2 | 3 | 200 | 216 | Clock / Programmable Thermostat | 0.14 | 0.14 | 50.25% | 0.50% | 75.00% | 10.0 | $0.0005 | $0.00 |
| 2 | 3 | 200 | 222 | Installation of Air Side Heat Recovery Systems | 0.14 | 0.14 | 78.34% | 15.00% | 50.00% | 20.0 | $0.9300 | $10.00 |
| 2 | 3 | 200 | 227 | High Efficiency Gas Furnace/Boiler | 0.14 | 0.14 | | 13.20% | | 20.0 | $0.2648 | $0.81 |
| 2 | 3 | 200 | 228 | Stack Heat Exchanger | 0.14 | 0.14 | 86.00% | 4.00% | 50.00% | 20.0 | $0.1064 | $0.00 |
| 2 | 3 | 400 | 400 | Base Water Heating, 100 gal., 88 kBtu, EF=.76 | 0.54 | 0.54 | 100.00% | 0.00% | 100.00% | 15.0 | $0.1560 | $0.16 |
| 2 | 3 | 400 | 401 | Hot Water (SHW) Pipe Insulation | 0.54 | 0.54 | 74.60% | 2.00% | 50.00% | 15.0 | $0.0239 | $0.05 |
| 2 | 3 | 400 | 403 | Water Heater Tank Blanket/Insulation | 0.54 | 0.54 | 86.30% | 5.00% | 95.00% | 15.0 | $0.0303 | $0.01 |
| 2 | 3 | 400 | 404 | Tankless Water Heater | 0.54 | 0.54 | 100.00% | 8.00% | 10.00% | 15.0 | $0.1510 | $0.16 |
| 2 | 3 | 400 | 405 | High-Efficiency Water Heater (gas), 100 gal., 88 kBTU, EF=.80 | 0.54 | 0.54 | | 5.00% | | 15.0 | $0.2720 | $0.16 |
| 2 | 3 | 400 | 406 | High-Efficiency Water Heater (gas), 100 gal., 120 kBTU, EF=.95 | 0.54 | 0.54 | | 20.00% | | 15.0 | $0.4240 | $0.16 |
| 2 | 4 | 100 | 100 | Base Cooking | 0.67 | 0.67 | 100.00% | 0.00% | 100.00% | 15.0 | $0.5229 | $0.52 |
| 2 | 4 | 100 | 102 | High-Efficiency Convection Oven | 0.67 | 0.67 | | 7.00% | | 15.0 | $0.4392 | $0.52 |
| 2 | 4 | 100 | 103 | Efficient Infrared Griddle | 0.67 | 0.67 | 80.00% | 1.00% | 60.00% | 15.0 | $0.1263 | $0.52 |
| 2 | 4 | 100 | 104 | Infrared Fryer | 0.67 | 0.67 | 80.00% | 1.00% | 60.00% | 15.0 | $0.1794 | $0.52 |
| 2 | 4 | 100 | 105 | Power Burner Oven | 0.67 | 0.67 | 80.00% | 2.00% | 60.00% | 15.0 | $0.5341 | $0.52 |
| 2 | 4 | 100 | 106 | Power Burner Fryer | 0.67 | 0.67 | 80.00% | 2.00% | 60.00% | 15.0 | $0.2138 | $0.52 |
| 2 | 4 | 100 | 107 | Infrared Conveyer Oven | 0.67 | 0.67 | 90.00% | 1.00% | 60.00% | 15.0 | $0.5726 | $0.52 |
| 2 | 4 | 200 | 200 | Base Heating | 0.20 | 0.20 | 100.00% | 0.00% | 100.00% | 20.0 | $0.3218 | $0.34 |
| 2 | 4 | 200 | 201 | High Efficiency Windows (Multiple Glazed, Low Emissivity) | 0.20 | 0.20 | 100.00% | 6.35% | 75.00% | 60.0 | $0.0266 | $0.82 |
| 2 | 4 | 200 | 202 | Insulation (ceiling) | 0.20 | 0.20 | 85.03% | 5.00% | 50.00% | 20.0 | $0.4615 | $19.64 |
| 2 | 4 | 200 | 203 | Insulation (wall) | 0.20 | 0.20 | 85.03% | 10.00% | 50.00% | 20.0 | $0.5204 | $19.64 |
| 2 | 4 | 200 | 209 | Insulation of Pipes | 0.20 | 0.20 | 25.00% | 1.00% | 100.00% | 20.0 | $0.0216 | $1.17 |
| 2 | 4 | 200 | 216 | Clock / Programmable Thermostat | 0.20 | 0.20 | 78.37% | 0.50% | 75.00% | 10.0 | $0.0005 | $0.00 |
| 2 | 4 | 200 | 222 | Installation of Air Side Heat Recovery Systems | 0.20 | 0.20 | 76.40% | 15.00% | 50.00% | 20.0 | $0.9300 | $10.00 |
| 2 | 4 | 200 | 227 | High Efficiency Gas Furnace/Boiler | 0.20 | 0.20 | | 13.20% | | 20.0 | $0.1101 | $0.34 |
| 2 | 4 | 200 | 228 | Stack Heat Exchanger | 0.20 | 0.20 | 87.00% | 4.00% | 50.00% | 20.0 | $0.0839 | $0.00 |
| 2 | 4 | 400 | 400 | Base Water Heating, 100 gal., 88 kBtu, EF=.76 | 0.09 | 0.09 | 100.00% | 0.00% | 100.00% | 15.0 | $0.0528 | $0.06 |
| 2 | 4 | 400 | 401 | Hot Water (SHW) Pipe Insulation | 0.09 | 0.09 | 69.50% | 2.00% | 50.00% | 15.0 | $0.0087 | $0.02 |
| 2 | 4 | 400 | 403 | Water Heater Tank Blanket/Insulation | 0.09 | 0.09 | 100.00% | 8.00% | 95.00% | 15.0 | $0.0110 | $0.00 |
| 2 | 4 | 400 | 404 | Tankless Water Heater | 0.09 | 0.09 | 100.00% | 8.00% | 10.00% | 15.0 | $0.0511 | $0.06 |
| 2 | 4 | 400 | 405 | High-Efficiency Water Heater (gas), 100 gal., 88 kBTU, EF=.80 | 0.09 | 0.09 | | 5.00% | | 15.0 | $0.0920 | $0.06 |
| 2 | 4 | 400 | 406 | High-Efficiency Water Heater (gas), 100 gal., 120 kBTU, EF=.95 | 0.09 | 0.09 | | 20.00% | | 15.0 | $0.1435 | $0.06 |
| 2 | 5 | 200 | 200 | Base Heating | 0.12 | 0.12 | 100.00% | 0.00% | 100.00% | 20.0 | $0.2349 | $0.25 |
| 2 | 5 | 200 | 201 | High Efficiency Windows (Multiple Glazed, Low Emissivity) | 0.12 | 0.12 | 100.00% | 1.00% | 75.00% | 60.0 | $0.0111 | $0.34 |
| 2 | 5 | 200 | 202 | Insulation (ceiling) | 0.12 | 0.12 | 33.67% | 15.00% | 50.00% | 20.0 | $0.4349 | $18.51 |
| 2 | 5 | 200 | 203 | Insulation (wall) | 0.12 | 0.12 | 44.52% | 10.00% | 50.00% | 20.0 | $0.4905 | $18.51 |

## Table B.4: Commercial Gas

| Segment | Building | Base Number | Measure Number | Measure Name | Stock Usage | Base Usage | Incomplete Factor | Energy Savings | Feasibility Factor | Measure Life | Full Per Unit Cost | Full Base Measure Cost |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2 | 5 | 200 | 209 | Insulation of Pipes | 0.12 | 0.12 | 25.00% | 1.00% | 100.00% | 20.0 | $0.0103 | $0.56 |
| 2 | 5 | 200 | 216 | Clock / Programmable Thermostat | 0.12 | 0.12 | 38.41% | 0.50% | 75.00% | 10.0 | $0.0005 | $0.00 |
| 2 | 5 | 200 | 222 | Installation of Air Side Heat Recovery Systems | 0.12 | 0.12 | 69.04% | 15.00% | 50.00% | 20.0 | $0.9300 | $10.00 |
| 2 | 5 | 200 | 227 | High Efficiency Gas Furnace/Boiler | 0.12 | 0.12 | | 13.20% | | 20.0 | $0.0804 | $0.25 |
| 2 | 5 | 200 | 228 | Stack Heat Exchanger | 0.12 | 0.12 | 84.00% | 4.00% | 50.00% | 20.0 | $0.0089 | $0.00 |
| 2 | 5 | 400 | 400 | Base Water Heating, 100 gal., 88 kBtu, EF=.76 | 0.01 | 0.01 | 100.00% | 0.00% | 100.00% | 15.0 | $0.0067 | $0.01 |
| 2 | 5 | 400 | 401 | Hot Water (SHW) Pipe Insulation | 0.01 | 0.01 | 75.80% | 2.00% | 50.00% | 15.0 | $0.0016 | $0.00 |
| 2 | 5 | 400 | 403 | Water Heater Tank Blanket/Insulation | 0.01 | 0.01 | 100.00% | 15.00% | 95.00% | 15.0 | $0.0020 | $0.00 |
| 2 | 5 | 400 | 404 | Tankless Water Heater | 0.01 | 0.01 | 100.00% | 8.00% | 10.00% | 15.0 | $0.0064 | $0.01 |
| 2 | 5 | 400 | 405 | High-Efficiency Water Heater (gas), 100 gal., 88 kBTU, EF=.80 | 0.01 | 0.01 | | 5.00% | | 15.0 | $0.0116 | $0.01 |
| 2 | 5 | 400 | 406 | High-Efficiency Water Heater (gas), 100 gal., 120 kBTU, EF=.95 | 0.01 | 0.01 | | 20.00% | | 15.0 | $0.0181 | $0.01 |
| 2 | 6 | 100 | 100 | Base Cooking | 0.03 | 0.03 | 100.00% | 0.00% | 100.00% | 15.0 | $0.2401 | $0.24 |
| 2 | 6 | 100 | 102 | High-Efficiency Convection Oven | 0.03 | 0.03 | | 14.00% | | 15.0 | $0.2017 | $0.24 |
| 2 | 6 | 100 | 103 | Efficient Infrared Griddle | 0.03 | 0.03 | 80.00% | 3.00% | 60.00% | 15.0 | $0.0580 | $0.24 |
| 2 | 6 | 100 | 104 | Infrared Fryer | 0.03 | 0.03 | 80.00% | 15.00% | 60.00% | 15.0 | $0.0824 | $0.24 |
| 2 | 6 | 100 | 105 | Power Burner Oven | 0.03 | 0.03 | 80.00% | 4.26% | 60.00% | 15.0 | $0.2453 | $0.24 |
| 2 | 6 | 100 | 106 | Power Burner Fryer | 0.03 | 0.03 | 80.00% | 4.26% | 60.00% | 15.0 | $0.0982 | $0.24 |
| 2 | 6 | 100 | 107 | Infrared Conveyer Oven | 0.03 | 0.03 | 90.00% | 5.00% | 60.00% | 15.0 | $0.2629 | $0.24 |
| 2 | 6 | 200 | 200 | Base Heating | 0.18 | 0.18 | 100.00% | 0.00% | 100.00% | 20.0 | $1.1446 | $1.20 |
| 2 | 6 | 200 | 201 | High Efficiency Windows (Multiple Glazed, Low Emissivity) | 0.18 | 0.18 | 99.20% | 6.00% | 75.00% | 60.0 | $0.0157 | $0.48 |
| 2 | 6 | 200 | 202 | Insulation (ceiling) | 0.18 | 0.18 | 44.94% | 5.00% | 50.00% | 20.0 | $0.4478 | $19.05 |
| 2 | 6 | 200 | 203 | Insulation (wall) | 0.18 | 0.18 | 47.86% | 10.00% | 50.00% | 20.0 | $0.5050 | $19.05 |
| 2 | 6 | 200 | 209 | Insulation of Pipes | 0.18 | 0.18 | 25.00% | 1.00% | 100.00% | 20.0 | $0.0109 | $0.59 |
| 2 | 6 | 200 | 212 | Boiler Tune-Up | 0.18 | 0.18 | 10.00% | 1.00% | 100.00% | 2.0 | $0.0053 | $0.00 |
| 2 | 6 | 200 | 216 | Clock / Programmable Thermostat | 0.18 | 0.18 | 49.43% | 0.50% | 75.00% | 10.0 | $0.0005 | $0.00 |
| 2 | 6 | 200 | 218 | Installation of Energy Management Systems (EMS) | 0.18 | 0.18 | 9.59% | 7.00% | 25.00% | 20.0 | $0.2500 | $20.00 |
| 2 | 6 | 200 | 222 | Installation of Air Side Heat Recovery Systems | 0.18 | 0.18 | 58.48% | 15.00% | 50.00% | 20.0 | $0.9300 | $10.00 |
| 2 | 6 | 200 | 227 | High Efficiency Gas Furnace/Boiler | 0.18 | 0.18 | | 13.20% | | 20.0 | $0.3916 | $1.20 |
| 2 | 6 | 200 | 228 | Stack Heat Exchanger | 0.18 | 0.18 | 84.00% | 4.00% | 50.00% | 20.0 | $0.0244 | $0.00 |
| 2 | 6 | 300 | 300 | Base Pool Heating | 0.03 | 0.03 | 100.00% | 0.00% | 100.00% | 10.0 | $0.1459 | $0.15 |
| 2 | 6 | 300 | 301 | Installation of Solar Pool/Spa Heating Systems | 0.03 | 0.03 | 100.00% | 15.80% | 100.00% | 10.0 | $0.3026 | $0.10 |
| 2 | 6 | 300 | 302 | Installation of Swimming Pool / Spa Covers | 0.03 | 0.03 | 29.00% | 35.00% | 90.00% | 5.0 | $0.0061 | $0.15 |
| 2 | 6 | 400 | 400 | Base Water Heating, 100 gal., 88 kBtu, EF=.76 | 0.18 | 0.18 | 100.00% | 0.00% | 100.00% | 15.0 | $0.1589 | $0.17 |
| 2 | 6 | 400 | 401 | Hot Water (SHW) Pipe Insulation | 0.18 | 0.18 | 25.10% | 2.00% | 50.00% | 15.0 | $0.0141 | $0.03 |
| 2 | 6 | 400 | 403 | Water Heater Tank Blanket/Insulation | 0.18 | 0.18 | 100.00% | 8.00% | 95.00% | 15.0 | $0.0179 | $0.00 |
| 2 | 6 | 400 | 404 | Tankless Water Heater | 0.18 | 0.18 | 100.00% | 8.00% | 10.00% | 15.0 | $0.1538 | $0.17 |
| 2 | 6 | 400 | 405 | High-Efficiency Water Heater (gas), 100 gal., 88 kBTU, EF=.80 | 0.18 | 0.18 | | 5.00% | | 15.0 | $0.2770 | $0.17 |
| 2 | 6 | 400 | 406 | High-Efficiency Water Heater (gas), 100 gal., 120 kBTU, EF=.95 | 0.18 | 0.18 | | 20.00% | | 15.0 | $0.4318 | $0.17 |
| 2 | 7 | 100 | 100 | Base Cooking | 0.03 | 0.03 | 100.00% | 0.00% | 100.00% | 15.0 | $0.1365 | $0.14 |
| 2 | 7 | 100 | 102 | High-Efficiency Convection Oven | 0.03 | 0.03 | | 5.00% | | 15.0 | $0.1147 | $0.14 |
| 2 | 7 | 100 | 103 | Efficient Infrared Griddle | 0.03 | 0.03 | 80.00% | 4.00% | 60.00% | 15.0 | $0.0330 | $0.14 |
| 2 | 7 | 100 | 104 | Infrared Fryer | 0.03 | 0.03 | 80.00% | 15.00% | 60.00% | 15.0 | $0.0468 | $0.14 |
| 2 | 7 | 100 | 105 | Power Burner Oven | 0.03 | 0.03 | 80.00% | 4.26% | 60.00% | 15.0 | $0.1394 | $0.14 |
| 2 | 7 | 100 | 106 | Power Burner Fryer | 0.03 | 0.03 | 80.00% | 4.26% | 60.00% | 15.0 | $0.0558 | $0.14 |

## Table B.4: Commercial Gas

| Segment | Building | Base Number | Measure Number | Measure Name | Stock Usage | Base Usage | Incomplete Factor | Energy Savings | Feasibility Factor | Measure Life | Full Per Unit Cost | Full Base Measure Cost |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2 | 7 | 100 | 107 | Infrared Conveyer Oven | 0.03 | 0.03 | 90.00% | 15.00% | 60.00% | 15.0 | $0.1495 | $0.14 |
| 2 | 7 | 200 | 200 | Base Heating | 0.26 | 0.26 | 100.00% | 0.00% | 100.00% | 20.0 | $0.4329 | $0.46 |
| 2 | 7 | 200 | 201 | High Efficiency Windows (Multiple Glazed, Low Emissivity) | 0.26 | 0.26 | 99.00% | 6.00% | 75.00% | 60.0 | $0.0406 | $1.25 |
| 2 | 7 | 200 | 202 | Insulation (ceiling) | 0.26 | 0.26 | 18.79% | 2.99% | 50.00% | 20.0 | $0.2830 | $12.04 |
| 2 | 7 | 200 | 203 | Insulation (wall) | 0.26 | 0.26 | 18.79% | 10.00% | 50.00% | 20.0 | $0.3191 | $12.04 |
| 2 | 7 | 200 | 209 | Insulation of Pipes | 0.26 | 0.26 | 25.00% | 1.00% | 100.00% | 20.0 | $0.0040 | $0.22 |
| 2 | 7 | 200 | 212 | Boiler Tune-Up | 0.26 | 0.26 | 10.00% | 1.00% | 100.00% | 2.0 | $0.0013 | $0.00 |
| 2 | 7 | 200 | 216 | Clock / Programmable Thermostat | 0.26 | 0.26 | 49.00% | 0.50% | 75.00% | 10.0 | $0.0005 | $0.00 |
| 2 | 7 | 200 | 218 | Installation of Energy Management Systems (EMS) | 0.26 | 0.26 | 23.20% | 7.00% | 25.00% | 20.0 | $0.2500 | $20.00 |
| 2 | 7 | 200 | 222 | Installation of Air Side Heat Recovery Systems | 0.26 | 0.26 | 80.00% | 15.00% | 50.00% | 20.0 | $0.9300 | $10.00 |
| 2 | 7 | 200 | 227 | High Efficiency Gas Furnace/Boiler | 0.26 | 0.26 | | 13.20% | | 20.0 | $0.1481 | $0.46 |
| 2 | 7 | 200 | 228 | Stack Heat Exchanger | 0.26 | 0.26 | 81.00% | 4.00% | 50.00% | 20.0 | $0.0058 | $0.00 |
| 2 | 7 | 300 | 300 | Base Pool Heating | 0.05 | 0.05 | 100.00% | 0.00% | 100.00% | 10.0 | $0.1152 | $0.12 |
| 2 | 7 | 300 | 301 | Installation of Solar Pool/Spa Heating Systems | 0.05 | 0.05 | 100.00% | 15.80% | 100.00% | 10.0 | $0.1954 | $0.07 |
| 2 | 7 | 300 | 302 | Installation of Swimming Pool / Spa Covers | 0.05 | 0.05 | 25.00% | 35.00% | 90.00% | 5.0 | $0.0048 | $0.12 |
| 2 | 7 | 400 | 400 | Base Water Heating, 100 gal., 88 kBtu, EF=.76 | 0.48 | 0.48 | 100.00% | 0.00% | 100.00% | 15.0 | $0.2823 | $0.30 |
| 2 | 7 | 400 | 401 | Hot Water (SHW) Pipe Insulation | 0.48 | 0.48 | 2.00% | 2.00% | 50.00% | 15.0 | $0.0238 | $0.05 |
| 2 | 7 | 400 | 403 | Water Heater Tank Blanket/Insulation | 0.48 | 0.48 | 50.00% | 5.00% | 95.00% | 15.0 | $0.0301 | $0.01 |
| 2 | 7 | 400 | 404 | Tankless Water Heater | 0.48 | 0.48 | 100.00% | 8.00% | 10.00% | 15.0 | $0.2733 | $0.30 |
| 2 | 7 | 400 | 405 | High-Efficiency Water Heater (gas), 100 gal., 88 kBTU, EF=.80 | 0.48 | 0.48 | | 5.00% | | 15.0 | $0.4922 | $0.30 |
| 2 | 7 | 400 | 406 | High-Efficiency Water Heater (gas), 100 gal., 120 kBTU, EF=.95 | 0.48 | 0.48 | | 20.00% | | 15.0 | $0.7673 | $0.30 |
| 2 | 8 | 100 | 100 | Base Cooking | 0.09 | 0.09 | 100.00% | 0.00% | 100.00% | 15.0 | $0.0914 | $0.09 |
| 2 | 8 | 100 | 102 | High-Efficiency Convection Oven | 0.09 | 0.09 | | 7.00% | | 15.0 | $0.0768 | $0.09 |
| 2 | 8 | 100 | 103 | Efficient Infrared Griddle | 0.09 | 0.09 | 80.00% | 3.00% | 60.00% | 15.0 | $0.0221 | $0.09 |
| 2 | 8 | 100 | 104 | Infrared Fryer | 0.09 | 0.09 | 80.00% | 15.00% | 60.00% | 15.0 | $0.0314 | $0.09 |
| 2 | 8 | 100 | 105 | Power Burner Oven | 0.09 | 0.09 | 80.00% | 4.26% | 60.00% | 15.0 | $0.0934 | $0.09 |
| 2 | 8 | 100 | 106 | Power Burner Fryer | 0.09 | 0.09 | 80.00% | 4.26% | 60.00% | 15.0 | $0.0374 | $0.09 |
| 2 | 8 | 100 | 107 | Infrared Conveyer Oven | 0.09 | 0.09 | 90.00% | 15.00% | 60.00% | 15.0 | $0.1001 | $0.09 |
| 2 | 8 | 200 | 200 | Base Heating | 0.47 | 0.47 | 100.00% | 0.00% | 100.00% | 20.0 | $0.3800 | $0.40 |
| 2 | 8 | 200 | 201 | High Efficiency Windows (Multiple Glazed, Low Emissivity) | 0.47 | 0.47 | 99.30% | 6.00% | 75.00% | 60.0 | $0.0131 | $0.40 |
| 2 | 8 | 200 | 202 | Insulation (ceiling) | 0.47 | 0.47 | 21.53% | 3.00% | 50.00% | 20.0 | $0.4102 | $17.46 |
| 2 | 8 | 200 | 203 | Insulation (wall) | 0.47 | 0.47 | 21.53% | 10.00% | 50.00% | 20.0 | $0.4626 | $17.46 |
| 2 | 8 | 200 | 209 | Insulation of Pipes | 0.47 | 0.47 | 25.00% | 1.00% | 100.00% | 20.0 | $0.0160 | $0.87 |
| 2 | 8 | 200 | 212 | Boiler Tune-Up | 0.47 | 0.47 | 10.00% | 1.00% | 100.00% | 2.0 | $0.0028 | $0.00 |
| 2 | 8 | 200 | 216 | Clock / Programmable Thermostat | 0.47 | 0.47 | 49.00% | 0.50% | 75.00% | 10.0 | $0.0005 | $0.00 |
| 2 | 8 | 200 | 218 | Installation of Energy Management Systems (EMS) | 0.47 | 0.47 | 74.60% | 7.00% | 25.00% | 20.0 | $0.2500 | $20.00 |
| 2 | 8 | 200 | 222 | Installation of Air Side Heat Recovery Systems | 0.47 | 0.47 | 80.00% | 15.00% | 50.00% | 20.0 | $0.9300 | $10.00 |
| 2 | 8 | 200 | 227 | High Efficiency Gas Furnace/Boiler | 0.47 | 0.47 | | 13.20% | | 20.0 | $0.1300 | $0.40 |
| 2 | 8 | 200 | 228 | Stack Heat Exchanger | 0.47 | 0.47 | 79.00% | 4.00% | 50.00% | 20.0 | $0.0129 | $0.00 |
| 2 | 8 | 300 | 300 | Base Pool Heating | 0.02 | 0.02 | 100.00% | 0.00% | 100.00% | 10.0 | $0.0243 | $0.02 |
| 2 | 8 | 300 | 301 | Installation of Solar Pool/Spa Heating Systems | 0.02 | 0.02 | 100.00% | 15.80% | 100.00% | 10.0 | $0.0234 | $0.01 |
| 2 | 8 | 300 | 302 | Installation of Swimming Pool / Spa Covers | 0.02 | 0.02 | 50.00% | 35.00% | 90.00% | 5.0 | $0.0010 | $0.02 |
| 2 | 8 | 400 | 400 | Base Water Heating, 100 gal., 88 kBtu, EF=.76 | 0.71 | 0.71 | 100.00% | 0.00% | 100.00% | 15.0 | $0.2482 | $0.26 |
| 2 | 8 | 400 | 401 | Hot Water (SHW) Pipe Insulation | 0.71 | 0.71 | 32.50% | 2.00% | 50.00% | 15.0 | $0.0088 | $0.02 |

## Table B.4: Commercial Gas

| Segment | Building | Base Number | Measure Number | Measure Name | Stock Usage | Base Usage | Incomplete Factor | Energy Savings | Feasibility Factor | Measure Life | Full Per Unit Cost | Full Base Measure Cost |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2 | 8 | 400 | 403 | Water Heater Tank Blanket/Insulation | 0.71 | 0.71 | 50.00% | 5.00% | 95.00% | 15.0 | $0.0380 | $0.01 |
| 2 | 8 | 400 | 404 | Tankless Water Heater | 0.71 | 0.71 | 91.80% | 8.00% | 10.00% | 15.0 | $0.2402 | $0.26 |
| 2 | 8 | 400 | 405 | High-Efficiency Water Heater (gas), 100 gal., 88 kBTU, EF=.80 | 0.71 | 0.71 | | 5.00% | | 15.0 | $0.4327 | $0.26 |
| 2 | 8 | 400 | 406 | High-Efficiency Water Heater (gas), 100 gal., 120 kBTU, EF=.95 | 0.71 | 0.71 | | 20.00% | | 15.0 | $0.6745 | $0.26 |
| 2 | 9 | 100 | 100 | Base Cooking | 0.11 | 0.11 | 100.00% | 0.00% | 100.00% | 15.0 | $0.1070 | $0.11 |
| 2 | 9 | 100 | 102 | High-Efficiency Convection Oven | 0.11 | 0.11 | | 6.00% | | 15.0 | $0.0899 | $0.11 |
| 2 | 9 | 100 | 103 | Efficient Infrared Griddle | 0.11 | 0.11 | 80.00% | 3.00% | 60.00% | 15.0 | $0.0259 | $0.11 |
| 2 | 9 | 100 | 104 | Infrared Fryer | 0.11 | 0.11 | 80.00% | 15.00% | 60.00% | 15.0 | $0.0367 | $0.11 |
| 2 | 9 | 100 | 105 | Power Burner Oven | 0.11 | 0.11 | 80.00% | 4.26% | 60.00% | 15.0 | $0.1093 | $0.11 |
| 2 | 9 | 100 | 106 | Power Burner Fryer | 0.11 | 0.11 | 80.00% | 4.26% | 60.00% | 15.0 | $0.0438 | $0.11 |
| 2 | 9 | 100 | 107 | Infrared Conveyer Oven | 0.11 | 0.11 | 90.00% | 5.00% | 60.00% | 15.0 | $0.1172 | $0.11 |
| 2 | 9 | 200 | 200 | Base Heating | 0.08 | 0.08 | 100.00% | 0.00% | 100.00% | 20.0 | $0.2822 | $0.30 |
| 2 | 9 | 200 | 201 | High Efficiency Windows (Multiple Glazed, Low Emissivity) | 0.08 | 0.08 | 97.50% | 6.00% | 75.00% | 60.0 | $0.0614 | $1.89 |
| 2 | 9 | 200 | 202 | Insulation (ceiling) | 0.08 | 0.08 | 62.26% | 3.00% | 50.00% | 20.0 | $0.2024 | $8.61 |
| 2 | 9 | 200 | 203 | Insulation (wall) | 0.08 | 0.08 | 100.00% | 10.00% | 50.00% | 20.0 | $0.2283 | $8.61 |
| 2 | 9 | 200 | 209 | Insulation of Pipes | 0.08 | 0.08 | 25.00% | 1.00% | 100.00% | 20.0 | $0.0090 | $0.49 |
| 2 | 9 | 200 | 212 | Boiler Tune-Up | 0.08 | 0.08 | 10.00% | 1.00% | 100.00% | 2.0 | $0.0024 | $0.00 |
| 2 | 9 | 200 | 213 | Occupancy Sensor for room HVAC units | 0.08 | 0.08 | 100.00% | 35.00% | 51.00% | 15.0 | $0.0440 | $8.61 |
| 2 | 9 | 200 | 216 | Clock / Programmable Thermostat | 0.08 | 0.08 | 33.66% | 0.50% | 75.00% | 10.0 | $0.0005 | $0.00 |
| 2 | 9 | 200 | 218 | Installation of Energy Management Systems (EMS) | 0.08 | 0.08 | 57.28% | 7.00% | 25.00% | 20.0 | $0.2500 | $20.00 |
| 2 | 9 | 200 | 222 | Installation of Air Side Heat Recovery Systems | 0.08 | 0.08 | 49.56% | 15.00% | 50.00% | 20.0 | $0.9300 | $10.00 |
| 2 | 9 | 200 | 227 | High Efficiency Gas Furnace/Boiler | 0.08 | 0.08 | | 13.20% | | 20.0 | $0.0965 | $0.30 |
| 2 | 9 | 200 | 228 | Stack Heat Exchanger | 0.08 | 0.08 | 85.00% | 4.00% | 50.00% | 20.0 | $0.0110 | $0.00 |
| 2 | 9 | 300 | 300 | Base Pool Heating | 0.06 | 0.06 | 100.00% | 0.00% | 100.00% | 10.0 | $0.0946 | $0.09 |
| 2 | 9 | 300 | 301 | Installation of Solar Pool/Spa Heating Systems | 0.06 | 0.06 | 100.00% | 15.80% | 100.00% | 10.0 | $0.0722 | $0.02 |
| 2 | 9 | 300 | 302 | Installation of Swimming Pool / Spa Covers | 0.06 | 0.06 | 80.00% | 35.00% | 90.00% | 5.0 | $0.0039 | $0.09 |
| 2 | 9 | 400 | 400 | Base Water Heating, 100 gal., 88 kBtu, EF=.76 | 0.37 | 0.37 | 100.00% | 0.00% | 100.00% | 15.0 | $0.2180 | $0.23 |
| 2 | 9 | 400 | 401 | Hot Water (SHW) Pipe Insulation | 0.37 | 0.37 | 49.00% | 2.00% | 50.00% | 15.0 | $0.0324 | $0.07 |
| 2 | 9 | 400 | 403 | Water Heater Tank Blanket/Insulation | 0.37 | 0.37 | 97.77% | 5.00% | 95.00% | 15.0 | $0.0410 | $0.01 |
| 2 | 9 | 400 | 404 | Tankless Water Heater | 0.37 | 0.37 | 100.00% | 8.00% | 10.00% | 15.0 | $0.2110 | $0.23 |
| 2 | 9 | 400 | 405 | High-Efficiency Water Heater (gas), 100 gal., 88 kBTU, EF=.80 | 0.37 | 0.37 | | 5.00% | | 15.0 | $0.3801 | $0.23 |
| 2 | 9 | 400 | 406 | High-Efficiency Water Heater (gas), 100 gal., 120 kBTU, EF=.95 | 0.37 | 0.37 | | 20.00% | | 15.0 | $0.5925 | $0.23 |
| 2 | 10 | 200 | 200 | Base Heating | 0.23 | 0.23 | 100.00% | 0.00% | 100.00% | 20.0 | $0.4803 | $0.51 |
| 2 | 10 | 200 | 201 | High Efficiency Windows (Multiple Glazed, Low Emissivity) | 0.23 | 0.23 | 98.90% | 6.40% | 75.00% | 60.0 | $0.0185 | $0.57 |
| 2 | 10 | 200 | 202 | Insulation (ceiling) | 0.23 | 0.23 | 14.47% | 9.54% | 50.00% | 20.0 | $0.4231 | $18.00 |
| 2 | 10 | 200 | 203 | Insulation (wall) | 0.23 | 0.23 | 63.74% | 10.00% | 50.00% | 20.0 | $0.4771 | $18.00 |
| 2 | 10 | 200 | 209 | Insulation of Pipes | 0.23 | 0.23 | 25.00% | 1.00% | 100.00% | 20.0 | $0.0217 | $1.17 |
| 2 | 10 | 200 | 212 | Boiler Tune-Up | 0.23 | 0.23 | 10.00% | 1.00% | 100.00% | 2.0 | $0.0036 | $0.00 |
| 2 | 10 | 200 | 216 | Clock / Programmable Thermostat | 0.23 | 0.23 | 41.94% | 0.50% | 75.00% | 10.0 | $0.0005 | $0.00 |
| 2 | 10 | 200 | 218 | Installation of Energy Management Systems (EMS) | 0.23 | 0.23 | 17.11% | 7.00% | 25.00% | 20.0 | $0.2500 | $20.00 |
| 2 | 10 | 200 | 222 | Installation of Air Side Heat Recovery Systems | 0.23 | 0.23 | 50.00% | 15.00% | 50.00% | 20.0 | $0.9300 | $10.00 |
| 2 | 10 | 200 | 227 | High Efficiency Gas Furnace/Boiler | 0.23 | 0.23 | | 13.20% | | 20.0 | $0.1643 | $0.51 |
| 2 | 10 | 200 | 228 | Stack Heat Exchanger | 0.23 | 0.23 | 84.00% | 4.00% | 50.00% | 20.0 | $0.0166 | $0.00 |
| 2 | 10 | 400 | 400 | Base Water Heating, 100 gal., 88 kBtu, EF=.76 | 0.37 | 0.37 | 100.00% | 0.00% | 100.00% | 15.0 | $0.2129 | $0.22 |

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## Table B.4: Commercial Gas

| Segment | Building | Base Number | Measure Number | Measure Name | Stock Usage | Base Usage | Incomplete Factor | Energy Savings | Feasibility Factor | Measure Life | Full Per Unit Cost | Full Base Measure Cost |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2 | 10 | 400 | 401 | Hot Water (SHW) Pipe Insulation | 0.37 | 0.37 | 58.80% | 2.00% | 50.00% | 15.0 | $0.0088 | $0.02 |
| 2 | 10 | 400 | 403 | Water Heater Tank Blanket/Insulation | 0.37 | 0.37 | 39.91% | 8.00% | 95.00% | 15.0 | $0.0111 | $0.00 |
| 2 | 10 | 400 | 404 | Tankless Water Heater | 0.37 | 0.37 | 100.00% | 8.00% | 10.00% | 15.0 | $0.2061 | $0.22 |
| 2 | 10 | 400 | 405 | High-Efficiency Water Heater (gas), 100 gal., 88 kBTU, EF=.80 | 0.37 | 0.37 | | 5.00% | | 15.0 | $0.3713 | $0.22 |
| 2 | 10 | 400 | 406 | High-Efficiency Water Heater (gas), 100 gal., 120 kBTU, EF=.95 | 0.37 | 0.37 | | 20.00% | | 15.0 | $0.5788 | $0.22 |

## Residential Electric

**Residential Electric Sales Forecast (MWh)**

| Year | Island | Jefferson | King | Kitsap | Kittitas | Pierce | Skagit | Thurston | Whatcom | Total |
|---|---|---|---|---|---|---|---|---|---|---|
| 2005 | 334,620 | 182,083 | 4,648,197 | 1,249,933 | 103,362 | 1,082,143 | 482,038 | 1,136,964 | 736,869 | 9,956,209 |
| 2006 | 336,439 | 188,023 | 4,636,615 | 1,250,872 | 105,630 | 1,103,506 | 486,163 | 1,143,897 | 748,016 | 9,999,161 |
| 2007 | 337,082 | 193,435 | 4,616,750 | 1,246,209 | 108,196 | 1,112,528 | 487,292 | 1,154,232 | 753,497 | 10,009,222 |
| 2008 | 336,342 | 197,355 | 4,624,964 | 1,236,576 | 110,407 | 1,129,011 | 485,290 | 1,154,776 | 751,896 | 10,026,618 |
| 2009 | 338,836 | 204,098 | 4,673,377 | 1,241,384 | 113,671 | 1,159,519 | 487,620 | 1,163,102 | 756,888 | 10,138,495 |
| 2010 | 343,834 | 213,519 | 4,722,675 | 1,255,623 | 118,331 | 1,187,760 | 494,610 | 1,187,050 | 770,915 | 10,294,319 |
| 2011 | 351,694 | 221,450 | 4,760,828 | 1,289,619 | 122,859 | 1,206,691 | 502,848 | 1,213,471 | 785,987 | 10,455,448 |
| 2012 | 359,285 | 227,629 | 4,783,566 | 1,325,916 | 127,008 | 1,229,355 | 510,629 | 1,248,179 | 800,009 | 10,611,576 |
| 2013 | 365,786 | 233,305 | 4,812,145 | 1,355,777 | 129,969 | 1,251,198 | 518,108 | 1,278,555 | 812,811 | 10,757,655 |
| 2014 | 371,435 | 238,593 | 4,853,763 | 1,382,214 | 132,237 | 1,271,376 | 524,963 | 1,304,153 | 825,042 | 10,903,777 |
| 2015 | 376,855 | 243,027 | 4,901,688 | 1,411,261 | 134,565 | 1,288,252 | 529,287 | 1,328,738 | 834,350 | 11,048,022 |
| 2016 | 382,474 | 246,816 | 4,951,058 | 1,441,699 | 137,040 | 1,304,728 | 532,275 | 1,355,287 | 840,844 | 11,192,221 |
| 2017 | 387,870 | 250,685 | 5,004,692 | 1,470,390 | 138,451 | 1,322,794 | 535,781 | 1,381,984 | 847,747 | 11,340,393 |
| 2018 | 393,148 | 254,762 | 5,063,259 | 1,498,087 | 138,694 | 1,342,401 | 539,896 | 1,406,685 | 855,602 | 11,492,535 |
| 2019 | 398,527 | 258,930 | 5,124,363 | 1,526,665 | 138,914 | 1,362,788 | 544,118 | 1,430,873 | 863,792 | 11,648,970 |
| 2020 | 404,101 | 263,249 | 5,186,548 | 1,556,586 | 139,243 | 1,383,788 | 548,482 | 1,456,458 | 872,302 | 11,810,757 |
| 2021 | 409,926 | 267,742 | 5,250,480 | 1,588,133 | 139,706 | 1,405,166 | 553,029 | 1,483,341 | 881,282 | 11,978,805 |
| 2022 | 415,889 | 271,637 | 5,326,860 | 1,611,236 | 141,739 | 1,425,608 | 561,074 | 1,504,919 | 894,102 | 12,153,063 |
| 2023 | 422,013 | 275,637 | 5,405,297 | 1,634,961 | 143,826 | 1,446,599 | 569,335 | 1,527,079 | 907,267 | 12,332,016 |
| 2024 | 428,326 | 279,759 | 5,486,148 | 1,659,416 | 145,977 | 1,468,237 | 577,851 | 1,549,921 | 920,838 | 12,516,474 |
| 2025 | 434,732 | 283,944 | 5,568,209 | 1,684,237 | 148,161 | 1,490,199 | 586,495 | 1,573,104 | 934,612 | 12,703,692 |

## Residential Electric Customer Count Forecast

| Year | Island | Jefferson | King | Kitsap | Kittitas | Pierce | Skagit | Thurston | Whatcom | Total |
|---|---|---|---|---|---|---|---|---|---|---|
| 2005 | 28,691 | 14,172 | 433,055 | 98,444 | 8,648 | 87,434 | 45,119 | 95,079 | 76,828 | 887,469 |
| 2006 | 29,163 | 14,794 | 436,724 | 99,597 | 8,937 | 90,139 | 46,005 | 96,708 | 78,847 | 900,913 |
| 2007 | 29,657 | 15,449 | 441,407 | 100,716 | 9,291 | 92,244 | 46,806 | 99,049 | 80,621 | 915,242 |
| 2008 | 30,031 | 15,995 | 448,783 | 101,423 | 9,623 | 95,005 | 47,308 | 100,570 | 81,648 | 930,387 |
| 2009 | 30,437 | 16,642 | 456,249 | 102,434 | 9,968 | 98,167 | 47,825 | 101,910 | 82,691 | 946,323 |
| 2010 | 30,964 | 17,454 | 462,241 | 103,871 | 10,402 | 100,814 | 48,634 | 104,272 | 84,439 | 963,090 |
| 2011 | 31,749 | 18,146 | 467,140 | 106,946 | 10,827 | 102,676 | 49,567 | 106,857 | 86,304 | 980,213 |
| 2012 | 32,517 | 18,700 | 470,578 | 110,234 | 11,218 | 104,872 | 50,463 | 110,192 | 88,069 | 996,843 |
| 2013 | 33,186 | 19,212 | 474,572 | 112,994 | 11,505 | 107,001 | 51,329 | 113,153 | 89,701 | 1,012,653 |
| 2014 | 33,770 | 19,690 | 479,734 | 115,446 | 11,731 | 108,965 | 52,123 | 115,668 | 91,252 | 1,028,379 |
| 2015 | 34,349 | 20,106 | 485,732 | 118,169 | 11,967 | 110,697 | 52,688 | 118,148 | 92,520 | 1,044,377 |
| 2016 | 34,952 | 20,473 | 492,034 | 121,044 | 12,221 | 112,431 | 53,135 | 120,837 | 93,505 | 1,060,632 |
| 2017 | 35,532 | 20,844 | 498,589 | 123,754 | 12,370 | 114,268 | 53,617 | 123,520 | 94,504 | 1,076,997 |
| 2018 | 36,090 | 21,227 | 505,483 | 126,349 | 12,417 | 116,205 | 54,142 | 125,991 | 95,580 | 1,093,484 |
| 2019 | 36,651 | 21,614 | 512,517 | 128,993 | 12,460 | 118,185 | 54,665 | 128,391 | 96,671 | 1,110,145 |
| 2020 | 37,223 | 22,010 | 519,580 | 131,734 | 12,509 | 120,201 | 55,193 | 130,898 | 97,782 | 1,127,130 |
| 2021 | 37,813 | 22,417 | 526,718 | 134,591 | 12,569 | 122,228 | 55,728 | 133,500 | 98,926 | 1,144,490 |
| 2022 | 38,517 | 22,827 | 533,979 | 136,765 | 12,723 | 124,443 | 56,480 | 135,759 | 100,757 | 1,162,249 |
| 2023 | 39,048 | 23,141 | 541,340 | 138,650 | 12,899 | 126,158 | 57,259 | 137,630 | 102,146 | 1,178,271 |
| 2024 | 39,586 | 23,460 | 548,803 | 140,561 | 13,076 | 127,897 | 58,048 | 139,528 | 103,554 | 1,194,513 |
| 2025 | 40,131 | 23,784 | 556,368 | 142,499 | 13,257 | 129,660 | 58,848 | 141,451 | 104,981 | 1,210,980 |

## Residential Electric Housing Type Allocation

| Year | County | Multi Family | Manufactured | Single Family |
|---|---|---|---|---|
| 2005 | Island | 0.109994176 | 0.114770965 | 0.775234859 |
| 2006 | Island | 0.109379809 | 0.113278365 | 0.777341826 |
| 2007 | Island | 0.108765443 | 0.111785764 | 0.779448793 |
| 2008 | Island | 0.108151076 | 0.110293164 | 0.78155576 |
| 2009 | Island | 0.107536709 | 0.108800564 | 0.783662728 |
| 2010 | Island | 0.106922342 | 0.107307963 | 0.785769695 |
| 2011 | Island | 0.106307975 | 0.105815363 | 0.787876662 |
| 2012 | Island | 0.105693608 | 0.104322763 | 0.789983629 |
| 2013 | Island | 0.105079241 | 0.102830162 | 0.792090596 |
| 2014 | Island | 0.104464874 | 0.101337562 | 0.794197564 |

## Residential Electric Housing Type Allocation

| Year | County | Multi Family | Manufactured | Single Family |
|---|---|---|---|---|
| 2015 | Island | 0.103850508 | 0.099844961 | 0.796304531 |
| 2016 | Island | 0.103236141 | 0.098352361 | 0.798411498 |
| 2017 | Island | 0.102621774 | 0.096859761 | 0.800518465 |
| 2018 | Island | 0.102007407 | 0.09536716 | 0.802625433 |
| 2019 | Island | 0.10139304 | 0.09387456 | 0.8047324 |
| 2020 | Island | 0.100778673 | 0.09238196 | 0.806839367 |
| 2021 | Island | 0.100164306 | 0.090889359 | 0.808946334 |
| 2022 | Island | 0.09954994 | 0.089396759 | 0.811053302 |
| 2023 | Island | 0.098935573 | 0.087904159 | 0.813160269 |
| 2024 | Island | 0.098321206 | 0.086411558 | 0.815267236 |
| 2025 | Island | 0.097706839 | 0.084918958 | 0.817374203 |
| 2005 | Jefferson | 0.075108418 | 0.183038725 | 0.741852857 |
| 2006 | Jefferson | 0.074885166 | 0.181262003 | 0.743852831 |
| 2007 | Jefferson | 0.074661914 | 0.179485281 | 0.745852806 |
| 2008 | Jefferson | 0.074438662 | 0.177708559 | 0.74785278 |
| 2009 | Jefferson | 0.07421541 | 0.175931836 | 0.749852754 |
| 2010 | Jefferson | 0.073992158 | 0.174155114 | 0.751852728 |
| 2011 | Jefferson | 0.073768906 | 0.172378392 | 0.753852702 |
| 2012 | Jefferson | 0.073545654 | 0.17060167 | 0.755852676 |
| 2013 | Jefferson | 0.073322402 | 0.168824948 | 0.75785265 |
| 2014 | Jefferson | 0.07309915 | 0.167048225 | 0.759852624 |
| 2015 | Jefferson | 0.072875898 | 0.165271503 | 0.761852599 |
| 2016 | Jefferson | 0.072652646 | 0.163494781 | 0.763852573 |
| 2017 | Jefferson | 0.072429394 | 0.161718059 | 0.765852547 |
| 2018 | Jefferson | 0.072206142 | 0.159941337 | 0.767852521 |
| 2019 | Jefferson | 0.07198289 | 0.158164614 | 0.769852495 |
| 2020 | Jefferson | 0.071759639 | 0.156387892 | 0.771852469 |
| 2021 | Jefferson | 0.071536387 | 0.15461117 | 0.773852443 |
| 2022 | Jefferson | 0.071313135 | 0.152834448 | 0.775852417 |
| 2023 | Jefferson | 0.071089883 | 0.151057726 | 0.777852392 |
| 2024 | Jefferson | 0.070866631 | 0.149281004 | 0.779852366 |
| 2025 | Jefferson | 0.070643379 | 0.147504281 | 0.78185234 |
| 2005 | King | 0.314379887 | 0.039035467 | 0.646584646 |
| 2006 | King | 0.3160933 | 0.038652426 | 0.645254274 |
| 2007 | King | 0.317806712 | 0.038269385 | 0.643923903 |
| 2008 | King | 0.319520124 | 0.037886344 | 0.642593532 |

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## Residential Electric Housing Type Allocation

| Year | County | Multi Family | Manufactured | Single Family |
|---|---|---|---|---|
| 2009 | King | 0.321233537 | 0.037503303 | 0.64126316 |
| 2010 | King | 0.322946949 | 0.037120262 | 0.639932789 |
| 2011 | King | 0.324660362 | 0.036737221 | 0.638602418 |
| 2012 | King | 0.326373774 | 0.03635418 | 0.637272046 |
| 2013 | King | 0.328087186 | 0.035971139 | 0.635941675 |
| 2014 | King | 0.329800599 | 0.035588097 | 0.634611304 |
| 2015 | King | 0.331514011 | 0.035205056 | 0.633280932 |
| 2016 | King | 0.333227424 | 0.034822015 | 0.631950561 |
| 2017 | King | 0.334940836 | 0.034438974 | 0.63062019 |
| 2018 | King | 0.336654248 | 0.034055933 | 0.629289818 |
| 2019 | King | 0.338367661 | 0.033672892 | 0.627959447 |
| 2020 | King | 0.340081073 | 0.033289851 | 0.626629076 |
| 2021 | King | 0.341794486 | 0.03290681 | 0.625298704 |
| 2022 | King | 0.343507898 | 0.032523769 | 0.623968333 |
| 2023 | King | 0.34522131 | 0.032140728 | 0.622637962 |
| 2024 | King | 0.346934723 | 0.031757687 | 0.621307591 |
| 2025 | King | 0.348648135 | 0.031374646 | 0.619977219 |
| 2005 | Kitsap | 0.189160848 | 0.105774646 | 0.705064506 |
| 2006 | Kitsap | 0.189047505 | 0.105526747 | 0.705425748 |
| 2007 | Kitsap | 0.188934162 | 0.105278847 | 0.705786991 |
| 2008 | Kitsap | 0.18882082 | 0.105030947 | 0.706148233 |
| 2009 | Kitsap | 0.188707477 | 0.104783047 | 0.706509475 |
| 2010 | Kitsap | 0.188594135 | 0.104535148 | 0.706870718 |
| 2011 | Kitsap | 0.188480792 | 0.104287248 | 0.70723196 |
| 2012 | Kitsap | 0.188367449 | 0.104039348 | 0.707593203 |
| 2013 | Kitsap | 0.188254107 | 0.103791448 | 0.707954445 |
| 2014 | Kitsap | 0.188140764 | 0.103543549 | 0.708315687 |
| 2015 | Kitsap | 0.188027421 | 0.103295649 | 0.70867693 |
| 2016 | Kitsap | 0.187914079 | 0.103047749 | 0.709038172 |
| 2017 | Kitsap | 0.187800736 | 0.102799849 | 0.709399415 |
| 2018 | Kitsap | 0.187687394 | 0.10255195 | 0.709760657 |
| 2019 | Kitsap | 0.187574051 | 0.10230405 | 0.710121899 |
| 2020 | Kitsap | 0.187460708 | 0.10205615 | 0.710483142 |
| 2021 | Kitsap | 0.187347366 | 0.10180825 | 0.710844384 |
| 2022 | Kitsap | 0.187234023 | 0.10156035 | 0.711205626 |
| 2023 | Kitsap | 0.187120681 | 0.101312451 | 0.711566869 |

## Residential Electric Housing Type Allocation

| Year | County | Multi Family | Manufactured | Single Family |
|---|---|---|---|---|
| 2024 | Kitsap | 0.187007338 | 0.101064551 | 0.711928111 |
| 2025 | Kitsap | 0.186893995 | 0.100816651 | 0.712289354 |
| 2005 | Kittitas | 0.05523072 | 0.203860048 | 0.740909233 |
| 2006 | Kittitas | 0.055422323 | 0.20468282 | 0.739894858 |
| 2007 | Kittitas | 0.055613926 | 0.205505592 | 0.738880482 |
| 2008 | Kittitas | 0.055805529 | 0.206328364 | 0.737866107 |
| 2009 | Kittitas | 0.055997132 | 0.207151136 | 0.736851732 |
| 2010 | Kittitas | 0.056188735 | 0.207973908 | 0.735837357 |
| 2011 | Kittitas | 0.056380339 | 0.20879668 | 0.734822982 |
| 2012 | Kittitas | 0.056571942 | 0.209619452 | 0.733808607 |
| 2013 | Kittitas | 0.056763545 | 0.210442224 | 0.732794232 |
| 2014 | Kittitas | 0.056955148 | 0.211264996 | 0.731779856 |
| 2015 | Kittitas | 0.057146751 | 0.212087768 | 0.730765481 |
| 2016 | Kittitas | 0.057338354 | 0.212910539 | 0.729751106 |
| 2017 | Kittitas | 0.057529958 | 0.213733311 | 0.728736731 |
| 2018 | Kittitas | 0.057721561 | 0.214556083 | 0.727722356 |
| 2019 | Kittitas | 0.057913164 | 0.215378855 | 0.726707981 |
| 2020 | Kittitas | 0.058104767 | 0.216201627 | 0.725693605 |
| 2021 | Kittitas | 0.05829637 | 0.217024399 | 0.72467923 |
| 2022 | Kittitas | 0.058487973 | 0.217847171 | 0.723664855 |
| 2023 | Kittitas | 0.058679577 | 0.218669943 | 0.72265048 |
| 2024 | Kittitas | 0.05887118 | 0.219492715 | 0.721636105 |
| 2025 | Kittitas | 0.059062783 | 0.220315487 | 0.72062173 |
| 2005 | Pierce | 0.177585887 | 0.117229396 | 0.705184717 |
| 2006 | Pierce | 0.174965938 | 0.116829286 | 0.708204776 |
| 2007 | Pierce | 0.172345989 | 0.116429175 | 0.711224836 |
| 2008 | Pierce | 0.16972604 | 0.116029065 | 0.714244896 |
| 2009 | Pierce | 0.16710609 | 0.115628954 | 0.717264956 |
| 2010 | Pierce | 0.164486141 | 0.115228843 | 0.720285015 |
| 2011 | Pierce | 0.161866192 | 0.114828733 | 0.723305075 |
| 2012 | Pierce | 0.159246243 | 0.114428622 | 0.726325135 |
| 2013 | Pierce | 0.156626294 | 0.114028512 | 0.729345195 |
| 2014 | Pierce | 0.154006344 | 0.113628401 | 0.732365254 |
| 2015 | Pierce | 0.151386395 | 0.113228291 | 0.735385314 |
| 2016 | Pierce | 0.148766446 | 0.11282818 | 0.738405374 |
| 2017 | Pierce | 0.146146497 | 0.112428069 | 0.741425434 |

## Residential Electric Housing Type Allocation

| Year | County | Multi Family | Manufactured | Single Family |
|---|---|---|---|---|
| 2018 | Pierce | 0.143526548 | 0.112027959 | 0.744445493 |
| 2019 | Pierce | 0.140906598 | 0.111627848 | 0.747465553 |
| 2020 | Pierce | 0.138286649 | 0.111227738 | 0.750485613 |
| 2021 | Pierce | 0.1356667 | 0.110827627 | 0.753505673 |
| 2022 | Pierce | 0.133046751 | 0.110427517 | 0.756525733 |
| 2023 | Pierce | 0.130426802 | 0.110027406 | 0.759545792 |
| 2024 | Pierce | 0.127806853 | 0.109627295 | 0.762565852 |
| 2025 | Pierce | 0.125186903 | 0.109227185 | 0.765585912 |
| 2005 | Skagit | 0.15657949 | 0.131288766 | 0.712131744 |
| 2006 | Skagit | 0.157766405 | 0.131915929 | 0.710317666 |
| 2007 | Skagit | 0.158953321 | 0.132543092 | 0.708503587 |
| 2008 | Skagit | 0.160140236 | 0.133170256 | 0.706689508 |
| 2009 | Skagit | 0.161327152 | 0.133797419 | 0.704875429 |
| 2010 | Skagit | 0.162514067 | 0.134424582 | 0.70306135 |
| 2011 | Skagit | 0.163700983 | 0.135051746 | 0.701247271 |
| 2012 | Skagit | 0.164887899 | 0.135678909 | 0.699433193 |
| 2013 | Skagit | 0.166074814 | 0.136306072 | 0.697619114 |
| 2014 | Skagit | 0.16726173 | 0.136933235 | 0.695805035 |
| 2015 | Skagit | 0.168448645 | 0.137560399 | 0.693990956 |
| 2016 | Skagit | 0.169635561 | 0.138187562 | 0.692176877 |
| 2017 | Skagit | 0.170822476 | 0.138814725 | 0.690362798 |
| 2018 | Skagit | 0.172009392 | 0.139441889 | 0.68854872 |
| 2019 | Skagit | 0.173196307 | 0.140069052 | 0.686734641 |
| 2020 | Skagit | 0.174383223 | 0.140696215 | 0.684920562 |
| 2021 | Skagit | 0.175570138 | 0.141323379 | 0.683106483 |
| 2022 | Skagit | 0.176757054 | 0.141950542 | 0.681292404 |
| 2023 | Skagit | 0.17794397 | 0.142577705 | 0.679478325 |
| 2024 | Skagit | 0.179130885 | 0.143204868 | 0.677664246 |
| 2025 | Skagit | 0.180317801 | 0.143832032 | 0.675850168 |
| 2005 | Thurston | 0.193034995 | 0.134239141 | 0.672725864 |
| 2006 | Thurston | 0.192765605 | 0.132731 | 0.674503395 |
| 2007 | Thurston | 0.192496214 | 0.131222859 | 0.676280927 |
| 2008 | Thurston | 0.192226823 | 0.129714718 | 0.678058458 |
| 2009 | Thurston | 0.191957433 | 0.128206578 | 0.67983599 |
| 2010 | Thurston | 0.191688042 | 0.126698437 | 0.681613521 |
| 2011 | Thurston | 0.191418652 | 0.125190296 | 0.683391053 |

## Residential Electric Housing Type Allocation

| Year | County | Multi Family | Manufactured | Single Family |
|---|---|---|---|---|
| 2012 | Thurston | 0.191149261 | 0.123682155 | 0.685168584 |
| 2013 | Thurston | 0.19087987 | 0.122174014 | 0.686946116 |
| 2014 | Thurston | 0.19061048 | 0.120665873 | 0.688723647 |
| 2015 | Thurston | 0.190341089 | 0.119157732 | 0.690501179 |
| 2016 | Thurston | 0.190071698 | 0.117649591 | 0.69227871 |
| 2017 | Thurston | 0.189802308 | 0.11614145 | 0.694056242 |
| 2018 | Thurston | 0.189532917 | 0.114633309 | 0.695833774 |
| 2019 | Thurston | 0.189263527 | 0.113125168 | 0.697611305 |
| 2020 | Thurston | 0.188994136 | 0.111617027 | 0.699388837 |
| 2021 | Thurston | 0.188724745 | 0.110108887 | 0.701166368 |
| 2022 | Thurston | 0.188455355 | 0.108600746 | 0.7029439 |
| 2023 | Thurston | 0.188185964 | 0.107092605 | 0.704721431 |
| 2024 | Thurston | 0.187916573 | 0.105584464 | 0.706498963 |
| 2025 | Thurston | 0.187647183 | 0.104076323 | 0.708276494 |
| 2005 | Whatcom | 0.242250515 | 0.128940741 | 0.628808744 |
| 2006 | Whatcom | 0.245397446 | 0.129263668 | 0.625338886 |
| 2007 | Whatcom | 0.248544376 | 0.129586595 | 0.621869029 |
| 2008 | Whatcom | 0.251691307 | 0.129909522 | 0.618399171 |
| 2009 | Whatcom | 0.254838238 | 0.130232449 | 0.614929313 |
| 2010 | Whatcom | 0.257985168 | 0.130555376 | 0.611459455 |
| 2011 | Whatcom | 0.261132099 | 0.130878303 | 0.607989597 |
| 2012 | Whatcom | 0.26427903 | 0.131201231 | 0.60451974 |
| 2013 | Whatcom | 0.26742596 | 0.131524158 | 0.601049882 |
| 2014 | Whatcom | 0.270572891 | 0.131847085 | 0.597580024 |
| 2015 | Whatcom | 0.273719822 | 0.132170012 | 0.594110166 |
| 2016 | Whatcom | 0.276866752 | 0.132492939 | 0.590640309 |
| 2017 | Whatcom | 0.280013683 | 0.132815866 | 0.587170451 |
| 2018 | Whatcom | 0.283160614 | 0.133138793 | 0.583700593 |
| 2019 | Whatcom | 0.286307545 | 0.13346172 | 0.580230735 |
| 2020 | Whatcom | 0.289454475 | 0.133784647 | 0.576760877 |
| 2021 | Whatcom | 0.292601406 | 0.134107574 | 0.57329102 |
| 2022 | Whatcom | 0.295748337 | 0.134430502 | 0.569821162 |
| 2023 | Whatcom | 0.298895267 | 0.134753429 | 0.566351304 |
| 2024 | Whatcom | 0.302042198 | 0.135076356 | 0.562881446 |
| 2025 | Whatcom | 0.305189129 | 0.135399283 | 0.559411589 |

## Residential Electric Housing Type Allocation

| Year | County | Multi Family | Manufactured | Single Family |
|---|---|---|---|---|

## Residential Electric Efficiency Shares

| bName | nName | fName | Stock | Standard | High | Premium |
|---|---|---|---|---|---|---|
| Manufactured | Central_AC | Electric | 0.5 | 0.4 | 0.09 | 0.01 |
| Manufactured | Cooking | Electric | 0.95 | 0.05 | - - - | - - - |
| Manufactured | Cooking | Gas | 1 | - - - | - - - | - - - |
| Manufactured | Freezer | Electric | 0.95 | 0.05 | - - - | - - - |
| Manufactured | Heat_Pump | Electric | 0.5 | 0.4 | 0.09 | 0.01 |
| Manufactured | Lighting | Electric | 0.7 | 0.2 | 0.075 | 0.025 |
| Manufactured | Other | Electric | 1 | - - - | - - - | - - - |
| Manufactured | Plug_Load | Electric | 1 | - - - | - - - | - - - |
| Manufactured | Refrigeration | Electric | 0.6 | 0.2 | 0.15 | 0.05 |
| Manufactured | Room_AC | Electric | 0.59 | 0.34 | 0.06 | 0.01 |
| Manufactured | Space_Heat | Electric | 0.95 | 0.04 | 0.009 | 0.001 |
| Manufactured | Space_Heat | Gas | 1 | - - - | - - - | - - - |
| Manufactured | Water_Heat | Electric | 0.1 | 0.68 | 0.21 | 0.01 |
| Manufactured | Water_Heat | Gas | 1 | - - - | - - - | - - - |
| Multi_Family | Central_AC | Electric | 0.5 | 0.4 | 0.09 | 0.01 |
| Multi_Family | Cooking | Electric | 0.95 | 0.05 | - - - | - - - |
| Multi_Family | Cooking | Gas | 1 | - - - | - - - | - - - |
| Multi_Family | Freezer | Electric | 0.95 | 0.05 | - - - | - - - |
| Multi_Family | Heat_Pump | Electric | 0.5 | 0.4 | 0.09 | 0.01 |
| Multi_Family | Lighting | Electric | 0.7 | 0.2 | 0.075 | 0.025 |
| Multi_Family | Other | Electric | 1 | - - - | - - - | - - - |
| Multi_Family | Plug_Load | Electric | 1 | - - - | - - - | - - - |
| Multi_Family | Refrigeration | Electric | 0.6 | 0.2 | 0.15 | 0.05 |
| Multi_Family | Room_AC | Electric | 0.5 | 0.48 | 0.01 | 0.01 |
| Multi_Family | Space_Heat | Electric | 0.95 | 0.04 | 0.009 | 0.001 |
| Multi_Family | Space_Heat | Gas | 1 | - - - | - - - | - - - |
| Multi_Family | Water_Heat | Electric | 0.13 | 0.76 | 0.1 | 0.01 |
| Multi_Family | Water_Heat | Gas | 1 | - - - | - - - | - - - |
| Single_Family | Central_AC | Electric | 0.5 | 0.4 | 0.09 | 0.01 |
| Single_Family | Cooking | Electric | 0.9 | 0.1 | - - - | - - - |

## Residential Electric Housing Type Allocation

| Year | County | Multi Family | Manufactured | Single Family | | |
|---|---|---|---|---|---|---|
| Single_Family | Cooking | Gas | 1 | - - - | - - - | - - - |
| Single_Family | Freezer | Electric | 0.95 | 0.05 | - - - | - - - |
| Single_Family | Heat_Pump | Electric | 0.5 | 0.4 | 0.09 | 0.01 |
| Single_Family | Lighting | Electric | 0.7 | 0.2 | 0.075 | 0.025 |
| Single_Family | Other | Electric | 1 | - - - | - - - | - - - |
| Single_Family | Plug_Load | Electric | 1 | - - - | - - - | - - - |
| Single_Family | Refrigeration | Electric | 0.6 | 0.2 | 0.15 | 0.05 |
| Single_Family | Room_AC | Electric | 0.59 | 0.34 | 0.06 | 0.01 |
| Single_Family | Space_Heat | Electric | 0.95 | 0.04 | 0.009 | 0.001 |
| Single_Family | Space_Heat | Gas | 1 | - - - | - - - | - - - |
| Single_Family | Water_Heat | Electric | 0.1 | 0.68 | 0.21 | 0.01 |
| Single_Family | Water_Heat | Gas | 1 | - - - | - - - | - - - |
| Manufactured | Dryer | Electric | 0.65 | 0.2 | 0.15 | . - - - |
| Multi_Family | Dryer | Electric | 0.65 | 0.2 | 0.15 | . - - - |
| Single_Family | Dryer | Electric | 0.65 | 0.2 | 0.15 | . - - - |
| Manufactured | Dryer | Gas | 1 | - - - | - - - | - - - |
| Multi_Family | Dryer | Gas | 1 | - - - | - - - | - - - |
| Single_Family | Dryer | Gas | 1 | - - - | - - - | - - - |

## Residential Electric Electric Price Forecast ($/kWh)

| Year | Res Price Deflator | Single_Family | | Multi_Family | | Manufactured | |
|---|---|---|---|---|---|---|---|
| | | Average Price | Marginal Price | Average Price | Marginal Price | Average Price | Marginal Price |
| 2005 | 100.00 | 0.06955 | 0.06955 | 0.06955 | 0.06955 | 0.06955 | 0.06955 |
| 2006 | 102.29 | 0.07614 | 0.07614 | 0.07614 | 0.07614 | 0.07614 | 0.07614 |
| 2007 | 104.61 | 0.08349 | 0.08349 | 0.08349 | 0.08349 | 0.08349 | 0.08349 |
| 2008 | 107.08 | 0.08539 | 0.08539 | 0.08539 | 0.08539 | 0.08539 | 0.08539 |
| 2009 | 109.72 | 0.08735 | 0.08735 | 0.08735 | 0.08735 | 0.08735 | 0.08735 |
| 2010 | 112.67 | 0.08953 | 0.08953 | 0.08953 | 0.08953 | 0.08953 | 0.08953 |
| 2011 | 115.97 | 0.09188 | 0.09188 | 0.09188 | 0.09188 | 0.09188 | 0.09188 |
| 2012 | 119.34 | 0.09419 | 0.09419 | 0.09419 | 0.09419 | 0.09419 | 0.09419 |
| 2013 | 123.05 | 0.09654 | 0.09654 | 0.09654 | 0.09654 | 0.09654 | 0.09654 |
| 2014 | 126.80 | 0.09907 | 0.09907 | 0.09907 | 0.09907 | 0.09907 | 0.09907 |
| 2015 | 130.47 | 0.10178 | 0.10178 | 0.10178 | 0.10178 | 0.10178 | 0.10178 |
| 2016 | 134.23 | 0.10445 | 0.10445 | 0.10445 | 0.10445 | 0.10445 | 0.10445 |
| 2017 | 138.36 | 0.10721 | 0.10721 | 0.10721 | 0.10721 | 0.10721 | 0.10721 |
| 2018 | 142.88 | 0.11008 | 0.11008 | 0.11008 | 0.11008 | 0.11008 | 0.11008 |
| 2019 | 147.75 | 0.11302 | 0.11302 | 0.11302 | 0.11302 | 0.11302 | 0.11302 |
| 2020 | 152.92 | 0.11597 | 0.11597 | 0.11597 | 0.11597 | 0.11597 | 0.11597 |
| 2021 | 158.32 | 0.11893 | 0.11893 | 0.11893 | 0.11893 | 0.11893 | 0.11893 |
| 2022 | 163.95 | 0.12190 | 0.12190 | 0.12190 | 0.12190 | 0.12190 | 0.12190 |
| 2023 | 169.82 | 0.12484 | 0.12484 | 0.12484 | 0.12484 | 0.12484 | 0.12484 |
| 2024 | 175.93 | 0.12778 | 0.12778 | 0.12778 | 0.12778 | 0.12778 | 0.12778 |
| 2025 | 182.27 | 0.13079 | 0.13079 | 0.13079 | 0.13079 | 0.13079 | 0.13079 |

## Residential Electric Gas Price Forecast ($/therm)

| Year | Res Price Deflator | Single_Family | | Multi_Family | | Manufactured | |
|---|---|---|---|---|---|---|---|
| | | Average Price | Marginal Price | Average Price | Marginal Price | Average Price | Marginal Price |
| 2005 | 100.00 | 1.09796 | 1.09796 | 1.09796 | 1.09796 | 1.09796 | 1.09796 |
| 2006 | 102.29 | 1.10498 | 1.10498 | 1.10498 | 1.10498 | 1.10498 | 1.10498 |
| 2007 | 104.61 | 1.10899 | 1.10899 | 1.10899 | 1.10899 | 1.10899 | 1.10899 |
| 2008 | 107.08 | 1.02027 | 1.02027 | 1.02027 | 1.02027 | 1.02027 | 1.02027 |
| 2009 | 109.72 | 0.99589 | 0.99589 | 0.99589 | 0.99589 | 0.99589 | 0.99589 |
| 2010 | 112.67 | 0.92554 | 0.92554 | 0.92554 | 0.92554 | 0.92554 | 0.92554 |
| 2011 | 115.97 | 1.00316 | 1.00316 | 1.00316 | 1.00316 | 1.00316 | 1.00316 |
| 2012 | 119.34 | 1.02242 | 1.02242 | 1.02242 | 1.02242 | 1.02242 | 1.02242 |
| 2013 | 123.05 | 1.09416 | 1.09416 | 1.09416 | 1.09416 | 1.09416 | 1.09416 |
| 2014 | 126.80 | 1.16195 | 1.16195 | 1.16195 | 1.16195 | 1.16195 | 1.16195 |
| 2015 | 130.47 | 1.17080 | 1.17080 | 1.17080 | 1.17080 | 1.17080 | 1.17080 |
| 2016 | 134.23 | 1.05989 | 1.05989 | 1.05989 | 1.05989 | 1.05989 | 1.05989 |
| 2017 | 138.36 | 1.09495 | 1.09495 | 1.09495 | 1.09495 | 1.09495 | 1.09495 |
| 2018 | 142.88 | 1.18576 | 1.18576 | 1.18576 | 1.18576 | 1.18576 | 1.18576 |
| 2019 | 147.75 | 1.27289 | 1.27289 | 1.27289 | 1.27289 | 1.27289 | 1.27289 |
| 2020 | 152.92 | 1.33734 | 1.33734 | 1.33734 | 1.33734 | 1.33734 | 1.33734 |
| 2021 | 158.32 | 1.36319 | 1.36319 | 1.36319 | 1.36319 | 1.36319 | 1.36319 |
| 2022 | 163.95 | 1.38512 | 1.38512 | 1.38512 | 1.38512 | 1.38512 | 1.38512 |
| 2023 | 169.82 | 1.40767 | 1.40767 | 1.40767 | 1.40767 | 1.40767 | 1.40767 |
| 2024 | 175.93 | 1.40731 | 1.40731 | 1.40731 | 1.40731 | 1.40731 | 1.40731 |
| 2025 | 182.27 | 1.43022 | 1.43022 | 1.43022 | 1.43022 | 1.43022 | 1.43022 |

## Residential Gas

**Residential Gas Sales Forecast (Therms)**

| Year | King | Kittitas | Lewis | Pierce | Snohomish | Thurston | Total |
|---|---|---|---|---|---|---|---|
| 2005 | 315,995,171 | 253,301 | 3,176,241 | 97,627,240 | 81,715,731 | 28,641,844 | 527,409,529 |
| 2006 | 319,460,427 | 255,649 | 3,210,976 | 98,706,886 | 82,674,044 | 28,952,733 | 533,260,715 |
| 2007 | 328,828,808 | 263,157 | 3,305,155 | 101,599,911 | 85,095,972 | 29,801,336 | 548,894,340 |
| 2008 | 338,616,082 | 271,017 | 3,403,535 | 104,622,225 | 87,627,680 | 30,687,762 | 565,228,301 |
| 2009 | 349,405,487 | 279,673 | 3,511,992 | 107,954,160 | 90,418,025 | 31,665,045 | 583,234,382 |
| 2010 | 359,791,451 | 288,007 | 3,616,392 | 111,161,516 | 93,104,245 | 32,605,778 | 600,567,388 |
| 2011 | 370,690,849 | 296,743 | 3,725,958 | 114,527,579 | 95,922,521 | 33,593,119 | 618,756,770 |
| 2012 | 378,822,775 | 303,244 | 3,807,721 | 117,038,608 | 98,022,663 | 34,329,784 | 632,324,795 |
| 2013 | 385,743,447 | 308,779 | 3,877,308 | 119,175,355 | 99,809,617 | 34,956,646 | 643,871,151 |
| 2014 | 390,844,814 | 312,864 | 3,928,605 | 120,749,925 | 101,126,184 | 35,418,578 | 652,380,970 |
| 2015 | 395,291,188 | 316,428 | 3,973,316 | 122,122,091 | 102,273,646 | 35,821,116 | 659,797,785 |
| 2016 | 401,054,975 | 321,053 | 4,031,264 | 123,901,316 | 103,762,704 | 36,343,012 | 669,414,324 |
| 2017 | 409,387,442 | 327,737 | 4,115,028 | 126,474,258 | 105,916,929 | 37,097,700 | 683,319,094 |
| 2018 | 415,920,020 | 332,972 | 4,180,706 | 128,491,086 | 107,604,570 | 37,689,318 | 694,218,673 |
| 2019 | 420,427,928 | 336,586 | 4,226,034 | 129,882,311 | 108,768,055 | 38,097,443 | 701,738,358 |
| 2020 | 424,464,144 | 339,826 | 4,266,620 | 131,127,776 | 109,809,823 | 38,462,792 | 708,470,980 |
| 2021 | 428,812,881 | 343,319 | 4,310,344 | 132,469,807 | 110,932,755 | 38,856,448 | 715,725,554 |
| 2022 | 433,841,251 | 347,356 | 4,360,899 | 134,021,852 | 112,231,687 | 39,311,700 | 724,114,746 |
| 2023 | 439,487,637 | 351,888 | 4,417,666 | 135,764,875 | 113,690,609 | 39,822,968 | 733,535,643 |
| 2024 | 445,219,452 | 356,489 | 4,475,290 | 137,534,302 | 115,171,762 | 40,341,975 | 743,099,271 |
| 2025 | 451,024,096 | 361,137 | 4,533,638 | 139,327,435 | 116,673,339 | 40,867,942 | 752,787,587 |

Exhibit No. ___(EMM-6)
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## Residential Gas Customer Count Forecast

| Year | King | Kittitas | Lewis | Pierce | Snohomish | Thurston | Total |
|---|---|---|---|---|---|---|---|
| 2005 | 366,807 | 430 | 4,180 | 117,212 | 97,531 | 36,151 | 622,311 |
| 2006 | 376,105 | 441 | 4,286 | 120,183 | 100,004 | 37,067 | 638,086 |
| 2007 | 385,273 | 452 | 4,391 | 123,112 | 102,441 | 37,971 | 653,639 |
| 2008 | 395,315 | 463 | 4,505 | 126,321 | 105,112 | 38,960 | 670,677 |
| 2009 | 406,645 | 477 | 4,634 | 129,942 | 108,125 | 40,077 | 689,900 |
| 2010 | 419,109 | 491 | 4,776 | 133,925 | 111,439 | 41,306 | 711,047 |
| 2011 | 432,375 | 507 | 4,928 | 138,164 | 114,966 | 42,613 | 733,553 |
| 2012 | 445,239 | 522 | 5,074 | 142,275 | 118,386 | 43,881 | 755,377 |
| 2013 | 457,023 | 536 | 5,209 | 146,040 | 121,519 | 45,042 | 775,368 |
| 2014 | 468,037 | 549 | 5,334 | 149,559 | 124,447 | 46,127 | 794,053 |
| 2015 | 478,650 | 561 | 5,455 | 152,950 | 127,269 | 47,173 | 812,058 |
| 2016 | 489,310 | 574 | 5,577 | 156,356 | 130,103 | 48,224 | 830,143 |
| 2017 | 500,435 | 587 | 5,703 | 159,911 | 133,061 | 49,320 | 849,018 |
| 2018 | 511,815 | 600 | 5,833 | 163,548 | 136,087 | 50,442 | 868,325 |
| 2019 | 523,049 | 613 | 5,961 | 167,137 | 139,074 | 51,549 | 887,384 |
| 2020 | 534,236 | 626 | 6,089 | 170,712 | 142,049 | 52,651 | 906,363 |
| 2021 | 545,659 | 640 | 6,219 | 174,362 | 145,086 | 53,777 | 925,742 |
| 2022 | 557,481 | 653 | 6,354 | 178,140 | 148,229 | 54,942 | 945,800 |
| 2023 | 569,757 | 668 | 6,493 | 182,063 | 151,494 | 56,152 | 966,627 |
| 2024 | 582,559 | 683 | 6,639 | 186,154 | 154,898 | 57,414 | 988,346 |
| 2025 | 593,880 | 728 | 6,710 | 191,174 | 159,471 | 58,839 | 1,010,802 |

## Residential Gas Building Type Allocation

| Year | County | Multi Family | Manufactured | Single Family |
|---|---|---|---|---|
| 2005 | King | 0.3838 | 0.0257 | 0.5906 |
| 2006 | King | 0.3856 | 0.0253 | 0.5891 |
| 2007 | King | 0.3875 | 0.0250 | 0.5876 |
| 2008 | King | 0.3893 | 0.0246 | 0.5861 |
| 2009 | King | 0.3912 | 0.0243 | 0.5846 |

## Residential Gas Building Type Allocation

| Year | County | Multi Family | Manufactured | Single Family |
|---|---|---|---|---|
| 2010 | King | 0.3930 | 0.0239 | 0.5831 |
| 2011 | King | 0.3948 | 0.0236 | 0.5816 |
| 2012 | King | 0.3967 | 0.0233 | 0.5801 |
| 2013 | King | 0.3985 | 0.0229 | 0.5785 |
| 2014 | King | 0.4004 | 0.0226 | 0.5770 |
| 2015 | King | 0.4022 | 0.0222 | 0.5755 |
| 2016 | King | 0.4041 | 0.0219 | 0.5740 |
| 2017 | King | 0.4059 | 0.0215 | 0.5725 |
| 2018 | King | 0.4078 | 0.0212 | 0.5710 |
| 2019 | King | 0.4096 | 0.0209 | 0.5695 |
| 2020 | King | 0.4115 | 0.0205 | 0.5680 |
| 2021 | King | 0.4133 | 0.0202 | 0.5665 |
| 2022 | King | 0.4151 | 0.0198 | 0.5650 |
| 2023 | King | 0.4170 | 0.0195 | 0.5635 |
| 2024 | King | 0.4188 | 0.0191 | 0.5620 |
| 2025 | King | 0.4207 | 0.0188 | 0.5605 |
| 2005 | Kittitas | 0.0552 | 0.2039 | 0.7409 |
| 2006 | Kittitas | 0.0554 | 0.2047 | 0.7399 |
| 2007 | Kittitas | 0.0556 | 0.2055 | 0.7389 |
| 2008 | Kittitas | 0.0558 | 0.2063 | 0.7379 |
| 2009 | Kittitas | 0.0560 | 0.2072 | 0.7369 |
| 2010 | Kittitas | 0.0562 | 0.2080 | 0.7358 |
| 2011 | Kittitas | 0.0564 | 0.2088 | 0.7348 |
| 2012 | Kittitas | 0.0566 | 0.2096 | 0.7338 |
| 2013 | Kittitas | 0.0568 | 0.2104 | 0.7328 |
| 2014 | Kittitas | 0.0570 | 0.2113 | 0.7318 |
| 2015 | Kittitas | 0.0571 | 0.2121 | 0.7308 |
| 2016 | Kittitas | 0.0573 | 0.2129 | 0.7298 |
| 2017 | Kittitas | 0.0575 | 0.2137 | 0.7287 |
| 2018 | Kittitas | 0.0577 | 0.2146 | 0.7277 |
| 2019 | Kittitas | 0.0579 | 0.2154 | 0.7267 |
| 2020 | Kittitas | 0.0581 | 0.2162 | 0.7257 |

## Residential Gas Building Type Allocation

| Year | County | Multi Family | Manufactured | Single Family |
|---|---|---|---|---|
| 2021 | Kittitas | 0.0583 | 0.2170 | 0.7247 |
| 2022 | Kittitas | 0.0585 | 0.2178 | 0.7237 |
| 2023 | Kittitas | 0.0587 | 0.2187 | 0.7227 |
| 2024 | Kittitas | 0.0589 | 0.2195 | 0.7216 |
| 2025 | Kittitas | 0.0591 | 0.2203 | 0.7206 |
| 2005 | Pierce | 0.2407 | 0.0832 | 0.6761 |
| 2006 | Pierce | 0.2395 | 0.0827 | 0.6777 |
| 2007 | Pierce | 0.2383 | 0.0823 | 0.6794 |
| 2008 | Pierce | 0.2371 | 0.0819 | 0.6810 |
| 2009 | Pierce | 0.2359 | 0.0815 | 0.6826 |
| 2010 | Pierce | 0.2347 | 0.0811 | 0.6843 |
| 2011 | Pierce | 0.2335 | 0.0806 | 0.6859 |
| 2012 | Pierce | 0.2322 | 0.0802 | 0.6876 |
| 2013 | Pierce | 0.2310 | 0.0798 | 0.6892 |
| 2014 | Pierce | 0.2298 | 0.0794 | 0.6908 |
| 2015 | Pierce | 0.2286 | 0.0789 | 0.6925 |
| 2016 | Pierce | 0.2274 | 0.0785 | 0.6941 |
| 2017 | Pierce | 0.2262 | 0.0781 | 0.6957 |
| 2018 | Pierce | 0.2250 | 0.0777 | 0.6974 |
| 2019 | Pierce | 0.2238 | 0.0772 | 0.6990 |
| 2020 | Pierce | 0.2226 | 0.0768 | 0.7006 |
| 2021 | Pierce | 0.2213 | 0.0764 | 0.7023 |
| 2022 | Pierce | 0.2201 | 0.0760 | 0.7039 |
| 2023 | Pierce | 0.2189 | 0.0756 | 0.7055 |
| 2024 | Pierce | 0.2177 | 0.0751 | 0.7072 |
| 2025 | Pierce | 0.2165 | 0.0747 | 0.7088 |
| 2005 | Snohomish | 0.2678 | 0.0736 | 0.6586 |
| 2006 | Snohomish | 0.2688 | 0.0716 | 0.6596 |
| 2007 | Snohomish | 0.2698 | 0.0695 | 0.6607 |
| 2008 | Snohomish | 0.2708 | 0.0674 | 0.6618 |
| 2009 | Snohomish | 0.2718 | 0.0653 | 0.6628 |
| 2010 | Snohomish | 0.2729 | 0.0632 | 0.6639 |

## Residential Gas Building Type Allocation

| Year | County | Multi Family | Manufactured | Single Family |
|---|---|---|---|---|
| 2011 | Snohomish | 0.2739 | 0.0612 | 0.6650 |
| 2012 | Snohomish | 0.2749 | 0.0591 | 0.6660 |
| 2013 | Snohomish | 0.2759 | 0.0570 | 0.6671 |
| 2014 | Snohomish | 0.2769 | 0.0549 | 0.6682 |
| 2015 | Snohomish | 0.2779 | 0.0528 | 0.6692 |
| 2016 | Snohomish | 0.2789 | 0.0508 | 0.6703 |
| 2017 | Snohomish | 0.2800 | 0.0487 | 0.6714 |
| 2018 | Snohomish | 0.2810 | 0.0466 | 0.6724 |
| 2019 | Snohomish | 0.2820 | 0.0445 | 0.6735 |
| 2020 | Snohomish | 0.2830 | 0.0424 | 0.6746 |
| 2021 | Snohomish | 0.2840 | 0.0403 | 0.6756 |
| 2022 | Snohomish | 0.2850 | 0.0383 | 0.6767 |
| 2023 | Snohomish | 0.2861 | 0.0362 | 0.6778 |
| 2024 | Snohomish | 0.2871 | 0.0341 | 0.6788 |
| 2025 | Snohomish | 0.2881 | 0.0320 | 0.6799 |
| 2005 | Thurston | 0.1930 | 0.1342 | 0.6727 |
| 2006 | Thurston | 0.1928 | 0.1327 | 0.6745 |
| 2007 | Thurston | 0.1925 | 0.1312 | 0.6763 |
| 2008 | Thurston | 0.1922 | 0.1297 | 0.6781 |
| 2009 | Thurston | 0.1920 | 0.1282 | 0.6798 |
| 2010 | Thurston | 0.1917 | 0.1267 | 0.6816 |
| 2011 | Thurston | 0.1914 | 0.1252 | 0.6834 |
| 2012 | Thurston | 0.1911 | 0.1237 | 0.6852 |
| 2013 | Thurston | 0.1909 | 0.1222 | 0.6869 |
| 2014 | Thurston | 0.1906 | 0.1207 | 0.6887 |
| 2015 | Thurston | 0.1903 | 0.1192 | 0.6905 |
| 2016 | Thurston | 0.1901 | 0.1176 | 0.6923 |
| 2017 | Thurston | 0.1898 | 0.1161 | 0.6941 |
| 2018 | Thurston | 0.1895 | 0.1146 | 0.6958 |
| 2019 | Thurston | 0.1893 | 0.1131 | 0.6976 |
| 2020 | Thurston | 0.1890 | 0.1116 | 0.6994 |
| 2021 | Thurston | 0.1887 | 0.1101 | 0.7012 |

## Residential Gas Building Type Allocation

| Year | County | Multi Family | Manufactured | Single Family |
|---|---|---|---|---|
| 2022 | Thurston | 0.1885 | 0.1086 | 0.7029 |
| 2023 | Thurston | 0.1882 | 0.1071 | 0.7047 |
| 2024 | Thurston | 0.1879 | 0.1056 | 0.7065 |
| 2025 | Thurston | 0.1876 | 0.1041 | 0.7083 |

## Residential Gas Efficiency Shares

| bName | N Name | F Name | Stock | Standard | High | Premium |
|---|---|---|---|---|---|---|
| Manufactured | Cooking | Gas | 0.95 | 0.05 | - - - | . - - - |
| Manufactured | Cooking | Electric | 1 | . - - - | . - - - | . - - - |
| Manufactured | Other | Gas | 1 | . - - - | . - - - | . - - - |
| Manufactured | Space_Heat | Gas | 0.5 | 0.46 | 0.03 | 0.01 |
| Manufactured | Space_Heat | Electric | 1 | . - - - | . - - - | . - - - |
| Manufactured | Water_Heat | Gas | 0.1 | 0.68 | 0.21 | 0.01 |
| Manufactured | Water_Heat | Electric | 1 | . - - - | . - - - | . - - - |
| Multi_Family | Cooking | Gas | 0.95 | 0.05 | . - - - | . - - - |
| Multi_Family | Cooking | Electric | 1 | . - - - | . - - - | . - - - |
| Multi_Family | Other | Gas | 1 | . - - - | . - - - | . - - - |
| Multi_Family | Space_Heat | Gas | 0.5 | 0.46 | 0.03 | 0.01 |
| Multi_Family | Space_Heat | Electric | 1 | . - - - | . - - - | . - - - |
| Multi_Family | Water_Heat | Gas | 0.13 | 0.76 | 0.1 | 0.01 |
| Multi_Family | Water_Heat | Electric | 1 | . - - - | . - - - | . - - - |
| Single_Family | Cooking | Gas | 0.9 | 0.1 | . - - - | . - - - |
| Single_Family | Cooking | Electric | 1 | . - - - | . - - - | . - - - |
| Single_Family | Other | Gas | 1 | . - - - | . - - - | . - - - |
| Single_Family | Space_Heat | Gas | 0.5 | 0.46 | 0.03 | 0.01 |
| Single_Family | Space_Heat | Electric | 1 | . - - - | . - - - | . - - - |
| Single_Family | Water_Heat | Gas | 0.1 | 0.68 | 0.21 | 0.01 |
| Single_Family | Water_Heat | Electric | 1 | . - - - | . - - - | . - - - |
| Manufactured | Dryer | Gas | 0.48 | 0.3 | 0.22 | . - - - |
| Multi_Family | Dryer | Gas | 0.48 | 0.3 | 0.22 | . - - - |
| Single_Family | Dryer | Gas | 0.48 | 0.3 | 0.22 | . - - - |
| Manufactured | Dryer | Electric | 1 | . - - - | . - - - | . - - - |
| Multi_Family | Dryer | Electric | 1 | . - - - | . - - - | . - - - |
| Single_Family | Dryer | Electric | 1 | . - - - | . - - - | . - - - |

## Residential Gas Electric Price Forecast ($/kWh)

| Year | Res Price Deflator | Single Family | | Multi Family | | Manufactured | |
|---|---|---|---|---|---|---|---|
| | | Average Price | Marginal Price | Average Price | Marginal Price | Average Price | Marginal Price |
| 2005 | 100.00 | 0.06955 | 0.06955 | 0.06955 | 0.06955 | 0.06955 | 0.06955 |
| 2006 | 102.29 | 0.07614 | 0.07614 | 0.07614 | 0.07614 | 0.07614 | 0.07614 |
| 2007 | 104.61 | 0.08349 | 0.08349 | 0.08349 | 0.08349 | 0.08349 | 0.08349 |
| 2008 | 107.08 | 0.08539 | 0.08539 | 0.08539 | 0.08539 | 0.08539 | 0.08539 |
| 2009 | 109.72 | 0.08735 | 0.08735 | 0.08735 | 0.08735 | 0.08735 | 0.08735 |
| 2010 | 112.67 | 0.08953 | 0.08953 | 0.08953 | 0.08953 | 0.08953 | 0.08953 |
| 2011 | 115.97 | 0.09188 | 0.09188 | 0.09188 | 0.09188 | 0.09188 | 0.09188 |
| 2012 | 119.34 | 0.09419 | 0.09419 | 0.09419 | 0.09419 | 0.09419 | 0.09419 |
| 2013 | 123.05 | 0.09654 | 0.09654 | 0.09654 | 0.09654 | 0.09654 | 0.09654 |
| 2014 | 126.80 | 0.09907 | 0.09907 | 0.09907 | 0.09907 | 0.09907 | 0.09907 |
| 2015 | 130.47 | 0.10178 | 0.10178 | 0.10178 | 0.10178 | 0.10178 | 0.10178 |
| 2016 | 134.23 | 0.10445 | 0.10445 | 0.10445 | 0.10445 | 0.10445 | 0.10445 |
| 2017 | 138.36 | 0.10721 | 0.10721 | 0.10721 | 0.10721 | 0.10721 | 0.10721 |
| 2018 | 142.88 | 0.11008 | 0.11008 | 0.11008 | 0.11008 | 0.11008 | 0.11008 |
| 2019 | 147.75 | 0.11302 | 0.11302 | 0.11302 | 0.11302 | 0.11302 | 0.11302 |
| 2020 | 152.92 | 0.11597 | 0.11597 | 0.11597 | 0.11597 | 0.11597 | 0.11597 |
| 2021 | 158.32 | 0.11893 | 0.11893 | 0.11893 | 0.11893 | 0.11893 | 0.11893 |
| 2022 | 163.95 | 0.12190 | 0.12190 | 0.12190 | 0.12190 | 0.12190 | 0.12190 |
| 2023 | 169.82 | 0.12484 | 0.12484 | 0.12484 | 0.12484 | 0.12484 | 0.12484 |
| 2024 | 175.93 | 0.12778 | 0.12778 | 0.12778 | 0.12778 | 0.12778 | 0.12778 |
| 2025 | 182.27 | 0.13079 | 0.13079 | 0.13079 | 0.13079 | 0.13079 | 0.13079 |

## Residential Gas Price Forecast ($/therm)

| Year | Res Price Deflator | Single Family | | Multi Family | | Manufactured | |
|---|---|---|---|---|---|---|---|
| | | Average Price | Marginal Price | Average Price | Marginal Price | Average Price | Marginal Price |
| 2005 | 100.00 | 1.09796 | 1.09796 | 1.09796 | 1.09796 | 1.09796 | 1.09796 |
| 2006 | 102.29 | 1.10498 | 1.10498 | 1.10498 | 1.10498 | 1.10498 | 1.10498 |
| 2007 | 104.61 | 1.10899 | 1.10899 | 1.10899 | 1.10899 | 1.10899 | 1.10899 |
| 2008 | 107.08 | 1.02027 | 1.02027 | 1.02027 | 1.02027 | 1.02027 | 1.02027 |
| 2009 | 109.72 | 0.99589 | 0.99589 | 0.99589 | 0.99589 | 0.99589 | 0.99589 |
| 2010 | 112.67 | 0.92554 | 0.92554 | 0.92554 | 0.92554 | 0.92554 | 0.92554 |
| 2011 | 115.97 | 1.00316 | 1.00316 | 1.00316 | 1.00316 | 1.00316 | 1.00316 |
| 2012 | 119.34 | 1.02242 | 1.02242 | 1.02242 | 1.02242 | 1.02242 | 1.02242 |
| 2013 | 123.05 | 1.09416 | 1.09416 | 1.09416 | 1.09416 | 1.09416 | 1.09416 |
| 2014 | 126.80 | 1.16195 | 1.16195 | 1.16195 | 1.16195 | 1.16195 | 1.16195 |
| 2015 | 130.47 | 1.17080 | 1.17080 | 1.17080 | 1.17080 | 1.17080 | 1.17080 |
| 2016 | 134.23 | 1.05989 | 1.05989 | 1.05989 | 1.05989 | 1.05989 | 1.05989 |
| 2017 | 138.36 | 1.09495 | 1.09495 | 1.09495 | 1.09495 | 1.09495 | 1.09495 |
| 2018 | 142.88 | 1.18576 | 1.18576 | 1.18576 | 1.18576 | 1.18576 | 1.18576 |
| 2019 | 147.75 | 1.27289 | 1.27289 | 1.27289 | 1.27289 | 1.27289 | 1.27289 |
| 2020 | 152.92 | 1.33734 | 1.33734 | 1.33734 | 1.33734 | 1.33734 | 1.33734 |
| 2021 | 158.32 | 1.36319 | 1.36319 | 1.36319 | 1.36319 | 1.36319 | 1.36319 |
| 2022 | 163.95 | 1.38512 | 1.38512 | 1.38512 | 1.38512 | 1.38512 | 1.38512 |
| 2023 | 169.82 | 1.40767 | 1.40767 | 1.40767 | 1.40767 | 1.40767 | 1.40767 |
| 2024 | 175.93 | 1.40731 | 1.40731 | 1.40731 | 1.40731 | 1.40731 | 1.40731 |
| 2025 | 182.27 | 1.43022 | 1.43022 | 1.43022 | 1.43022 | 1.43022 | 1.43022 |

## Commercial Electric

**Commercial Electric Sales Forecast (MWh)**

| Year | Island | Jefferson | King | Kitsap | Kittitas | Pierce | Skagit | Thurston | Whatcom | Total |
|---|---|---|---|---|---|---|---|---|---|---|
| 2005 | 194,879 | 86,095 | 5,083,803 | 681,480 | 64,357 | 535,571 | 477,222 | 872,865 | 671,323 | 8,667,596 |
| 2006 | 198,148 | 88,856 | 5,131,202 | 690,723 | 65,669 | 552,002 | 488,831 | 892,234 | 693,203 | 8,800,869 |
| 2007 | 204,323 | 94,126 | 5,242,137 | 702,031 | 67,220 | 572,627 | 504,248 | 909,693 | 720,706 | 9,017,110 |
| 2008 | 209,461 | 98,088 | 5,408,223 | 713,895 | 68,598 | 598,061 | 516,237 | 933,936 | 739,671 | 9,286,169 |
| 2009 | 211,900 | 100,978 | 5,529,414 | 726,151 | 69,728 | 620,217 | 524,027 | 964,860 | 750,879 | 9,498,155 |
| 2010 | 218,339 | 106,475 | 5,681,341 | 747,008 | 72,114 | 645,605 | 541,408 | 1,000,406 | 778,367 | 9,791,062 |
| 2011 | 223,849 | 111,713 | 5,771,484 | 782,698 | 73,560 | 662,716 | 555,619 | 1,052,487 | 801,190 | 10,035,317 |
| 2012 | 232,197 | 116,022 | 5,863,828 | 817,869 | 75,835 | 687,043 | 572,817 | 1,090,479 | 828,292 | 10,284,381 |
| 2013 | 240,409 | 120,167 | 5,968,664 | 848,638 | 77,744 | 712,270 | 590,043 | 1,122,447 | 854,695 | 10,535,077 |
| 2014 | 247,454 | 124,119 | 6,081,901 | 875,229 | 79,349 | 736,148 | 606,307 | 1,151,305 | 880,633 | 10,782,444 |
| 2015 | 253,440 | 127,540 | 6,195,454 | 903,462 | 80,999 | 755,784 | 618,809 | 1,183,139 | 902,548 | 11,021,175 |
| 2016 | 260,262 | 130,638 | 6,319,674 | 936,485 | 82,709 | 775,016 | 629,598 | 1,217,808 | 920,759 | 11,272,950 |
| 2017 | 267,349 | 133,741 | 6,449,619 | 967,434 | 84,347 | 795,444 | 640,766 | 1,248,465 | 938,910 | 11,526,075 |
| 2018 | 274,086 | 136,938 | 6,584,096 | 997,679 | 85,842 | 816,804 | 652,619 | 1,279,607 | 958,150 | 11,785,822 |
| 2019 | 280,688 | 140,194 | 6,721,614 | 1,029,083 | 87,347 | 838,734 | 664,717 | 1,313,041 | 978,030 | 12,053,449 |
| 2020 | 287,553 | 143,532 | 6,861,340 | 1,061,548 | 88,946 | 861,106 | 677,008 | 1,346,794 | 998,282 | 12,326,110 |
| 2021 | 294,644 | 146,992 | 7,005,049 | 1,095,527 | 90,630 | 883,666 | 689,545 | 1,381,689 | 1,019,133 | 12,606,874 |
| 2022 | 301,429 | 150,377 | 7,166,354 | 1,120,754 | 92,717 | 904,014 | 705,423 | 1,413,505 | 1,042,601 | 12,897,173 |
| 2023 | 308,432 | 153,871 | 7,332,862 | 1,146,794 | 94,872 | 925,018 | 721,813 | 1,446,347 | 1,066,825 | 13,196,834 |
| 2024 | 315,675 | 157,484 | 7,505,058 | 1,173,724 | 97,099 | 946,740 | 738,763 | 1,480,311 | 1,091,877 | 13,506,733 |
| 2025 | 323,088 | 161,182 | 7,681,298 | 1,201,286 | 99,380 | 968,972 | 756,112 | 1,515,073 | 1,117,518 | 13,823,909 |

## Commercial Electric Customer Count Forecast

| Year | Island | Jefferson | King | Kitsap | Kittitas | Pierce | Skagit | Thurston | Whatcom | Total |
|---|---|---|---|---|---|---|---|---|---|---|
| 2005 | 4,011 | 2,666 | 51,710 | 12,334 | 1,881 | 9,797 | 7,714 | 12,683 | 11,103 | 113,900 |
| 2006 | 4,096 | 2,764 | 52,405 | 12,552 | 1,927 | 10,139 | 7,933 | 13,018 | 11,512 | 116,346 |
| 2007 | 4,209 | 2,918 | 53,363 | 12,716 | 1,967 | 10,483 | 8,157 | 13,229 | 11,929 | 118,972 |
| 2008 | 4,290 | 3,023 | 54,735 | 12,856 | 1,995 | 10,885 | 8,302 | 13,503 | 12,172 | 121,762 |
| 2009 | 4,347 | 3,117 | 56,050 | 13,097 | 2,031 | 11,307 | 8,441 | 13,972 | 12,376 | 124,738 |
| 2010 | 4,447 | 3,263 | 57,178 | 13,377 | 2,086 | 11,685 | 8,659 | 14,383 | 12,738 | 127,816 |
| 2011 | 4,543 | 3,411 | 57,872 | 13,965 | 2,120 | 11,951 | 8,853 | 15,076 | 13,063 | 130,854 |
| 2012 | 4,690 | 3,526 | 58,525 | 14,525 | 2,175 | 12,332 | 9,085 | 15,548 | 13,442 | 133,847 |
| 2013 | 4,836 | 3,637 | 59,322 | 15,008 | 2,221 | 12,732 | 9,319 | 15,937 | 13,813 | 136,823 |
| 2014 | 4,962 | 3,745 | 60,265 | 15,431 | 2,260 | 13,118 | 9,547 | 16,297 | 14,189 | 139,815 |
| 2015 | 5,076 | 3,843 | 61,307 | 15,908 | 2,303 | 13,450 | 9,731 | 16,726 | 14,522 | 142,866 |
| 2016 | 5,203 | 3,930 | 62,426 | 16,461 | 2,348 | 13,769 | 9,883 | 17,186 | 14,788 | 145,995 |
| 2017 | 5,338 | 4,018 | 63,621 | 16,982 | 2,391 | 14,112 | 10,045 | 17,594 | 15,059 | 149,160 |
| 2018 | 5,464 | 4,108 | 64,851 | 17,487 | 2,430 | 14,469 | 10,215 | 18,006 | 15,345 | 152,376 |
| 2019 | 5,586 | 4,199 | 66,097 | 18,008 | 2,468 | 14,833 | 10,387 | 18,447 | 15,637 | 155,663 |
| 2020 | 5,715 | 4,293 | 67,372 | 18,549 | 2,510 | 15,207 | 10,564 | 18,893 | 15,938 | 159,039 |
| 2021 | 5,846 | 4,389 | 68,675 | 19,113 | 2,553 | 15,581 | 10,743 | 19,352 | 16,245 | 162,498 |
| 2022 | 5,953 | 4,468 | 69,831 | 19,509 | 2,557 | 15,898 | 10,946 | 19,679 | 16,530 | 165,372 |
| 2023 | 6,035 | 4,530 | 70,793 | 19,778 | 2,592 | 16,118 | 11,097 | 19,951 | 16,758 | 167,652 |
| 2024 | 6,119 | 4,592 | 71,769 | 20,051 | 2,628 | 16,340 | 11,249 | 20,226 | 16,989 | 169,963 |
| 2025 | 6,203 | 4,656 | 72,758 | 20,327 | 2,664 | 16,565 | 11,405 | 20,504 | 17,224 | 172,306 |

## Commercial Electric Building Type Allocation

| Year | County | Dry Goods Retail | Grocery | Office | Restau-rant | Ware-house | Hospital | Hotel/ Motel | School | Univer-sity | Other |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 2005 | Island | 0.172020 | 0.030356 | 0.142423 | 0.015748 | 0.098356 | 0.085371 | 0.007183 | 0.174241 | 0.031634 | 0.242667 |
| 2006 | Island | 0.172020 | 0.030356 | 0.142423 | 0.015748 | 0.098356 | 0.085371 | 0.007183 | 0.174241 | 0.031634 | 0.242667 |
| 2007 | Island | 0.172020 | 0.030356 | 0.142423 | 0.015748 | 0.098356 | 0.085371 | 0.007183 | 0.174241 | 0.031634 | 0.242667 |
| 2008 | Island | 0.172020 | 0.030356 | 0.142423 | 0.015748 | 0.098356 | 0.085371 | 0.007183 | 0.174241 | 0.031634 | 0.242667 |
| 2009 | Island | 0.172020 | 0.030356 | 0.142423 | 0.015748 | 0.098356 | 0.085371 | 0.007183 | 0.174241 | 0.031634 | 0.242667 |
| 2010 | Island | 0.172020 | 0.030356 | 0.142423 | 0.015748 | 0.098356 | 0.085371 | 0.007183 | 0.174241 | 0.031634 | 0.242667 |

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## Commercial Electric Building Type Allocation

| Year | County | Dry Goods Retail | Grocery | Office | Restau-rant | Ware-house | Hospital | Hotel/ Motel | School | Univer-sity | Other |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 2011 | Island | 0.172020 | 0.030356 | 0.142423 | 0.015748 | 0.098356 | 0.085371 | 0.007183 | 0.174241 | 0.031634 | 0.242667 |
| 2012 | Island | 0.172020 | 0.030356 | 0.142423 | 0.015748 | 0.098356 | 0.085371 | 0.007183 | 0.174241 | 0.031634 | 0.242667 |
| 2013 | Island | 0.172020 | 0.030356 | 0.142423 | 0.015748 | 0.098356 | 0.085371 | 0.007183 | 0.174241 | 0.031634 | 0.242667 |
| 2014 | Island | 0.172020 | 0.030356 | 0.142423 | 0.015748 | 0.098356 | 0.085371 | 0.007183 | 0.174241 | 0.031634 | 0.242667 |
| 2015 | Island | 0.172020 | 0.030356 | 0.142423 | 0.015748 | 0.098356 | 0.085371 | 0.007183 | 0.174241 | 0.031634 | 0.242667 |
| 2016 | Island | 0.172020 | 0.030356 | 0.142423 | 0.015748 | 0.098356 | 0.085371 | 0.007183 | 0.174241 | 0.031634 | 0.242667 |
| 2017 | Island | 0.172020 | 0.030356 | 0.142423 | 0.015748 | 0.098356 | 0.085371 | 0.007183 | 0.174241 | 0.031634 | 0.242667 |
| 2018 | Island | 0.172020 | 0.030356 | 0.142423 | 0.015748 | 0.098356 | 0.085371 | 0.007183 | 0.174241 | 0.031634 | 0.242667 |
| 2019 | Island | 0.172020 | 0.030356 | 0.142423 | 0.015748 | 0.098356 | 0.085371 | 0.007183 | 0.174241 | 0.031634 | 0.242667 |
| 2020 | Island | 0.172020 | 0.030356 | 0.142423 | 0.015748 | 0.098356 | 0.085371 | 0.007183 | 0.174241 | 0.031634 | 0.242667 |
| 2021 | Island | 0.172020 | 0.030356 | 0.142423 | 0.015748 | 0.098356 | 0.085371 | 0.007183 | 0.174241 | 0.031634 | 0.242667 |
| 2022 | Island | 0.172020 | 0.030356 | 0.142423 | 0.015748 | 0.098356 | 0.085371 | 0.007183 | 0.174241 | 0.031634 | 0.242667 |
| 2023 | Island | 0.172020 | 0.030356 | 0.142423 | 0.015748 | 0.098356 | 0.085371 | 0.007183 | 0.174241 | 0.031634 | 0.242667 |
| 2024 | Island | 0.172020 | 0.030356 | 0.142423 | 0.015748 | 0.098356 | 0.085371 | 0.007183 | 0.174241 | 0.031634 | 0.242667 |
| 2025 | Island | 0.172020 | 0.030356 | 0.142423 | 0.015748 | 0.098356 | 0.085371 | 0.007183 | 0.174241 | 0.031634 | 0.242667 |
| 2005 | Jefferson | 0.064440 | 0.011372 | 0.068437 | 0.004867 | 0.054572 | 0.161062 | 0.128614 | 0.274779 | 0.060472 | 0.171386 |
| 2006 | Jefferson | 0.064440 | 0.011372 | 0.068437 | 0.004867 | 0.054572 | 0.161062 | 0.128614 | 0.274779 | 0.060472 | 0.171386 |
| 2007 | Jefferson | 0.064440 | 0.011372 | 0.068437 | 0.004867 | 0.054572 | 0.161062 | 0.128614 | 0.274779 | 0.060472 | 0.171386 |
| 2008 | Jefferson | 0.064440 | 0.011372 | 0.068437 | 0.004867 | 0.054572 | 0.161062 | 0.128614 | 0.274779 | 0.060472 | 0.171386 |
| 2009 | Jefferson | 0.064440 | 0.011372 | 0.068437 | 0.004867 | 0.054572 | 0.161062 | 0.128614 | 0.274779 | 0.060472 | 0.171386 |
| 2010 | Jefferson | 0.064440 | 0.011372 | 0.068437 | 0.004867 | 0.054572 | 0.161062 | 0.128614 | 0.274779 | 0.060472 | 0.171386 |
| 2011 | Jefferson | 0.064440 | 0.011372 | 0.068437 | 0.004867 | 0.054572 | 0.161062 | 0.128614 | 0.274779 | 0.060472 | 0.171386 |
| 2012 | Jefferson | 0.064440 | 0.011372 | 0.068437 | 0.004867 | 0.054572 | 0.161062 | 0.128614 | 0.274779 | 0.060472 | 0.171386 |
| 2013 | Jefferson | 0.064440 | 0.011372 | 0.068437 | 0.004867 | 0.054572 | 0.161062 | 0.128614 | 0.274779 | 0.060472 | 0.171386 |
| 2014 | Jefferson | 0.064440 | 0.011372 | 0.068437 | 0.004867 | 0.054572 | 0.161062 | 0.128614 | 0.274779 | 0.060472 | 0.171386 |
| 2015 | Jefferson | 0.064440 | 0.011372 | 0.068437 | 0.004867 | 0.054572 | 0.161062 | 0.128614 | 0.274779 | 0.060472 | 0.171386 |
| 2016 | Jefferson | 0.064440 | 0.011372 | 0.068437 | 0.004867 | 0.054572 | 0.161062 | 0.128614 | 0.274779 | 0.060472 | 0.171386 |
| 2017 | Jefferson | 0.064440 | 0.011372 | 0.068437 | 0.004867 | 0.054572 | 0.161062 | 0.128614 | 0.274779 | 0.060472 | 0.171386 |
| 2018 | Jefferson | 0.064440 | 0.011372 | 0.068437 | 0.004867 | 0.054572 | 0.161062 | 0.128614 | 0.274779 | 0.060472 | 0.171386 |
| 2019 | Jefferson | 0.064440 | 0.011372 | 0.068437 | 0.004867 | 0.054572 | 0.161062 | 0.128614 | 0.274779 | 0.060472 | 0.171386 |
| 2020 | Jefferson | 0.064440 | 0.011372 | 0.068437 | 0.004867 | 0.054572 | 0.161062 | 0.128614 | 0.274779 | 0.060472 | 0.171386 |
| 2021 | Jefferson | 0.064440 | 0.011372 | 0.068437 | 0.004867 | 0.054572 | 0.161062 | 0.128614 | 0.274779 | 0.060472 | 0.171386 |
| 2022 | Jefferson | 0.064440 | 0.011372 | 0.068437 | 0.004867 | 0.054572 | 0.161062 | 0.128614 | 0.274779 | 0.060472 | 0.171386 |
| 2023 | Jefferson | 0.064440 | 0.011372 | 0.068437 | 0.004867 | 0.054572 | 0.161062 | 0.128614 | 0.274779 | 0.060472 | 0.171386 |

## Commercial Electric Building Type Allocation

| Year | County | Dry Goods Retail | Grocery | Office | Restau-rant | Ware-house | Hospital | Hotel/ Motel | School | Univer-sity | Other |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 2024 | Jefferson | 0.064440 | 0.011372 | 0.068437 | 0.004867 | 0.054572 | 0.161062 | 0.128614 | 0.274779 | 0.060472 | 0.171386 |
| 2025 | Jefferson | 0.064440 | 0.011372 | 0.068437 | 0.004867 | 0.054572 | 0.161062 | 0.128614 | 0.274779 | 0.060472 | 0.171386 |
| 2005 | King | 0.104450 | 0.018432 | 0.252147 | 0.006858 | 0.120457 | 0.041644 | 0.047810 | 0.054901 | 0.021634 | 0.331668 |
| 2006 | King | 0.104450 | 0.018432 | 0.252147 | 0.006858 | 0.120457 | 0.041644 | 0.047810 | 0.054901 | 0.021634 | 0.331668 |
| 2007 | King | 0.104450 | 0.018432 | 0.252147 | 0.006858 | 0.120457 | 0.041644 | 0.047810 | 0.054901 | 0.021634 | 0.331668 |
| 2008 | King | 0.104450 | 0.018432 | 0.252147 | 0.006858 | 0.120457 | 0.041644 | 0.047810 | 0.054901 | 0.021634 | 0.331668 |
| 2009 | King | 0.104450 | 0.018432 | 0.252147 | 0.006858 | 0.120457 | 0.041644 | 0.047810 | 0.054901 | 0.021634 | 0.331668 |
| 2010 | King | 0.104450 | 0.018432 | 0.252147 | 0.006858 | 0.120457 | 0.041644 | 0.047810 | 0.054901 | 0.021634 | 0.331668 |
| 2011 | King | 0.104450 | 0.018432 | 0.252147 | 0.006858 | 0.120457 | 0.041644 | 0.047810 | 0.054901 | 0.021634 | 0.331668 |
| 2012 | King | 0.104450 | 0.018432 | 0.252147 | 0.006858 | 0.120457 | 0.041644 | 0.047810 | 0.054901 | 0.021634 | 0.331668 |
| 2013 | King | 0.104450 | 0.018432 | 0.252147 | 0.006858 | 0.120457 | 0.041644 | 0.047810 | 0.054901 | 0.021634 | 0.331668 |
| 2014 | King | 0.104450 | 0.018432 | 0.252147 | 0.006858 | 0.120457 | 0.041644 | 0.047810 | 0.054901 | 0.021634 | 0.331668 |
| 2015 | King | 0.104450 | 0.018432 | 0.252147 | 0.006858 | 0.120457 | 0.041644 | 0.047810 | 0.054901 | 0.021634 | 0.331668 |
| 2016 | King | 0.104450 | 0.018432 | 0.252147 | 0.006858 | 0.120457 | 0.041644 | 0.047810 | 0.054901 | 0.021634 | 0.331668 |
| 2017 | King | 0.104450 | 0.018432 | 0.252147 | 0.006858 | 0.120457 | 0.041644 | 0.047810 | 0.054901 | 0.021634 | 0.331668 |
| 2018 | King | 0.104450 | 0.018432 | 0.252147 | 0.006858 | 0.120457 | 0.041644 | 0.047810 | 0.054901 | 0.021634 | 0.331668 |
| 2019 | King | 0.104450 | 0.018432 | 0.252147 | 0.006858 | 0.120457 | 0.041644 | 0.047810 | 0.054901 | 0.021634 | 0.331668 |
| 2020 | King | 0.104450 | 0.018432 | 0.252147 | 0.006858 | 0.120457 | 0.041644 | 0.047810 | 0.054901 | 0.021634 | 0.331668 |
| 2021 | King | 0.104450 | 0.018432 | 0.252147 | 0.006858 | 0.120457 | 0.041644 | 0.047810 | 0.054901 | 0.021634 | 0.331668 |
| 2022 | King | 0.104450 | 0.018432 | 0.252147 | 0.006858 | 0.120457 | 0.041644 | 0.047810 | 0.054901 | 0.021634 | 0.331668 |
| 2023 | King | 0.104450 | 0.018432 | 0.252147 | 0.006858 | 0.120457 | 0.041644 | 0.047810 | 0.054901 | 0.021634 | 0.331668 |
| 2024 | King | 0.104450 | 0.018432 | 0.252147 | 0.006858 | 0.120457 | 0.041644 | 0.047810 | 0.054901 | 0.021634 | 0.331668 |
| 2025 | King | 0.104450 | 0.018432 | 0.252147 | 0.006858 | 0.120457 | 0.041644 | 0.047810 | 0.054901 | 0.021634 | 0.331668 |
| 2005 | Kitsap | 0.246691 | 0.043534 | 0.101196 | 0.010705 | 0.055223 | 0.102951 | 0.009493 | 0.157107 | 0.003093 | 0.270007 |
| 2006 | Kitsap | 0.246691 | 0.043534 | 0.101196 | 0.010705 | 0.055223 | 0.102951 | 0.009493 | 0.157107 | 0.003093 | 0.270007 |
| 2007 | Kitsap | 0.246691 | 0.043534 | 0.101196 | 0.010705 | 0.055223 | 0.102951 | 0.009493 | 0.157107 | 0.003093 | 0.270007 |
| 2008 | Kitsap | 0.246691 | 0.043534 | 0.101196 | 0.010705 | 0.055223 | 0.102951 | 0.009493 | 0.157107 | 0.003093 | 0.270007 |
| 2009 | Kitsap | 0.246691 | 0.043534 | 0.101196 | 0.010705 | 0.055223 | 0.102951 | 0.009493 | 0.157107 | 0.003093 | 0.270007 |
| 2010 | Kitsap | 0.246691 | 0.043534 | 0.101196 | 0.010705 | 0.055223 | 0.102951 | 0.009493 | 0.157107 | 0.003093 | 0.270007 |
| 2011 | Kitsap | 0.246691 | 0.043534 | 0.101196 | 0.010705 | 0.055223 | 0.102951 | 0.009493 | 0.157107 | 0.003093 | 0.270007 |
| 2012 | Kitsap | 0.246691 | 0.043534 | 0.101196 | 0.010705 | 0.055223 | 0.102951 | 0.009493 | 0.157107 | 0.003093 | 0.270007 |
| 2013 | Kitsap | 0.246691 | 0.043534 | 0.101196 | 0.010705 | 0.055223 | 0.102951 | 0.009493 | 0.157107 | 0.003093 | 0.270007 |
| 2014 | Kitsap | 0.246691 | 0.043534 | 0.101196 | 0.010705 | 0.055223 | 0.102951 | 0.009493 | 0.157107 | 0.003093 | 0.270007 |
| 2015 | Kitsap | 0.246691 | 0.043534 | 0.101196 | 0.010705 | 0.055223 | 0.102951 | 0.009493 | 0.157107 | 0.003093 | 0.270007 |

## Commercial Electric Building Type Allocation

| Year | County | Dry Goods Retail | Grocery | Office | Restau-rant | Ware-house | Hospital | Hotel/ Motel | School | Univer-sity | Other |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 2016 | Kitsap | 0.246691 | 0.043534 | 0.101196 | 0.010705 | 0.055223 | 0.102951 | 0.009493 | 0.157107 | 0.003093 | 0.270007 |
| 2017 | Kitsap | 0.246691 | 0.043534 | 0.101196 | 0.010705 | 0.055223 | 0.102951 | 0.009493 | 0.157107 | 0.003093 | 0.270007 |
| 2018 | Kitsap | 0.246691 | 0.043534 | 0.101196 | 0.010705 | 0.055223 | 0.102951 | 0.009493 | 0.157107 | 0.003093 | 0.270007 |
| 2019 | Kitsap | 0.246691 | 0.043534 | 0.101196 | 0.010705 | 0.055223 | 0.102951 | 0.009493 | 0.157107 | 0.003093 | 0.270007 |
| 2020 | Kitsap | 0.246691 | 0.043534 | 0.101196 | 0.010705 | 0.055223 | 0.102951 | 0.009493 | 0.157107 | 0.003093 | 0.270007 |
| 2021 | Kitsap | 0.246691 | 0.043534 | 0.101196 | 0.010705 | 0.055223 | 0.102951 | 0.009493 | 0.157107 | 0.003093 | 0.270007 |
| 2022 | Kitsap | 0.246691 | 0.043534 | 0.101196 | 0.010705 | 0.055223 | 0.102951 | 0.009493 | 0.157107 | 0.003093 | 0.270007 |
| 2023 | Kitsap | 0.246691 | 0.043534 | 0.101196 | 0.010705 | 0.055223 | 0.102951 | 0.009493 | 0.157107 | 0.003093 | 0.270007 |
| 2024 | Kitsap | 0.246691 | 0.043534 | 0.101196 | 0.010705 | 0.055223 | 0.102951 | 0.009493 | 0.157107 | 0.003093 | 0.270007 |
| 2025 | Kitsap | 0.246691 | 0.043534 | 0.101196 | 0.010705 | 0.055223 | 0.102951 | 0.009493 | 0.157107 | 0.003093 | 0.270007 |
| 2005 | Kittitas | 0.214310 | 0.037819 | 0.018725 | 0.005524 | 0.057017 | 0.048685 | 0.080985 | 0.214680 | 0.239678 | 0.082577 |
| 2006 | Kittitas | 0.214310 | 0.037819 | 0.018725 | 0.005524 | 0.057017 | 0.048685 | 0.080985 | 0.214680 | 0.239678 | 0.082577 |
| 2007 | Kittitas | 0.214310 | 0.037819 | 0.018725 | 0.005524 | 0.057017 | 0.048685 | 0.080985 | 0.214680 | 0.239678 | 0.082577 |
| 2008 | Kittitas | 0.214310 | 0.037819 | 0.018725 | 0.005524 | 0.057017 | 0.048685 | 0.080985 | 0.214680 | 0.239678 | 0.082577 |
| 2009 | Kittitas | 0.214310 | 0.037819 | 0.018725 | 0.005524 | 0.057017 | 0.048685 | 0.080985 | 0.214680 | 0.239678 | 0.082577 |
| 2010 | Kittitas | 0.214310 | 0.037819 | 0.018725 | 0.005524 | 0.057017 | 0.048685 | 0.080985 | 0.214680 | 0.239678 | 0.082577 |
| 2011 | Kittitas | 0.214310 | 0.037819 | 0.018725 | 0.005524 | 0.057017 | 0.048685 | 0.080985 | 0.214680 | 0.239678 | 0.082577 |
| 2012 | Kittitas | 0.214310 | 0.037819 | 0.018725 | 0.005524 | 0.057017 | 0.048685 | 0.080985 | 0.214680 | 0.239678 | 0.082577 |
| 2013 | Kittitas | 0.214310 | 0.037819 | 0.018725 | 0.005524 | 0.057017 | 0.048685 | 0.080985 | 0.214680 | 0.239678 | 0.082577 |
| 2014 | Kittitas | 0.214310 | 0.037819 | 0.018725 | 0.005524 | 0.057017 | 0.048685 | 0.080985 | 0.214680 | 0.239678 | 0.082577 |
| 2015 | Kittitas | 0.214310 | 0.037819 | 0.018725 | 0.005524 | 0.057017 | 0.048685 | 0.080985 | 0.214680 | 0.239678 | 0.082577 |
| 2016 | Kittitas | 0.214310 | 0.037819 | 0.018725 | 0.005524 | 0.057017 | 0.048685 | 0.080985 | 0.214680 | 0.239678 | 0.082577 |
| 2017 | Kittitas | 0.214310 | 0.037819 | 0.018725 | 0.005524 | 0.057017 | 0.048685 | 0.080985 | 0.214680 | 0.239678 | 0.082577 |
| 2018 | Kittitas | 0.214310 | 0.037819 | 0.018725 | 0.005524 | 0.057017 | 0.048685 | 0.080985 | 0.214680 | 0.239678 | 0.082577 |
| 2019 | Kittitas | 0.214310 | 0.037819 | 0.018725 | 0.005524 | 0.057017 | 0.048685 | 0.080985 | 0.214680 | 0.239678 | 0.082577 |
| 2020 | Kittitas | 0.214310 | 0.037819 | 0.018725 | 0.005524 | 0.057017 | 0.048685 | 0.080985 | 0.214680 | 0.239678 | 0.082577 |
| 2021 | Kittitas | 0.214310 | 0.037819 | 0.018725 | 0.005524 | 0.057017 | 0.048685 | 0.080985 | 0.214680 | 0.239678 | 0.082577 |
| 2022 | Kittitas | 0.214310 | 0.037819 | 0.018725 | 0.005524 | 0.057017 | 0.048685 | 0.080985 | 0.214680 | 0.239678 | 0.082577 |
| 2023 | Kittitas | 0.214310 | 0.037819 | 0.018725 | 0.005524 | 0.057017 | 0.048685 | 0.080985 | 0.214680 | 0.239678 | 0.082577 |
| 2024 | Kittitas | 0.214310 | 0.037819 | 0.018725 | 0.005524 | 0.057017 | 0.048685 | 0.080985 | 0.214680 | 0.239678 | 0.082577 |
| 2025 | Kittitas | 0.214310 | 0.037819 | 0.018725 | 0.005524 | 0.057017 | 0.048685 | 0.080985 | 0.214680 | 0.239678 | 0.082577 |
| 2005 | Pierce | 0.173205 | 0.030566 | 0.131323 | 0.010872 | 0.228504 | 0.071500 | 0.017294 | 0.104852 | 0.012382 | 0.219503 |
| 2006 | Pierce | 0.173205 | 0.030566 | 0.131323 | 0.010872 | 0.228504 | 0.071500 | 0.017294 | 0.104852 | 0.012382 | 0.219503 |
| 2007 | Pierce | 0.173205 | 0.030566 | 0.131323 | 0.010872 | 0.228504 | 0.071500 | 0.017294 | 0.104852 | 0.012382 | 0.219503 |

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## Commercial Electric Building Type Allocation

| Year | County | Dry Goods Retail | Grocery | Office | Restau-rant | Ware-house | Hospital | Hotel/ Motel | School | Univer-sity | Other |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 2008 | Pierce | 0.173205 | 0.030566 | 0.131323 | 0.010872 | 0.228504 | 0.071500 | 0.017294 | 0.104852 | 0.012382 | 0.219503 |
| 2009 | Pierce | 0.173205 | 0.030566 | 0.131323 | 0.010872 | 0.228504 | 0.071500 | 0.017294 | 0.104852 | 0.012382 | 0.219503 |
| 2010 | Pierce | 0.173205 | 0.030566 | 0.131323 | 0.010872 | 0.228504 | 0.071500 | 0.017294 | 0.104852 | 0.012382 | 0.219503 |
| 2011 | Pierce | 0.173205 | 0.030566 | 0.131323 | 0.010872 | 0.228504 | 0.071500 | 0.017294 | 0.104852 | 0.012382 | 0.219503 |
| 2012 | Pierce | 0.173205 | 0.030566 | 0.131323 | 0.010872 | 0.228504 | 0.071500 | 0.017294 | 0.104852 | 0.012382 | 0.219503 |
| 2013 | Pierce | 0.173205 | 0.030566 | 0.131323 | 0.010872 | 0.228504 | 0.071500 | 0.017294 | 0.104852 | 0.012382 | 0.219503 |
| 2014 | Pierce | 0.173205 | 0.030566 | 0.131323 | 0.010872 | 0.228504 | 0.071500 | 0.017294 | 0.104852 | 0.012382 | 0.219503 |
| 2015 | Pierce | 0.173205 | 0.030566 | 0.131323 | 0.010872 | 0.228504 | 0.071500 | 0.017294 | 0.104852 | 0.012382 | 0.219503 |
| 2016 | Pierce | 0.173205 | 0.030566 | 0.131323 | 0.010872 | 0.228504 | 0.071500 | 0.017294 | 0.104852 | 0.012382 | 0.219503 |
| 2017 | Pierce | 0.173205 | 0.030566 | 0.131323 | 0.010872 | 0.228504 | 0.071500 | 0.017294 | 0.104852 | 0.012382 | 0.219503 |
| 2018 | Pierce | 0.173205 | 0.030566 | 0.131323 | 0.010872 | 0.228504 | 0.071500 | 0.017294 | 0.104852 | 0.012382 | 0.219503 |
| 2019 | Pierce | 0.173205 | 0.030566 | 0.131323 | 0.010872 | 0.228504 | 0.071500 | 0.017294 | 0.104852 | 0.012382 | 0.219503 |
| 2020 | Pierce | 0.173205 | 0.030566 | 0.131323 | 0.010872 | 0.228504 | 0.071500 | 0.017294 | 0.104852 | 0.012382 | 0.219503 |
| 2021 | Pierce | 0.173205 | 0.030566 | 0.131323 | 0.010872 | 0.228504 | 0.071500 | 0.017294 | 0.104852 | 0.012382 | 0.219503 |
| 2022 | Pierce | 0.173205 | 0.030566 | 0.131323 | 0.010872 | 0.228504 | 0.071500 | 0.017294 | 0.104852 | 0.012382 | 0.219503 |
| 2023 | Pierce | 0.173205 | 0.030566 | 0.131323 | 0.010872 | 0.228504 | 0.071500 | 0.017294 | 0.104852 | 0.012382 | 0.219503 |
| 2024 | Pierce | 0.173205 | 0.030566 | 0.131323 | 0.010872 | 0.228504 | 0.071500 | 0.017294 | 0.104852 | 0.012382 | 0.219503 |
| 2025 | Pierce | 0.173205 | 0.030566 | 0.131323 | 0.010872 | 0.228504 | 0.071500 | 0.017294 | 0.104852 | 0.012382 | 0.219503 |
| 2005 | Skagit | 0.272020 | 0.048004 | 0.092464 | 0.011480 | 0.195768 | 0.083520 | 0.034286 | 0.074339 | 0.005698 | 0.182421 |
| 2006 | Skagit | 0.272020 | 0.048004 | 0.092464 | 0.011480 | 0.195768 | 0.083520 | 0.034286 | 0.074339 | 0.005698 | 0.182421 |
| 2007 | Skagit | 0.272020 | 0.048004 | 0.092464 | 0.011480 | 0.195768 | 0.083520 | 0.034286 | 0.074339 | 0.005698 | 0.182421 |
| 2008 | Skagit | 0.272020 | 0.048004 | 0.092464 | 0.011480 | 0.195768 | 0.083520 | 0.034286 | 0.074339 | 0.005698 | 0.182421 |
| 2009 | Skagit | 0.272020 | 0.048004 | 0.092464 | 0.011480 | 0.195768 | 0.083520 | 0.034286 | 0.074339 | 0.005698 | 0.182421 |
| 2010 | Skagit | 0.272020 | 0.048004 | 0.092464 | 0.011480 | 0.195768 | 0.083520 | 0.034286 | 0.074339 | 0.005698 | 0.182421 |
| 2011 | Skagit | 0.272020 | 0.048004 | 0.092464 | 0.011480 | 0.195768 | 0.083520 | 0.034286 | 0.074339 | 0.005698 | 0.182421 |
| 2012 | Skagit | 0.272020 | 0.048004 | 0.092464 | 0.011480 | 0.195768 | 0.083520 | 0.034286 | 0.074339 | 0.005698 | 0.182421 |
| 2013 | Skagit | 0.272020 | 0.048004 | 0.092464 | 0.011480 | 0.195768 | 0.083520 | 0.034286 | 0.074339 | 0.005698 | 0.182421 |
| 2014 | Skagit | 0.272020 | 0.048004 | 0.092464 | 0.011480 | 0.195768 | 0.083520 | 0.034286 | 0.074339 | 0.005698 | 0.182421 |
| 2015 | Skagit | 0.272020 | 0.048004 | 0.092464 | 0.011480 | 0.195768 | 0.083520 | 0.034286 | 0.074339 | 0.005698 | 0.182421 |
| 2016 | Skagit | 0.272020 | 0.048004 | 0.092464 | 0.011480 | 0.195768 | 0.083520 | 0.034286 | 0.074339 | 0.005698 | 0.182421 |
| 2017 | Skagit | 0.272020 | 0.048004 | 0.092464 | 0.011480 | 0.195768 | 0.083520 | 0.034286 | 0.074339 | 0.005698 | 0.182421 |
| 2018 | Skagit | 0.272020 | 0.048004 | 0.092464 | 0.011480 | 0.195768 | 0.083520 | 0.034286 | 0.074339 | 0.005698 | 0.182421 |
| 2019 | Skagit | 0.272020 | 0.048004 | 0.092464 | 0.011480 | 0.195768 | 0.083520 | 0.034286 | 0.074339 | 0.005698 | 0.182421 |
| 2020 | Skagit | 0.272020 | 0.048004 | 0.092464 | 0.011480 | 0.195768 | 0.083520 | 0.034286 | 0.074339 | 0.005698 | 0.182421 |

## Commercial Electric Building Type Allocation

| Year | County | Dry Goods Retail | Grocery | Office | Restau-rant | Ware-house | Hospital | Hotel/ Motel | School | Univer-sity | Other |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 2021 | Skagit | 0.272020 | 0.048004 | 0.092464 | 0.011480 | 0.195768 | 0.083520 | 0.034286 | 0.074339 | 0.005698 | 0.182421 |
| 2022 | Skagit | 0.272020 | 0.048004 | 0.092464 | 0.011480 | 0.195768 | 0.083520 | 0.034286 | 0.074339 | 0.005698 | 0.182421 |
| 2023 | Skagit | 0.272020 | 0.048004 | 0.092464 | 0.011480 | 0.195768 | 0.083520 | 0.034286 | 0.074339 | 0.005698 | 0.182421 |
| 2024 | Skagit | 0.272020 | 0.048004 | 0.092464 | 0.011480 | 0.195768 | 0.083520 | 0.034286 | 0.074339 | 0.005698 | 0.182421 |
| 2025 | Skagit | 0.272020 | 0.048004 | 0.092464 | 0.011480 | 0.195768 | 0.083520 | 0.034286 | 0.074339 | 0.005698 | 0.182421 |
| 2005 | Thurston | 0.159739 | 0.028189 | 0.212291 | 0.011545 | 0.199104 | 0.064561 | 0.032951 | 0.115326 | 0.018908 | 0.157386 |
| 2006 | Thurston | 0.159739 | 0.028189 | 0.212291 | 0.011545 | 0.199104 | 0.064561 | 0.032951 | 0.115326 | 0.018908 | 0.157386 |
| 2007 | Thurston | 0.159739 | 0.028189 | 0.212291 | 0.011545 | 0.199104 | 0.064561 | 0.032951 | 0.115326 | 0.018908 | 0.157386 |
| 2008 | Thurston | 0.159739 | 0.028189 | 0.212291 | 0.011545 | 0.199104 | 0.064561 | 0.032951 | 0.115326 | 0.018908 | 0.157386 |
| 2009 | Thurston | 0.159739 | 0.028189 | 0.212291 | 0.011545 | 0.199104 | 0.064561 | 0.032951 | 0.115326 | 0.018908 | 0.157386 |
| 2010 | Thurston | 0.159739 | 0.028189 | 0.212291 | 0.011545 | 0.199104 | 0.064561 | 0.032951 | 0.115326 | 0.018908 | 0.157386 |
| 2011 | Thurston | 0.159739 | 0.028189 | 0.212291 | 0.011545 | 0.199104 | 0.064561 | 0.032951 | 0.115326 | 0.018908 | 0.157386 |
| 2012 | Thurston | 0.159739 | 0.028189 | 0.212291 | 0.011545 | 0.199104 | 0.064561 | 0.032951 | 0.115326 | 0.018908 | 0.157386 |
| 2013 | Thurston | 0.159739 | 0.028189 | 0.212291 | 0.011545 | 0.199104 | 0.064561 | 0.032951 | 0.115326 | 0.018908 | 0.157386 |
| 2014 | Thurston | 0.159739 | 0.028189 | 0.212291 | 0.011545 | 0.199104 | 0.064561 | 0.032951 | 0.115326 | 0.018908 | 0.157386 |
| 2015 | Thurston | 0.159739 | 0.028189 | 0.212291 | 0.011545 | 0.199104 | 0.064561 | 0.032951 | 0.115326 | 0.018908 | 0.157386 |
| 2016 | Thurston | 0.159739 | 0.028189 | 0.212291 | 0.011545 | 0.199104 | 0.064561 | 0.032951 | 0.115326 | 0.018908 | 0.157386 |
| 2017 | Thurston | 0.159739 | 0.028189 | 0.212291 | 0.011545 | 0.199104 | 0.064561 | 0.032951 | 0.115326 | 0.018908 | 0.157386 |
| 2018 | Thurston | 0.159739 | 0.028189 | 0.212291 | 0.011545 | 0.199104 | 0.064561 | 0.032951 | 0.115326 | 0.018908 | 0.157386 |
| 2019 | Thurston | 0.159739 | 0.028189 | 0.212291 | 0.011545 | 0.199104 | 0.064561 | 0.032951 | 0.115326 | 0.018908 | 0.157386 |
| 2020 | Thurston | 0.159739 | 0.028189 | 0.212291 | 0.011545 | 0.199104 | 0.064561 | 0.032951 | 0.115326 | 0.018908 | 0.157386 |
| 2021 | Thurston | 0.159739 | 0.028189 | 0.212291 | 0.011545 | 0.199104 | 0.064561 | 0.032951 | 0.115326 | 0.018908 | 0.157386 |
| 2022 | Thurston | 0.159739 | 0.028189 | 0.212291 | 0.011545 | 0.199104 | 0.064561 | 0.032951 | 0.115326 | 0.018908 | 0.157386 |
| 2023 | Thurston | 0.159739 | 0.028189 | 0.212291 | 0.011545 | 0.199104 | 0.064561 | 0.032951 | 0.115326 | 0.018908 | 0.157386 |
| 2024 | Thurston | 0.159739 | 0.028189 | 0.212291 | 0.011545 | 0.199104 | 0.064561 | 0.032951 | 0.115326 | 0.018908 | 0.157386 |
| 2025 | Thurston | 0.159739 | 0.028189 | 0.212291 | 0.011545 | 0.199104 | 0.064561 | 0.032951 | 0.115326 | 0.018908 | 0.157386 |
| 2005 | Whatcom | 0.299755 | 0.052898 | 0.123137 | 0.017978 | 0.138547 | 0.075238 | 0.045420 | 0.016278 | 0.045022 | 0.185726 |
| 2006 | Whatcom | 0.299755 | 0.052898 | 0.123137 | 0.017978 | 0.138547 | 0.075238 | 0.045420 | 0.016278 | 0.045022 | 0.185726 |
| 2007 | Whatcom | 0.299755 | 0.052898 | 0.123137 | 0.017978 | 0.138547 | 0.075238 | 0.045420 | 0.016278 | 0.045022 | 0.185726 |
| 2008 | Whatcom | 0.299755 | 0.052898 | 0.123137 | 0.017978 | 0.138547 | 0.075238 | 0.045420 | 0.016278 | 0.045022 | 0.185726 |
| 2009 | Whatcom | 0.299755 | 0.052898 | 0.123137 | 0.017978 | 0.138547 | 0.075238 | 0.045420 | 0.016278 | 0.045022 | 0.185726 |
| 2010 | Whatcom | 0.299755 | 0.052898 | 0.123137 | 0.017978 | 0.138547 | 0.075238 | 0.045420 | 0.016278 | 0.045022 | 0.185726 |
| 2011 | Whatcom | 0.299755 | 0.052898 | 0.123137 | 0.017978 | 0.138547 | 0.075238 | 0.045420 | 0.016278 | 0.045022 | 0.185726 |
| 2012 | Whatcom | 0.299755 | 0.052898 | 0.123137 | 0.017978 | 0.138547 | 0.075238 | 0.045420 | 0.016278 | 0.045022 | 0.185726 |

## Commercial Electric Building Type Allocation

| Year | County | Dry Goods Retail | Grocery | Office | Restau-rant | Ware-house | Hospital | Hotel/ Motel | School | Univer-sity | Other |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 2013 | Whatcom | 0.299755 | 0.052898 | 0.123137 | 0.017978 | 0.138547 | 0.075238 | 0.045420 | 0.016278 | 0.045022 | 0.185726 |
| 2014 | Whatcom | 0.299755 | 0.052898 | 0.123137 | 0.017978 | 0.138547 | 0.075238 | 0.045420 | 0.016278 | 0.045022 | 0.185726 |
| 2015 | Whatcom | 0.299755 | 0.052898 | 0.123137 | 0.017978 | 0.138547 | 0.075238 | 0.045420 | 0.016278 | 0.045022 | 0.185726 |
| 2016 | Whatcom | 0.299755 | 0.052898 | 0.123137 | 0.017978 | 0.138547 | 0.075238 | 0.045420 | 0.016278 | 0.045022 | 0.185726 |
| 2017 | Whatcom | 0.299755 | 0.052898 | 0.123137 | 0.017978 | 0.138547 | 0.075238 | 0.045420 | 0.016278 | 0.045022 | 0.185726 |
| 2018 | Whatcom | 0.299755 | 0.052898 | 0.123137 | 0.017978 | 0.138547 | 0.075238 | 0.045420 | 0.016278 | 0.045022 | 0.185726 |
| 2019 | Whatcom | 0.299755 | 0.052898 | 0.123137 | 0.017978 | 0.138547 | 0.075238 | 0.045420 | 0.016278 | 0.045022 | 0.185726 |
| 2020 | Whatcom | 0.299755 | 0.052898 | 0.123137 | 0.017978 | 0.138547 | 0.075238 | 0.045420 | 0.016278 | 0.045022 | 0.185726 |
| 2021 | Whatcom | 0.299755 | 0.052898 | 0.123137 | 0.017978 | 0.138547 | 0.075238 | 0.045420 | 0.016278 | 0.045022 | 0.185726 |
| 2022 | Whatcom | 0.299755 | 0.052898 | 0.123137 | 0.017978 | 0.138547 | 0.075238 | 0.045420 | 0.016278 | 0.045022 | 0.185726 |
| 2023 | Whatcom | 0.299755 | 0.052898 | 0.123137 | 0.017978 | 0.138547 | 0.075238 | 0.045420 | 0.016278 | 0.045022 | 0.185726 |
| 2024 | Whatcom | 0.299755 | 0.052898 | 0.123137 | 0.017978 | 0.138547 | 0.075238 | 0.045420 | 0.016278 | 0.045022 | 0.185726 |
| 2025 | Whatcom | 0.299755 | 0.052898 | 0.123137 | 0.017978 | 0.138547 | 0.075238 | 0.045420 | 0.016278 | 0.045022 | 0.185726 |

## Commercial Electric Efficiency Shares

| bName | nName | fName | Stock | Standard | High | Premium |
|---|---|---|---|---|---|---|
| Dry_Goods_Retail | Cooling_Chillers | Electric | 0.515 | 0.456 | 0.023 | 0.007 |
| Dry_Goods_Retail | Cooling_DX | Electric | 0.515 | 0.456 | 0.023 | 0.007 |
| Dry_Goods_Retail | Cooling_HeatPump | Electric | 0.515 | 0.456 | 0.023 | 0.007 |
| Dry_Goods_Retail | Lighting_2L4T12 | Electric | 0.900 | 0.050 | 0.030 | 0.020 |
| Dry_Goods_Retail | Lighting_2L4T8 | Electric | 0.900 | 0.050 | 0.030 | 0.020 |
| Dry_Goods_Retail | Lighting_2L8T12 | Electric | 0.900 | 0.050 | 0.030 | 0.020 |
| Dry_Goods_Retail | Lighting_3L4T12 | Electric | 0.900 | 0.050 | 0.030 | 0.020 |
| Dry_Goods_Retail | Lighting_3L4T8 | Electric | 0.9000 | 0.0900 | 0.0075 | 0.0025 |
| Dry_Goods_Retail | Lighting_4L4T12 | Electric | 0.900 | 0.050 | 0.030 | 0.020 |
| Dry_Goods_Retail | Lighting_4L4T8 | Electric | 0.900 | 0.090 | 0.008 | 0.003 |
| Dry_Goods_Retail | Lighting_INC150W | Electric | 0.900 | 0.050 | 0.030 | 0.020 |
| Dry_Goods_Retail | Lighting_INC75W | Electric | 0.900 | 0.050 | 0.030 | 0.020 |
| Dry_Goods_Retail | Lighting_MV400W | Electric | 0.900 | 0.050 | 0.030 | 0.020 |
| Dry_Goods_Retail | Other | Electric | 1.000 | - - - | - - - | - - - |
| Dry_Goods_Retail | Plug_Load | Electric | 0.950 | 0.050 | - - - | - - - |
| Dry_Goods_Retail | Space_Heat | Electric | 1.000 | - - - | - - - | - - - |

## Commercial Electric Efficiency Shares

| bName | nName | fName | Stock | Standard | High | Premium |
|---|---|---|---|---|---|---|
| Dry_Goods_Retail | Space_Heat | Gas | 1.000 | - - - | - - - | - - - |
| Dry_Goods_Retail | Ventilation | Electric | 0.550 | 0.400 | 0.050 | - - - |
| Dry_Goods_Retail | Water_Heat | Electric | 0.700 | 0.225 | 0.045 | 0.030 |
| Dry_Goods_Retail | Water_Heat | Gas | 1.000 | - - - | - - - | - - - |
| Grocery | Cooking | Electric | 0.950 | 0.050 | - - - | - - - |
| Grocery | Cooking | Gas | 1.000 | - - - | - - - | - - - |
| Grocery | Cooling_Chillers | Electric | 0.515 | 0.456 | 0.023 | 0.007 |
| Grocery | Cooling_DX | Electric | 0.515 | 0.456 | 0.023 | 0.007 |
| Grocery | Cooling_HeatPump | Electric | 0.515 | 0.456 | 0.023 | 0.007 |
| Grocery | Lighting_2L4T12 | Electric | 0.900 | 0.050 | 0.030 | 0.020 |
| Grocery | Lighting_2L4T8 | Electric | 0.900 | 0.050 | 0.030 | 0.020 |
| Grocery | Lighting_2L8T12 | Electric | 0.900 | 0.050 | 0.030 | 0.020 |
| Grocery | Lighting_3L4T12 | Electric | 0.900 | 0.050 | 0.030 | 0.020 |
| Grocery | Lighting_3L4T8 | Electric | 0.9000 | 0.0900 | 0.0075 | 0.0025 |
| Grocery | Lighting_4L4T12 | Electric | 0.900 | 0.050 | 0.030 | 0.020 |
| Grocery | Lighting_4L4T8 | Electric | 0.900 | 0.090 | 0.008 | 0.003 |
| Grocery | Lighting_INC150W | Electric | 0.900 | 0.050 | 0.030 | 0.020 |
| Grocery | Lighting_INC75W | Electric | 0.900 | 0.050 | 0.030 | 0.020 |
| Grocery | Lighting_MV400W | Electric | 0.900 | 0.050 | 0.030 | 0.020 |
| Grocery | Other | Electric | 1.000 | - - - | - - - | - - - |
| Grocery | Plug_Load | Electric | 0.950 | 0.050 | - - - | - - - |
| Grocery | Refrigeration | Electric | 0.950 | 0.050 | - - - | - - - |
| Grocery | Space_Heat | Electric | 1.000 | - - - | - - - | - - - |
| Grocery | Space_Heat | Gas | 1.000 | - - - | - - - | - - - |
| Grocery | Ventilation | Electric | 0.550 | 0.400 | 0.050 | - - - |
| Grocery | Water_Heat | Electric | 0.700 | 0.225 | 0.045 | 0.030 |
| Grocery | Water_Heat | Gas | 1.000 | - - - | - - - | - - - |
| Hospital | Cooling_Chillers | Electric | 0.515 | 0.456 | 0.023 | 0.007 |
| Hospital | Cooling_DX | Electric | 0.515 | 0.456 | 0.023 | 0.007 |
| Hospital | Cooling_HeatPump | Electric | 0.515 | 0.456 | 0.023 | 0.007 |
| Hospital | Lighting_2L4T12 | Electric | 0.900 | 0.050 | 0.030 | 0.020 |
| Hospital | Lighting_2L4T8 | Electric | 0.900 | 0.050 | 0.030 | 0.020 |
| Hospital | Lighting_2L8T12 | Electric | 0.900 | 0.050 | 0.030 | 0.020 |
| Hospital | Lighting_3L4T12 | Electric | 0.900 | 0.050 | 0.030 | 0.020 |
| Hospital | Lighting_3L4T8 | Electric | 0.9000 | 0.0900 | 0.0075 | 0.0025 |
| Hospital | Lighting_4L4T12 | Electric | 0.900 | 0.050 | 0.030 | 0.020 |

## Commercial Electric Efficiency Shares

| bName | nName | fName | Stock | Standard | High | Premium |
|---|---|---|---|---|---|---|
| Hospital | Lighting_4L4T8 | Electric | 0.900 | 0.090 | 0.008 | 0.003 |
| Hospital | Lighting_INC150W | Electric | 0.900 | 0.050 | 0.030 | 0.020 |
| Hospital | Lighting_INC75W | Electric | 0.900 | 0.050 | 0.030 | 0.020 |
| Hospital | Lighting_MV400W | Electric | 0.900 | 0.050 | 0.030 | 0.020 |
| Hospital | Other | Electric | 1.000 | - - - | - - - | - - - |
| Hospital | Plug_Load | Electric | 0.950 | 0.050 | . | . |
| Hospital | Space_Heat | Electric | 1.000 | - - - | - - - | - - - |
| Hospital | Space_Heat | Gas | 1.000 | - - - | - - - | - - - |
| Hospital | Ventilation | Electric | 0.550 | 0.400 | 0.050 | . |
| Hospital | Water_Heat | Electric | 0.700 | 0.225 | 0.045 | 0.030 |
| Hospital | Water_Heat | Gas | 1.000 | - - - | - - - | - - - |
| Hotel_Motel | Cooking | Electric | 0.950 | 0.050 | - - - | - - - |
| Hotel_Motel | Cooking | Gas | 1.000 | - - - | - - - | - - - |
| Hotel_Motel | Cooling_Chillers | Electric | 0.515 | 0.456 | 0.023 | 0.007 |
| Hotel_Motel | Cooling_DX | Electric | 0.515 | 0.456 | 0.023 | 0.007 |
| Hotel_Motel | Cooling_HeatPump | Electric | 0.515 | 0.456 | 0.023 | 0.007 |
| Hotel_Motel | Lighting_2L4T12 | Electric | 0.900 | 0.050 | 0.030 | 0.020 |
| Hotel_Motel | Lighting_2L4T8 | Electric | 0.900 | 0.050 | 0.030 | 0.020 |
| Hotel_Motel | Lighting_2L8T12 | Electric | 0.900 | 0.050 | 0.030 | 0.020 |
| Hotel_Motel | Lighting_3L4T12 | Electric | 0.900 | 0.050 | 0.030 | 0.020 |
| Hotel_Motel | Lighting_3L4T8 | Electric | 0.9000 | 0.0900 | 0.0075 | 0.0025 |
| Hotel_Motel | Lighting_4L4T12 | Electric | 0.900 | 0.050 | 0.030 | 0.020 |
| Hotel_Motel | Lighting_4L4T8 | Electric | 0.900 | 0.090 | 0.008 | 0.003 |
| Hotel_Motel | Lighting_INC150W | Electric | 0.900 | 0.050 | 0.030 | 0.020 |
| Hotel_Motel | Lighting_INC75W | Electric | 0.900 | 0.050 | 0.030 | 0.020 |
| Hotel_Motel | Lighting_MV400W | Electric | 0.900 | 0.050 | 0.030 | 0.020 |
| Hotel_Motel | Other | Electric | 1.000 | - - - | - - - | - - - |
| Hotel_Motel | Plug_Load | Electric | 0.950 | 0.050 | - - - | - - - |
| Hotel_Motel | Space_Heat | Electric | 1.000 | - - - | - - - | - - - |
| Hotel_Motel | Space_Heat | Gas | 1.000 | - - - | - - - | - - - |
| Hotel_Motel | Ventilation | Electric | 0.550 | 0.400 | 0.050 | - - - |
| Hotel_Motel | Water_Heat | Electric | 0.700 | 0.225 | 0.045 | 0.030 |
| Hotel_Motel | Water_Heat | Gas | 1.000 | - - - | - - - | - - - |
| Office | Cooling_Chillers | Electric | 0.515 | 0.456 | 0.023 | 0.007 |
| Office | Cooling_DX | Electric | 0.515 | 0.456 | 0.023 | 0.007 |
| Office | Cooling_HeatPump | Electric | 0.515 | 0.456 | 0.023 | 0.007 |

## Commercial Electric Efficiency Shares

| bName | nName | fName | Stock | Standard | High | Premium |
|---|---|---|---|---|---|---|
| Office | Lighting_2L4T12 | Electric | 0.900 | 0.050 | 0.030 | 0.020 |
| Office | Lighting_2L4T8 | Electric | 0.900 | 0.050 | 0.030 | 0.020 |
| Office | Lighting_2L8T12 | Electric | 0.900 | 0.050 | 0.030 | 0.020 |
| Office | Lighting_3L4T12 | Electric | 0.900 | 0.050 | 0.030 | 0.020 |
| Office | Lighting_3L4T8 | Electric | 0.9000 | 0.0900 | 0.0075 | 0.0025 |
| Office | Lighting_4L4T12 | Electric | 0.900 | 0.050 | 0.030 | 0.020 |
| Office | Lighting_4L4T8 | Electric | 0.900 | 0.090 | 0.008 | 0.003 |
| Office | Lighting_INC150W | Electric | 0.900 | 0.050 | 0.030 | 0.020 |
| Office | Lighting_INC75W | Electric | 0.900 | 0.050 | 0.030 | 0.020 |
| Office | Lighting_MV400W | Electric | 0.900 | 0.050 | 0.030 | 0.020 |
| Office | Other | Electric | 1.000 | - - - | - - - | - - - |
| Office | Plug_Load | Electric | 0.950 | 0.050 | - - - | - - - |
| Office | Space_Heat | Electric | 1.000 | - - - | - - - | - - - |
| Office | Space_Heat | Gas | 1.000 | - - - | - - - | - - - |
| Office | Ventilation | Electric | 0.550 | 0.400 | 0.050 | - - - |
| Office | Water_Heat | Electric | 0.700 | 0.225 | 0.045 | 0.030 |
| Office | Water_Heat | Gas | 1.000 | - - - | - - - | - - - |
| Other | Cooling_Chillers | Electric | 0.515 | 0.456 | 0.023 | 0.007 |
| Other | Cooling_DX | Electric | 0.515 | 0.456 | 0.023 | 0.007 |
| Other | Cooling_HeatPump | Electric | 0.515 | 0.456 | 0.023 | 0.007 |
| Other | Lighting_2L4T12 | Electric | 0.900 | 0.050 | 0.030 | 0.020 |
| Other | Lighting_2L4T8 | Electric | 0.900 | 0.050 | 0.030 | 0.020 |
| Other | Lighting_2L8T12 | Electric | 0.900 | 0.050 | 0.030 | 0.020 |
| Other | Lighting_3L4T12 | Electric | 0.900 | 0.050 | 0.030 | 0.020 |
| Other | Lighting_3L4T8 | Electric | 0.9000 | 0.0900 | 0.0075 | 0.0025 |
| Other | Lighting_4L4T12 | Electric | 0.900 | 0.050 | 0.030 | 0.020 |
| Other | Lighting_4L4T8 | Electric | 0.900 | 0.090 | 0.008 | 0.003 |
| Other | Lighting_INC150W | Electric | 0.900 | 0.050 | 0.030 | 0.020 |
| Other | Lighting_INC75W | Electric | 0.900 | 0.050 | 0.030 | 0.020 |
| Other | Lighting_MV400W | Electric | 0.900 | 0.050 | 0.030 | 0.020 |
| Other | Other | Electric | 1.000 | - - - | - - - | - - - |
| Other | Plug_Load | Electric | 0.950 | 0.050 | - - - | - - - |
| Other | Space_Heat | Electric | 1.000 | - - - | - - - | - - - |
| Other | Space_Heat | Gas | 1.000 | - - - | - - - | - - - |
| Other | Ventilation | Electric | 0.550 | 0.400 | 0.050 | . |
| Other | Water_Heat | Electric | 0.700 | 0.225 | 0.045 | 0.030 |

## Commercial Electric Efficiency Shares

| bName | nName | fName | Stock | Standard | High | Premium |
|---|---|---|---|---|---|---|
| Other | Water_Heat | Gas | 1.000 | - - - | - - - | - - - |
| Restaurant | Cooking | Electric | 0.950 | 0.050 | - - - | - - - |
| Restaurant | Cooking | Gas | 1.000 | - - - | - - - | - - - |
| Restaurant | Cooling_Chillers | Electric | 0.515 | 0.456 | 0.023 | 0.007 |
| Restaurant | Cooling_DX | Electric | 0.515 | 0.456 | 0.023 | 0.007 |
| Restaurant | Cooling_HeatPump | Electric | 0.515 | 0.456 | 0.023 | 0.007 |
| Restaurant | Lighting_2L4T12 | Electric | 0.900 | 0.050 | 0.030 | 0.020 |
| Restaurant | Lighting_2L4T8 | Electric | 0.900 | 0.050 | 0.030 | 0.020 |
| Restaurant | Lighting_2L8T12 | Electric | 0.900 | 0.050 | 0.030 | 0.020 |
| Restaurant | Lighting_3L4T12 | Electric | 0.900 | 0.050 | 0.030 | 0.020 |
| Restaurant | Lighting_3L4T8 | Electric | 0.9000 | 0.0900 | 0.0075 | 0.0025 |
| Restaurant | Lighting_4L4T12 | Electric | 0.900 | 0.050 | 0.030 | 0.020 |
| Restaurant | Lighting_4L4T8 | Electric | 0.900 | 0.090 | 0.008 | 0.003 |
| Restaurant | Lighting_INC150W | Electric | 0.900 | 0.050 | 0.030 | 0.020 |
| Restaurant | Lighting_INC75W | Electric | 0.900 | 0.050 | 0.030 | 0.020 |
| Restaurant | Lighting_MV400W | Electric | 0.900 | 0.050 | 0.030 | 0.020 |
| Restaurant | Other | Electric | 1.000 | - - - | - - - | - - - |
| Restaurant | Plug_Load | Electric | 0.950 | 0.050 | - - - | - - - |
| Restaurant | Refrigeration | Electric | 0.950 | 0.050 | - - - | - - - |
| Restaurant | Space_Heat | Electric | 1.000 | - - - | - - - | - - - |
| Restaurant | Space_Heat | Gas | 1.000 | - - - | - - - | - - - |
| Restaurant | Ventilation | Electric | 0.550 | 0.400 | 0.050 | . |
| Restaurant | Water_Heat | Electric | 0.700 | 0.225 | 0.045 | 0.030 |
| Restaurant | Water_Heat | Gas | 1.000 | - - - | - - - | - - - |
| School | Cooking | Electric | 0.950 | 0.050 | - - - | - - - |
| School | Cooking | Gas | 1.000 | - - - | - - - | - - - |
| School | Cooling_Chillers | Electric | 0.515 | 0.456 | 0.023 | 0.007 |
| School | Cooling_DX | Electric | 0.515 | 0.456 | 0.023 | 0.007 |
| School | Cooling_HeatPump | Electric | 0.515 | 0.456 | 0.023 | 0.007 |
| School | Lighting_2L4T12 | Electric | 0.900 | 0.050 | 0.030 | 0.020 |
| School | Lighting_2L4T8 | Electric | 0.900 | 0.050 | 0.030 | 0.020 |
| School | Lighting_2L8T12 | Electric | 0.900 | 0.050 | 0.030 | 0.020 |
| School | Lighting_3L4T12 | Electric | 0.900 | 0.050 | 0.030 | 0.020 |
| School | Lighting_3L4T8 | Electric | 0.9000 | 0.0900 | 0.0075 | 0.0025 |
| School | Lighting_4L4T12 | Electric | 0.900 | 0.050 | 0.030 | 0.020 |
| School | Lighting_4L4T8 | Electric | 0.900 | 0.090 | 0.008 | 0.003 |

## Commercial Electric Efficiency Shares

| bName | nName | fName | Stock | Standard | High | Premium |
|---|---|---|---|---|---|---|
| School | Lighting_INC150W | Electric | 0.900 | 0.050 | 0.030 | 0.020 |
| School | Lighting_INC75W | Electric | 0.900 | 0.050 | 0.030 | 0.020 |
| School | Lighting_MV400W | Electric | 0.900 | 0.050 | 0.030 | 0.020 |
| School | Other | Electric | 1.000 | - - - | - - - | - - - |
| School | Plug_Load | Electric | 0.950 | 0.050 | - - - | - - - |
| School | Space_Heat | Electric | 1.000 | - - - | - - - | - - - |
| School | Space_Heat | Gas | 1.000 | - - - | - - - | - - - |
| School | Ventilation | Electric | 0.550 | 0.400 | 0.050 | . |
| School | Water_Heat | Electric | 0.700 | 0.225 | 0.045 | 0.030 |
| School | Water_Heat | Gas | 1.000 | - - - | - - - | - - - |
| University | Cooling_Chillers | Electric | 0.515 | 0.456 | 0.023 | 0.007 |
| University | Cooling_DX | Electric | 0.515 | 0.456 | 0.023 | 0.007 |
| University | Cooling_HeatPump | Electric | 0.515 | 0.456 | 0.023 | 0.007 |
| University | Lighting_2L4T12 | Electric | 0.900 | 0.050 | 0.030 | 0.020 |
| University | Lighting_2L4T8 | Electric | 0.900 | 0.050 | 0.030 | 0.020 |
| University | Lighting_2L8T12 | Electric | 0.900 | 0.050 | 0.030 | 0.020 |
| University | Lighting_3L4T12 | Electric | 0.900 | 0.050 | 0.030 | 0.020 |
| University | Lighting_3L4T8 | Electric | 0.9000 | 0.0900 | 0.0075 | 0.0025 |
| University | Lighting_4L4T12 | Electric | 0.900 | 0.050 | 0.030 | 0.020 |
| University | Lighting_4L4T8 | Electric | 0.900 | 0.090 | 0.008 | 0.003 |
| University | Lighting_INC150W | Electric | 0.900 | 0.050 | 0.030 | 0.020 |
| University | Lighting_INC75W | Electric | 0.900 | 0.050 | 0.030 | 0.020 |
| University | Lighting_MV400W | Electric | 0.900 | 0.050 | 0.030 | 0.020 |
| University | Other | Electric | 1.000 | - - - | - - - | - - - |
| University | Plug_Load | Electric | 0.950 | 0.050 | - - - | - - - |
| University | Space_Heat | Electric | 1.000 | - - - | - - - | - - - |
| University | Space_Heat | Gas | 1.000 | - - - | - - - | - - - |
| University | Ventilation | Electric | 0.550 | 0.400 | 0.050 | . |
| University | Water_Heat | Electric | 0.700 | 0.225 | 0.045 | 0.030 |
| University | Water_Heat | Gas | 1.000 | - - - | - - - | - - - |
| Warehouse | Cooling_Chillers | Electric | 0.515 | 0.456 | 0.023 | 0.007 |
| Warehouse | Cooling_DX | Electric | 0.515 | 0.456 | 0.023 | 0.007 |
| Warehouse | Cooling_HeatPump | Electric | 0.515 | 0.456 | 0.023 | 0.007 |
| Warehouse | Lighting_2L4T12 | Electric | 0.900 | 0.050 | 0.030 | 0.020 |
| Warehouse | Lighting_2L4T8 | Electric | 0.900 | 0.050 | 0.030 | 0.020 |
| Warehouse | Lighting_2L8T12 | Electric | 0.900 | 0.050 | 0.030 | 0.020 |

## Commercial Electric Efficiency Shares

| bName | nName | fName | Stock | Standard | High | Premium |
|---|---|---|---|---|---|---|
| Warehouse | Lighting_3L4T12 | Electric | 0.900 | 0.050 | 0.030 | 0.020 |
| Warehouse | Lighting_3L4T8 | Electric | 0.9000 | 0.0900 | 0.0075 | 0.0025 |
| Warehouse | Lighting_4L4T12 | Electric | 0.900 | 0.050 | 0.030 | 0.020 |
| Warehouse | Lighting_4L4T8 | Electric | 0.900 | 0.090 | 0.008 | 0.003 |
| Warehouse | Lighting_INC150W | Electric | 0.900 | 0.050 | 0.030 | 0.020 |
| Warehouse | Lighting_INC75W | Electric | 0.900 | 0.050 | 0.030 | 0.020 |
| Warehouse | Lighting_MV400W | Electric | 0.900 | 0.050 | 0.030 | 0.020 |
| Warehouse | Other | Electric | 1.000 | - - - | - - - | - - - |
| Warehouse | Plug_Load | Electric | 0.950 | 0.050 | - - - | - - - |
| Warehouse | Space_Heat | Electric | 1.000 | - - - | - - - | - - - |
| Warehouse | Space_Heat | Gas | 1.000 | - - - | - - - | - - - |
| Warehouse | Ventilation | Electric | 0.550 | 0.400 | 0.050 | . |
| Warehouse | Water_Heat | Electric | 0.700 | 0.225 | 0.045 | 0.030 |
| Warehouse | Water_Heat | Gas | 1.000 | - - - | - - - | - - - |

Exhibit No. ___(EMM-6)
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## Commercial Electric Electric Price Forecast ($/kWh)

| Year | Price Deflator | Commercial Average Price | Commercial Marginal Price |
|---|---|---|---|
| 2005 | 100.00 | 0.07395 | 0.07395 |
| 2006 | 102.29 | 0.07665 | 0.07665 |
| 2007 | 104.61 | 0.07528 | 0.07528 |
| 2008 | 107.08 | 0.07694 | 0.07694 |
| 2009 | 109.72 | 0.07868 | 0.07868 |
| 2010 | 112.67 | 0.08066 | 0.08066 |
| 2011 | 115.97 | 0.08284 | 0.08284 |
| 2012 | 119.34 | 0.08505 | 0.08505 |
| 2013 | 123.05 | 0.08736 | 0.08736 |
| 2014 | 126.80 | 0.08991 | 0.08991 |
| 2015 | 130.47 | 0.09273 | 0.09273 |
| 2016 | 134.23 | 0.09558 | 0.09558 |
| 2017 | 138.36 | 0.09863 | 0.09863 |
| 2018 | 142.88 | 0.10190 | 0.10190 |
| 2019 | 147.75 | 0.10536 | 0.10536 |
| 2020 | 152.92 | 0.10895 | 0.10895 |
| 2021 | 158.32 | 0.11267 | 0.11267 |
| 2022 | 163.95 | 0.11653 | 0.11653 |
| 2023 | 169.82 | 0.12049 | 0.12049 |
| 2024 | 175.93 | 0.12458 | 0.12458 |
| 2025 | 182.27 | 0.12881 | 0.12881 |

## Commercial Electric Gas Price Forecast ($/therm)

| Year | Price Deflator | Commercial Average Price | Commercial Marginal Price |
|---|---|---|---|
| 2005 | 100.00 | 0.98069 | 0.98069 |
| 2006 | 102.29 | 0.98887 | 0.98887 |
| 2007 | 104.61 | 0.97624 | 0.97624 |
| 2008 | 107.08 | 0.88972 | 0.88972 |
| 2009 | 109.72 | 0.86538 | 0.86538 |
| 2010 | 112.67 | 0.79505 | 0.79505 |
| 2011 | 115.97 | 0.87203 | 0.87203 |
| 2012 | 119.34 | 0.89133 | 0.89133 |
| 2013 | 123.05 | 0.96310 | 0.96310 |
| 2014 | 126.80 | 1.02968 | 1.02968 |
| 2015 | 130.47 | 1.03847 | 1.03847 |
| 2016 | 134.23 | 0.92677 | 0.92677 |
| 2017 | 138.36 | 0.96180 | 0.96180 |
| 2018 | 142.88 | 1.05257 | 1.05257 |
| 2019 | 147.75 | 1.13966 | 1.13966 |
| 2020 | 152.92 | 1.20407 | 1.20407 |
| 2021 | 158.32 | 1.22945 | 1.22945 |
| 2022 | 163.95 | 1.25134 | 1.25134 |
| 2023 | 169.82 | 1.27385 | 1.27385 |
| 2024 | 175.93 | 1.27357 | 1.27357 |
| 2025 | 182.27 | 1.29648 | 1.29648 |

## Commercial Electric Average Square Footage by Building Type

| Year | Dry Goods Retail | Grocery | Office | Restaurant | Ware-house | Hospital | Hotel/ Motel | School | University | Other |
|---|---|---|---|---|---|---|---|---|---|---|
| 2005 | 6,421 | 8,637 | 12,985 | 12,772 | 9,525 | 8,153 | 3,126 | 22,241 | 32,392 | 15,284 |
| 2006 | 6,421 | 8,637 | 12,985 | 12,772 | 9,525 | 8,153 | 3,126 | 22,241 | 32,392 | 15,284 |
| 2007 | 6,421 | 8,637 | 12,985 | 12,772 | 9,525 | 8,153 | 3,126 | 22,241 | 32,392 | 15,284 |
| 2008 | 6,421 | 8,637 | 12,985 | 12,772 | 9,525 | 8,153 | 3,126 | 22,241 | 32,392 | 15,284 |
| 2009 | 6,421 | 8,637 | 12,985 | 12,772 | 9,525 | 8,153 | 3,126 | 22,241 | 32,392 | 15,284 |
| 2010 | 6,421 | 8,637 | 12,985 | 12,772 | 9,525 | 8,153 | 3,126 | 22,241 | 32,392 | 15,284 |
| 2011 | 6,421 | 8,637 | 12,985 | 12,772 | 9,525 | 8,153 | 3,126 | 22,241 | 32,392 | 15,284 |
| 2012 | 6,421 | 8,637 | 12,985 | 12,772 | 9,525 | 8,153 | 3,126 | 22,241 | 32,392 | 15,284 |
| 2013 | 6,421 | 8,637 | 12,985 | 12,772 | 9,525 | 8,153 | 3,126 | 22,241 | 32,392 | 15,284 |
| 2014 | 6,421 | 8,637 | 12,985 | 12,772 | 9,525 | 8,153 | 3,126 | 22,241 | 32,392 | 15,284 |
| 2015 | 6,421 | 8,637 | 12,985 | 12,772 | 9,525 | 8,153 | 3,126 | 22,241 | 32,392 | 15,284 |
| 2016 | 6,421 | 8,637 | 12,985 | 12,772 | 9,525 | 8,153 | 3,126 | 22,241 | 32,392 | 15,284 |
| 2017 | 6,421 | 8,637 | 12,985 | 12,772 | 9,525 | 8,153 | 3,126 | 22,241 | 32,392 | 15,284 |
| 2018 | 6,421 | 8,637 | 12,985 | 12,772 | 9,525 | 8,153 | 3,126 | 22,241 | 32,392 | 15,284 |
| 2019 | 6,421 | 8,637 | 12,985 | 12,772 | 9,525 | 8,153 | 3,126 | 22,241 | 32,392 | 15,284 |
| 2020 | 6,421 | 8,637 | 12,985 | 12,772 | 9,525 | 8,153 | 3,126 | 22,241 | 32,392 | 15,284 |
| 2021 | 6,421 | 8,637 | 12,985 | 12,772 | 9,525 | 8,153 | 3,126 | 22,241 | 32,392 | 15,284 |
| 2022 | 6,421 | 8,637 | 12,985 | 12,772 | 9,525 | 8,153 | 3,126 | 22,241 | 32,392 | 15,284 |
| 2023 | 6,421 | 8,637 | 12,985 | 12,772 | 9,525 | 8,153 | 3,126 | 22,241 | 32,392 | 15,284 |
| 2024 | 6,421 | 8,637 | 12,985 | 12,772 | 9,525 | 8,153 | 3,126 | 22,241 | 32,392 | 15,284 |
| 2025 | 6,421 | 8,637 | 12,985 | 12,772 | 9,525 | 8,153 | 3,126 | 22,241 | 32,392 | 15,284 |

## Commercial Electric Number of Electric Meters Per Building

| Year | Dry Goods Retail | Grocery | Office | Restaurant | Ware-house | Hospital | Hotel /Motel | School | University | Other |
|---|---|---|---|---|---|---|---|---|---|---|
| 2005 | 1.137 | 1.000 | 1.140 | 1.038 | 1.140 | 2.489 | 1.301 | 1.628 | 2.000 | 1.290 |
| 2006 | 1.137 | 1.000 | 1.140 | 1.038 | 1.140 | 2.489 | 1.301 | 1.628 | 2.000 | 1.290 |
| 2007 | 1.137 | 1.000 | 1.140 | 1.038 | 1.140 | 2.489 | 1.301 | 1.628 | 2.000 | 1.290 |
| 2008 | 1.137 | 1.000 | 1.140 | 1.038 | 1.140 | 2.489 | 1.301 | 1.628 | 2.000 | 1.290 |
| 2009 | 1.137 | 1.000 | 1.140 | 1.038 | 1.140 | 2.489 | 1.301 | 1.628 | 2.000 | 1.290 |
| 2010 | 1.137 | 1.000 | 1.140 | 1.038 | 1.140 | 2.489 | 1.301 | 1.628 | 2.000 | 1.290 |
| 2011 | 1.137 | 1.000 | 1.140 | 1.038 | 1.140 | 2.489 | 1.301 | 1.628 | 2.000 | 1.290 |
| 2012 | 1.137 | 1.000 | 1.140 | 1.038 | 1.140 | 2.489 | 1.301 | 1.628 | 2.000 | 1.290 |
| 2013 | 1.137 | 1.000 | 1.140 | 1.038 | 1.140 | 2.489 | 1.301 | 1.628 | 2.000 | 1.290 |
| 2014 | 1.137 | 1.000 | 1.140 | 1.038 | 1.140 | 2.489 | 1.301 | 1.628 | 2.000 | 1.290 |
| 2015 | 1.137 | 1.000 | 1.140 | 1.038 | 1.140 | 2.489 | 1.301 | 1.628 | 2.000 | 1.290 |
| 2016 | 1.137 | 1.000 | 1.140 | 1.038 | 1.140 | 2.489 | 1.301 | 1.628 | 2.000 | 1.290 |
| 2017 | 1.137 | 1.000 | 1.140 | 1.038 | 1.140 | 2.489 | 1.301 | 1.628 | 2.000 | 1.290 |
| 2018 | 1.137 | 1.000 | 1.140 | 1.038 | 1.140 | 2.489 | 1.301 | 1.628 | 2.000 | 1.290 |
| 2019 | 1.137 | 1.000 | 1.140 | 1.038 | 1.140 | 2.489 | 1.301 | 1.628 | 2.000 | 1.290 |
| 2020 | 1.137 | 1.000 | 1.140 | 1.038 | 1.140 | 2.489 | 1.301 | 1.628 | 2.000 | 1.290 |
| 2021 | 1.137 | 1.000 | 1.140 | 1.038 | 1.140 | 2.489 | 1.301 | 1.628 | 2.000 | 1.290 |
| 2022 | 1.137 | 1.000 | 1.140 | 1.038 | 1.140 | 2.489 | 1.301 | 1.628 | 2.000 | 1.290 |
| 2023 | 1.137 | 1.000 | 1.140 | 1.038 | 1.140 | 2.489 | 1.301 | 1.628 | 2.000 | 1.290 |
| 2024 | 1.137 | 1.000 | 1.140 | 1.038 | 1.140 | 2.489 | 1.301 | 1.628 | 2.000 | 1.290 |
| 2025 | 1.137 | 1.000 | 1.140 | 1.038 | 1.140 | 2.489 | 1.301 | 1.628 | 2.000 | 1.290 |

## Commercial Gas

**Commercial Gas Sales Forecast (Therms)**

| Year | King | Kittitas | Lewis | Pierce | Snohomish | Thurston | Total |
|---|---|---|---|---|---|---|---|
| 2005 | 138,109,539 | 94,588 | 3,327,592 | 37,516,456 | 31,849,557 | 11,055,390 | 221,953,121 |
| 2006 | 140,811,165 | 96,483 | 3,392,075 | 38,233,906 | 32,488,858 | 11,266,781 | 226,289,268 |
| 2007 | 145,913,660 | 100,086 | 3,514,938 | 39,621,346 | 33,665,375 | 11,675,948 | 234,491,353 |
| 2008 | 151,088,434 | 103,726 | 3,639,540 | 41,028,129 | 34,858,758 | 12,090,775 | 242,809,362 |
| 2009 | 157,538,166 | 108,238 | 3,794,855 | 42,781,043 | 36,346,338 | 12,607,592 | 253,176,232 |
| 2010 | 164,096,176 | 112,810 | 3,952,791 | 44,563,146 | 37,858,946 | 13,132,976 | 263,716,845 |
| 2011 | 170,633,990 | 117,369 | 4,110,240 | 46,339,763 | 39,366,889 | 13,656,742 | 274,224,994 |
| 2012 | 175,947,682 | 121,091 | 4,238,199 | 47,784,024 | 40,592,401 | 14,082,575 | 282,765,972 |
| 2013 | 181,384,954 | 124,896 | 4,369,128 | 49,261,784 | 41,846,511 | 14,518,272 | 291,505,545 |
| 2014 | 186,868,125 | 128,732 | 4,501,164 | 50,752,001 | 43,111,205 | 14,957,639 | 300,318,867 |
| 2015 | 192,636,847 | 132,764 | 4,640,090 | 52,319,801 | 44,441,665 | 15,419,872 | 309,591,038 |
| 2016 | 199,208,746 | 137,343 | 4,798,366 | 54,105,647 | 45,957,445 | 15,946,353 | 320,153,901 |
| 2017 | 206,837,991 | 142,644 | 4,982,103 | 56,178,466 | 47,717,333 | 16,557,384 | 332,415,921 |
| 2018 | 213,736,680 | 147,445 | 5,148,243 | 58,052,945 | 49,308,640 | 17,109,971 | 343,503,923 |
| 2019 | 220,041,486 | 151,839 | 5,300,078 | 59,766,193 | 50,762,894 | 17,615,049 | 353,637,539 |
| 2020 | 226,518,970 | 156,351 | 5,456,072 | 61,526,304 | 52,257,004 | 18,133,933 | 364,048,633 |
| 2021 | 233,495,387 | 161,203 | 5,624,089 | 63,421,865 | 53,866,223 | 18,692,728 | 375,261,495 |
| 2022 | 241,017,804 | 166,427 | 5,805,260 | 65,465,649 | 55,601,421 | 19,295,196 | 387,351,757 |
| 2023 | 248,839,392 | 171,855 | 5,993,635 | 67,590,618 | 57,405,695 | 19,921,580 | 399,922,776 |
| 2024 | 256,936,222 | 177,470 | 6,188,642 | 69,790,296 | 59,273,483 | 20,569,977 | 412,936,090 |
| 2025 | 265,296,816 | 183,245 | 6,390,018 | 72,061,242 | 61,202,217 | 21,239,315 | 426,372,851 |

## Commercial Gas Customer Count Forecast

| Year | King | Kittitas | Lewis | Pierce | Snohomish | Thurston | Total |
|---|---|---|---|---|---|---|---|
| 2005 | 30,103 | 38 | 848 | 8,558 | 7,127 | 2,932 | 49,606 |
| 2006 | 30,950 | 39 | 871 | 8,799 | 7,328 | 3,015 | 51,003 |
| 2007 | 31,821 | 40 | 896 | 9,046 | 7,534 | 3,100 | 52,437 |
| 2008 | 32,709 | 41 | 921 | 9,299 | 7,744 | 3,186 | 53,900 |
| 2009 | 33,622 | 43 | 947 | 9,559 | 7,961 | 3,275 | 55,406 |
| 2010 | 34,558 | 44 | 973 | 9,825 | 8,182 | 3,366 | 56,948 |
| 2011 | 35,511 | 45 | 1,000 | 10,096 | 8,408 | 3,459 | 58,519 |
| 2012 | 36,484 | 46 | 1,027 | 10,372 | 8,638 | 3,554 | 60,122 |
| 2013 | 37,486 | 48 | 1,056 | 10,657 | 8,875 | 3,651 | 61,773 |
| 2014 | 38,522 | 49 | 1,085 | 10,952 | 9,121 | 3,752 | 63,481 |
| 2015 | 39,584 | 50 | 1,115 | 11,253 | 9,372 | 3,856 | 65,230 |
| 2016 | 40,660 | 52 | 1,145 | 11,559 | 9,627 | 3,961 | 67,003 |
| 2017 | 41,760 | 53 | 1,176 | 11,872 | 9,887 | 4,068 | 68,816 |
| 2018 | 42,894 | 54 | 1,208 | 12,194 | 10,156 | 4,178 | 70,684 |
| 2019 | 44,059 | 56 | 1,241 | 12,526 | 10,432 | 4,292 | 72,605 |
| 2020 | 45,256 | 57 | 1,274 | 12,866 | 10,715 | 4,408 | 74,577 |
| 2021 | 46,484 | 59 | 1,309 | 13,215 | 11,006 | 4,528 | 76,600 |
| 2022 | 47,741 | 61 | 1,344 | 13,572 | 11,304 | 4,650 | 78,672 |
| 2023 | 49,030 | 62 | 1,381 | 13,939 | 11,609 | 4,776 | 80,796 |
| 2024 | 50,355 | 64 | 1,418 | 14,316 | 11,922 | 4,905 | 82,980 |
| 2025 | 51,488 | 65 | 1,444 | 14,715 | 12,270 | 5,054 | 85,035 |

## Commercial Gas Building Type Allocation

| Year | County | Dry Goods Retail | Grocery | Office | Restaur ant | Ware-house | Hospital | Hotel/ Motel | School | Universi ty | Other |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 2005 | King | 0.104450 | 0.018432 | 0.252147 | 0.006858 | 0.120457 | 0.041644 | 0.047810 | 0.054901 | 0.021634 | 0.331668 |
| 2006 | King | 0.104450 | 0.018432 | 0.252147 | 0.006858 | 0.120457 | 0.041644 | 0.047810 | 0.054901 | 0.021634 | 0.331668 |
| 2007 | King | 0.104450 | 0.018432 | 0.252147 | 0.006858 | 0.120457 | 0.041644 | 0.047810 | 0.054901 | 0.021634 | 0.331668 |
| 2008 | King | 0.104450 | 0.018432 | 0.252147 | 0.006858 | 0.120457 | 0.041644 | 0.047810 | 0.054901 | 0.021634 | 0.331668 |
| 2009 | King | 0.104450 | 0.018432 | 0.252147 | 0.006858 | 0.120457 | 0.041644 | 0.047810 | 0.054901 | 0.021634 | 0.331668 |

## Commercial Gas Building Type Allocation

| Year | County | Dry Goods Retail | Grocery | Office | Restaurant | Ware-house | Hospital | Hotel/ Motel | School | University | Other |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 2010 | King | 0.104450 | 0.018432 | 0.252147 | 0.006858 | 0.120457 | 0.041644 | 0.047810 | 0.054901 | 0.021634 | 0.331668 |
| 2011 | King | 0.104450 | 0.018432 | 0.252147 | 0.006858 | 0.120457 | 0.041644 | 0.047810 | 0.054901 | 0.021634 | 0.331668 |
| 2012 | King | 0.104450 | 0.018432 | 0.252147 | 0.006858 | 0.120457 | 0.041644 | 0.047810 | 0.054901 | 0.021634 | 0.331668 |
| 2013 | King | 0.104450 | 0.018432 | 0.252147 | 0.006858 | 0.120457 | 0.041644 | 0.047810 | 0.054901 | 0.021634 | 0.331668 |
| 2014 | King | 0.104450 | 0.018432 | 0.252147 | 0.006858 | 0.120457 | 0.041644 | 0.047810 | 0.054901 | 0.021634 | 0.331668 |
| 2015 | King | 0.104450 | 0.018432 | 0.252147 | 0.006858 | 0.120457 | 0.041644 | 0.047810 | 0.054901 | 0.021634 | 0.331668 |
| 2016 | King | 0.104450 | 0.018432 | 0.252147 | 0.006858 | 0.120457 | 0.041644 | 0.047810 | 0.054901 | 0.021634 | 0.331668 |
| 2017 | King | 0.104450 | 0.018432 | 0.252147 | 0.006858 | 0.120457 | 0.041644 | 0.047810 | 0.054901 | 0.021634 | 0.331668 |
| 2018 | King | 0.104450 | 0.018432 | 0.252147 | 0.006858 | 0.120457 | 0.041644 | 0.047810 | 0.054901 | 0.021634 | 0.331668 |
| 2019 | King | 0.104450 | 0.018432 | 0.252147 | 0.006858 | 0.120457 | 0.041644 | 0.047810 | 0.054901 | 0.021634 | 0.331668 |
| 2020 | King | 0.104450 | 0.018432 | 0.252147 | 0.006858 | 0.120457 | 0.041644 | 0.047810 | 0.054901 | 0.021634 | 0.331668 |
| 2021 | King | 0.104450 | 0.018432 | 0.252147 | 0.006858 | 0.120457 | 0.041644 | 0.047810 | 0.054901 | 0.021634 | 0.331668 |
| 2022 | King | 0.104450 | 0.018432 | 0.252147 | 0.006858 | 0.120457 | 0.041644 | 0.047810 | 0.054901 | 0.021634 | 0.331668 |
| 2023 | King | 0.104450 | 0.018432 | 0.252147 | 0.006858 | 0.120457 | 0.041644 | 0.047810 | 0.054901 | 0.021634 | 0.331668 |
| 2024 | King | 0.104450 | 0.018432 | 0.252147 | 0.006858 | 0.120457 | 0.041644 | 0.047810 | 0.054901 | 0.021634 | 0.331668 |
| 2025 | King | 0.104450 | 0.018432 | 0.252147 | 0.006858 | 0.120457 | 0.041644 | 0.047810 | 0.054901 | 0.021634 | 0.331668 |
| 2005 | Kittitas | 0.214310 | 0.037819 | 0.018725 | 0.005524 | 0.057017 | 0.048685 | 0.080985 | 0.214680 | 0.239678 | 0.082577 |
| 2006 | Kittitas | 0.214310 | 0.037819 | 0.018725 | 0.005524 | 0.057017 | 0.048685 | 0.080985 | 0.214680 | 0.239678 | 0.082577 |
| 2007 | Kittitas | 0.214310 | 0.037819 | 0.018725 | 0.005524 | 0.057017 | 0.048685 | 0.080985 | 0.214680 | 0.239678 | 0.082577 |
| 2008 | Kittitas | 0.214310 | 0.037819 | 0.018725 | 0.005524 | 0.057017 | 0.048685 | 0.080985 | 0.214680 | 0.239678 | 0.082577 |
| 2009 | Kittitas | 0.214310 | 0.037819 | 0.018725 | 0.005524 | 0.057017 | 0.048685 | 0.080985 | 0.214680 | 0.239678 | 0.082577 |
| 2010 | Kittitas | 0.214310 | 0.037819 | 0.018725 | 0.005524 | 0.057017 | 0.048685 | 0.080985 | 0.214680 | 0.239678 | 0.082577 |
| 2011 | Kittitas | 0.214310 | 0.037819 | 0.018725 | 0.005524 | 0.057017 | 0.048685 | 0.080985 | 0.214680 | 0.239678 | 0.082577 |
| 2012 | Kittitas | 0.214310 | 0.037819 | 0.018725 | 0.005524 | 0.057017 | 0.048685 | 0.080985 | 0.214680 | 0.239678 | 0.082577 |
| 2013 | Kittitas | 0.214310 | 0.037819 | 0.018725 | 0.005524 | 0.057017 | 0.048685 | 0.080985 | 0.214680 | 0.239678 | 0.082577 |
| 2014 | Kittitas | 0.214310 | 0.037819 | 0.018725 | 0.005524 | 0.057017 | 0.048685 | 0.080985 | 0.214680 | 0.239678 | 0.082577 |
| 2015 | Kittitas | 0.214310 | 0.037819 | 0.018725 | 0.005524 | 0.057017 | 0.048685 | 0.080985 | 0.214680 | 0.239678 | 0.082577 |
| 2016 | Kittitas | 0.214310 | 0.037819 | 0.018725 | 0.005524 | 0.057017 | 0.048685 | 0.080985 | 0.214680 | 0.239678 | 0.082577 |
| 2017 | Kittitas | 0.214310 | 0.037819 | 0.018725 | 0.005524 | 0.057017 | 0.048685 | 0.080985 | 0.214680 | 0.239678 | 0.082577 |
| 2018 | Kittitas | 0.214310 | 0.037819 | 0.018725 | 0.005524 | 0.057017 | 0.048685 | 0.080985 | 0.214680 | 0.239678 | 0.082577 |

## Commercial Gas Building Type Allocation

| Year | County | Dry Goods Retail | Grocery | Office | Restaur ant | Ware-house | Hospital | Hotel/ Motel | School | Universi ty | Other |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 2019 | Kittitas | 0.214310 | 0.037819 | 0.018725 | 0.005524 | 0.057017 | 0.048685 | 0.080985 | 0.214680 | 0.239678 | 0.082577 |
| 2020 | Kittitas | 0.214310 | 0.037819 | 0.018725 | 0.005524 | 0.057017 | 0.048685 | 0.080985 | 0.214680 | 0.239678 | 0.082577 |
| 2021 | Kittitas | 0.214310 | 0.037819 | 0.018725 | 0.005524 | 0.057017 | 0.048685 | 0.080985 | 0.214680 | 0.239678 | 0.082577 |
| 2022 | Kittitas | 0.214310 | 0.037819 | 0.018725 | 0.005524 | 0.057017 | 0.048685 | 0.080985 | 0.214680 | 0.239678 | 0.082577 |
| 2023 | Kittitas | 0.214310 | 0.037819 | 0.018725 | 0.005524 | 0.057017 | 0.048685 | 0.080985 | 0.214680 | 0.239678 | 0.082577 |
| 2024 | Kittitas | 0.214310 | 0.037819 | 0.018725 | 0.005524 | 0.057017 | 0.048685 | 0.080985 | 0.214680 | 0.239678 | 0.082577 |
| 2025 | Kittitas | 0.214310 | 0.037819 | 0.018725 | 0.005524 | 0.057017 | 0.048685 | 0.080985 | 0.214680 | 0.239678 | 0.082577 |
| 2005 | Lewis | 0.200933 | 0.035459 | 0.055959 | 0.000000 | 0.286611 | 0.064613 | 0.025289 | 0.082369 | 0.031387 | 0.217380 |
| 2006 | Lewis | 0.200933 | 0.035459 | 0.055959 | 0.000000 | 0.286611 | 0.064613 | 0.025289 | 0.082369 | 0.031387 | 0.217380 |
| 2007 | Lewis | 0.200933 | 0.035459 | 0.055959 | 0.000000 | 0.286611 | 0.064613 | 0.025289 | 0.082369 | 0.031387 | 0.217380 |
| 2008 | Lewis | 0.200933 | 0.035459 | 0.055959 | 0.000000 | 0.286611 | 0.064613 | 0.025289 | 0.082369 | 0.031387 | 0.217380 |
| 2009 | Lewis | 0.200933 | 0.035459 | 0.055959 | 0.000000 | 0.286611 | 0.064613 | 0.025289 | 0.082369 | 0.031387 | 0.217380 |
| 2010 | Lewis | 0.200933 | 0.035459 | 0.055959 | 0.000000 | 0.286611 | 0.064613 | 0.025289 | 0.082369 | 0.031387 | 0.217380 |
| 2011 | Lewis | 0.200933 | 0.035459 | 0.055959 | 0.000000 | 0.286611 | 0.064613 | 0.025289 | 0.082369 | 0.031387 | 0.217380 |
| 2012 | Lewis | 0.200933 | 0.035459 | 0.055959 | 0.000000 | 0.286611 | 0.064613 | 0.025289 | 0.082369 | 0.031387 | 0.217380 |
| 2013 | Lewis | 0.200933 | 0.035459 | 0.055959 | 0.000000 | 0.286611 | 0.064613 | 0.025289 | 0.082369 | 0.031387 | 0.217380 |
| 2014 | Lewis | 0.200933 | 0.035459 | 0.055959 | 0.000000 | 0.286611 | 0.064613 | 0.025289 | 0.082369 | 0.031387 | 0.217380 |
| 2015 | Lewis | 0.200933 | 0.035459 | 0.055959 | 0.000000 | 0.286611 | 0.064613 | 0.025289 | 0.082369 | 0.031387 | 0.217380 |
| 2016 | Lewis | 0.200933 | 0.035459 | 0.055959 | 0.000000 | 0.286611 | 0.064613 | 0.025289 | 0.082369 | 0.031387 | 0.217380 |
| 2017 | Lewis | 0.200933 | 0.035459 | 0.055959 | 0.000000 | 0.286611 | 0.064613 | 0.025289 | 0.082369 | 0.031387 | 0.217380 |
| 2018 | Lewis | 0.200933 | 0.035459 | 0.055959 | 0.000000 | 0.286611 | 0.064613 | 0.025289 | 0.082369 | 0.031387 | 0.217380 |
| 2019 | Lewis | 0.200933 | 0.035459 | 0.055959 | 0.000000 | 0.286611 | 0.064613 | 0.025289 | 0.082369 | 0.031387 | 0.217380 |
| 2020 | Lewis | 0.200933 | 0.035459 | 0.055959 | 0.000000 | 0.286611 | 0.064613 | 0.025289 | 0.082369 | 0.031387 | 0.217380 |
| 2021 | Lewis | 0.200933 | 0.035459 | 0.055959 | 0.000000 | 0.286611 | 0.064613 | 0.025289 | 0.082369 | 0.031387 | 0.217380 |
| 2022 | Lewis | 0.200933 | 0.035459 | 0.055959 | 0.000000 | 0.286611 | 0.064613 | 0.025289 | 0.082369 | 0.031387 | 0.217380 |
| 2023 | Lewis | 0.200933 | 0.035459 | 0.055959 | 0.000000 | 0.286611 | 0.064613 | 0.025289 | 0.082369 | 0.031387 | 0.217380 |
| 2024 | Lewis | 0.200933 | 0.035459 | 0.055959 | 0.000000 | 0.286611 | 0.064613 | 0.025289 | 0.082369 | 0.031387 | 0.217380 |
| 2025 | Lewis | 0.200933 | 0.035459 | 0.055959 | 0.000000 | 0.286611 | 0.064613 | 0.025289 | 0.082369 | 0.031387 | 0.217380 |
| 2005 | Pierce | 0.173205 | 0.030566 | 0.131323 | 0.010872 | 0.228504 | 0.071500 | 0.017294 | 0.104852 | 0.012382 | 0.219503 |
| 2006 | Pierce | 0.173205 | 0.030566 | 0.131323 | 0.010872 | 0.228504 | 0.071500 | 0.017294 | 0.104852 | 0.012382 | 0.219503 |

## Commercial Gas Building Type Allocation

| Year | County | Dry Goods Retail | Grocery | Office | Restaurant | Ware-house | Hospital | Hotel/ Motel | School | University | Other |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 2007 | Pierce | 0.173205 | 0.030566 | 0.131323 | 0.010872 | 0.228504 | 0.071500 | 0.017294 | 0.104852 | 0.012382 | 0.219503 |
| 2008 | Pierce | 0.173205 | 0.030566 | 0.131323 | 0.010872 | 0.228504 | 0.071500 | 0.017294 | 0.104852 | 0.012382 | 0.219503 |
| 2009 | Pierce | 0.173205 | 0.030566 | 0.131323 | 0.010872 | 0.228504 | 0.071500 | 0.017294 | 0.104852 | 0.012382 | 0.219503 |
| 2010 | Pierce | 0.173205 | 0.030566 | 0.131323 | 0.010872 | 0.228504 | 0.071500 | 0.017294 | 0.104852 | 0.012382 | 0.219503 |
| 2011 | Pierce | 0.173205 | 0.030566 | 0.131323 | 0.010872 | 0.228504 | 0.071500 | 0.017294 | 0.104852 | 0.012382 | 0.219503 |
| 2012 | Pierce | 0.173205 | 0.030566 | 0.131323 | 0.010872 | 0.228504 | 0.071500 | 0.017294 | 0.104852 | 0.012382 | 0.219503 |
| 2013 | Pierce | 0.173205 | 0.030566 | 0.131323 | 0.010872 | 0.228504 | 0.071500 | 0.017294 | 0.104852 | 0.012382 | 0.219503 |
| 2014 | Pierce | 0.173205 | 0.030566 | 0.131323 | 0.010872 | 0.228504 | 0.071500 | 0.017294 | 0.104852 | 0.012382 | 0.219503 |
| 2015 | Pierce | 0.173205 | 0.030566 | 0.131323 | 0.010872 | 0.228504 | 0.071500 | 0.017294 | 0.104852 | 0.012382 | 0.219503 |
| 2016 | Pierce | 0.173205 | 0.030566 | 0.131323 | 0.010872 | 0.228504 | 0.071500 | 0.017294 | 0.104852 | 0.012382 | 0.219503 |
| 2017 | Pierce | 0.173205 | 0.030566 | 0.131323 | 0.010872 | 0.228504 | 0.071500 | 0.017294 | 0.104852 | 0.012382 | 0.219503 |
| 2018 | Pierce | 0.173205 | 0.030566 | 0.131323 | 0.010872 | 0.228504 | 0.071500 | 0.017294 | 0.104852 | 0.012382 | 0.219503 |
| 2019 | Pierce | 0.173205 | 0.030566 | 0.131323 | 0.010872 | 0.228504 | 0.071500 | 0.017294 | 0.104852 | 0.012382 | 0.219503 |
| 2020 | Pierce | 0.173205 | 0.030566 | 0.131323 | 0.010872 | 0.228504 | 0.071500 | 0.017294 | 0.104852 | 0.012382 | 0.219503 |
| 2021 | Pierce | 0.173205 | 0.030566 | 0.131323 | 0.010872 | 0.228504 | 0.071500 | 0.017294 | 0.104852 | 0.012382 | 0.219503 |
| 2022 | Pierce | 0.173205 | 0.030566 | 0.131323 | 0.010872 | 0.228504 | 0.071500 | 0.017294 | 0.104852 | 0.012382 | 0.219503 |
| 2023 | Pierce | 0.173205 | 0.030566 | 0.131323 | 0.010872 | 0.228504 | 0.071500 | 0.017294 | 0.104852 | 0.012382 | 0.219503 |
| 2024 | Pierce | 0.173205 | 0.030566 | 0.131323 | 0.010872 | 0.228504 | 0.071500 | 0.017294 | 0.104852 | 0.012382 | 0.219503 |
| 2025 | Pierce | 0.173205 | 0.030566 | 0.131323 | 0.010872 | 0.228504 | 0.071500 | 0.017294 | 0.104852 | 0.012382 | 0.219503 |
| 2005 | Snohomish | 0.167209 | 0.029507 | 0.186335 | 0.011317 | 0.159915 | 0.051368 | 0.027461 | 0.131856 | 0.004983 | 0.230049 |
| 2006 | Snohomish | 0.167209 | 0.029507 | 0.186335 | 0.011317 | 0.159915 | 0.051368 | 0.027461 | 0.131856 | 0.004983 | 0.230049 |
| 2007 | Snohomish | 0.167209 | 0.029507 | 0.186335 | 0.011317 | 0.159915 | 0.051368 | 0.027461 | 0.131856 | 0.004983 | 0.230049 |
| 2008 | Snohomish | 0.167209 | 0.029507 | 0.186335 | 0.011317 | 0.159915 | 0.051368 | 0.027461 | 0.131856 | 0.004983 | 0.230049 |
| 2009 | Snohomish | 0.167209 | 0.029507 | 0.186335 | 0.011317 | 0.159915 | 0.051368 | 0.027461 | 0.131856 | 0.004983 | 0.230049 |
| 2010 | Snohomish | 0.167209 | 0.029507 | 0.186335 | 0.011317 | 0.159915 | 0.051368 | 0.027461 | 0.131856 | 0.004983 | 0.230049 |
| 2011 | Snohomish | 0.167209 | 0.029507 | 0.186335 | 0.011317 | 0.159915 | 0.051368 | 0.027461 | 0.131856 | 0.004983 | 0.230049 |
| 2012 | Snohomish | 0.167209 | 0.029507 | 0.186335 | 0.011317 | 0.159915 | 0.051368 | 0.027461 | 0.131856 | 0.004983 | 0.230049 |
| 2013 | Snohomish | 0.167209 | 0.029507 | 0.186335 | 0.011317 | 0.159915 | 0.051368 | 0.027461 | 0.131856 | 0.004983 | 0.230049 |
| 2014 | Snohomish | 0.167209 | 0.029507 | 0.186335 | 0.011317 | 0.159915 | 0.051368 | 0.027461 | 0.131856 | 0.004983 | 0.230049 |
| 2015 | Snohomish | 0.167209 | 0.029507 | 0.186335 | 0.011317 | 0.159915 | 0.051368 | 0.027461 | 0.131856 | 0.004983 | 0.230049 |

## Commercial Gas Building Type Allocation

| Year | County | Dry Goods Retail | Grocery | Office | Restaurant | Ware-house | Hospital | Hotel/ Motel | School | University | Other |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 2016 | Snohomish | 0.167209 | 0.029507 | 0.186335 | 0.011317 | 0.159915 | 0.051368 | 0.027461 | 0.131856 | 0.004983 | 0.230049 |
| 2017 | Snohomish | 0.167209 | 0.029507 | 0.186335 | 0.011317 | 0.159915 | 0.051368 | 0.027461 | 0.131856 | 0.004983 | 0.230049 |
| 2018 | Snohomish | 0.167209 | 0.029507 | 0.186335 | 0.011317 | 0.159915 | 0.051368 | 0.027461 | 0.131856 | 0.004983 | 0.230049 |
| 2019 | Snohomish | 0.167209 | 0.029507 | 0.186335 | 0.011317 | 0.159915 | 0.051368 | 0.027461 | 0.131856 | 0.004983 | 0.230049 |
| 2020 | Snohomish | 0.167209 | 0.029507 | 0.186335 | 0.011317 | 0.159915 | 0.051368 | 0.027461 | 0.131856 | 0.004983 | 0.230049 |
| 2021 | Snohomish | 0.167209 | 0.029507 | 0.186335 | 0.011317 | 0.159915 | 0.051368 | 0.027461 | 0.131856 | 0.004983 | 0.230049 |
| 2022 | Snohomish | 0.167209 | 0.029507 | 0.186335 | 0.011317 | 0.159915 | 0.051368 | 0.027461 | 0.131856 | 0.004983 | 0.230049 |
| 2023 | Snohomish | 0.167209 | 0.029507 | 0.186335 | 0.011317 | 0.159915 | 0.051368 | 0.027461 | 0.131856 | 0.004983 | 0.230049 |
| 2024 | Snohomish | 0.167209 | 0.029507 | 0.186335 | 0.011317 | 0.159915 | 0.051368 | 0.027461 | 0.131856 | 0.004983 | 0.230049 |
| 2025 | Snohomish | 0.167209 | 0.029507 | 0.186335 | 0.011317 | 0.159915 | 0.051368 | 0.027461 | 0.131856 | 0.004983 | 0.230049 |
| 2005 | Thurston | 0.159739 | 0.028189 | 0.212291 | 0.011545 | 0.199104 | 0.064561 | 0.032951 | 0.115326 | 0.018908 | 0.157386 |
| 2006 | Thurston | 0.159739 | 0.028189 | 0.212291 | 0.011545 | 0.199104 | 0.064561 | 0.032951 | 0.115326 | 0.018908 | 0.157386 |
| 2007 | Thurston | 0.159739 | 0.028189 | 0.212291 | 0.011545 | 0.199104 | 0.064561 | 0.032951 | 0.115326 | 0.018908 | 0.157386 |
| 2008 | Thurston | 0.159739 | 0.028189 | 0.212291 | 0.011545 | 0.199104 | 0.064561 | 0.032951 | 0.115326 | 0.018908 | 0.157386 |
| 2009 | Thurston | 0.159739 | 0.028189 | 0.212291 | 0.011545 | 0.199104 | 0.064561 | 0.032951 | 0.115326 | 0.018908 | 0.157386 |
| 2010 | Thurston | 0.159739 | 0.028189 | 0.212291 | 0.011545 | 0.199104 | 0.064561 | 0.032951 | 0.115326 | 0.018908 | 0.157386 |
| 2011 | Thurston | 0.159739 | 0.028189 | 0.212291 | 0.011545 | 0.199104 | 0.064561 | 0.032951 | 0.115326 | 0.018908 | 0.157386 |
| 2012 | Thurston | 0.159739 | 0.028189 | 0.212291 | 0.011545 | 0.199104 | 0.064561 | 0.032951 | 0.115326 | 0.018908 | 0.157386 |
| 2013 | Thurston | 0.159739 | 0.028189 | 0.212291 | 0.011545 | 0.199104 | 0.064561 | 0.032951 | 0.115326 | 0.018908 | 0.157386 |
| 2014 | Thurston | 0.159739 | 0.028189 | 0.212291 | 0.011545 | 0.199104 | 0.064561 | 0.032951 | 0.115326 | 0.018908 | 0.157386 |
| 2015 | Thurston | 0.159739 | 0.028189 | 0.212291 | 0.011545 | 0.199104 | 0.064561 | 0.032951 | 0.115326 | 0.018908 | 0.157386 |
| 2016 | Thurston | 0.159739 | 0.028189 | 0.212291 | 0.011545 | 0.199104 | 0.064561 | 0.032951 | 0.115326 | 0.018908 | 0.157386 |
| 2017 | Thurston | 0.159739 | 0.028189 | 0.212291 | 0.011545 | 0.199104 | 0.064561 | 0.032951 | 0.115326 | 0.018908 | 0.157386 |
| 2018 | Thurston | 0.159739 | 0.028189 | 0.212291 | 0.011545 | 0.199104 | 0.064561 | 0.032951 | 0.115326 | 0.018908 | 0.157386 |
| 2019 | Thurston | 0.159739 | 0.028189 | 0.212291 | 0.011545 | 0.199104 | 0.064561 | 0.032951 | 0.115326 | 0.018908 | 0.157386 |
| 2020 | Thurston | 0.159739 | 0.028189 | 0.212291 | 0.011545 | 0.199104 | 0.064561 | 0.032951 | 0.115326 | 0.018908 | 0.157386 |
| 2021 | Thurston | 0.159739 | 0.028189 | 0.212291 | 0.011545 | 0.199104 | 0.064561 | 0.032951 | 0.115326 | 0.018908 | 0.157386 |
| 2022 | Thurston | 0.159739 | 0.028189 | 0.212291 | 0.011545 | 0.199104 | 0.064561 | 0.032951 | 0.115326 | 0.018908 | 0.157386 |
| 2023 | Thurston | 0.159739 | 0.028189 | 0.212291 | 0.011545 | 0.199104 | 0.064561 | 0.032951 | 0.115326 | 0.018908 | 0.157386 |
| 2024 | Thurston | 0.159739 | 0.028189 | 0.212291 | 0.011545 | 0.199104 | 0.064561 | 0.032951 | 0.115326 | 0.018908 | 0.157386 |

## Commercial Gas Building Type Allocation

| Year | County | Dry Goods Retail | Grocery | Office | Restaurant | Ware-house | Hospital | Hotel/ Motel | School | University | Other |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 2025 | Thurston | 0.159739 | 0.028189 | 0.212291 | 0.011545 | 0.199104 | 0.064561 | 0.032951 | 0.115326 | 0.018908 | 0.157386 |

## Commercial Gas Efficiency Shares

| bName | nName | fName | Stock | Standard | High | Premium |
|---|---|---|---|---|---|---|
| Dry_Goods_Retail | Other | Gas | 1 | - - - | - - - | - - - |
| Dry_Goods_Retail | Space_Heat | Electric | 1 | - - - | - - - | - - - |
| Dry_Goods_Retail | Space_Heat | Gas | 0.37 | 0.6 | 0.02 | 0.01 |
| Dry_Goods_Retail | Water_Heat | Electric | 1 | - - - | - - - | - - - |
| Dry_Goods_Retail | Water_Heat | Gas | 0.700 | 0.225 | 0.045 | 0.030 |
| Grocery | Other | Gas | 1 | - - - | - - - | - - - |
| Grocery | Space_Heat | Electric | 1 | - - - | - - - | - - - |
| Grocery | Space_Heat | Gas | 0.37 | 0.6 | 0.02 | 0.01 |
| Grocery | Water_Heat | Electric | 1 | - - - | - - - | - - - |
| Grocery | Water_Heat | Gas | 0.700 | 0.225 | 0.045 | 0.030 |
| Hospital | Cooking | Electric | 1 | - - - | - - - | - - - |
| Hospital | Cooking | Gas | 0.95 | 0.05 | - - - | - - - |
| Hospital | Other | Gas | 1 | - - - | - - - | - - - |
| Hospital | Pool_Heat | Gas | 1 | - - - | - - - | - - - |
| Hospital | Space_Heat | Electric | 1 | - - - | - - - | - - - |
| Hospital | Space_Heat | Gas | 0.37 | 0.6 | 0.02 | 0.01 |
| Hospital | Water_Heat | Electric | 1 | - - - | - - - | - - - |
| Hospital | Water_Heat | Gas | 0.700 | 0.225 | 0.045 | 0.030 |
| Hotel_Motel | Other | Gas | 1 | - - - | - - - | - - - |
| Hotel_Motel | Pool_Heat | Gas | 1 | - - - | - - - | - - - |
| Hotel_Motel | Space_Heat | Electric | 1 | - - - | - - - | - - - |
| Hotel_Motel | Space_Heat | Gas | 0.37 | 0.6 | 0.02 | 0.01 |
| Hotel_Motel | Water_Heat | Electric | 1 | - - - | - - - | - - - |
| Hotel_Motel | Water_Heat | Gas | 0.700 | 0.225 | 0.045 | 0.030 |
| Office | Other | Gas | 1 | - - - | - - - | - - - |

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## Commercial Gas Efficiency Shares

| bName | nName | fName | Stock | Standard | High | Premium |
|---|---|---|---|---|---|---|
| Office | Space_Heat | Electric | 1 | - - - | - - - | - - - |
| Office | Space_Heat | Gas | 0.37 | 0.6 | 0.02 | 0.01 |
| Office | Water_Heat | Electric | 1 | - - - | - - - | - - - |
| Office | Water_Heat | Gas | 0.700 | 0.225 | 0.045 | 0.030 |
| Other | Other | Gas | 1 | - - - | - - - | - - - |
| Other | Space_Heat | Electric | 1 | - - - | - - - | - - - |
| Other | Space_Heat | Gas | 0.37 | 0.6 | 0.02 | 0.01 |
| Other | Water_Heat | Electric | 1 | - - - | - - - | - - - |
| Other | Water_Heat | Gas | 0.700 | 0.225 | 0.045 | 0.030 |
| Restaurant | Cooking | Electric | 1 | - - - | - - - | - - - |
| Restaurant | Cooking | Gas | 0.95 | 0.05 | - - - | - - - |
| Restaurant | Other | Gas | 1 | - - - | - - - | - - - |
| Restaurant | Space_Heat | Electric | 1 | - - - | - - - | - - - |
| Restaurant | Space_Heat | Gas | 0.37 | 0.6 | 0.02 | 0.01 |
| Restaurant | Water_Heat | Electric | 1 | . | . | . |
| Restaurant | Water_Heat | Gas | 0.700 | 0.225 | 0.045 | 0.030 |
| School | Other | Gas | 1 | - - - | - - - | - - - |
| School | Pool_Heat | Gas | 1 | - - - | - - - | - - - |
| School | Space_Heat | Electric | 1 | - - - | - - - | - - - |
| School | Space_Heat | Gas | 0.37 | 0.6 | 0.02 | 0.01 |
| School | Water_Heat | Electric | 1 | . | . | . |
| School | Water_Heat | Gas | 0.700 | 0.225 | 0.045 | 0.030 |
| University | Cooking | Electric | 1 | - - - | - - - | - - - |
| University | Cooking | Gas | 0.95 | 0.05 | - - - | - - - |
| University | Other | Gas | 1 | - - - | - - - | - - - |
| University | Pool_Heat | Gas | 1 | - - - | - - - | - - - |
| University | Space_Heat | Electric | 1 | - - - | - - - | - - - |
| University | Space_Heat | Gas | 0.37 | 0.6 | 0.02 | 0.01 |
| University | Water_Heat | Electric | 1 | - - - | - - - | - - - |
| University | Water_Heat | Gas | 0.700 | 0.225 | 0.045 | 0.030 |
| Warehouse | Other | Gas | 1 | - - - | - - - | - - - |
| Warehouse | Space_Heat | Electric | 1 | - - - | - - - | - - - |

## Commercial Gas Efficiency Shares

| bName | nName | fName | Stock | Standard | High | Premium |
|---|---|---|---|---|---|---|
| Warehouse | Space_Heat | Gas | 0.37 | 0.6 | 0.02 | 0.01 |
| Warehouse | Water_Heat | Electric | 1 | - - - | - - - | - - - |
| Warehouse | Water_Heat | Gas | 0.700 | 0.225 | 0.045 | 0.030 |
| Hotel_Motel | Cooking | Electric | 1 | - - - | - - - | - - - |
| Hotel_Motel | Cooking | Gas | 0.95 | 0.05 | - - - | - - - |
| School | Cooking | Electric | 1 | - - - | - - - | - - - |
| School | Cooking | Gas | 0.95 | 0.05 | - - - | - - - |
| Grocery | Cooking | Electric | 1 | - - - | - - - | - - - |
| Grocery | Cooking | Gas | 0.95 | 0.05 | - - - | - - - |

## Commercial Gas Electric Price Forecast ($/kWh)

| Year | Price Deflator | Commercial Average Price | Commercial Marginal Price |
|---|---|---|---|
| 2005 | 100.00 | 0.07395 | 0.07395 |
| 2006 | 102.29 | 0.07665 | 0.07665 |
| 2007 | 104.61 | 0.07528 | 0.07528 |
| 2008 | 107.08 | 0.07694 | 0.07694 |
| 2009 | 109.72 | 0.07868 | 0.07868 |
| 2010 | 112.67 | 0.08066 | 0.08066 |
| 2011 | 115.97 | 0.08284 | 0.08284 |
| 2012 | 119.34 | 0.08505 | 0.08505 |
| 2013 | 123.05 | 0.08736 | 0.08736 |
| 2014 | 126.80 | 0.08991 | 0.08991 |
| 2015 | 130.47 | 0.09273 | 0.09273 |
| 2016 | 134.23 | 0.09558 | 0.09558 |
| 2017 | 138.36 | 0.09863 | 0.09863 |
| 2018 | 142.88 | 0.10190 | 0.10190 |
| 2019 | 147.75 | 0.10536 | 0.10536 |
| 2020 | 152.92 | 0.10895 | 0.10895 |
| 2021 | 158.32 | 0.11267 | 0.11267 |
| 2022 | 163.95 | 0.11653 | 0.11653 |
| 2023 | 169.82 | 0.12049 | 0.12049 |
| 2024 | 175.93 | 0.12458 | 0.12458 |
| 2025 | 182.27 | 0.12881 | 0.12881 |

## Commercial Gas Gas Price Forecast ($/therm)

| Year | Price Deflator | Commercial Average Price | Commercial Marginal Price |
|---|---|---|---|
| 2005 | 100.00 | 0.98069 | 0.98069 |
| 2006 | 102.29 | 0.98887 | 0.98887 |
| 2007 | 104.61 | 0.97624 | 0.97624 |
| 2008 | 107.08 | 0.88972 | 0.88972 |
| 2009 | 109.72 | 0.86538 | 0.86538 |
| 2010 | 112.67 | 0.79505 | 0.79505 |
| 2011 | 115.97 | 0.87203 | 0.87203 |
| 2012 | 119.34 | 0.89133 | 0.89133 |
| 2013 | 123.05 | 0.96310 | 0.96310 |
| 2014 | 126.80 | 1.02968 | 1.02968 |
| 2015 | 130.47 | 1.03847 | 1.03847 |
| 2016 | 134.23 | 0.92677 | 0.92677 |
| 2017 | 138.36 | 0.96180 | 0.96180 |
| 2018 | 142.88 | 1.05257 | 1.05257 |
| 2019 | 147.75 | 1.13966 | 1.13966 |
| 2020 | 152.92 | 1.20407 | 1.20407 |
| 2021 | 158.32 | 1.22945 | 1.22945 |
| 2022 | 163.95 | 1.25134 | 1.25134 |
| 2023 | 169.82 | 1.27385 | 1.27385 |
| 2024 | 175.93 | 1.27357 | 1.27357 |
| 2025 | 182.27 | 1.29648 | 1.29648 |

## Commercial Gas Average Square Footage by Building Type

| Year | Dry Goods Retail | Grocery | Office | Restau-rant | Ware-house | Hospital | Hotel/ Motel | School | University | Other |
|---|---|---|---|---|---|---|---|---|---|---|
| 2005 | 6,421 | 8,637 | 12,985 | 12,772 | 9,525 | 8,153 | 3,126 | 22,241 | 32,392 | 15,284 |
| 2006 | 6,421 | 8,637 | 12,985 | 12,772 | 9,525 | 8,153 | 3,126 | 22,241 | 32,392 | 15,284 |
| 2007 | 6,421 | 8,637 | 12,985 | 12,772 | 9,525 | 8,153 | 3,126 | 22,241 | 32,392 | 15,284 |
| 2008 | 6,421 | 8,637 | 12,985 | 12,772 | 9,525 | 8,153 | 3,126 | 22,241 | 32,392 | 15,284 |
| 2009 | 6,421 | 8,637 | 12,985 | 12,772 | 9,525 | 8,153 | 3,126 | 22,241 | 32,392 | 15,284 |
| 2010 | 6,421 | 8,637 | 12,985 | 12,772 | 9,525 | 8,153 | 3,126 | 22,241 | 32,392 | 15,284 |
| 2011 | 6,421 | 8,637 | 12,985 | 12,772 | 9,525 | 8,153 | 3,126 | 22,241 | 32,392 | 15,284 |
| 2012 | 6,421 | 8,637 | 12,985 | 12,772 | 9,525 | 8,153 | 3,126 | 22,241 | 32,392 | 15,284 |
| 2013 | 6,421 | 8,637 | 12,985 | 12,772 | 9,525 | 8,153 | 3,126 | 22,241 | 32,392 | 15,284 |
| 2014 | 6,421 | 8,637 | 12,985 | 12,772 | 9,525 | 8,153 | 3,126 | 22,241 | 32,392 | 15,284 |
| 2015 | 6,421 | 8,637 | 12,985 | 12,772 | 9,525 | 8,153 | 3,126 | 22,241 | 32,392 | 15,284 |
| 2016 | 6,421 | 8,637 | 12,985 | 12,772 | 9,525 | 8,153 | 3,126 | 22,241 | 32,392 | 15,284 |
| 2017 | 6,421 | 8,637 | 12,985 | 12,772 | 9,525 | 8,153 | 3,126 | 22,241 | 32,392 | 15,284 |
| 2018 | 6,421 | 8,637 | 12,985 | 12,772 | 9,525 | 8,153 | 3,126 | 22,241 | 32,392 | 15,284 |
| 2019 | 6,421 | 8,637 | 12,985 | 12,772 | 9,525 | 8,153 | 3,126 | 22,241 | 32,392 | 15,284 |
| 2020 | 6,421 | 8,637 | 12,985 | 12,772 | 9,525 | 8,153 | 3,126 | 22,241 | 32,392 | 15,284 |
| 2021 | 6,421 | 8,637 | 12,985 | 12,772 | 9,525 | 8,153 | 3,126 | 22,241 | 32,392 | 15,284 |
| 2022 | 6,421 | 8,637 | 12,985 | 12,772 | 9,525 | 8,153 | 3,126 | 22,241 | 32,392 | 15,284 |
| 2023 | 6,421 | 8,637 | 12,985 | 12,772 | 9,525 | 8,153 | 3,126 | 22,241 | 32,392 | 15,284 |
| 2024 | 6,421 | 8,637 | 12,985 | 12,772 | 9,525 | 8,153 | 3,126 | 22,241 | 32,392 | 15,284 |
| 2025 | 6,421 | 8,637 | 12,985 | 12,772 | 9,525 | 8,153 | 3,126 | 22,241 | 32,392 | 15,284 |

## Commercial Gas Number of Gas Meters Per Building

| Year | Dry Goods Retail | Grocery | Office | Restau-rant | Ware-house | Hospital | Hotel/ Motel | School | University | Other |
|---|---|---|---|---|---|---|---|---|---|---|
| 2005 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| 2006 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| 2007 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| 2008 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| 2009 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| 2010 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| 2011 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| 2012 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| 2013 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| 2014 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| 2015 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| 2016 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| 2017 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| 2018 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| 2019 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| 2020 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| 2021 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| 2022 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| 2023 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| 2024 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| 2025 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |

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# APPENDIX C
# ELECTRIC MODELS

PSE uses three primary models for least cost planning. The AURORA model analyzes the western power market to produce hourly electricity price forecasts. The Portfolio Screening Model (PSM) tests portfolios to evaluate PSE's long-term incremental portfolio costs. Finally, the Conservation Screening Model (CSM) tests demand-side resource cases to determine the most cost effective level for a given generation portfolio.

The first section of this appendix discusses the AURORA model's algorithm along with key inputs used. The AUIRORA section ends with tables of monthly power prices for the scenarios used. The second section discusses the Portfolio Screening Model (PSM) and the Conservation Screening Model (CSM), and provides key input information. The results from PSM and CSM are detailed in Chapter X and Appendix G.

# THE AURORA DISPATCH MODEL

## A. Overview

PSE uses the AURORA model to estimate the market price of power used in serving its 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, regional demand for power, and transmission, which drive the electric energy market. 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.

## B. 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 21 areas primarily by state and province, except for California which has eight areas, Nevada which has two areas, and Oregon and Washington which are combined. 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.

Load forecasts are created for each area. The load forecast includes the base year load forecast and an annual average growth rate. Since the demand for electricity changes both 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. PSE adopted the long-run forecast from EPIS after reviewing and comparing the forecast with the U.S. Energy Information Agency (EIA) and the Northwest Power and Conservation Council (NPCC). The EPIS and NPCC forecasts were very close, and EPIS relied on EIA and North American Electric Reliability Council (NERC).

**Exhibit C-1**
**Regional Growth Rates**

| **Regions (States)** | **Annual Average Growth Rate** |
|---|---|
| Rockies (WY, MT, CO, ID) | 2.0% |
| Northwest (WA, OR, BC, NV-No.) | 1.8% |
| California | 1.97% |
| Southwest (AZ, NM, NV-So.) | 2.5% |
| Utah | 1.8% |

All generating resources are included in the resource database. Information on each resource includes its area, capacity, fuel type, efficiency, and expected outages (both forced and unforced). Previously, the generating resource landscape saw few changes; however, numerous plants are under construction, and many more are in the planning stage. PSE uses current knowledge of Northwest resources, and utilizes EPIS, Henwood, public sources (e.g., Cal-ISO, CEC, etc.) and private contacts to update the over 3,000 electric power resources in the West.

The model incorporates resources that are under construction with expected online dates; however, because of numerous factors causing uncertainty, PSE includes only new plants fueled by natural gas that will be completed in 2005. Coal plants currently under construction with online dates through 2006 were also included, as well as two wind plant projects in which PSE is directly participating.

**Exhibit C-2**
**Power Plants under Construction**

| Plant | Location | Fuel | Capacity (MW) | Online Date |
|---|---|---|---|---|
| Genesee | AB | Coal | 440 | 1/1/2005 |
| Montana First | MT | Gas | 240 | 1/1/2005 |
| Pastoria Energy Center | CA | Gas | 750 | 6/1/2005 |
| Metcalf Energy Center | CA | Gas | 600 | 6/1/2005 |
| Cosumnes Power Plant | CA | Gas | 500 | 6/1/2005 |
| Rocky Mt. Power | MT | Coal | 116 | 12/1/2005 |
| Hopkins Ridge | WA | Wind | 149.4 | 1/1/2006 |
| Springerville | AZ | Coal | 400 | 6/30/2006 |
| Wild Horse | WA | Wind | 239.4 | 1/1/2007 |

Many states in the WECC have passed statutes requiring renewable portfolio standards (RPS) to support the development of renewable resources. Typically an RPS states that a specific percentage of energy consumed must be from renewable resources by a certain date (e.g., 10 percent by 2015). While these states have shown clear intent for policy to support renewable energy development, they also provide pathways to avoid these strict requirements. CERA, as part of its Rearview Mirror scenario, assumes that the laws will be relaxed after 2010. Exhibit C-3 shows the scope and timing of the various RPS in the WECC.

**Exhibit C-3**
**State Renewable Energy Portfolios**

| State | Percent Renewable Energy | Effective Date |
|---|---|---|
| CA | 20 | 2017 |
| AZ | 1.1 | 2007 |
| NM | 10 | 2011 |
| NV | 15 | 2013 |
| CO | 10 | 2015 |
| OR/WA | 10 | 2013 |

For the Green World scenario, PSE included all necessary resources so that all states would meet the guidelines. For the Business as Usual scenario, renewable resources are built until 2011 and the market may build more after that. The Current Momentum scenario follows the Business as Usual, with the addition of a standard for OR and WA.

The price of fuel is an important factor in determining the economics of electric power production. The two most important fuels are natural gas and coal. The fuels need to be priced appropriately for each area. For example, a plant in Washington may receive its gas from Canada at the Sumas hub, whereas a plant in Southern California may receive gas from New Mexico or Texas at the Topock hub, which is priced differently. PSE adopted the CERA Rearview Mirror forecast as its base forecast in 2004. In addition to the Rearview Mirror forecast, PSE also uses the CERA Green World forecast and the CERA World in Turmoil forecast for other scenarios.

Coal prices were adopted from the EIA 2004 Annual Energy Outlook. They provide long-run prices for three coal basins: Southwest (NM and AZ), Rockies (CO and UT) and Powder River Basin (MT and WY). They also provide information on costs associated with transporting the coal to other areas, which is added into the fuel cost for resources for the different areas.

Water availability greatly influences the price of electric power in the Northwest. PSE assumes that hydro power generation is based on the average stream flows for the 60 historical years of 1929-1988. While there is also much hydro power 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 hydro power 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." Transmission analysis for the May, 2005 Least Cost Plan was done outside the AURORA model.

### C. 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; 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.

Exhibit C-4 shows the cost and performance characteristics for the generic resources in AURORA. The primary source of information is the EIA, "Cost and Performance Characteristics of New Central Station Electricity Generating Technologies." The costs were adjusted to $2,000, which is necessary for input to AURORA.

**Exhibit C-4**
**Cost and Performance Characteristics**

| Technology | Capacity (MW) | Heat Rate (btu/kWh) | All-In-Cost ($/kW) | Fixed O&M ($/kW-yr) | Variable O&M ($/MWh) |
|---|---|---|---|---|---|
| CCCT | 400 | 6928 | 602 | 40.55 | 1.97 |
| SCCT | 188 | 9,545 | 399 | 24.84 | 3.90 |
| Scrubbed Coal | 600 | 9,000 | 1,112 | 39.00 | 2.95 |
| Coal with CO2 Mitigation | 380 | 9600 | 1,987 | 54.00 | 2.41 |
| Wind | 100 | | 1,084 | 38.44 | 2.95 |

Costs in $2000 for AURORA modeling
Fixed O&M includes fixed power transmission and fixed gas charge for CCCT

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. Exhibit C-5 is a series of tables with the AURORA price forecasts for the different scenarios.

**Exhibit C-5**
**Monthly Flat Mid-C Prices**
**(Nominal $/MWH)**

## Business as Usual (BAU)

| Business As Usual | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **FLAT** | **Jan** | **Feb** | **Mar** | **Apr** | **May** | **Jun** | **Jul** | **Aug** | **Sep** | **Oct** | **Nov** | **Dec** | **Ave** |
| **2006** | 53.73 | 41.33 | 46.03 | 37.42 | 33.08 | 28.01 | 34.00 | 41.60 | 43.31 | 44.67 | 47.94 | 48.75 | 41.69 |
| **2007** | 48.79 | 41.32 | 42.45 | 38.84 | 34.27 | 29.08 | 35.92 | 45.49 | 49.00 | 47.28 | 46.97 | 46.62 | 42.19 |
| **2008** | 46.61 | 37.10 | 40.26 | 34.44 | 31.37 | 28.42 | 34.47 | 42.22 | 44.35 | 43.15 | 41.33 | 40.45 | 38.71 |
| **2009** | 37.69 | 33.32 | 36.27 | 30.73 | 27.80 | 23.07 | 29.10 | 36.31 | 39.75 | 38.60 | 37.00 | 36.02 | 33.82 |
| **2010** | 35.85 | 29.39 | 31.69 | 27.10 | 24.73 | 20.88 | 26.06 | 31.89 | 35.09 | 33.74 | 37.95 | 37.96 | 31.05 |
| **2011** | 36.89 | 34.12 | 36.88 | 31.10 | 27.50 | 22.95 | 30.98 | 38.62 | 42.82 | 39.99 | 41.56 | 41.37 | 35.42 |
| **2012** | 41.73 | 36.38 | 38.81 | 32.50 | 29.51 | 25.02 | 33.52 | 42.66 | 51.26 | 42.53 | 45.82 | 46.43 | 38.87 |
| **2013** | 44.91 | 40.93 | 43.35 | 36.04 | 31.51 | 26.33 | 37.02 | 46.73 | 59.18 | 47.48 | 51.65 | 51.95 | 43.10 |
| **2014** | 48.40 | 44.59 | 47.75 | 38.27 | 33.16 | 25.88 | 37.46 | 48.64 | 68.78 | 51.86 | 55.51 | 55.14 | 46.29 |
| **2015** | 54.22 | 46.43 | 49.66 | 40.56 | 35.35 | 28.48 | 41.28 | 52.81 | 73.23 | 53.88 | 54.61 | 52.47 | 48.59 |
| **2016** | 51.30 | 39.28 | 43.11 | 35.61 | 32.31 | 27.73 | 36.21 | 48.70 | 74.09 | 49.16 | 48.44 | 48.34 | 44.55 |
| **2017** | 46.64 | 42.09 | 42.99 | 36.70 | 34.21 | 29.79 | 38.98 | 51.99 | 73.43 | 52.40 | 51.73 | 51.21 | 46.02 |
| **2018** | 49.97 | 45.68 | 48.37 | 42.18 | 38.56 | 33.42 | 44.68 | 57.74 | 78.00 | 55.74 | 56.35 | 56.56 | 50.62 |
| **2019** | 54.47 | 49.55 | 52.36 | 45.24 | 40.57 | 30.70 | 43.89 | 55.86 | 71.99 | 57.30 | 60.44 | 60.69 | 51.94 |
| **2020** | 56.89 | 51.68 | 56.21 | 46.23 | 40.12 | 28.97 | 40.60 | 52.47 | 64.36 | 59.30 | 58.04 | 59.11 | 51.18 |
| **2021** | 58.13 | 53.46 | 57.12 | 48.32 | 41.91 | 31.06 | 42.78 | 55.50 | 74.43 | 61.33 | 61.66 | 61.63 | 53.95 |
| **2022** | 59.57 | 54.49 | 58.90 | 49.64 | 44.35 | 33.07 | 44.42 | 58.73 | 75.90 | 61.99 | 62.24 | 63.19 | 55.55 |
| **2023** | 62.50 | 56.91 | 60.73 | 53.46 | 49.70 | 37.10 | 49.55 | 64.99 | 81.74 | 63.75 | 64.76 | 65.27 | 59.22 |
| **2024** | 66.21 | 66.96 | 64.36 | 54.82 | 50.71 | 38.52 | 51.96 | 68.46 | 86.85 | 67.19 | 67.74 | 66.65 | 62.51 |
| **2025** | 66.16 | 64.21 | 65.98 | 60.86 | 52.20 | 42.19 | 56.45 | 77.82 | 90.52 | 70.13 | 70.51 | 69.03 | 65.51 |

## Current Momentum (CM)

| Current Momentum | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| FLAT | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Ave |
| 2006 | 53.25 | 41.24 | 45.96 | 37.09 | 33.03 | 27.56 | 34.04 | 41.51 | 43.20 | 44.72 | 47.69 | 48.65 | 41.50 |
| 2007 | 48.41 | 40.95 | 42.09 | 38.13 | 33.73 | 27.17 | 34.66 | 44.32 | 48.31 | 46.45 | 46.38 | 45.94 | 41.38 |
| 2008 | 45.79 | 36.18 | 39.68 | 33.84 | 30.12 | 27.42 | 33.29 | 41.22 | 43.45 | 42.39 | 40.56 | 40.05 | 37.83 |
| 2009 | 37.27 | 32.75 | 35.78 | 30.50 | 27.19 | 22.01 | 28.15 | 35.33 | 39.07 | 38.15 | 36.70 | 35.64 | 33.21 |
| 2010 | 38.28 | 31.94 | 33.96 | 29.76 | 27.83 | 24.83 | 28.75 | 34.23 | 37.70 | 36.72 | 40.17 | 39.95 | 33.68 |
| 2011 | 38.64 | 36.02 | 39.01 | 33.44 | 30.14 | 26.01 | 32.31 | 39.20 | 43.82 | 42.35 | 43.48 | 42.85 | 37.27 |
| 2012 | 42.32 | 37.41 | 40.70 | 34.20 | 31.57 | 26.97 | 34.14 | 41.31 | 47.28 | 44.39 | 47.02 | 47.65 | 39.58 |
| 2013 | 44.75 | 42.01 | 45.17 | 37.72 | 33.10 | 27.09 | 36.30 | 44.68 | 54.30 | 48.58 | 51.98 | 52.08 | 43.15 |
| 2014 | 50.09 | 46.68 | 49.66 | 41.08 | 35.87 | 29.12 | 39.81 | 49.74 | 61.46 | 52.95 | 56.44 | 56.06 | 47.41 |
| 2015 | 55.67 | 48.50 | 51.77 | 43.13 | 38.71 | 31.80 | 42.31 | 53.57 | 71.88 | 55.94 | 55.89 | 54.28 | 50.29 |
| 2016 | 53.56 | 42.28 | 45.70 | 38.68 | 36.12 | 31.88 | 38.67 | 48.71 | 73.38 | 50.74 | 50.20 | 50.66 | 46.71 |
| 2017 | 50.39 | 45.58 | 46.53 | 40.29 | 37.81 | 33.75 | 41.71 | 57.16 | 81.27 | 55.83 | 55.12 | 55.51 | 50.08 |
| 2018 | 52.96 | 47.99 | 51.00 | 44.69 | 40.96 | 34.19 | 44.98 | 57.56 | 85.49 | 59.86 | 59.89 | 60.26 | 53.32 |
| 2019 | 56.79 | 51.61 | 55.76 | 46.13 | 40.77 | 32.73 | 43.28 | 54.38 | 80.04 | 60.49 | 62.03 | 63.76 | 53.98 |
| 2020 | 62.27 | 55.44 | 59.58 | 49.29 | 43.55 | 34.45 | 46.54 | 59.19 | 80.27 | 63.67 | 62.51 | 63.27 | 56.67 |
| 2021 | 60.80 | 55.50 | 59.27 | 50.29 | 44.66 | 36.00 | 47.21 | 59.87 | 81.34 | 63.71 | 63.16 | 64.45 | 57.19 |
| 2022 | 63.52 | 58.68 | 61.52 | 52.78 | 48.55 | 39.22 | 51.18 | 65.00 | 85.75 | 66.78 | 66.02 | 66.40 | 60.45 |
| 2023 | 64.74 | 60.03 | 63.00 | 54.79 | 51.42 | 40.98 | 52.37 | 66.76 | 89.56 | 68.09 | 66.78 | 68.04 | 62.21 |
| 2024 | 64.65 | 58.66 | 64.59 | 55.72 | 50.27 | 40.42 | 52.64 | 65.16 | 85.93 | 67.86 | 68.31 | 68.44 | 61.89 |
| 2025 | 66.82 | 61.11 | 66.20 | 57.09 | 52.96 | 42.85 | 54.70 | 68.05 | 87.27 | 69.55 | 69.08 | 70.38 | 63.84 |

## Green World (GW)

| Green World | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| FLAT | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Ave |
| 2006 | 52.12 | 39.84 | 45.03 | 36.27 | 32.18 | 25.08 | 32.43 | 40.71 | 42.59 | 44.06 | 46.63 | 48.74 | 40.47 |
| 2007 | 47.57 | 40.84 | 42.13 | 37.74 | 33.00 | 24.46 | 32.90 | 43.17 | 46.65 | 45.42 | 45.95 | 45.69 | 40.46 |
| 2008 | 44.60 | 35.41 | 39.24 | 33.58 | 29.31 | 25.08 | 31.32 | 40.44 | 43.15 | 41.55 | 45.15 | 44.33 | 37.76 |
| 2009 | 40.13 | 35.71 | 40.18 | 33.65 | 30.31 | 22.98 | 30.67 | 40.13 | 44.34 | 43.41 | 45.18 | 45.03 | 37.64 |
| 2010 | 45.99 | 42.86 | 48.65 | 43.84 | 38.16 | 30.55 | 40.44 | 51.32 | 57.09 | 54.79 | 55.50 | 54.95 | 47.01 |
| 2011 | 52.04 | 48.46 | 55.29 | 46.48 | 41.61 | 31.73 | 43.07 | 55.22 | 61.24 | 58.80 | 57.92 | 51.65 | 50.29 |
| 2012 | 51.46 | 47.16 | 52.35 | 44.13 | 40.50 | 33.77 | 43.22 | 53.79 | 58.83 | 55.86 | 55.63 | 55.47 | 49.35 |
| 2013 | 53.94 | 48.98 | 53.33 | 45.28 | 41.55 | 34.53 | 44.19 | 54.60 | 61.51 | 57.42 | 57.74 | 57.41 | 50.87 |
| 2014 | 57.59 | 52.71 | 57.19 | 48.94 | 44.75 | 37.52 | 47.96 | 60.50 | 68.89 | 61.70 | 61.71 | 61.97 | 55.12 |
| 2015 | 59.99 | 54.86 | 58.94 | 51.10 | 47.14 | 40.96 | 50.71 | 62.52 | 72.50 | 63.48 | 62.42 | 61.22 | 57.15 |
| 2016 | 60.99 | 54.93 | 59.15 | 52.02 | 48.34 | 42.45 | 53.28 | 65.62 | 81.89 | 66.87 | 65.09 | 66.78 | 59.78 |
| 2017 | 62.25 | 55.98 | 61.50 | 53.50 | 49.90 | 42.44 | 52.93 | 65.67 | 78.01 | 67.98 | 67.70 | 68.65 | 60.54 |
| 2018 | 64.99 | 58.77 | 64.56 | 56.11 | 51.36 | 42.00 | 54.47 | 67.95 | 82.26 | 70.90 | 68.34 | 68.91 | 62.55 |
| 2019 | 67.94 | 59.79 | 64.41 | 55.15 | 51.04 | 42.28 | 54.21 | 68.12 | 83.54 | 70.64 | 69.46 | 71.22 | 63.15 |
| 2020 | 71.94 | 64.17 | 71.17 | 61.01 | 56.57 | 48.41 | 60.01 | 73.36 | 85.93 | 75.67 | 70.70 | 70.71 | 67.47 |
| 2021 | 73.81 | 65.14 | 71.01 | 61.56 | 58.18 | 50.66 | 62.23 | 76.17 | 90.48 | 75.93 | 73.15 | 73.70 | 69.34 |
| 2022 | 74.73 | 66.18 | 72.36 | 62.21 | 59.90 | 53.71 | 65.45 | 81.24 | 94.67 | 77.58 | 74.13 | 74.00 | 71.35 |
| 2023 | 76.95 | 68.22 | 73.96 | 64.60 | 63.29 | 57.25 | 70.03 | 90.70 | 100.66 | 81.03 | 76.48 | 76.50 | 74.97 |
| 2024 | 78.36 | 69.49 | 76.39 | 65.40 | 65.03 | 59.97 | 73.29 | 98.27 | 105.07 | 82.73 | 77.73 | 78.09 | 77.49 |
| 2025 | 80.19 | 71.26 | 78.01 | 67.60 | 67.43 | 62.60 | 75.16 | 105.27 | 105.93 | 83.72 | 78.80 | 79.23 | 79.60 |

## Low Growth (LG)

| Low Growth | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **FLAT** | **Jan** | **Feb** | **Mar** | **Apr** | **May** | **Jun** | **Jul** | **Aug** | **Sep** | **Oct** | **Nov** | **Dec** | **Ave** |
| **2006** | 53.12 | 41.13 | 45.68 | 37.29 | 32.74 | 27.62 | 33.74 | 41.51 | 43.11 | 44.66 | 47.50 | 48.63 | 41.40 |
| **2007** | 48.00 | 39.71 | 43.70 | 37.52 | 33.05 | 27.31 | 35.00 | 44.46 | 47.51 | 46.47 | 46.61 | 45.29 | 41.22 |
| **2008** | 46.03 | 34.21 | 37.54 | 32.46 | 29.12 | 25.78 | 31.64 | 39.29 | 41.39 | 40.41 | 38.69 | 37.60 | 36.18 |
| **2009** | 37.21 | 29.19 | 31.72 | 27.49 | 25.51 | 22.74 | 26.93 | 32.61 | 34.57 | 33.79 | 33.79 | 32.94 | 30.71 |
| **2010** | 33.31 | 30.20 | 32.63 | 28.27 | 26.10 | 23.44 | 27.52 | 33.52 | 35.40 | 34.40 | 34.90 | 34.45 | 31.18 |
| **2011** | 33.10 | 30.66 | 33.80 | 28.44 | 26.26 | 22.64 | 27.63 | 34.29 | 37.33 | 35.68 | 35.88 | 35.94 | 31.80 |
| **2012** | 35.90 | 32.27 | 35.54 | 29.93 | 27.73 | 23.84 | 29.59 | 37.21 | 45.95 | 37.78 | 40.32 | 40.47 | 34.71 |
| **2013** | 39.60 | 36.36 | 39.77 | 33.37 | 30.84 | 25.71 | 32.40 | 41.51 | 56.28 | 42.31 | 44.08 | 44.29 | 38.88 |
| **2014** | 42.51 | 38.98 | 42.54 | 34.75 | 31.62 | 26.16 | 34.40 | 43.74 | 57.91 | 45.06 | 46.64 | 46.63 | 40.91 |
| **2015** | 46.22 | 41.42 | 45.13 | 37.14 | 33.47 | 28.65 | 36.81 | 48.13 | 63.81 | 48.29 | 47.48 | 45.60 | 43.51 |
| **2016** | 45.65 | 40.44 | 43.84 | 37.46 | 34.70 | 31.11 | 38.92 | 53.53 | 71.64 | 49.85 | 48.64 | 48.04 | 45.32 |
| **2017** | 48.51 | 43.74 | 47.15 | 40.61 | 38.04 | 34.54 | 43.19 | 63.80 | 87.76 | 54.94 | 51.26 | 50.52 | 50.34 |
| **2018** | 48.72 | 42.81 | 46.66 | 39.95 | 37.19 | 33.16 | 41.49 | 56.64 | 81.71 | 52.40 | 48.71 | 47.79 | 48.10 |
| **2019** | 47.29 | 41.53 | 44.64 | 38.30 | 36.14 | 33.57 | 41.13 | 61.04 | 81.34 | 51.72 | 50.22 | 50.15 | 48.09 |
| **2020** | 49.88 | 44.69 | 49.36 | 42.41 | 39.87 | 35.69 | 45.05 | 65.83 | 82.77 | 56.35 | 48.09 | 46.94 | 50.58 |
| **2021** | 49.07 | 43.96 | 48.13 | 41.06 | 39.06 | 35.51 | 44.27 | 66.15 | 82.17 | 55.79 | 49.61 | 49.09 | 50.32 |
| **2022** | 49.74 | 45.49 | 49.57 | 41.98 | 40.55 | 37.79 | 46.47 | 77.16 | 80.71 | 57.09 | 50.53 | 49.74 | 52.24 |
| **2023** | 50.50 | 46.56 | 50.38 | 43.48 | 41.30 | 39.05 | 48.29 | 77.76 | 84.26 | 56.91 | 51.43 | 50.62 | 53.38 |
| **2024** | 50.47 | 45.83 | 50.99 | 43.74 | 41.70 | 37.30 | 46.09 | 77.50 | 83.73 | 58.99 | 51.30 | 50.61 | 53.19 |
| **2025** | 51.11 | 46.36 | 51.41 | 43.67 | 41.87 | 35.63 | 44.29 | 68.78 | 84.76 | 58.00 | 51.79 | 51.29 | 52.41 |

## Robust Growth (RG)

| Robust Growth | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **FLAT** | **Jan** | **Feb** | **Mar** | **Apr** | **May** | **Jun** | **Jul** | **Aug** | **Sep** | **Oct** | **Nov** | **Dec** | **Ave** |
| **2006** | 54.16 | 42.09 | 46.38 | 37.93 | 33.25 | 28.50 | 34.57 | 42.09 | 43.78 | 45.14 | 48.11 | 49.36 | 42.11 |
| **2007** | 49.87 | 42.27 | 43.36 | 39.76 | 34.73 | 29.99 | 36.91 | 46.62 | 49.98 | 47.92 | 47.57 | 47.27 | 43.02 |
| **2008** | 47.65 | 37.84 | 41.13 | 35.30 | 31.99 | 29.50 | 35.86 | 43.50 | 45.43 | 44.20 | 42.20 | 41.52 | 39.68 |
| **2009** | 39.35 | 34.53 | 37.60 | 31.78 | 29.11 | 24.78 | 30.57 | 38.44 | 41.60 | 39.89 | 38.20 | 37.42 | 35.27 |
| **2010** | 38.36 | 30.66 | 33.25 | 28.21 | 26.14 | 22.46 | 27.64 | 34.43 | 39.06 | 35.30 | 39.64 | 39.92 | 32.92 |
| **2011** | 39.98 | 36.14 | 39.13 | 32.83 | 29.94 | 26.10 | 33.74 | 42.67 | 51.72 | 42.67 | 43.61 | 43.61 | 38.51 |
| **2012** | 43.19 | 37.09 | 39.66 | 33.23 | 30.62 | 26.63 | 35.14 | 44.16 | 60.62 | 44.05 | 47.12 | 47.75 | 40.77 |
| **2013** | 42.53 | 39.22 | 42.63 | 34.79 | 30.78 | 23.17 | 32.63 | 41.26 | 54.23 | 45.92 | 49.01 | 49.60 | 40.48 |
| **2014** | 48.63 | 43.86 | 47.55 | 38.27 | 32.52 | 24.21 | 34.00 | 45.02 | 62.55 | 51.54 | 54.35 | 55.00 | 44.79 |
| **2015** | 54.76 | 46.42 | 49.63 | 41.07 | 36.36 | 27.89 | 38.20 | 51.36 | 71.35 | 53.22 | 53.62 | 52.13 | 48.00 |
| **2016** | 51.33 | 39.23 | 42.73 | 35.55 | 32.83 | 27.60 | 35.32 | 45.78 | 65.91 | 48.11 | 47.11 | 47.03 | 43.21 |
| **2017** | 47.36 | 43.16 | 43.35 | 37.54 | 35.07 | 31.18 | 39.86 | 56.78 | 76.13 | 53.18 | 51.85 | 51.74 | 47.27 |
| **2018** | 50.42 | 46.33 | 48.47 | 42.93 | 39.11 | 32.34 | 42.64 | 54.59 | 74.36 | 55.98 | 56.15 | 56.27 | 49.97 |
| **2019** | 54.57 | 49.18 | 53.41 | 44.64 | 39.55 | 28.81 | 39.36 | 50.69 | 70.68 | 58.38 | 59.07 | 60.24 | 50.72 |
| **2020** | 61.01 | 54.90 | 58.56 | 50.10 | 43.98 | 31.83 | 43.73 | 56.29 | 72.86 | 62.09 | 60.45 | 61.18 | 54.75 |
| **2021** | 60.43 | 57.32 | 59.02 | 52.23 | 47.92 | 36.45 | 48.81 | 63.17 | 76.77 | 63.21 | 62.63 | 63.33 | 57.61 |
| **2022** | 62.79 | 59.08 | 62.48 | 55.25 | 50.58 | 42.48 | 55.41 | 76.86 | 84.71 | 67.22 | 65.80 | 65.14 | 62.32 |
| **2023** | 63.82 | 63.25 | 64.48 | 58.54 | 55.19 | 45.29 | 57.18 | 77.75 | 87.28 | 67.21 | 66.57 | 66.46 | 64.42 |
| **2024** | 65.73 | 66.86 | 66.09 | 60.30 | 55.62 | 49.96 | 63.31 | 93.29 | 91.03 | 71.75 | 67.72 | 68.27 | 68.33 |
| **2025** | 68.30 | 65.32 | 70.30 | 62.39 | 58.47 | 52.76 | 68.83 | 102.96 | 96.00 | 73.45 | 70.58 | 71.15 | 71.71 |

# Detail on Electric Screening Models

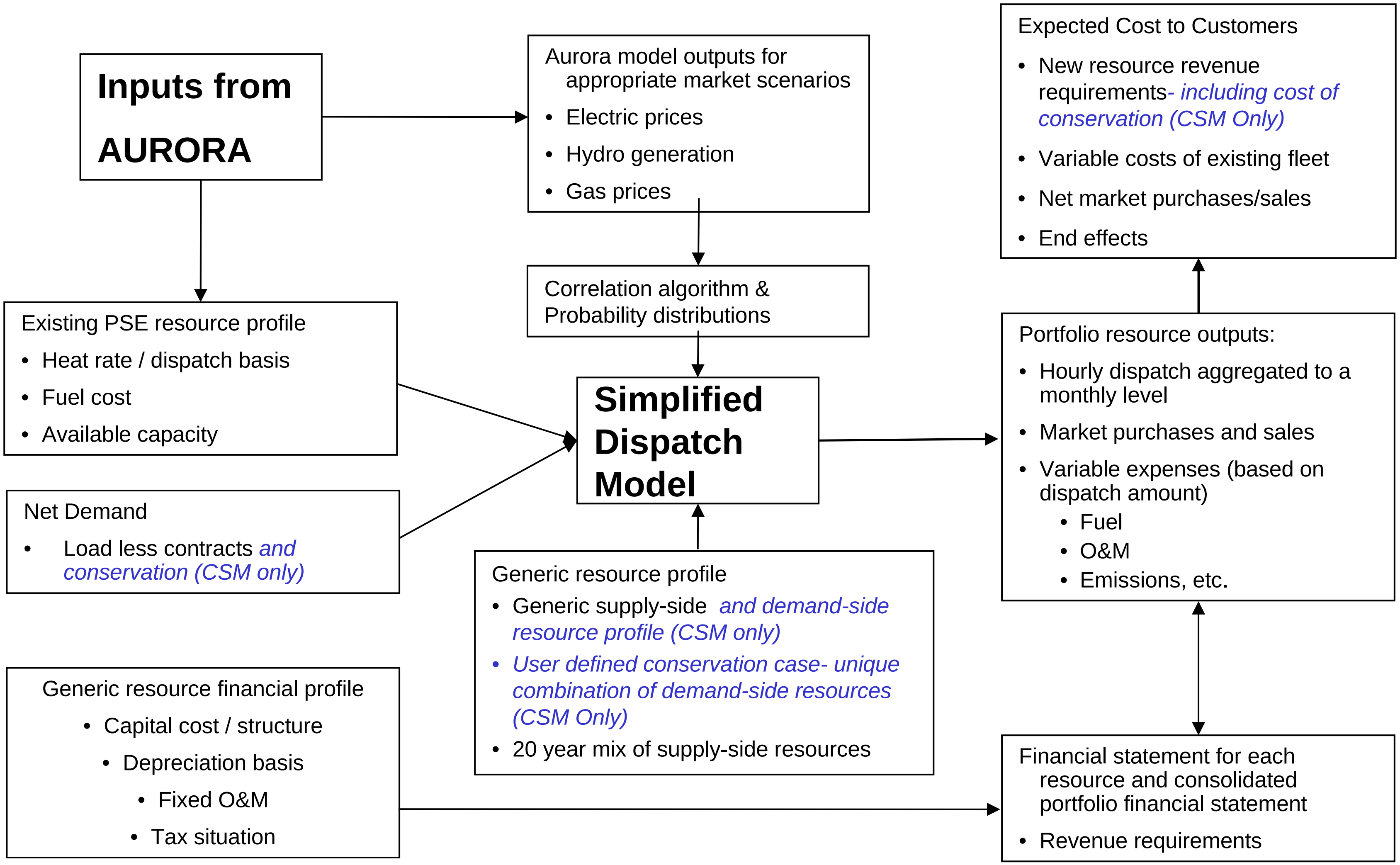
# LCP Portfolio Screening Model - Overview

**The Portfolio Screening Model (PSM) is composed of two main parts:**

- Dispatch Model Calculation
  - Dispatches PSE fleet and potential new resources against hourly power prices from AURORA for WA/OR region
  - Utilizes the same inputs to AURORA for plant profiles and demand
  - Uses Crystal Ball Monte Carlo simulation to achieve probability weighted results
  - Output from dispatch model includes MWh for the PSE fleet and an assumed portfolio of new resources and their associated variable (or incremental) costs (fuel, O&M, etc.)

- Financial Summary and Expected Cost to Customer Calculation
  - MWhs produced and variable cost data from the dispatch model is used in conjunction with fixed cost assumptions to derive a 'bottom up' revenue requirement for each new resource being considered
  - A financial summary is generated for each new resource technology that includes an income statement, cash flow summary and an approximation of regulatory asset base
  - Financial data from each new resource are then consolidated
  - The comparative incremental cost to customers for a particular resource portfolio is developed by combining the variable cost of dispatch from the existing dispatchable PSE fleet, the variable emission cost from the existing PSE fleet, the cost of market purchases, and the revenue from market sales with the revenue requirements from the new resource portfolio over a 20-year period
  - The NPV of the 20-year strip of incremental costs to customers is then calculated at the weighted average cost of capital (WACC)
  - The NPV of the expected cost to customers are for comparative purposes only

# Integrated LCP Screening Model Process Flow Chart



# Net Demand Development

- Hourly demand, resource, and contract summaries extracted from Aurora for the forecast period are used to develop Net Demand
- The Net Demand is derived by taking the total demand and subtracting contract purchases/(sales) and wind projects currently being developed

# Dispatchable Resources

- **The dispatchable plants are:**
  - PSE owned: Fredonia1&2, Fredonia 3&4, Frederickson 1&2, Frederickson CC, Whitehorn 2&3, Colstrip 1&2, Colstrip 3&4 and Encogen (dispatchable)
  - NUG's: March Point 2 (dispatchable), Sumas, and Tenaska
  - New resources: CCGT, Coal, and Winter Call Options
- **There are two primary data inputs to the dispatch logic from the dispatchable plants:**
  - Dispatch Basis: This is the marginal cost of dispatch and is sum of variable O&M, fuel cost (calculated by running a "burner tip" $/MMBtu fuel cost through the plants heat rate to arrive at $/MWh), and any other incremental costs (e.g. emissions, transmission, etc.). The dispatch basis determines whether a plan runs at its Dispatch Capacity or is shut down.
  - Dispatchable Capacity: The dispatchable capacity adjusts the net capacity for an asset by a forced outage rate applied evenly over all periods, and an planned outage rate applied when the outage is expected.

| **Plant** | Nameplate Capacity (MW) | Heat Rate (Btu/KWh) | Forced Outage Rate (%) | VOM ($/MWh) | Fuel Cost ($/MMBtu) | Planned Outage Period (Approx.) |
|---|---|---|---|---|---|---|
| Fredonia 1&2 | 202.1 | 11,687 | 0.5% | 2.0 | Sumas + trans. | 12 days in May |
| Frederickson 1&2 | 141.0 | 12,499 | 3.1% | 2.0 | Sumas + trans. | 12 days in March |
| Frederickson CC | 123.4 | 7,070 | 4.0% | 2.8 | Sumas + trans. | 15 days in June |
| Frederickson DF | 13.4 | 9,800 | 4.0% | 2.8 | Sumas + trans. | 15 days in June |
| Fredonia 3&4 | 118.2 | 10,444 | 2.7% | 2.0 | Sumas + trans. | 12 days in May |
| Whitehorn 2&3 | 134.4 | 12,965 | 4.0% | 2.0 | Sumas + trans. | 12 days in June |
| Colstrip 1&2 | 307.0 | 11,045 | 10.8% | 2.0 | 0.51 | 11 days in May & 14 in June |
| Colstrip 3&4 | 371.3 | 10,687 | 11.0% | 2.0 | 0.58 | 15 days in April & 7 days in May |
| Encogen (Dispatchable) | 113.1 | 9,960 | 0.3% | 2.0 | Sumas + trans. | 5 days in April |
| March Point 2 (Dispatchable) | 22.0 | 11,350 | 0.0% | 2.0 | Sumas | 5 days in May |
| Sumas | 133.0 | 8,230 | 0.0% | 2.0 | Sumas | 25 days in June |
| Tenaska | 245.0 | 8,184 | 0.0% | 2.0 | Sumas | 31 days in May |
| Generic CCGT | NA | 6,711 | 5.0% | 4.8 | Sumas | None |
| Generic Coal | NA | 9,274 | 10.0% | 3.4 | 0.91 | 16 days in May |

# Must Run and Renewable Resources

- The must run plants are:
  - PSE Owned: All hydro plants, Encogen & March Point MR
  - NUG's: March Point 1&2 MR
  - New generic resources: Wind and Biomass
- The Must Run plants generate power in the model when they are available regardless of variable cost
  - The must run portions of Encogen and March Point and generic biomass plants run based upon their adjusted net capacity, similar to the calculation of dispatchable capacity for dispatched plants.
  - The wind units have their nominal capacity adjusted for monthly availability based on seasonal variations in wind patterns (the proxy is currently for wind located in the Basin & Range region of OR and ID)
  - The hydro unit generation is based on the monthly availability for the average water year in the 60-year hydro data set from NWPP, the hourly dispatch shape for a 2006 base year in Aurora, and current contract terms with assumed renewals.
  - Hydro capacity and energy for Chelan PUD is assumed to be renewed at  50% when the contract expires.

| Plant | Nameplate Capacity (MW) | Heat Rate (Btu/KWh) | Forced Outage Rate (%) | VOM ($/MWh) | Fuel Cost | Planned Outage Period (Approx.) |
|---|---|---|---|---|---|---|
| Encogen (MR) | 56.6 | 9,960 | 0.3% | 2 | NA | 5 days in April |
| March Point 1 & 2 (MR) | 123.0 | 8,500 | 0.3% | 2 | NA | 5 days in May |
| Hopkins Ridge | 149.4 | NA | 65.1% | NA | NA | None |
| Wild Horse | 239.4 | NA | 60.3% | NA | NA | None |
| Wind | 100.0 | NA | 68.0% | NA | NA | None |
| Biomass | 25.0 | NA | 15.0% | NA | NA | None |

# Must Run and Renewable Resources Continued

| Wind Profiles | Basin & Range | Cascades & Inland | Northern California | Northwest coast | Rockies & Plains | Southern California |
|---|---|---|---|---|---|---|
| January | 119% | 103% | 22% | 119% | 161% | 68% |
| February | 139% | 90% | 28% | 157% | 157% | 66% |
| March | 107% | 107% | 69% | 107% | 102% | 97% |
| April | 105% | 107% | 113% | 86% | 84% | 128% |
| May | 94% | 121% | 181% | 84% | 77% | 175% |
| June | 71% | 107% | 188% | 84% | 73% | 133% |
| July | 56% | 111% | 210% | 101% | 35% | 147% |
| August | 61% | 107% | 185% | 54% | 42% | 95% |
| September | 72% | 94% | 96% | 66% | 52% | 87% |
| October | 74% | 73% | 65% | 80% | 100% | 82% |
| November | 159% | 85% | 24% | 140% | 130% | 65% |
| December | 143% | 96% | 18% | 121% | 188% | 57% |

- PSE is currently using the Cascade & Inland profile for generic wind resource availability estimates
  - Appears to be where the most promising near term projects are located

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# Emissions Assumptions

| Emission rate (T/GWh) | **SO2** | **NOX** | **CO2** |
|---|---|---|---|
| Fredonia 1&2 | 0.001 | 0.201 | 582 |
| Frederickson 1&2 | 0.001 | 0.201 | 582 |
| Frederickson CC | 0.002 | 0.039 | 411 |
| Frederickson DF | 0.001 | 0.055 | 582 |
| Fredonia 3&4 | 0.001 | 0.201 | 582 |
| Whitehorn 2&3 | 0.001 | 0.201 | 582 |
| Colstrip 1&2 | 2.276 | 2.090 | 1,119 |
| Colstrip 3&4 | 0.502 | 2.195 | 1,098 |
| Encogen (Dispatchable) | 0.002 | 0.039 | 411 |
| March Point 2 (Dispatchable) | 0.002 | 0.039 | 411 |
| Sumas | 0.002 | 0.039 | 411 |
| Tenaska | 0.002 | 0.039 | 411 |
| Generic CCGT | 0.000 | 0.041 | 411 |
| Generic SCGT | 0.005 | 0.057 | 568 |
| Generic Coal | 0.580 | 0.222 | 953 |
| | | | |
| Base Cost ($/Ton) | 290 | - | - |

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## Dispatch Logic

- The hourly dispatch of the PSE fleet and the new resources considered in the planning portfolio is done on a month by month basis
- The dispatch logic is as follows:
  - For each hour, the Dispatch Basis for each dispatchable plant is compared to the market price for that hour, if the Dispatch Basis is less than the market price, then the plant generates its Dispatchable Capacity for that hour, else, it does not dispatch that hour
  - The total generation from the dispatchable plants is summed for each hour
  - The total generation from the must run plants is added to the total generation from the dispatchable plants
  - The grand total of plant generation (dispatchable and must run) is compared to the Net Demand for each hour, if the amount generated is less than the Net Demand, then that amount represents a market purchase, if the amount generated is greater than Net Demand, than that amount represents a market sale
  - For every hour where there is a market sale or purchase, the market price at that hour is used to calculate the financial impact of the purchase or sale
- The major simplification from the dispatch logic in AURORA is that there is no provision for unit minimum run times, ramp rates, minimum dispatch levels, etc.

# End Effects for Supply Resources in the Screening Model

- The issue of end effects arises because we have a 20 year evaluation period and assets with up to 30 year life. This is compounded by the fact that our portfolio planning horizon allows asset additions to occur through year 20, effectively creating a 50 year horizon for asset life
- To deal with years 21-50 in the analysis, we use the following methodology:
  - Forecast the free cash flows (100% equity basis) from the assets for years 21 to 50
  - NPV the free cash flows to year 20 at the WACC
  - Compare the NPV at year 20 to the remaining book value at year 20
  - NPV the difference to year one at the WACC
  - Subtract the year one value from the Total Cost to Customer
- The free cash flow are estimated using the following assumptions:
  - Revenue: The revenue from year 17-20 is averaged and escalated at 2.5%
  - Fuel and VOM: The fuel and VOM from year 17-20 is averaged and escalated at 2.5%
  - Capacity Factor: The capacity factor from year 17-20 is averaged and held constant for year 21-40
  - FOM: The FOM continues to be escalated as in years 1-20
  - Property Tax: The property tax is trended down from year 17-20 (follows the trend down in rate base)
  - Insurance: The insurance is trended down from year 17-20 (follows the trend down in rate base)
  - Depreciation: The tax depreciation is run out normally for all assets past year 20
  - Emissions Cost: The emissions cost escalates year 20 cost at 2.5%

# Financial Summary and Revenue Requirement Calculation - *Assumptions and Methodologies*

- Dates used for analysis period
  - Planning horizon in the model is 20 years beginning Jan. 1, 2006

- Expense / Capital escalation rates
  - Both fixed and variable O&M currently assume a 2.5% annual escalation factor
  - Acquisition capex assume a 2.5% annual escalation factor
    - ✓ The model assumes that 'acquisition capex', or capital expenditures related to acquiring new generation MW are financed using the debt to equity ratio supplied by PSE (57% debt to 43% equity).

- Capital Costs (New Acquisition Capex in $/kw)

| | All in Cost ($/kW) |
|---|---|
| CCGT | $790 |
| Coal | $1,672 |
| Wind | $1,438 |
| Duct Fired | $790 |
| Biomass | $1,911 |

# Financial Summary and Revenue Requirement Calculation - *Assumptions and Methodologies - continued*

O&M Costs (Table below outlining Fixed rates in $/kw-yr and Variable O&M rates in $/MWh)

| **Fixed Expenses ($/kW-year)** | CCGT | Coal | Wind Before Trans. Solution | Duct Fired | Biomass | Wind After Trans. Solution |
|---|---|---|---|---|---|---|
| O&M and Fixed Transmission | 57.4 | 126.6 | 50.0 | 57.4 | 66.3 | 87.2 |
| **Variable Expenses ($/MWh)** | | | | | | |
| VOM | 2.4 | 3.4 | 4.3 | 2.4 | 13.3 | 4.3 |
| Fuel Basis Differential | 2.4 | 0.0 | 0.0 | 3.4 | 0.0 | 0.0 |
| *Total* | 4.8 | 3.4 | 4.3 | 5.8 | 13.3 | 4.3 |

- Finance and Regulatory assumptions
  - Cost of equity and debt (used for both the WACC and debt amortization calculations) – 10.3% and 6.96% respectively
  - WACC / After Tax WACC – 8.40% and 7.01% respectively
  - Conversion Factor (gross-up factor used in revenue requirement calculation) – 65.0%
    - ✓ Roughly equivalent to (1- Federal tax rate)
- Heat Rate and Forced Outage Rates

| | CCGT | Coal | Wind Before Trans. Solution | Duct Fired | Biomass | Call Option | Wind After Trans. Solution |
|---|---|---|---|---|---|---|---|
| Heat Rates | 6,711 | 9,274 | NA | 9,500 | NA | 12,000 | NA |
| Forced Outage Rates | 5% | 10% | 68% | 0% | 15% | NA | 68% |

# Financial Summary and Revenue Requirement Calculation - *Calculation Detail*

**The revenue requirement for a specified portfolio utilizes a 'bottom-up' approach where total fixed and variable costs are used to back solve for the appropriate revenue stream that would yield an operating income stream sufficient to provide a desired regulated rate of return. The following discussion outlines how individual components of fixed and variable expenses are calculated:**

- Variable Costs – Fuel and Variable O&M
  - Fuel expense is calculated by multiplying the calculated number of MWh dispatched or generated each month, times the heat rate of the plant times the appropriate fuel curve (i.e. gas or coal)
  - Variable O&M is calculated by taking the appropriate VOM factor (as provided by PSE and illustrated on the previous slide), applying the VOM escalation percentage adjusted for time, and multiplying the resulting inflation adjusted VOM factor (in $/Kwh) times the number of Kwh produced for the selected technology
  - Variable Transmission
- Fixed Costs – Fixed O&M
  - The FOM Factor provided by PSE should include all categories of fixed costs associated with the various technologies under consideration
  - The fixed cost calculation is similar to that of Variable O&M in that the FOM factor (quoted in $/Kw) provided by PSE is inflation adjusted using the escalation factor and multiplied times the plant capacity (rather than the number of Kwh produced)
  - Fixed transmission ($/KW-year) varies with transmission scenario and timing of transmission solution
- Depreciation - Book and Tax
  - Book – Modeled value assumes 30 year recovery on all capital additions (Wind 20 years)
  - Tax – The portfolio model contains flexibility to select from 5, 10, 15 and 20 year MACRS (half-year convention)
    - ✓ The current test cases utilize 5 year MACRS for wind resources, 7 year MACRS for biomass resources,15 year MACRS for combined cycle gas and 20 year MACRS for coal fired resources.

# Financial Summary and Revenue Requirement Calculation - *Calculation Detail - continued*

- Debt Service – Interest
  - The interest is calculated as a function of Rate Base
  - The long-term capital structure assumes 57% debt
  - The interest rate is assumed to be 6.96%

- Tax – Current and Deferred
  - Current taxes are computed on taxable income calculated using tax depreciation rates previously discussed
  - Differences between book and tax depreciation are the only items considered to generate book/tax differences that give rise to deferred taxes.
  - Currently, the model assumes a 35% effective marginal rate

# Financial Summary and Revenue Requirement Calculation - *Expected Cost to Customer*

- Expected Cost to Customer is the point at which various alternative portfolios will be measured
- Expected Cost to Customer in the portfolio model is calculated as follows:
  - The comparative incremental cost to customers for a particular resource portfolio is developed by combining:
    - ✓ The variable cost of dispatch from the existing dispatchable PSE fleet
    - ✓ The variable emission cost from the existing PSE fleet
    - ✓ The cost of market purchases
    - ✓ The revenue from market sales
    - ✓ The revenue requirements from the new resource portfolio over a 20 year period including the variable expense associated with market sales and the costs associated with conservation
  - The NPV of the 20 year strip of incremental costs to customers is then calculated at the WACC
  - The NPV of the Expected Cost to Customers are for comparative purposes only

# Integrated Conservation Screening Model - Overview

**The Conservation Screening Model (CSM) is composed of three main parts:**

- Conservation Load Impact and Supply Resource Calculator
  - The zero conservation total demand forecast is adjusted by the amount of conservation assumed in a conservation case and is used to re-calculate the PSE need for both energy and capacity
  - Supply resources are added subject to user-defined rules to meet the remaining need

- Dispatch Model Calculation
  - Dispatches PSE fleet and potential new supply resources against hourly power prices from Aurora for WA/OR region
  - Output from dispatch model includes MWh for the PSE fleet and an assumed portfolio of new resources and their associated variable (or incremental) costs (fuel, O&M, etc.)

- Financial Summary and Expected Cost to Customer Calculation
  - MWhs produced and variable cost data from the dispatch model is used in conjunction with fixed cost assumptions to derive a 'bottom up' revenue requirement for each new resource being considered
  - A financial summary is generated for each new resource technology that includes an regulated income statement and an approximation of regulatory asset base
  - Financial data from each new resource is then consolidated
  - The 20-year incremental portfolio cost (or going forward cost) to customers for a particular resource portfolio is developed by combining the variable cost of dispatch from the existing dispatchable PSE fleet, the variable emission cost from the existing PSE fleet, the cost of market purchases, and the revenue from market sales with the revenue requirements (including conservation expense) from the new resource portfolio over a 20 year period
  - The NPV of the 20 year strip of incremental costs to customers is then calculated at the WACC
  - The NPV of the Expected Cost to Customers are for comparative purposes only

# Detailed View of the Conservation Impact and Supply Resource Calculation Process – Input Data

- Conservation load impact data in total MWh form as follows:
  - Eight residential bundles: Appliances, HVAC, Lighting, and Water Heating for both new construction and existing construction
  - Eight commercial bundles: Appliances, HVAC, Lighting, and Water Heating for both new construction and existing construction
  - One Industrial bundle
- The MWh of conservation were further broken down into price points, four for the residential and commercial bundles and one for industrial totaling 65 individual unique conservation bundle/price points
- The duration of benefit of each of the 65 conservation bundle/price points
- Weighted 8760 load shapes for the 17 bundles (8 residential, 8 commercial, and 1 industrial)
  - The load shapes were normalized such that the total annual MWh conservation impact could be multiplied by each hours value to yield the hourly conservation impact
  - The load shapes provided were based on shapes originally developed by NPPC

## Detailed View of the Conservation Impact and Supply Resource Calculation Process – Total Demand Adjustment and Supply Resource Calculation

- Conservation cases are user defined by selecting a mix of the 65 unique bundle/price points
- The MWh associated with the selected bundle/price points are rolled up to the bundle level and grossed up by 6.8% for line losses
- Each of the 17 bundles has an associated hourly load shape that has been normalized to allow the rolled up bundle annual MWh to be directly spread to hourly before they are consolidated into a total hourly conservation impact
  - The base load shapes provided were developed from the load shapes defined by NPPC
  - The load shapes are for a 2006 base year and are adjusted for the proper annual start date for the years 2006-2025
- The 20-year total hourly conservation impact is then subtracted from the 20-year no-conservation total demand forecast (net of PSE contracts and wind resources) to develop the conservation adjusted total demand forecast
- The conservation adjusted hourly total demand forecast is rolled up to a monthly aMW level and used to recalculate the PSE energy need
- The capacity value of conservation is assumed to be the average of the maximum hour of conservation in December, January, and February and is used to adjust the capacity need
  - Assumes that the highest hour of conservation savings is coincident with the peak hour of load
- Supply portfolios are constructed based on recalculated capacity and energy need

# Detailed View of the Conservation Impact and Supply Resource Calculation Process – Dispatch and Financial Impact of Conservation

- **The 20-year total hourly conservation impact is subtracted from net demand associated with the 20-year no-conservation total demand forecast**
  - This process is mathematically equivalent to the treatment of the must-run resources (wind, NUG's, etc.) and the hydro resources
  - The net demand is the total demand minus current PSE contracts and PSE wind projects being developed
- **The calculated supply portfolios are dispatched against the AURORA price forecast, hourly spot market purchase and sales are based on the total hourly dispatch of the PSE fleet (current and future generic) and the hourly conservation adjusted net demand**
- **The cost of the conservation bundles/price points assumed in the case flow directly to revenue requirement and are calculated as follows:**
  - The cost of each conservation bundle/price point is spread over the respective useful life of the bundle/price point
  - For bundle/price points where the useful life is less than 20 years, we assume a 100% "re-up" rate for as many times as necessary to fill the 20 year period
  - There is no escalation of cost of bundle/price points when spread over the useful life or when re-upped
  - The total cost of the bundle/price points are reduced by 10% to reflect the non-quantifiable benefit of foregoing fossil supply additions through conservation
  - The total cost of conservation flows to revenue requirement with no return component
- **End effects are dealt with in a similar fashion as the end effects of supply resources**
  - A market benefit of the residual conservation from year 2026-2055 is calculated by subtracting the total cost of conservation from the market value of the conserved MWhs
  - This value is discounted back to year 1 and raises or lowers the revenue requirement based on the attractiveness of the conservation case

# Short-term Operational Impacts of Wind Generation on the Puget Sound Energy Power System

## Phase 2 Studies

Golden Energy Services, Inc.

March 3, 2005

# Table of Contents

# Section 1 - Executive Summary

## 1.1 The PSE Wind Phase 2 Project Scope

While the body of literature surrounding wind generation development is fairly voluminous, it has only been in the last couple of years that coordinated attempts have been made to identify and quantify the short-term operational impacts of large-scale wind farms on utility power systems. As part of PSE's overall effort in evaluating wind resources, Golden Energy Services (Golden) was asked in mid-2003 to assist PSE personnel in the evaluation of the short-term operating impacts of wind generation on the PSE power system.

A report titled Short-term Operational Impacts of Wind Generation on the Puget Sound Energy Power System (also known as the Phase 1 Report) was presented to PSE on August 22, 2003. This report provided an evaluation of the short-term operational characteristics of wind generation specifically for the PSE power system. In December 2003, PSE proposed that Golden perform additional wind generation related analysis work in order to: 1) expand upon the results of the previously completed Phase 1 studies, and 2) to develop information that would assist PSE in evaluating wind resource bids. The additional wind generation analysis to be performed by Golden and selected PSE staff were termed the PSE Wind Phase 2 studies.

This Phase 2 Report provides a description of the analysis work performed by Golden and PSE subsequent to the completion of the Phase 1 Project. Specifically, Golden analyzed the following four operational impacts categories in the Phase 2 studies: 1) PSE Regulation impacts, 2) PSE Operating Reserve impacts, 3) PSE Hour-Ahead impacts, and 4) PSE Day-Ahead impacts. Since portions of the Phase 2 Project Scope build upon work completed during the Phase 1 studies, important conclusions from the Phase 1 studies are also at times referenced in the Phase 2 report.

For the purpose of evaluating short-term operating impacts of wind generation on the PSE power system, Golden and PSE utilized actual wind generation data from an operating wind project located in the Columbia River Basin. Golden and PSE also utilized simulated wind generation data that was developed in the Phase 1 studies for a wind project located near Ellensburg, Washington.

## 1.2 Summary Description of the Phase 2 Report

Sections 2 and 3 contain a description of the Phase 2 Project Scope, along with Golden's general approach to the Project. These sections also provide a description of how the Phase 2 analysis expands upon the work previously conducted under Phase 1.

Section 4 presents summary information regarding the observed wind generation data that was developed for the Phase 2 Study. This section is intended to provide a high level review of the operating characteristics of an operating Northwest wind project.

Section 5 provides details on the construction of three separate data sets for an operating Northwest wind farm. This data was subsequently used to develop Hour-Ahead and Day-Ahead wind forecast error probability tables.

The impacts of wind generation on PSE system regulation requirements are presented in Section 6. Section 7 quantifies the impacts of wind generation on PSE's operating reserve requirements.

Section 8 contains an overview and brief summary of three separate modeling methodologies that were evaluated in order to determine the Hour-Ahead and Day-Ahead wind integration impacts for the PSE system. Each of these three models in discussed separately in Sections 9-10.

Section 9 describes the Standard Options modeling approach. Section 9 provides details on the Mid-C Flex Model while Section 10 discusses the Virtual Storage Model.

Section 11 provides an in depth analysis of Hour-Ahead cost impacts associated with wind generation on the PSE system while Section 12 provides a similar evaluation for Day-Ahead cost impacts.

Section 13 provides an overall summary of all four short-term cost impact categories for wind farm capacities ranging in size from 25 MW to 450 MW. The PSE Phase 2 results are also compared to the Phase 1 results, and also against five other similar studies performed for other utility systems. Overall conclusions for the Phase 2 studies are presented in Section 14.

## 1.3 Summary of PSE Short-term Wind Generation Integration Costs

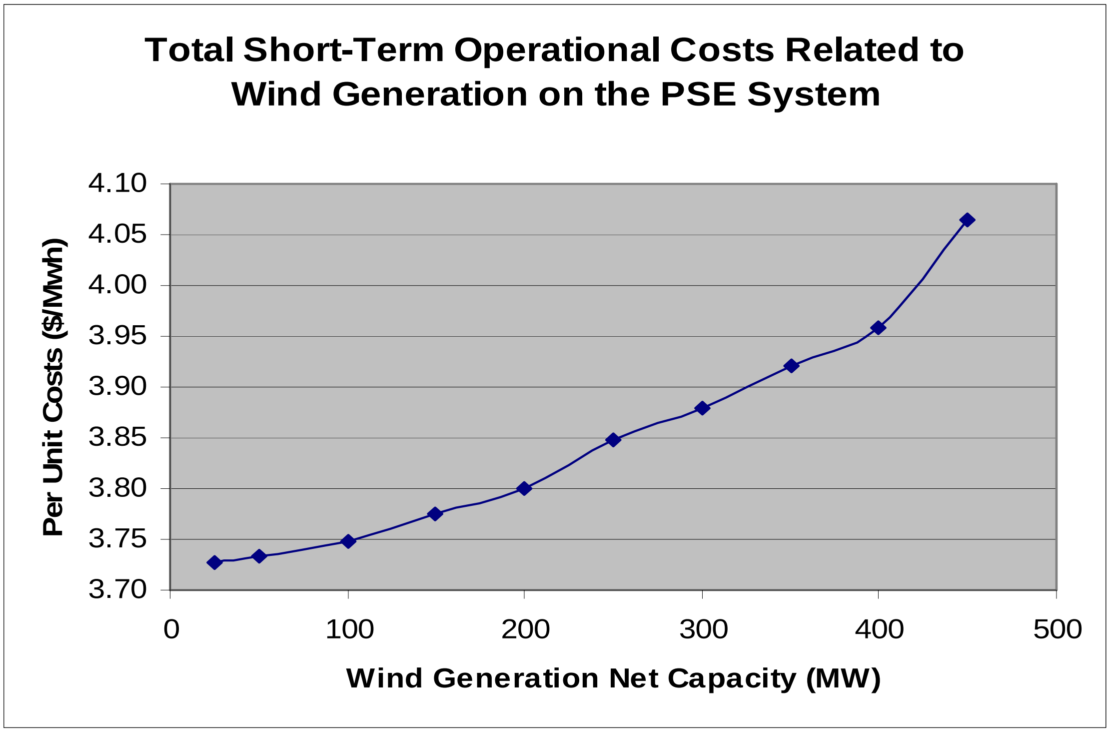
The table shown below presents the impacts on the PSE power system of the four identified short-term wind impacts categories:

**Table 1.3 - Summary of Short-Term Operational Impacts due to the Addition of Varying Amounts of Wind Generation on the PSE System**

| Wind Generation Net Capacity (MW) | Regulation ($/Mwh) | Operating Reserves ($/Mwh) | Hour-Ahead Costs ($/Mwh) | Day-Ahead Costs ($/Mwh) | Total Costs ($/Mwh) |
|---|---|---|---|---|---|
| 25 | 0.16 | 0.00 | 2.72 | 0.84 | 3.73 |
| 50 | 0.16 | 0.00 | 2.73 | 0.84 | 3.73 |
| 100 | 0.16 | 0.00 | 2.75 | 0.84 | 3.75 |
| 150 | 0.16 | 0.00 | 2.78 | 0.84 | 3.77 |
| 200 | 0.16 | 0.00 | 2.81 | 0.83 | 3.80 |
| 250 | 0.16 | 0.00 | 2.85 | 0.84 | 3.85 |
| 300 | 0.16 | 0.00 | 2.89 | 0.83 | 3.88 |
| 350 | 0.16 | 0.00 | 2.93 | 0.83 | 3.92 |
| 400 | 0.16 | 0.00 | 2.97 | 0.82 | 3.96 |
| 450 | 0.16 | 0.00 | 3.01 | 0.89 | 4.06 |

Chart 1.3 shows the trend in per unit total operational costs as a function of wind generation net capacity on the PSE system:

**Chart 1.3**




As can be seen from Table 1.3 and Chart 1.3, the addition of 150 MW of net wind capacity to the PSE system would be expected to result in additional short-term operational costs of approximately $3.77/Mwh on an annual average basis. This cost rises to $4.06/Mwh for 450 MW net capacity of wind generation.

## 1.4 Sensitivity of Results

In addition to the scaling studies performed to analyze the impacts of varying wind generation amounts, Golden also performed a cost sensitivity study for the 150 MW wind capacity case. Table 1.4 below presents the results of this sensitivity study; figures shown in bold type indicate the recommended baseline results previously reported in Table 1.3.

**Table 1.4**
**Cost Sensitivity Results for 150 MW Net Capacity Wind Generation**

| Impacts Category | Low Side of Cost Range ($/Mwh) | Recommended Cost ($/Mwh) | High Side of Cost Range ($/Mwh) |
|---|---|---|---|
| Regulation | 0.01 | **0.16** | 0.19 |
| Operating Reserves | 0.00 | **0.00** | 0.00 |
| Hour-Ahead | 0.98 | **2.78** | 3.25 |
| Day-Ahead | 0.75 | **0.84** | 1.96 |
| Total | 1.74 | **3.77** | 5.40 |

### 1.5 Summary Comparison of Phase 2 versus Phase 1 Results

Table 1.5 below presents a summarized cost comparison of the four short-term wind related impacts categories that were analyzed in both the PSE Phase 1 and Phase 2 studies, referenced to a common wind generation amount of 136.4 MW net capacity:

**Table 1.5**
**Comparison of Phase 1 and Phase 2 Study Results – 136.4 MW Net Wind Capacity**

| Impacts Category | PSE Phase 1 Study Results ($/Mwh) | PSE Phase 2 Study Results ($/Mwh) |
|---|---|---|
| Regulation | 0.16 | 0.16 |
| Operating Reserves | 0.00 | 0.00 |
| Hour-Ahead | 1.54 | 2.77 |
| Day-Ahead | 2.24 | 0.84 |
| Total | 3.94 | 3.77 |

### 1.6 The PSE Phase 2 Costs versus Other Reported Results

In November, 2003, UWIG released a technical paper entitled Wind Power Impacts on Electric-Power-System Operating Costs – Summary and Perspective on Work Done to Date. This paper summarized the results of six studies conducted by other entities that focused on quantifying the short-term operational impacts of integrating wind generation into large utility systems. All of the six studies except one (the so called Hirst study) evaluated Regulation, Hour-Ahead ("load following") and Day-Ahead ("unit commitment") impacts. While these impact categories match up fairly well with the impacts analyzed in the PSE Phase 2 studies, it should be noted that the results of the five UWIG reported studies (excluding Hirst) may not be directly comparable to each other or the PSE Phase 2 results since all of the studies used differing wind penetration levels.

A comparison of the five UWIG reported studies (excluding Hirst) and the PSE Phase 2 study does, however, provide some useful information as to the probable *range* of short-term wind integration costs. Table 1.6 below shows such a summary:

**Table 1.6 - Short-Term Operational Costs of Wind Generation**
**On Large Utility Power Systems**

| Study | Wind Penetration Level (Percent of Peak Load) | Total Short-Term Operational Costs ($/Mwh) |
|---|---|---|
| **PSE Phase 2 (150 MW Case)** | **3.3** | **3.77** |
| UWIG/XCEL | 3.5 | 1.85 |
| Pacificorp | 20.0 | 5.50 |
| BPA | 7.0 | 1.47-2.27 |
| We Energies I | 4.0 | 1.90 |
| We Energies II | 29.0 | 2.92 |

## Section 2 - The PSE Wind Phase 2 Project Scope and Purpose

### 2.1 Introduction

On November 13, 2003, Puget Sound Energy (PSE) issued an RFP for the potential acquisition of wind-based resources. Among the alternatives under consideration by PSE is the purchase of "green" wholesale power from other utilities/marketers, or the purchase of wind generation directly from a wind farm developer. In the first case, ancillary services related to wind generation (including but not limited to regulation, operating reserves and generation following/balancing) would likely be included in the wholesale product purchased by PSE. However, if PSE elects to purchase wind generation directly from a site located within or connected to its load control area, PSE would be responsible for providing, and absorbing the cost of, these ancillary services.

In order for PSE to evaluate the relative economics of purchasing wholesale wind energy from other utilities (where many if not all of the ancillary services would be included in the purchase price) versus interconnecting a wind farm to its own control area (where PSE would self-provide ancillaries or purchase the ancillaries separately from the raw wind power output), PSE needs to determine both the magnitude and cost of ancillary services associated with wind generation.

### 2.2 Recap of the Wind Phase 1 Project Scope and Results

In mid-2003, Golden Energy Services (Golden) was asked to assist PSE personnel in the evaluation of the short-term operating impacts of wind generation on the PSE power system. Golden was not asked to review specific wind generation proposals but rather was directed by PSE to help generally define and quantify the operational impacts of wind generation for the PSE power portfolio.

A decision potentially facing PSE is whether PSE would prefer to have purchased wind generation integrated directly into its own control area, or whether it would be more desirable (from either an operational or economic perspective) to have the generation integrated into another control area. A major goal of the Phase 1 studies was to develop data and information that would assist PSE in evaluating the overall merits of each of these cases.

Golden presented the Wind Phase 1 findings to PSE on August 22, 2003 in a report titled Short-Term Operational Impacts of Wind Generation on the Puget Sound Energy Power System (herein referred to as the Phase 1 Report). This report contained a quantitative analysis of wind generation for four separate short-term operational impact categories: 1) Regulation, 2) Operating Reserves, 3) Intra-Hour (i.e. Hour-Ahead) balancing, and 4) Day-Ahead balancing.

The analysis of Intra-Hour and Day-Ahead impacts relied primarily on the wind generation output of a simulated 154.5 MW gross capacity (136.4 MW net capacity) wind farm located in the area of Ellensburg, Washington. The simulated wind generation series was based upon a potential future wind farm consisting of 103, 1.5 MW GE Model 1.5sl wind turbines with a total gross installed capacity of 154.5 MW. This figure represented an approximate 3.3% wind penetration rate based on a PSE winter peak load of 4500 MW.

The Phase 1 Report computed $/Mwh impacts for each of the four defined impact categories, based on the interconnection of a 136.4 MW (net capacity) wind farm to the PSE control area. A summary of the cost impacts derived in the Phase 1 studies is provided below:

**Table 2.2**
**Summary of Wind Generation Related Short-Term Operational Impacts On the PSE Power System - Phase 1 Study Results**

| Short-Term Impacts Category | Annual Average Cost ($/Mwh) |
|---|---|
| Regulation | 0.16 |
| Operating Reserves | 0.00 |
| Intra-Hourly (Hour-Ahead) | 1.54 |
| Day-Ahead | 2.24 |
| Total Short-Term Impacts | 3.94 |

## 2.3 The PSE Wind Phase 2 Project Scope

Upon the completion of the Wind Phase 1 studies in August 2003, both PSE and Golden recognized that further research in some targeted areas would be beneficial in providing additional useful information regarding short-term wind resource integration costs and effects.

In December 2003, PSE asked Golden to perform additional wind generation studies to refine and expand upon the work that was completed as part of the Phase 1 studies. In Particular, Golden was directed by PSE to perform the following tasks as part of the Phase 2 Project scope:

Refine Operational Cost Estimates for Hour-Ahead and Day-Ahead Impacts
Considerable effort was directed in the Phase 1 studies towards identifying and quantifying the short-term generation balancing requirements of wind generation, both on an Hour-Ahead and Day-Ahead basis. Two areas that were specifically identified by PSE and Golden for further study included the following:

Refinement of a Short-term Dispatch Model for the PSE system
The Phase 1 studies utilized a simplified PSE operations model approach to value wind generation variations. PSE and Golden felt that the development of a more sophisticated model might be beneficial in

providing improved operational cost estimates regarding wind generation variations.

Development of Options-Based Valuation Techniques

The Phase 1 studies utilized a simplified off-peak/on-peak wholesale price differential approach in valuing Hour-Ahead and Day-Ahead operational costs associated with wind generation variability. A key goal of the Phase 2 studies was to consider the applicability of option valuation techniques in evaluating the costs of short-term wind generation variations.

Develop Factors to Allow for Easy Comparison of Different Wind Products

Pursuant to the schedule released as part of PSE's November 2003 Wind RFP, PSE expected that it would receive offers for wind generation products in January, 2004. It was also believed that prospective bidders would likely offer differently tailored wind products. A goal of the Phase 2 Project was therefore to develop and present the study results in a fashion that would enable PSE personnel to evaluate different wind RFP bids using a standardized set of cost adjustment factors.

Incorporate Newly Available Wind Generation Data

At the time the Phase 1 studies were being completed, PSE had very little actual wind generation data available that was suitable for conducting short-term operational studies. PSE had begun purchasing a wind generation product in April 2003, however only approximately two months of actual wind generation data were available at the time the Phase 1 studies were being completed. For the Phase 2 studies, a primary goal was to incorporate detailed real-time wind generation data that was just becoming available to PSE, and to use this information to augment the simulated wind generation data series developed as part of Phase 1.

Perform Wind Farm Capacity Scaling Studies

The Phase 1 studies assumed a static wind farm size of 154.5 MW gross capacity (136.5 MW net capacity after losses). A stated goal of the Phase 2 studies was therefore to investigate scaling impacts; how the per unit short-term operational costs for the PSE system might vary according to installed wind generation capacity.

Utilize Dynamic Wind Forecasting Techniques

The Phase 1 studies computed wind generation forecast error (for both the Hour-Ahead and Day-Ahead time frames) over an 11 ½ month period. In valuing forecast error, the average Hour-Ahead and Day-Ahead errors over the entire 11 ½ month period were utilized. It was recognized in the Phase 1 studies that a more preferable method of valuing wind generation forecasting error would be to utilize a dynamic "bandwidth" type forecast whereby the Hour-Ahead and Day-Ahead forecasts were based on a set of forecast errors determined for specific wind forecast ranges.

**2.4 Short-Term Wind Impacts Categories**

The Phase 1 studies identified four separate short-term operational impact categories. At the onset of the Phase 2 studies, Golden first evaluated the appropriateness of these same four impact categories and whether any modifications and/or additions were warranted. Golden concluded that these same four impact categories, as further described below, were still appropriate for use in the Phase 2 studies:

Regulating Reserves (Regulation)

The impacts of very short-term (i.e. seconds to minutes) variations in wind generation was assessed for the PSE system. Wind generation variations in this timeframe could cause PSE to carry additional regulating reserves in order to maintain short-term load/resource balance and conform to NERC/WECC reliability criteria.

Operating Reserves in Addition to Regulation

In addition to maintaining adequate regulating reserves, PSE is also required by NERC/WECC performance standards to maintain an additional operating reserve amount. Since it is not possible to "carry" operating reserves related to on-line wind generation capacity on the wind units themselves (since wind generation is non-dispatchable), the impacts of carrying wind related operating reserves on other PSE resources was examined.

Hour-Ahead Wind Generation Variability

Since the standard Northwest scheduling increment is one clock hour in length, forecasted wind generation will be prescheduled at a flat MW level for an entire hour. Wind generation, however, is variable within the schedule hour; therefore there is a need for other resources to provide intra-hourly "generation following" in order to offset the changes in wind generation.

Preschedule (i.e. Day-Ahead) Wind Generation Variability

This time period stretches from the end of the Hour-Ahead period through the end of the preschedule period, which in most cases (except for weekends and holidays) is through hour ending 2400 on the following day. Impacts associated with potential variations of wind generation output versus the original prescheduled hourly amounts was analyzed and quantified.

The results of the Phase 1 studies (as was previously summarized in Table 2.2) determined that the short-term wind related operational costs for the Regulation and Operating Reserve impacts categories were very small in relation to the Hour-Ahead and Day-Ahead costs. Golden determined that the per unit costs derived in the Phase 1 studies remained valid and no further study work was required in these areas as part of the Phase 2 Project Scope. However, for the sake of completeness, a brief discussion of Regulation and Operating Reserve impacts based upon the Phase 1 study work are included in this report as well.

## Section 3 - Golden's Approach to the PSE Phase 2 Project

### 3.1 Golden's General Approach

While the body of literature surrounding wind generation development is fairly voluminous, it has only been in the last couple of years that coordinated attempts have been made to identify and quantify the short-term operational impacts of large-scale wind farms on utility power systems. Recently, the members of the Utility Wind Interest Group (UWIG) identified that their highest priority concern was a better understanding of wind generation's short-term operational impacts. The result of the UWIG initiative, as well as other research sponsored by organizations such as the National Renewable Energy Laboratory (NREL), has been a number of studies initiated in the last 2-3 years aimed specifically at providing more information on the short-term impacts of large wind farm development.

Golden's approach in quantifying short-term operating impacts for the PSE system involved implementing the following two-step approach:

1) Determine the MW magnitude and potential range of predefined wind related short-term operating characteristic for the PSE power system, given the unique attributes of PSE's system, and
2) Determine probable economic values or costs associated with the MW values determined in No. 1 above.

Golden also desired to avoid "re-inventing the wheel" but rather rely, in part, on existing data and/or research in determining the approximate short-term operating impacts on the PSE power system. In some areas, most notably the analysis of Regulation impacts, research and data from other recent studies provided useful conclusions that would be expected to be reasonably valid for PSE's system. In other areas, however, the existing body of research did not adequately address issues that are relevant to PSE's specific situation including: 1) the impacts of hydro generation, 2) Northwest site specific wind characteristics, and 3) the consideration of lost option value.

Golden also utilized the body of work performed in the Phase 1 studies to help "target" the additional Phase 2 efforts into the specific areas that were expected to provide the most useful new information, such as incorporating dynamic wind generation forecasting techniques. Conversely, the Phase 1 studies concluded that Regulation and Operating Reserve costs associated with wind generation were relatively low; therefore the Phase 2 studies did not focus on these impact categories but rather adopted the results of the Phase 1 report (with some minor updates).

Finally, Golden has taken care to set up the Phase 2 studies from the perspective of how PSE's System Operators and Power Traders would actually make short-term operating decisions in real life. This includes grounding the studies on the same timeframes that System Operators and Traders have to deal in when making operational decisions and also not assuming any "perfect foresight" regarding Hour-Ahead or Day-Ahead wind generation forecasts.

### 3.2 PSE Power Portfolio Assumptions

The operational cost impacts of wind generation on a particular utility's power portfolio are very sensitive to the amount of installed wind capacity relative to the amount of flexible resources available to the utility to manage wind generation variability. In particular for PSE, the amount of available Mid-Columbia hydro (Mid-C) generation flexibility relative to total installed wind generation is a key cost determinate. Wind farm sizes ranging from 25 MW up to 450 MW were then evaluated and operational costs computed that incorporated PSE's current maximum Mid-C capacity figure.

It is recognized that PSE's power portfolio will likely undergo changes in the years to come as PSE embarks on a program to: 1) meet expected future retail load growth via new dedicated firm resources, and 2) replace long-term power purchase agreements that have recently terminated. Also, the amount of PSE's future Mid-C capacity may change from present levels as the current long-term Mid-C purchase agreement come up for renewal. The results of the Phase 2 studies are referenced to PSE's current amount of contracted Mid-C capacity; to the extent that PSE's has less Mid-C capacity in the future, it would generally be expected that the per unit operational costs associated with wind generation would be somewhat higher than what is presented herein.

### 3.3 Potential Impacts of RTO Implementation

As noted in Section 3.2 above, Golden has primarily studied the PSE power portfolio as it is currently situated including the incorporation of general industry scheduling/operating conventions that are presently in place. It is possible, however, that the electric industry in the Northwest may be restructured in the future to include a Regional Transmission Organization (RTO). Under such a restructuring, the manner in which PSE would operate its power portfolio could change, as could even PSE's status as a control area operator.

Due to the current uncertainty surrounding the formation of a Northwest RTO (to be known as Grid West), Golden has not attempted to analyze the short-term operational impacts of integrating wind generation under a Grid West operated Northwest grid.

### 3.4 Study Assumptions and Base Data

It was the general intent of Golden and PSE personnel to utilize the datasets assembled for the Phase 1 Project as much as possible for the Phase 2 Project. It was also recognized, however, that some new real-time Northwest wind generation data had become available following the completion of the Phase 1 studies. It was therefore Golden and PSE's intent to utilize the Phase 1 datasets and report conclusions where applicable, but also to augment and expand upon the Phase 1 data where updated information was available.

A prerequisite to evaluating the short-term operational and economic impacts of wind generation on the PSE power system is the availability of a very short time increment wind generation data series. In particular, the evaluation in Hour-Ahead wind effects requires a wind generation time series that is on a time increment of one hour or less in duration.

Since PSE currently does not have any wind generation interconnected to its control area, the Phase 1 studies relied heavily upon a set of wind generation time series that were synthesized from Ellensburg area wind speed data. Golden constructed an 11 ½ month continuous wind generation dataset from 10-minute increment wind speed data measured at six different locations near Ellensburg. The resulting 10-minute increment wind generation time series was then utilized to compute Hour-Ahead and Day-Ahead wind variability for a representative 136.4 MW net capacity Northwest regional wind farm. Additional information regarding the Ellensburg area wind speed data and the mechanisms used to create the 10-minute increment wind generation time series are detailed in Section 6 of the Phase 1 Report.

On April 1, 2003, PSE began taking delivery of a 25 MW (net peak capacity) wind generation product from an operating wind farm located in the Columbia River Basin (hereafter referred to as the CRB Project). This wind product was designated as an "hour-ahead" firm product, meaning that the seller would establish a delivery schedule for the next preschedule hour and that the seller (not PSE) would absorb any variation in actual wind generation that occurred during that same hour.

The seller also provided PSE with a non-binding Day-Ahead wind generation estimate, as well as after-the-fact actual wind generation quantities on a 10-minute increment basis. PSE would therefore have available from the CRB Project wind generation amounts on three different time frames: 1) real-time (i.e. 10-minute increment), 2) Hour-Ahead schedules, and 3) Day-Ahead schedules.

The Phase 2 wind studies relied primarily on the above referenced CRB Project wind generation data for the purpose of evaluating probable wind forecast variations. However, since this data was only available for an eight month period (April–November 2003) at the time the Phase 2 studies were being performed, the previously assembled 10-minute increment Ellensburg based wind generation dataset was also utilized such that a full 12-month wind generation dataset could be analyzed.

PSE specific Regulation impacts were primarily developed based on the reported results from other operating wind farms and relevant technical papers published by "independent" third party sources such as NREL. Also, as is more fully described in Section 6, Regulation impacts are not very significant, so an in depth technical analysis specifically for the PSE system would probably not be warranted especially given the lack of "hard" data.

## Section 4 – Columbia River Basin Project Wind Generation Summary

### 4.1 Overview and Summary of the CRB Project Wind Data

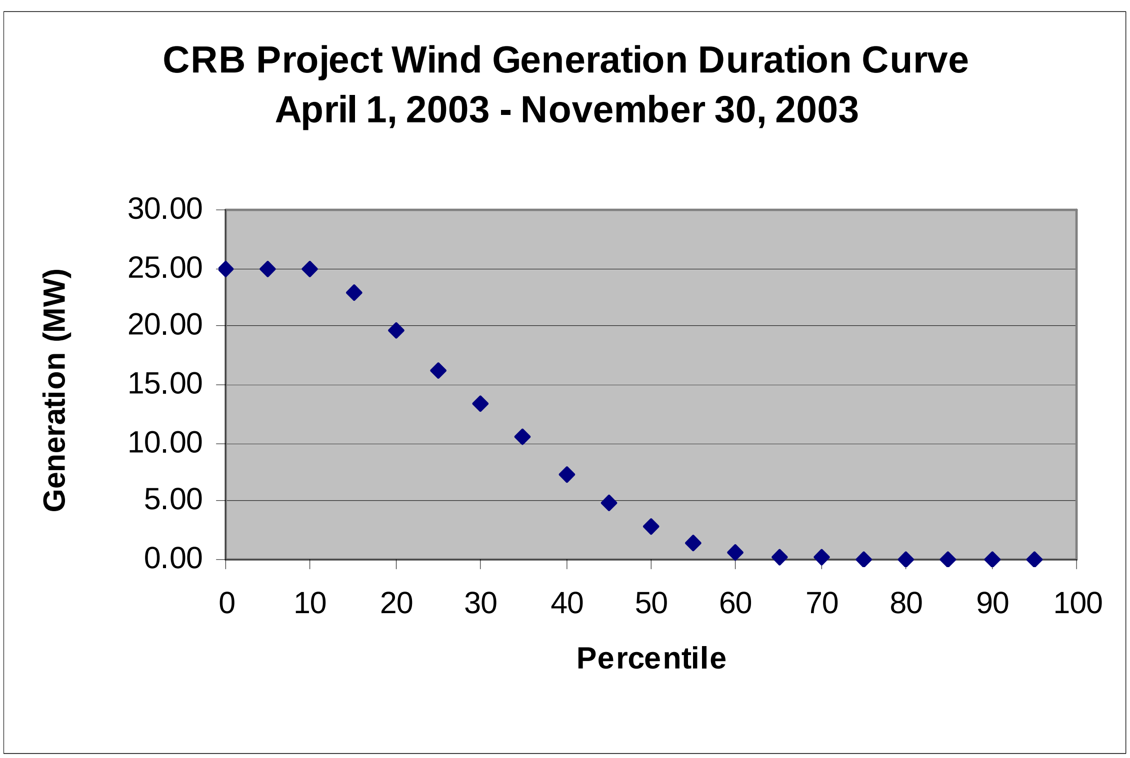
Following the methodologies more fully described in Section 5, Golden assembled a wind generation time series based on 10-minute increment actual generation readings for the period April 1, 2003 – November 30, 2003 from the CRB Project. This generation dataset is referenced to a 25 MW pro-rated portion of the CRB Project's overall capacity. Some useful general observations and statistics on this wind generation dataset are presented in Table 4.1 below:

**Table 4.1**
**CRB Project Wind Farm Generation Summary (25 MW Prorated Share)**

| | April 1, 2003 - November 30, 2003 |
|---|---|
| Net Capacity (MW) | 25.00 |
| Average Actual Wind Generation (25 MW Share, aMW) | 8.13 |
| Average Capacity Factor (Percent) | 32.5% |

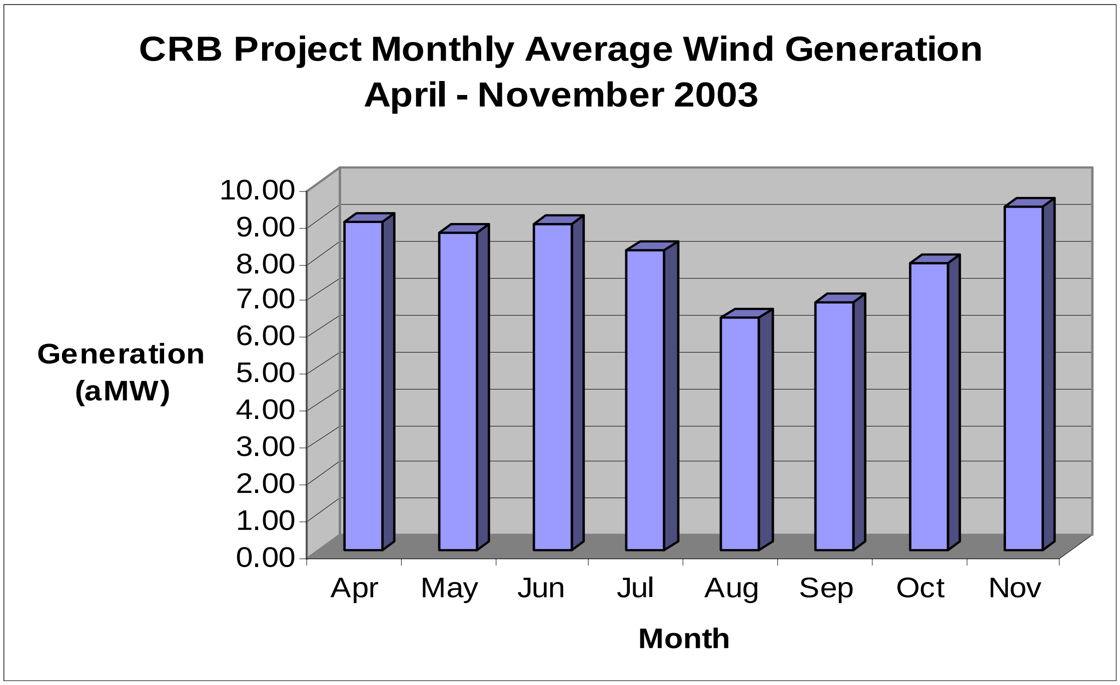
Figure 4.1a below shows a wind generation duration graph for the CRB Project, based on eight months of actual 10-minute increment generation data:

**Figure 4.1a**



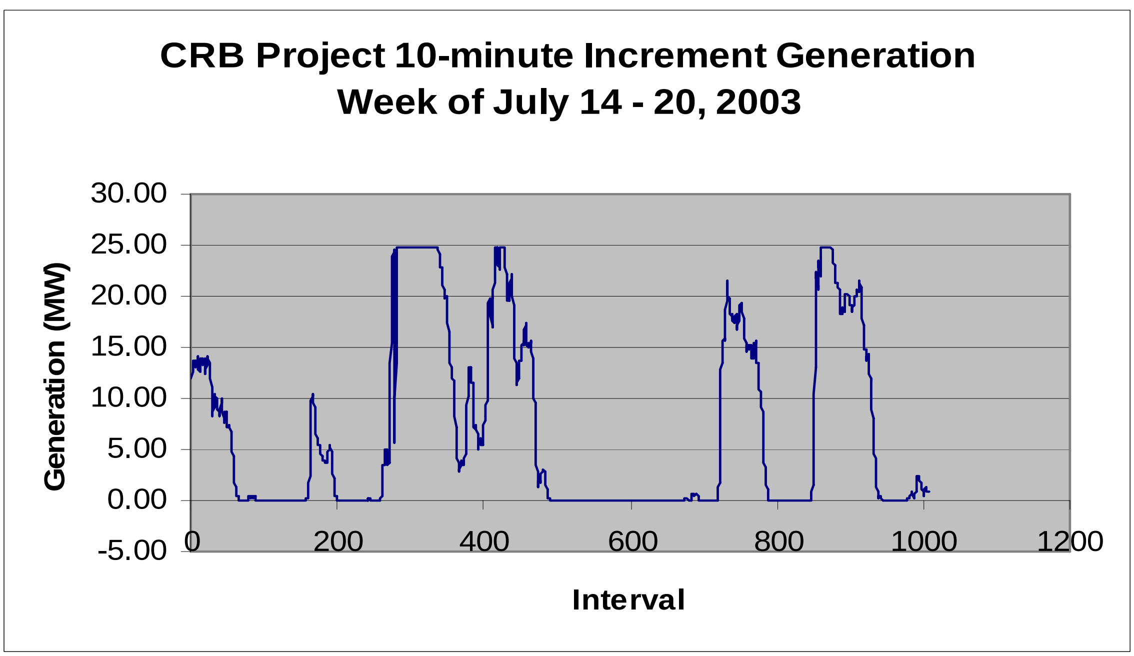
The 10-minute increment generation amounts were also averaged to produce monthly generation amounts, as is shown in Figure 4.1b below:

**Figure 4.1b**




Finally, Figure 4.1c below illustrates the potential short-term variations in generation at the CRB Project site for a typical one-week period:

**Figure 4.1c**



## Section 5 - Development of the Columbia River Basin Project Wind Generation/Wind Forecast Data

### 5.1 Wind Generation Data Utilized in the Phase 1 Studies

As has been previously stated, one impediment to performing wind generation studies on the PSE power system is the lack of historical wind generation data. In order to perform wind integration studies specifically referenced to the PSE power system, the Phase 1 studies relied upon an 11 ½ month simulated record of 10-minute increment wind generation amounts. Complete details regarding the derivation of the Ellensburg simulated wind generation data series is outlined in Section 6 of the Phase 1 report.

One drawback of the simulated Ellensburg wind generation data is that there were no historical wind generation forecasts available for inspection. The Phase 1 studies therefore relied upon standard persistence forecasting techniques to develop a series of simulated Hour-Ahead wind generation forecasts. A similar technique was employed to produce simulated Day-Ahead wind generation forecasts with the addition of an assumed forecast error reduction factor.

### 5.2 Use of the CRB Project Wind Generation Data

One of the stated goals of the Phase 2 studies was to augment the use of the simulated Ellensburg area data with actual "real-life" wind generation data. Specifically, PSE began receiving wind generation data from the CRB Project beginning in April, 2003. Golden therefore decided to utilize this wind generation dataset for the Phase 2 studies to the extent practical, and to use the previously derived Ellensburg wind generation data to fill in any gaps (such as the four winter months where the CRB Project data was not yet available).

Pursuant to PSE's wind generation purchase agreement, PSE had the following wind generation data available, referenced to a 25 MW maximum capacity figure:

1) After-the-fact 10-minute increment actual generation amounts
2) A firm wind generation schedule for the upcoming schedule hour
3) An estimated Day-Ahead wind generation schedule for each hour of the next day

Using the above referenced data, PSE could compute actual Hour-Ahead and Day-Ahead wind forecast errors based upon an operating Northwest wind farm, rather than relying upon simulated persistence based forecasts as was done in the Phase 1 studies.

### 5.3 Development of the CRB Project Wind Generation Datasets

Pursuant to the terms of PSE's wind purchase agreement, the following CRB Project wind generation data was available to PSE:

Actual 10-Minute Increment Data

At the time the Phase 2 studies were being set up in December 2003, PSE had 10-minute actual wind generation data available for the period April – November 2003. In some cases, the raw 10-minute data files supplied by the seller contained missing intervals and/or spurious data values. Golden examined all of the actual generation data and where necessary, filled in missing intervals and replaced erroneous data points utilizing linear interpolation techniques.

Hour-Ahead Firm Wind Generation Schedules

The seller communicated to PSE the amount of wind generation that it was going to deliver to PSE during the next hour at least 35 minutes prior to the start of that hour. Once the Hour-Ahead schedule was communicated to PSE, the seller delivered the agreed upon Hour-Ahead amount regardless of what the actual wind generation was within that hour.

Day-Ahead Wind Generation Estimates

The seller also provided PSE with non-binding, Day-Ahead estimates of hourly wind generation amounts. These estimates were provided to PSE prior to 10:00 AM on the day before delivery.

## 5.4 Interrelation of the 10-minute, Hour-Ahead and Day-Ahead CRB Project Data

In analyzing the above referenced wind generation data, it was readily apparent that the Day-Ahead estimates and the Hour-Ahead delivery amounts had a consistent low side bias; in all eight months studied, the monthly average of the Day-Ahead and Hour-Ahead forecasts were both much lower than the monthly average of the actual 10-minute increment generation.

The following table summarizes the monthly averages of the CRB Project wind data for the period April 2003–November 2003:

**Table 5.4**
**Comparison of PSE CRB Project Wind Generation Quantities**

| Month | PSE-CRB Project Actual Wind Generation (aMW) | PSE-CRB Project Hour-Ahead Wind Forecast (aMW) | PSE-CRB Project Day-Ahead Wind Forecast (aMW) |
|---|---|---|---|
| April-03 | 8.99 | 7.75 | 4.04 |
| May-03 | 8.65 | 6.74 | 2.35 |
| June-03 | 8.91 | 7.08 | 3.46 |
| July-03 | 8.21 | 5.97 | 2.25 |
| August-03 | 6.36 | 5.18 | 2.34 |
| September-03 | 6.76 | 5.05 | 2.84 |
| October-03 | 7.83 | 5.71 | 4.52 |
| November-03 | 9.38 | 7.17 | 6.31 |

**5.5 <u>Adjustments to the CRB Project Hour-Ahead and Day-Ahead Data</u>**

As can be seen in Table 5.4 above**,** the Hour-Ahead forecasts for the period April 2003–November 2003 averaged 22% lower than the associated actual generation. The Day-Ahead forecasts for the same period averaged 57% less than the associated actual generation. Golden therefore determined that it was prudent to modify the initial Hour-Ahead and Day-Ahead forecasts to remove their inherent low side bias. This was done by employing the following process:

1) For the Day-Ahead forecast, the total monthly wind generation was computed and compared to the total monthly actual wind generation
2) The monthly ratio of actual generation to Day-Ahead forecast generation was computed
3) Each non-zero hourly Day-Ahead forecast was increased by the monthly ratio computed in step No. 3 above
4) Each adjusted hourly Day-Ahead forecast was limited to 25 MW
5) A second iteration of steps No, 1-4 was performed to re-allocate any hourly reductions made due to the application of the 25 MW hourly limit, with the exception that all hours were adjusted upwards.
6) Day-Ahead forecasts were also adjusted as described in steps 1-5 above.

**5.6 <u>Development of CRB Project Wind Forecast Error Tables</u>**

One of the goals of the Phase 2 studies was to employ a more sophisticated dynamic wind forecasting technique when determining the amount of PSE system flexibility required to manage wind generation variability. Utilizing the adjusted forecast values as determined in Section 5.5, Golden and PSE computed a series of wind forecast error tables assuming confidence intervals ranging from 50% confidence to 99% confidence. Separate forecast error values were computed for potential increases in wind generation (i.e. over-generation) and potential decreases in wind generation (i.e. under-generation).

Table 5.6a shows the forecast error tables for the adjusted CRB Project Hour-Ahead forecasts versus actual CRB Project wind generation:

**Table 5.6a**
**Hour-Ahead Adjusted CRB Project Wind Generation Forecast Errors**
**April 2003-November 2003**

| | 95% Confidence | | 75% Confidence | | 50% Confidence | |
|---|---|---|---|---|---|---|
| Forecast Range (MW) | Under Generation Error (MW) | Over Generation Error (MW) | Under Generation Error (MW) | Over Generation Error (MW) | Under Generation Error (MW) | Over Generation Error (MW) |
| 0.00 - 5.00 | 1.58 | 8.69 | 0.93 | 5.00 | 0.48 | 2.44 |
| 5.01 - 10.00 | 6.76 | 12.84 | 4.65 | 8.45 | 3.19 | 5.40 |
| 10.01 - 15.00 | 10.33 | 10.97 | 6.97 | 7.33 | 4.63 | 4.80 |
| 15.01 - 20.00 | 13.26 | 8.27 | 8.69 | 5.72 | 5.52 | 3.94 |
| 20.01 - 25.00 | 11.82 | 3.62 | 6.79 | 2.48 | 3.28 | 1.69 |

For instance, table 5.6a indicates that when CRB Project wind generation is forecasted for the next hour to be a value X where X is between 0 and 5.00 MW, there is a 95% probability that the actual wind generation average for that hour will be between a minimum of X-1.58 MW (limited by zero) and a maximum X+8.69 MW.

Table 5.6b shows the forecast error tables for the adjusted CRB Project Day-Ahead forecasts versus actual CRB Project wind generation:

**Table 5.6b**
**Day-Ahead Adjusted CRB Project Wind Generation Forecast Errors**
**April 2003-November 2003**

| | 95% Confidence | | 75% Confidence | | 50% Confidence | |
|---|---|---|---|---|---|---|
| Forecast Range (MW) | Under Generation Error (MW) | Over Generation Error (MW) | Under Generation Error (MW) | Over Generation Error (MW) | Under Generation Error (MW) | Over Generation Error (MW) |
| 0.00 - 5.00 | 3.45 | 21.29 | 2.55 | 14.21 | 1.93 | 9.29 |
| 5.01 - 10.00 | 9.09 | 19.78 | 6.80 | 13.91 | 5.22 | 9.83 |
| 10.01 - 15.00 | 14.48 | 14.20 | 10.51 | 10.05 | 7.75 | 7.17 |
| 15.01 - 20.00 | 18.92 | 10.00 | 13.47 | 7.49 | 9.68 | 5.66 |
| 20.01 - 25.00 | 21.08 | 4.40 | 13.06 | 3.03 | 7.48 | 2.09 |

### 5.7 <u>Development of Full Year Wind Generation/Forecast Data Series</u>

A shortcoming of the CRB Project data is that only eight months of wind generation data and forecasts were available at the time the Phase 2 studies were being completed in December 2003 and January 2004. From the Phase 1 studies, it was known that the wind generation load factor in the Ellensburg area was significantly lower in the winter months than during other times of the year; it therefore was desirable to construct a full 12 month wind dataset such that full annual cost figures could be evaluated.

Golden therefore decided to combine the CRB Project and Ellensburg area data as follows in order to produce one integrated set of wind generation and forecast data:

- The hourly average of the 10-Minute increment simulated Ellensburg actual wind generation amounts were utilized as a proxy for PSE wind generation. This data is referenced to a maximum net generating capacity of 136.4 MW.

- The Hour-Ahead and Day-Ahead wind forecast error tables computed from the adjusted CRB Project data were applied to the hourly Ellensburg wind generation amounts in order to compute the probable range of wind generation for each hour. Since the CRB Project error tables were referenced to a maximum net generating capacity of 25 MW, the individual entries in the error tables were multiplied by the ratio of 136.4/25.0 in order to produce adjusted error tables that were referenced to a maximum net capacity of 136.4 MW.

## Section 6 - Regulation Impacts due to Wind Generation on the PSE System

### 6.1 Summary of Regulation Impacts Determined in the Phase 1 Studies

Regulating reserves are very short time-frame (i.e. several seconds to several minute) reserves that are maintained by control area operators in order to: 1) balance rapidly fluctuating control area loads and resources, 2) maintain scheduled power transfers between different control areas, and 3) maintain system frequency within a narrow bandwidth around 60 hz. The second-to-second and minute-to-minute load fluctuations of end use electric customers are largely uncorrelated and are therefore essentially random in nature.

Section 7 of the Phase 1 report contained a comprehensive analysis of the Regulation impacts associated with wind generation on the PSE control area. Due to the lack of data for Northwest wind farms, the conclusions of the Phase 1 studies relied on several technical papers that reported on the results of detailed Regulation studies conducted with actual operating data from two existing Midwest wind farms (Lake Benton and Storm Lake). The Phase 1 Report concluded that Regulation impacts for the PSE system would be expected to be very small, and that based on the available Ellensburg area wind data, the costs of managing Regulation impacts associated with wind generation on the PSE control area would be approximately $0.16/Mwh. Also, based on the analysis of the Phase 1 report, a 154.5 MW gross capacity wind farm would require only an additional 1.0 MW of regulating margin on the PSE control area system.

### 6.2 Regulation Impacts in the Phase 2 Studies

Between the time that Golden performed the Phase 1 studies (summer 2003) and was setting up the Phase 2 studies (December 2003), no new data regarding regulation impacts of wind generation on the PSE control area became available. While PSE did receive some operational data from the CRB Project, PSE did not receive any data on a short enough time frame to evaluate Regulation impacts (plus the CRB Project is not interconnected to the PSE control area).

Also, during the approximate six month period between the Phase 1 and the Phase 2 studies, no new technical literature was released that contradicted the previously reported results of wind related Regulation impacts on the Lake Benton and Storm Lake wind farms. These observations, combined with the fact that the Phase 1 studies concluded that Regulation impacts of wind generation was likely very small for the PSE system, lead Golden to conclude that additional detailed work to quantify Regulation impacts was not warranted in the Phase 2 studies. Therefore, the Phase 2 study adopts the results of the Phase 1 study regarding the Regulation impacts of wind generation on the PSE system.

## Section 7 - Operating Reserve Impacts due to Wind Generation on the PSE System

### 7.1 Summary of Operating Reserve Impacts Determined in the Phase 1 Studies

Section 9 of the Phase 1 report contained a detailed analysis of the effects of wind generation on PSE's Operating Reserve requirements. At the time the Phase 1 studies were being completed in the summer of 2003, the Northwest Power Pool (NWPP) had not yet determined the appropriate amount of Operating Reserves to be maintained for wind resources. The Phase 1 studies were therefore based on Golden's opinion that the likely "worse case" scenario was that the NWPP would treat wind resources similar to non-hydro resources and therefore require that Operating Reserves be calculated based on 7% of the on-line wind generation amount.

The Phase 1 report concluded that PSE's Operating Reserve requirement would not be appreciably changed by the addition of 136.4 MW (net capacity) of wind generation on the PSE system. The Phase 1 report noted that based on the Ellensburg area wind data, the average expected operating reserve impact was only 0.4 MW and that the maximum possible Operating Reserve impact was +/- 2.7 MW. Golden therefore concluded that the addition of 136.4 MW of wind generation to the current PSE power portfolio would have an insignificant impact on PSE's operating reserve requirements.

### 7.2 Updated NWPP Operating Reserve Policies

In January 2004, the NWPP implemented two revisions to its Operating Reserve policies that have a bearing on wind related resources. First, effective January 1, 2004, Operating Reserves associated with wind generation are computed based on 5% of the on-line wind generation amount. Second, effective February 20, 2004, the largest single contingency requirement was dropped from the determination of the minimum Operating Reserve amount.

### 7.3 Summary of Operating Reserve Impacts Determined in the Phase 2 Studies

Neither of the changes noted in Section 7.2 has an appreciable impact on PSE regarding the amount of Operating Reserves to be maintained for wind generation. The addition of any new generation resources on the PSE system (no matter what the fuel source or generation type) would result in the requirement for PSE to carry additional Operating Reserves pursuant to the NWPP's 5%/7% calculation. The addition of wind generation in the PSE control area would, in itself, not increase PSE's Operating Reserve requirement relative to the addition of a non-wind resource.

Based upon the results of the Phase 1 studies and taking into account the NWPP's updated Operating Reserve criteria, Golden's concludes that PSE's wind-related Operating Reserve costs would remain negligible (i.e. $0.00/Mwh) for wind farm sizes up to at least 450 MW, given PSE's current Mid-C maximum capacity amount.

## Section 8
## Discussion of the Phase 2 Methodologies Utilized to Evaluate Hour-Ahead and Day-Ahead Wind Impacts on the PSE System

### 8.1 Overview of the Phase 1 Hour-Ahead and Day-Ahead Study Methodologies

The Phase 1 studies primarily employed a simplified hydro storage/release model for the purpose of determining Hour-Ahead and Day-Ahead operational impacts of wind generation. While this model had a number of strong points (simplicity, results consistent with operational experience), it was recognized that some improvements could be made. In particular, Golden felt that "hard" operating constraints on the PSE system, such as maximum and minimum Mid-C generation levels, were not being fully considered in the simplified Phase 1 model. While these constraints were not expected to have a major influence for 136.4 MW of net wind generation capacity on the PSE system (the amount evaluated in the Phase 1 studies), it was anticipated that as the wind generation amount was increased that these types of real life operational constraints would come into play more and more often. Also, it was contemplated that the inclusion of option valuation techniques might provide a more comprehensive measure of the operational flexibility costs associated with managing wind generation variability.

### 8.2 Overview of the Phase 2 Hour-Ahead and Day-Ahead Study Methodologies

For the Phase 2 studies, Golden and PSE jointly decided to evaluate the following three methodologies for valuing the Hour-Ahead and Day-Ahead operational impacts of wind generation on the PSE system:

1. An options based model utilizing standard option valuation techniques (termed the Standard Options Model). Under this concept, the magnitude of the physical power options required to manage short-term wind generation variations would be determined and then valued pursuant to the Black-Scholes options pricing methodology.

2. An enhanced operations-based hydro routing model (ultimately termed the Mid-C Flex Model). Under this concept, Golden and PSE would build upon the Phase 1 work and would attempt to incorporate more real-life operational constraints into the subject models. This approach also included the potential development of an hourly (or shorter) least cost dispatch model for the PSE system. A detailed assessment of the Mid-C Flex model is discussed in Section 9.

3. A modified options-based model (termed the Virtual Storage Model). Under this concept, a "virtual" hydro pondage account would be defined and dedicated to managing short-term wind generation variations based on a pre-defined set of Mid-C based operating constraints. The value of the virtual hydro storage account would then be assessed utilizing the Black-Scholes methodology. A detailed assessment of the Virtual Storage model is discussed in Section 10.

### 8.3 Summary of Hour-Ahead and Day-Ahead Study Methodology Results

Each of the three aforementioned modeling concepts was fully evaluated as part of the Phase 2 studies. High level results of these investigations are summarized below:

Standard Options Model

Upon further investigation, Golden and PSE determined that the Standard Options Methodology resulted in an "overkill" situation and that the computed Hour-Ahead and Day-Ahead wind integration costs using this method were significantly higher than would be reasonably expected. This methodology was therefore dropped from final consideration.

Mid-C Flex Model/Least Cost Dispatch Model

The development of a full-blown hourly least cost dispatch model for the PSE system was ultimately abandoned as: 1) not being feasible within the project timeline, and 2) being too heavily dependant upon subjective input assumptions. The PSE dispatch model concept was therefore replaced with a more conceptual Mid-C operational-based storage/release model. Golden and PSE felt that this model was successful in incorporating several key physical Mid-C operating constraints. The Mid-C Flex model yielded overall results that were generally in line with published results for other utility systems.

Virtual Storage Model

The Virtual Storage Model yielded general results reasonably in line with published wind studies for other utilities. While this model incorporates superior valuation techniques, PSE and Golden recognized that it does not incorporate physical PSE operating constraints as well as the Mid-C Flex Model.

### 8.4 Overall Hour-Ahead/Day-Ahead Model Summary

Upon review of preliminary modeling results, PSE and Golden felt that a "blending" of the Mid-C Flex methodology and the Virtual Storage methodology would yield the optimal results. In this fashion, physical PSE operating constraints and sophisticated options valuation techniques could both be incorporated into the assessment of Hour-Ahead and Day-Ahead wind integration costs. The Hour-Ahead and Day-Ahead cost results presented in Sections 11-13 of this report therefore utilize a 50/50 blending of the individual results of the Mid-C Flex and the Virtual Storage models.

# Section 9 - PSE Mid-C Flex Model

## 9.1 Overview

A key component in determining the short-term operational and cost impacts of wind generation on a utility's power system is the development of an analytical tool to quantify and measure how wind generation interacts with other system resources. This can especially be a daunting task in the case where the wind resources have not yet been integrated into the subject utility's system since many of the operational impacts are very much a function of the specific characteristics of the subject utility's power portfolio.

In the Phase 1 studies, a simplified Mid-C pondage/storage model was utilized to determine the amount of Mid-C flexibility that was required to manage wind generation variability on the PSE system. While this model was fairly simple to implement and yielded reasonable results (as compared to similar studies performed on other utility systems), Golden and PSE felt that some improvements could be made, especially in the area of more accurately modeling PSE's operational constraints.

## 9.2 The Mid-C Flex Model Approach

Upon abandoning the development of an hourly PSE LCD model (see Section 8.3), Golden pursued an approach of fine tuning the methodology originally developed in the Phase 1 studies. That approach used the concept that most wind generation deviations would be managed by PSE's share of the Mid-C plants. Golden decided to utilize the same basic approach in the Phase 2 studies, with additional enhancements regarding the size of the wind generation additions and a more detailed incorporation of the Mid-C plants' operating constraints.

The Mid-C Flex model was based on several general resource management goals that PSE personnel attempt to implement as a part their ongoing resource optimization activities. For instance, inflows to the Mid-C plants are generally heavily reshaped to minimize generation amounts during the off-peak hours and maximum generation during the on-peak hours. This operation must be done pursuant to: 1) minimum Mid-C generation constraints, 2) maximum Mid-C generation constraints, and 3) other constraints such as environmental and/or recreational requirements.

Some of the key operational constraints and resource strategies incorporated into the Mid-C Flex model are highlighted below:

<u>Mid-C Minimum and Maximum Generation Constraints</u>

In most cases, the Mid-C minimum is the controlling constraint during off-peak hours and the Mid-C maximum is the controlling constraint during on-peak hours. With the addition of variable wind generation to the PSE power portfolio, the two main conditions that need to be actively managed (and that may result in incremental operational costs) are as follows:

1. For off-peak hours, the potential that wind generation could *increase* within the hour (above the Hour-Ahead forecasted amount) could result in PSE hitting its Mid-C minimum generation constraint within the hour.

2. For on-peak hours, the potential that wind generation could *decrease* within the hour (below the Hour-Ahead forecasted amount) could result in PSE hitting its Mid-C maximum generation constraint within the hour.

In both of the above cases, PSE's Traders and System Operators need to preschedule the Mid-C generation in such a manner as to be able to counteract the *forecasted* wind variations within the next schedule hour.

The Mid-C Flex model determines on which specific hours PSE would need to increase and decrease scheduled Mid-C generation in order to manage the wind resource and keep the Mid-C within its allowable minimum and maximum generation constraints.

<u>Forced Off-Peak Sales and Forced On-Peak Capacity Purchases</u>
Since the Mid-C minimum is the controlling constraint during off-peak hours, PSE would need to schedule its Mid-C generation at a somewhat higher level than what it would do in the absence of wind generation. This operation is driven by the probability that actual wind generation could be higher than the forecasted amount. Increasing the loading on the Mid-C units during off-peak hours would typically be accomplished by PSE selling additional energy into the off-peak wholesale markets.

Since the Mid-C maximum is the controlling constraint during on-peak hours, PSE would need to schedule its Mid-C generation at a somewhat lower level than what it would do in the absence of wind generation on the specific hours that PSE is in danger of hitting its Mid-C maximum constraint. This operation (which would necessitate an incremental PSE energy purchase) is driven by the probability that actual wind generation could be lower than the forecasted amount.

<u>Daily Water Balance</u>
While PSE can actively shift Mid-C generation in time by implementing short-term fills and releases from its pondage accounts, PSE cannot change the overall amount of water that is flowing into the Mid-C complex. If PSE generates an incremental additional amount of power from the Mid-C during off-peak hours, it will need to generate the same increment less power from the Mid-C during some other future hours. The model compensates for water balance by forcing each day's total PSE Mid-C generation to be the same in both the pre and post wind cases.

Dual Constraint Limitations

During some high flow periods, it is possible that PSE's Mid-C loading gets "squeezed" by both the minimum and maximum constraints on the same hour. In this situation, PSE does not physically have enough Mid-C flexibility to manage the expected wind generation variations within the hour no matter what "corrective" actions PSE may take (such as buying or selling power in advance of the next hour). If this situation occurs (identified as a "dual constraint" hour in the model), PSE must utilize some other means to manage the wind variability. The frequency of occurrence of dual constraint hours is therefore an important metric regarding whether PSE's power portfolio has enough Mid-C capacity to physically manage wind generation variability in the Hour-Ahead and Day-Ahead timeframes.

## 9.3 Mid-C Flex Model Base Data and assumptions

Some of the key input data and related assumptions used in the Mid-C model are briefly described below:

Base (pre-wind) Hourly Mid-C Generation Series

PSE's actual hourly Mid-C generation for the period January 1 – December 11, 2003 was utilized for this purpose. This Mid-C generation dataset contains a good mixture of low, medium and high flow days, therefore it is considered to be more or less "normal". It is possible that the overall results of the Mid-C Flex model could be somewhat different (as compared to the results presented herein) for either a specific very dry, or a very wet water year.

Mid-C Maximum Generation Constraint

PSE's maximum gross Mid-C generation capacity as of January, 2004 was utilized in the model. It was assumed that PSE maintained 100% of its Operating Reserve requirements on the Mid-C units. The model was configured such that the maximum Mid-C constraint could be modified to reflect: 1) a different PSE Mid-C maximum gross capacity or, 2) a different Operating Reserve treatment.

Mid-C Minimum Generation Constraint

PSE's minimum Mid-C generating constraint is highly variable in nature and is closely tied to real-time river operations. The model assumes that PSE managed (prior to the acquisition of wind power) its Mid-C generation to the minimum level possible on all off-peak hours in order to maximize off-peak/on-peak economic load factoring operations.

Hourly Mid-C Wholesale Power Prices

Actual hourly Mid-C power prices for the period January 1 – December 31, 2003 (as reported by Dow Jones) were used to compute the dollar impacts of Hour-Ahead and Day-Ahead wind variations. Specifically, the Mid-C Flex model used hourly prices to value the incremental PSE purchases and PSE sales required to manage short-term wind generation variations.

# Section 10 – Virtual Storage Model

## 10.1 Overview

The use of a Standard Options methodology for evaluating wind variation impacts, while promising in concept, was determined to exhibit a number of drawbacks. Golden and PSE, however, felt that the use of an options valuation technique might still be promising given a revised framework. The Virtual Storage methodology uses the concept of a virtual hydro storage account in a virtual pond. The virtual pond is assumed to be a sub-set of PSE's actual Mid-C pondage rights that is effectively "set aside" to manage wind generation variability. The value of the virtual pond is then determined by computing the option value associated with PSE's operational ability to store and deliver power into and out of the virtual pond account, subject to the pre-defined limits.

## 10.2 Short-term Option Value of the PSE Power Portfolio

The current PSE power portfolio contains a significant amount of short-term operational flexibility, particularly from the Mid-C plants. Another way to view this flexibility is from the perspective of option value: PSE has the right, but not the obligation, to generate power at any particular time. This generation option right, coupled with PSE's pondage capabilities, allows PSE to shift power into higher value periods, or into periods where increased (or decreased) generation is required to meet system load/resource needs.

This portfolio option value is heavily utilized by PSE (in conjunction with short-term wholesale market purchases and sales) to minimize PSE's overall net power costs on a long-term basis. Even if events happen exactly as forecasted for a particular time period (such as variable wind generation), there is always a level of uncertainty in the outcome that has to be managed, in advance and in real-time, by PSE's System Operators and Traders. The optionality inherent in the PSE power portfolio therefore has significant value in that it allows PSE to manage such uncertain events while minimizing overall operational costs.

## 10.3 Virtual Storage Model Principles and Assumptions

Instead of modeling PSE's entire Mid-C physical generation/pondage operations (which is done in part in the Mid-C Flex model), the Virtual Pond method assumes that a portion of PSE's overall Mid-C pondage rights are dedicated to managing wind generation variability. The Virtual Storage methodology computes the amount of hydro storage flexibility that is required to integrate wind generation into the PSE portfolio, and then values this flexibility and capacity using option valuation techniques.

The Virtual Pond has a "neutral" storage point of 0 Mwh; energy can be stored into the account (thereby creating a positive balance) or drafted out of the account (creating a negative balance). For each hour of the day, wind generation uncertainty is computed utilizing a user defined confidence interval (discussed in more detail in Sections 11 and

12). These wind forecast uncertainties are then used to determine hourly generating and storage constraints. The maximum amount of storage flexibility required (i.e. the maximum allowed positive and negative balances of the Virtual Pond) was determined from the CRB Project wind generation forecast error tables previously discussed in Section 5.6.

One of the key inputs to the Virtual Storage model is the frequency in which the storage account is effectively "reset" back to a neutral zero balance. This feature is necessary to isolate short-term storage operations required to manage Hour-Ahead and Day-Ahead wind variations from longer-term storage operations that off-set large wind imbalances within a given month. While such longer-term imbalance effects are also important in evaluating wind generation impacts, they are outside the bounds of the impacts to be studied in the Phase 2 studies.

Given the aforementioned general principles, the model calculates a storage value via a linear program that optimizes revenues given actual hourly Mid-C power prices for a one year historical period. This model uses a base wind generation net capacity of 25 MW, and all of the pre-defined Virtual Storage limitations, constraints and assumptions are referenced to this particular wind generation capacity. Wind forecast error confidence intervals of between 50% and 99% were also evaluated.

## 10.4 Virtual Storage Model Results

Numerous Virtual Storage model runs were set up and conducted by PSE staff in order to test the validity of concept and to evaluate differing sets of input parameters. The Virtual Storage model yielded results that were judged by Golden and PSE to be more reasonable than the Standard Options methodology. Preliminary results from the Virtual Storage model for Hour-Ahead and Day-Ahead wind generation cost impacts were also in line with other publicly available wind integration studies.

The preliminary results for the Virtual Storage model were also somewhat higher than the comparable results for the Mid-C Flex model; this outcome was, however, somewhat expected given that the Mid-C Flex model does not include a full option value treatment.

While exhibiting some clear advantages over the Standard Options methodology, one drawback of the Virtual Storage methodology is that the model itself cannot determine the appropriate limits to place on the operation of the Virtual Pond. Since the definition of the appropriate Virtual Pond limits and constraints becomes progressively more subjective as wind generation capacity is scaled up above 25 MW, the Virtual Storage model is not as well suited as the Mid-C Flex model for the purpose of evaluating wind capacity scaling effects. Also, the option valuation inherent in the Virtual Storage model assumes as infinite market size: for instance the per unit option value of an 100 Mwh virtual pond would therefore be the same as for a 1,000 Mwh virtual pond.

## Section 11 – Evaluation of PSE Hour-Ahead Wind Generation Impacts

### 11.1 The Evaluation of Hour-Ahead Impacts in the Phase 1 Studies

The setup and approach of the Hour-Ahead impacts analysis in the Phase 1 studies were driven in part by the availability and form of the wind speed data available at the time. As has been previously referenced, Golden obtained approximately one year's worth of 10-minute increment wind speed data for six sites located near Ellensburg. Since no actual short-term wind generation forecasts existed for the Ellensburg recording sites, the Phase 1 studies employed a 2 hour delay persistence technique to forecast the next hour's wind generation.

Hour-Ahead forecast errors were computed and an 11 ½ month average error was determined for both the over-forecast and under-forecast cases. These average over and under forecast errors were then combined with a simplified Mid-C storage/release algorithm to compute the amount of Mid-C flexibility that was required to be set aside to manage wind generation deviations. Finally, the amount of Mid-C flexibility dedicated to managing wind variations was valued by applying a multi-year average price differential between on-peak and off-peak hours. Section 8 of the Phase 1 Report contains an in depth discussion of how the original Hour-Ahead studies were set up and performed.

### 11.2 The Evaluation of Hour-Ahead Impacts in the Phase 2 Studies

During the initial set up of the Phase 2 studies, five key areas were identified as exhibiting the potential to improve upon the Phase 1 results:

1. Utilize Hour-Ahead forecasts and actual wind generation from an operating Northwest wind farm (Discussed in Sections 4 and 5)
2. Replace the static average forecast error approach with a dynamic forecast error approach (Discussed in Section 5)
3. Develop, if practical, a 10-minute or hourly increment dispatch model for the PSE system to enable a more detailed analysis of PSE system operation impacts (Discussed in Section 8.3)
4. Employ options-based techniques to value wind generation variations (Discussed in Section 10)
5. Perform "scaling" studies to evaluate Hour-Ahead impacts for wind farm capacities ranging up to 450 MW (Discussed in this Section 11)

### 11.3 Common Phase 1/Phase 2 Study Conventions and Methodologies

The Phase 2 Hour-Ahead studies employed some of the basic conventions and assumptions that were also utilized in the Phase 1 studies. For instance in order to evaluate Hour-Ahead wind generation variations, it is important to understand the timeframe on which System Operators and Traders make real-time operating and/or marketing decisions. Outside of certain transactions with the California ISO, energy transfers between control areas in the Northwest (including wholesale purchases, sales and exchanges) are scheduled on a clock hour basis. Energy transfers are scheduled at a uniform delivery rate for the entire hour.

Control area operators and merchant personnel generally agree to scheduled energy transactions at least 30 minutes prior to the beginning of the next scheduling hour. This means that the System Operator/Trader will have to make forecasts of certain operating conditions (such as retail load levels and generation output) up to 1 ½ hours into the future, based on the information that is available at that moment. PSE's System Operators and Traders will also be required to develop an hourly wind generation forecast on this same timeframe.

## 11.4 Use of CRB Project Hour-Ahead Wind Generation Forecasts

For the Phase 2 studies, Golden and PSE had available a set of actual Hour-Ahead wind schedules from the aforementioned CRB Project. As was previously discussed in Section 5, upon analysis of the CRB Project wind generation data Golden identified that the Hour-Ahead wind schedules exhibited a consistent low-side bias when compared to the actual after-the-fact wind generation. The CRB Project Hour-Ahead schedules were therefore adjusted by Golden to remove this bias. Golden utilized the adjusted CRB Project data for the purpose of computing Hour-Ahead wind forecasts as opposed to computing persistence based forecasts (as was done in the Phase 1 studies).

## 11.5 Determining the Hour-Ahead Wind Forecast Confidence Interval

The CRB Project wind forecast analysis models were specifically designed to allow for the use of differing confidence intervals. For instance, use of a 95% confidence interval would indicate that the difference between the Hour-Ahead wind forecast and the actual hourly average wind generation for that same hour would be expected to be within the indicated range 95% of the time.

Golden and PSE ran a series of Hour-Ahead wind forecast sensitivity studies employing confidence intervals ranging from 50% to 99%. In choosing which confidence interval to use as the recommended level, PSE and Golden considered several factors regarding how PSE's Traders and System Operators actually make operating decisions and how power is traded in the real-time marketplace.

While the Pacific Northwest has a very active Hour-Ahead power market, there is virtually no within-the-hour market. Within-the-hour purchases and sales are generally limited to those transactions that are initiated by unforeseeable real-time events such as a generating unit trip, transmission line outage, or a sudden curtailment of another scheduled transaction. Because the within-the-hour market is so illiquid, Traders and System Operators generally do not want to be in the position of *having to* enter into a within-the-hour transaction; one will usually pay a premium (which can be significant) for a within-the-hour transaction versus an hour ahead prescheduled purchase or sale.

Traders and System Operators do not want to manage intra-hourly wind variability with within-the-hour transactions. In fact, due to implementation considerations and lack of a liquid market, *it may not even be possible to enter into certain desired intra-hourly transactions.* Because of the lack of a viable within-the-hour wholesale market, the premium that PSE would likely have to pay for within-the-hour transactions (relative to Hour-Ahead prescheduled transactions), and the potential for PSE to hit hard operating constraints within the hour, PSE and Golden agreed that a confidence interval of 95% was appropriate for use in evaluating Hour-Ahead wind generation impacts.

### 11.6 Wind Generation Hour-Ahead Scaling Impacts

The Phase 1 study results were based on the integration of a 154.5 MW (136.4 net output) wind farm on the PSE power system. The Hour-Ahead operational impacts and related costs that were computed pursuant to that study were therefore based on a single, static wind farm size.

One of the goals of the Phase 2 studies was to investigate Hour-Ahead operational impacts on the PSE system as the size of the installed wind generation was varied. While no hard wind farm size constraints were originally dictated for the Phase 2 studies, PSE staff and Golden agreed to evaluate total wind generation levels ranging from 25 MW (net capacity) to 450 MW (net capacity).

The Ellensburg Area wind generation data and the associated Hour-Ahead CRB Project forecast error tables (ratioed up to 136.4 MW net capacity) were used as the base case for the scaling studies. All of this data is referenced to a 136.4 MW net capacity wind generation level. When evaluating wind farm sizes smaller than, or greater than 136.4 MW, the wind generation data series and the base forecast error tables were then adjusted based on the ratio of the wind generation capacity being evaluated divided by 136.4 MW. Impacts were computed for each wind capacity level using a constant 95% forecast confidence interval.

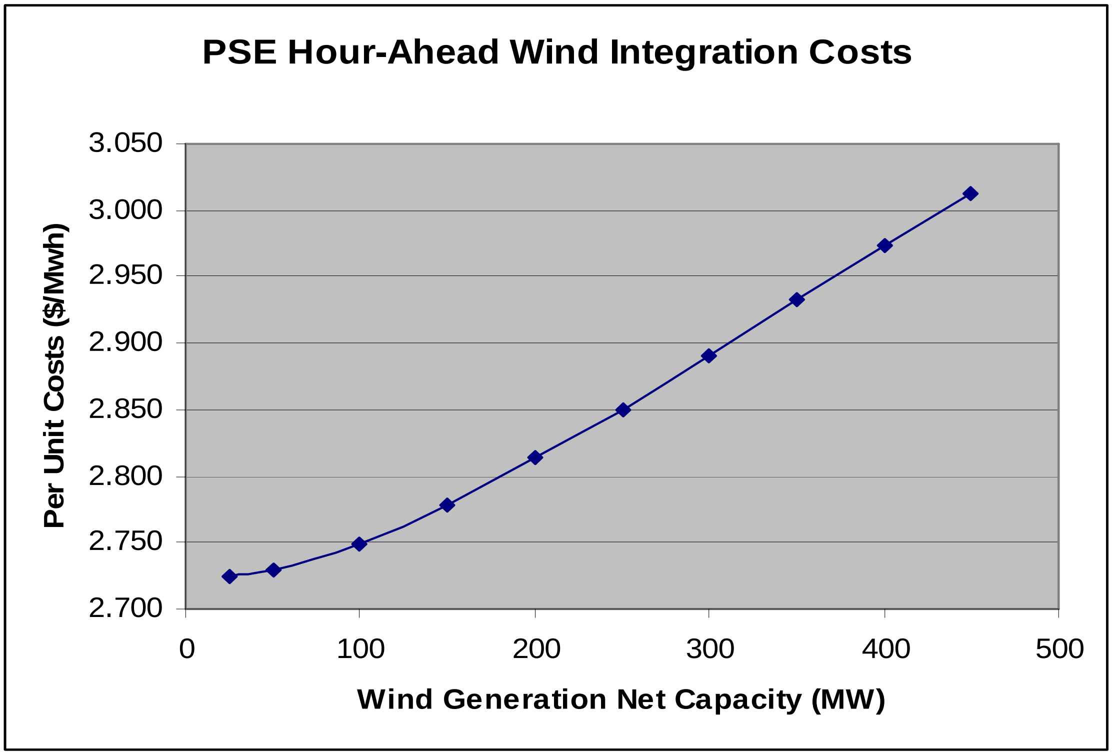
The Mid-C Flex model was specifically designed to accommodate varying amounts total installed wind generation. In order to produce a family of per unit Hour-Ahead cost impacts, a series of model runs were made whereby the wind generation net capacity was increased from a minimum of 25 MW to a maximum of 450 MW.

### 11.7 Summary Results of the Hour-Ahead Studies

Both the Mid-C Flex model and the Virtual Storage model were run to determine Hour-Ahead impacts for wind generation net capacities ranging from 25 MW to 450 MW. These model runs used an Hour-Ahead wind generation forecast confidence interval of 95% and also utilized the specific modeling constraints and assumptions previously described in Sections 9 and 10.

Results of the Hour-Ahead scaling studies are summarized in the following chart:

**Chart 11.7**



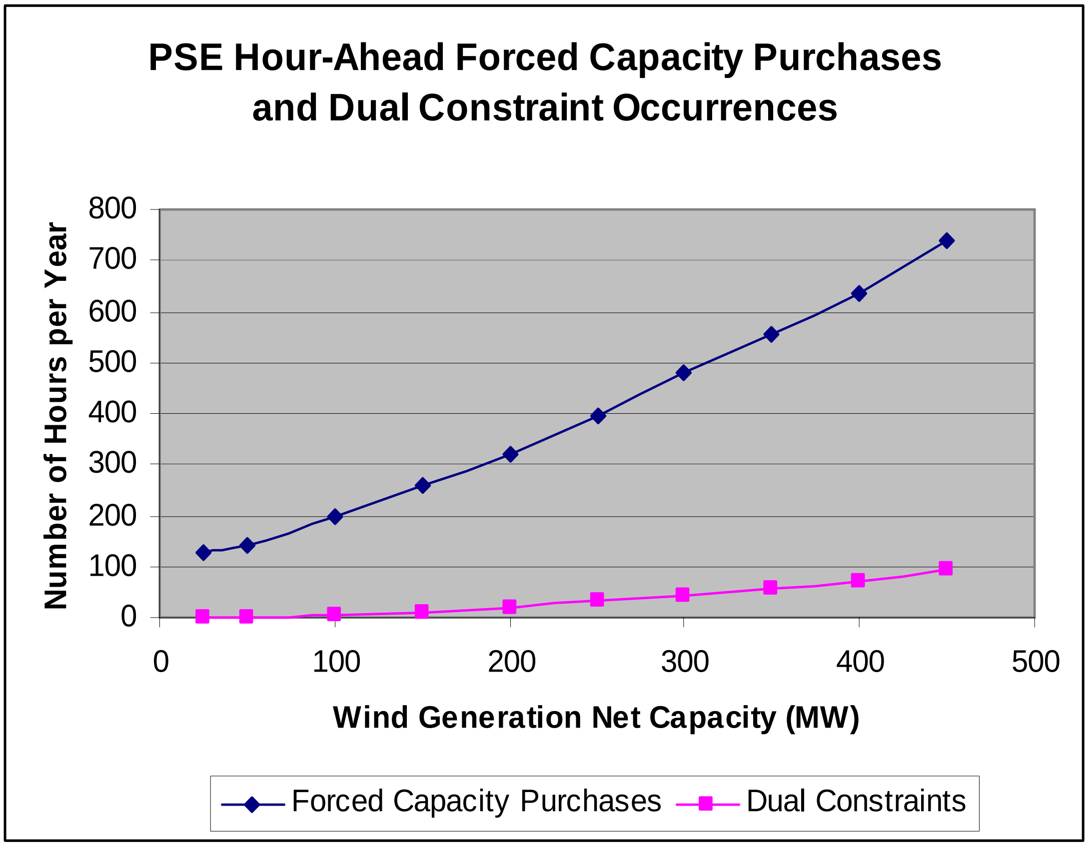

The per unit Hour-Ahead costs range from a low of $2.72/Mwh for the 25 MW wind capacity case to a high of $3.01/Mwh for the 450 MW wind capacity case. It should be noted that there is a moderate exponential trend in the per unit Hour-Ahead costs as wind generation capacity is increased: this feature is due primarily to the fact that the number of hours on which PSE is forced to purchase capacity in order to stay below its maximum Mid-C generating constraint also increases exponentially as wind generation capacity is increased.

### 11.8 <u>Forced Capacity Purchases and Dual Constraint Hours</u>

As was discussed in Section 9, the Mid-C Flex model computes two important operational metrics for the PSE system: 1) the number of hours that PSE is required to purchase capacity in order to keep its Mid-C loading below its maximum generating constraint, and 2) the number of hours that PSE encounters dual constraint problems (i.e. when the MW difference between the Mid-C maximum and minimum constraints is less than the total forecasted wind generation variation range).

Chart 11.8 below shows the frequency of occurrence of forced capacity purchase hours and dual constraint hours for wind generation capacities ranging from 25 MW to 450 MW:

**Chart 11.8**




As can be seen from Chart 11.8, the number of hours that PSE would be required to purchase capacity in the Hour-Ahead markets in order to keep its Mid-C loading below its maximum generating constraint ranges from 126 hours/year for the 25 MW case up to 738 hours/year for the 450 MW case. This is equivalent to a 1.4% occurrence rate for the 25 MW case and an 8.4% occurrence rate for the 450 MW case.

As can also be seen from Chart 11.8, the number of occurrences of dual constraint hours is relatively small under the conditions studied. The number of dual constraint hours ranges from 1 hour/year for the 25 MW case up to 95 hours/year for the 450 MW case. This is equivalent to a 0.01% occurrence rate for the 25 MW case and a 1.1% occurrence rate for the 450 MW case. In a high streamflow year, it would be expected that the occurrence of dual constraint hours would be higher than what is presented here.

The Mid-C Flex model does not attempt to value the occurrences of dual constraint hours; since dual constraints occurrences were fairly small in the Phase 2 studies, Golden would not expect that the overall Hour-Ahead wind integration costs would be appreciably impacted by excluding dual constraint related costs (under the conditions studied). However, if PSE's overall Mid-C capacity were to be significantly reduced from its current level, a valuation of dual constraint impacts would be required in order to accurately evaluate PSE's overall Hour-Ahead wind integration costs.

# Section 12 – Evaluation of PSE Day-Ahead Wind Generation Impacts

## 12.1 The Evaluation of Day-Ahead Impacts in the Phase 1 Studies

Like the evaluation of Hour-Ahead effects in the Phase 1 studies, the setup and approach of the Phase 1 Day-Ahead analysis was driven in part by the availability and form of the available wind speed data. The analysis was conducted in a similar fashion as for the Hour-Ahead studies, with the primary exception that Day-Ahead versus actual generation forecast errors were utilized.

Since the general accuracy of a persistence type wind forecast decreases rapidly for forecasts beyond roughly six hours into the future, it was assumed in the Phase 1 study that PSE's Traders would also have access to specialized meteorological forecasting tools for the purposes of developing Day-Ahead wind generation forecasts. As a proxy for such an undeveloped meteorological forecasting tool, Golden utilized a 2 day delay persistence forecasting model with an assumed 20% forecast error improvement adjustment.

## 12.2 The Evaluation of Day-Ahead Impacts in the Phase 2 Studies

All of the Phase 2 study goals that were mentioned in Section 11.2 regarding the evaluation of Hour-Ahead impacts also apply to the evaluation of Day-Ahead impacts. For measuring Day-Ahead effects, Golden and PSE desired to utilize the available Day-Ahead wind generation preschedules for the CRB Project.

## 12.3 Common Phase 1/Phase 2 Study Conventions and Methodologies

The Phase 2 Day-Ahead studies expanded upon some of the basic conventions and assumptions that were also utilized in the Phase 1 studies. Day-Ahead load forecasts, resource commitment schedules and scheduled energy transfers between control areas in the Northwest (including wholesale purchases, sales and exchanges) for a given 24 hour day are generally established prior to approximately 0700 on the preceding work day. For example, most energy transactions for HE 0100 – HE 2400 on a Tuesday would usually be established by approximately 0700 on the preceding Monday morning. Since PSE's Traders generally need to commit to scheduled power transactions early each workday morning (for delivery the following preschedule day), the Traders also need to develop Day-Ahead forecasts of PSE generator output on this same general timeframe.

## 12.4 Use of CRB Project Day-Ahead Wind Generation Forecasts

For the Phase 2 studies, Golden and PSE had available a set of actual Day-Ahead wind schedules from the CRB Project. As was previously discussed in Section 5, upon analysis of the available wind generation data Golden identified that the CRB Project Day-Ahead wind schedules exhibited a consistent low-side bias when compared to the actual after-the-fact wind generation. The CRB Project Day-Ahead schedules were therefore adjusted by Golden to remove this bias.

Golden utilized the adjusted CRB Project data for the purpose of computing Day-Ahead wind forecasts as opposed to computing persistence based forecasts (as was done in the Phase 1 studies). Even though the adjusted Day-Ahead preschedules were not "firm" (the seller had the right to change the Day-Ahead prescheduled amounts up to 35 minutes prior to the start of the delivery hour), Golden and PSE felt that the adjusted Day-Ahead wind schedules represented the "best available" forecast of the CRB Project's next day wind generation.

### 12.5 Determining the Day-Ahead Wind Forecast Confidence Interval

Golden and PSE ran a series of Day-Ahead wind forecast sensitivity studies employing confidence intervals ranging from 50% to 99%. In choosing which confidence interval to use as the recommended level, PSE and Golden considered several factors regarding how PSE's Traders and System Operators actually make operating decisions and how power is traded in the real-time marketplace.

The Pacific Northwest has historically had, and is expected to continue to have, an active and liquid hourly power market. From an implementation and timing perspective, it is therefore possible for utilities such as PSE to reasonably off-set at least some variations in Day-Ahead schedules in the real-time hourly markets. This situation is in contrast to the Hour-Ahead case (discussed in Section 11.5) where deviations in Hour-Ahead schedules generally cannot be off-set by within-the-hour transactions. Due to the existence of a liquid real-time hourly market, using a high Day-Ahead wind generation confidence interval (such as 95%) to compute Day-Ahead wind integration costs would probably overstate the costs involved.

For instance, capacity purchased on a Day-Ahead basis by PSE to keep prescheduled Mid-C loading below its maximum generation constraint can, in some cases, be re-sold back into the real-time hourly markets if it is not needed on an Hour-Ahead basis. This type of operation is made possible due to the availability of an updated Hour-Ahead wind generation forecast, which would be expected to be more accurate than the Day-Ahead forecast. The Mid-C Flex model was configured to compare the Day-Ahead forced capacity purchases and off-peak energy sales to what would be expected to be needed for the next schedule hour, utilizing the updated Hour-Ahead wind generation forecasts. If PSE had effectively over-purchased peaking capacity in the Day-Ahead market, the capacity not needed to manage the next hour's forecasted wind generation was resold back into the market.

Because of the existence of a viable real-time Hour-Ahead wholesale market and the ability of PSE to enter into incremental hourly transactions to off-set Day-Ahead wind generation forecast errors, PSE and Golden agreed that a confidence interval of 75% was appropriate for use in evaluating Day-Ahead wind generation impacts.

### 12.6 Wind Generation Day-Ahead Scaling Impacts

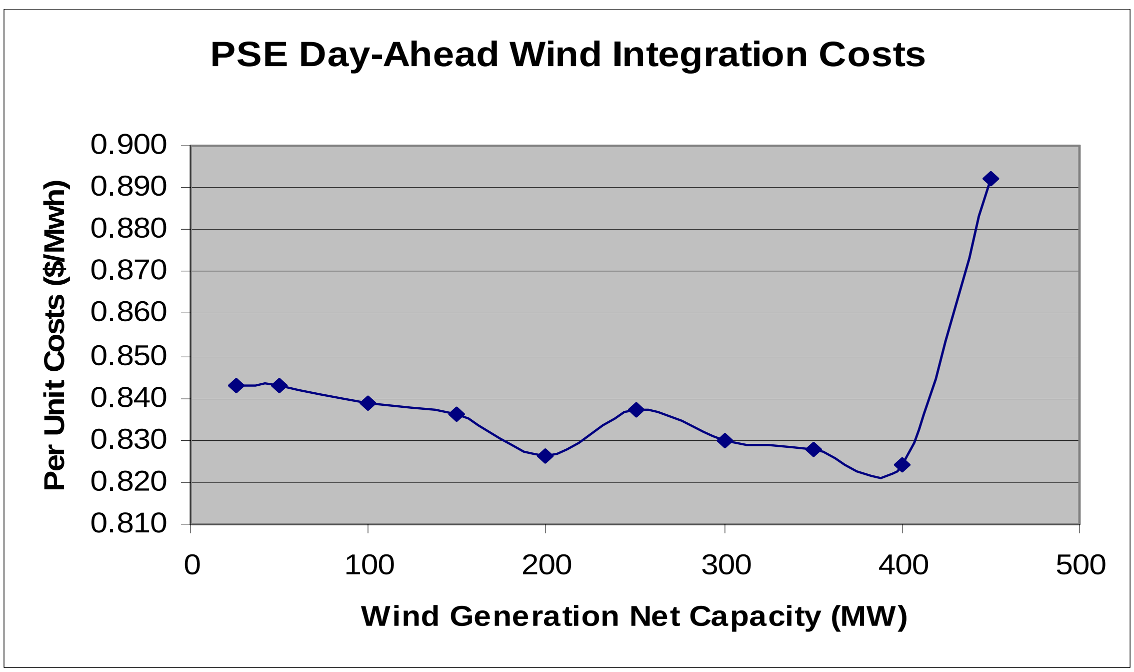
One of the goals of the Phase 2 studies was to investigate Day-Ahead operational impacts on the PSE system as the size of installed wind generation was varied. Day-Ahead impacts were therefore analyzed for wind amounts ranging from 25 MW (net capacity) to 450 MW (net capacity).

The Ellensburg wind generation data and the associated CRB Project Day-Ahead forecast error tables were used as the base case for the scaling studies. All of this data was referenced to a 136.4 MW net capacity wind generation level. When evaluating wind farm sizes smaller than, or greater than 136.4 MW, the base forecast error tables were then adjusted based on the ratio of the wind generation amount being evaluated divided by 136.4 MW. Impacts were computed for each wind generation level using a constant 75% forecast confidence interval. In order to produce a family of per unit Day-Ahead cost impacts, a series of model runs were made whereby the wind generation net capacity was increased from a minimum of 25 MW to a maximum of 450 MW.

### 12.7 Summary Results of the Day-Ahead Studies

Both the Mid-C Flex model and the Virtual Storage model were run to determine Day-Ahead impacts for wind generation net capacities ranging from 25 MW to 450 MW. These model runs used an Hour-Ahead wind generation forecast confidence interval of 75% and also utilized the specific modeling constraints and assumptions described in Sections 10 and 11. *Day-Ahead Costs that are in addition to the previously reported Hour-Ahead costs are summarized below:*

**Chart 12.7**



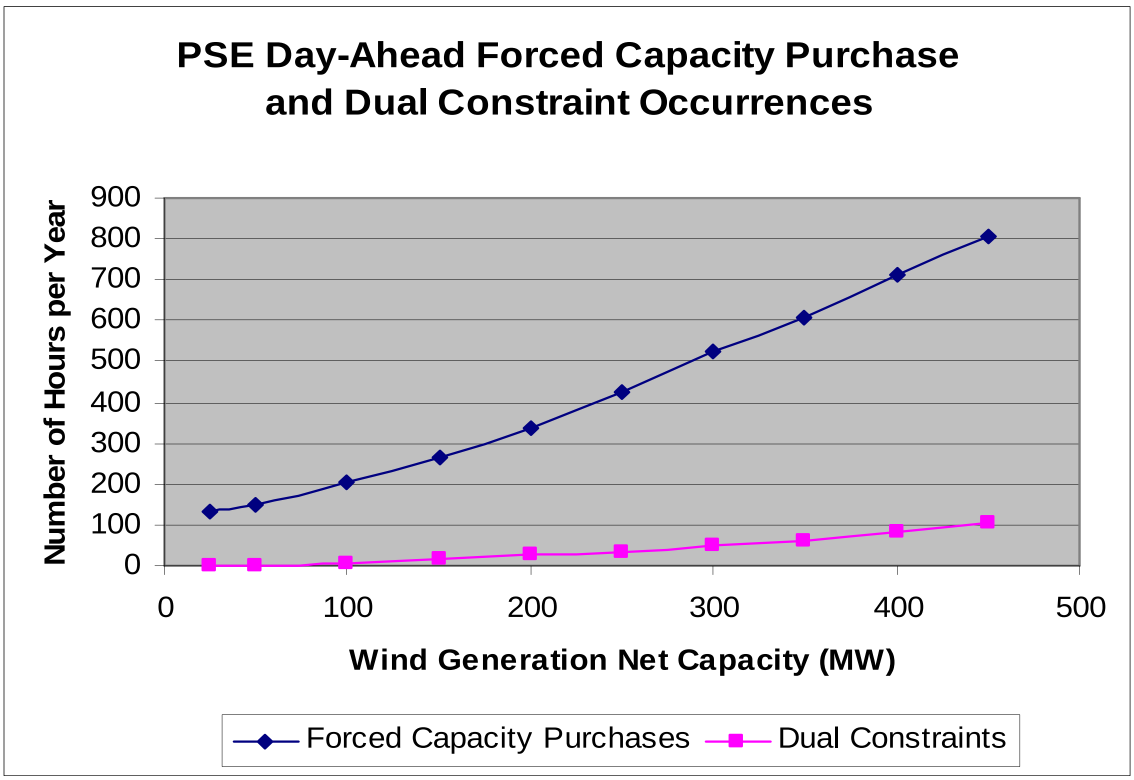
While the trend-line of the above graph appears at first glance to be somewhat "lumpy", it should be noted that the vertical scale of this graph is extremely compressed, with per unit costs varying only by +/- $0.01/Mwh over a generation range of 25 MW to 400MW.

## 12.8 Forced Capacity Purchases and Dual Constraint Hours

Forced capacity purchase hours and dual constraint hours were previously discussed in Section 11.8 regarding Hour-Ahead effects. For Day-Ahead effects, these issues are somewhat less critical cost drivers since PSE has the opportunity to modify generation levels and power purchase and sales schedules in the hourly real-time markets. So while the Day-Ahead preschedules may indicate forced capacity purchases and/or dual constraint problems for the upcoming delivery day, PSE may not actually be forced to modify a Day-Ahead operation in order to manage these events.

Day-Ahead indicated forced capacity purchase occurrences and indicated Day-Ahead dual constraint occurrences are shown below in Chart 12.8:

**Chart 12.8**




As was the case with Hour-Ahead impacts, Day-Ahead dual constraint hours are not a significant cost driver given the current amount of PSE's Mid-C flexibility relative to the wind generation capacities studied. The costs of managing Day-Ahead dual constraint hours could, however, be a more significant issue if PSE's Mid-C capacity were to be reduced from current levels.

## Section 13 - Summary of PSE Short-term Wind Generation Integration Costs

### 13.1 Summary of Results

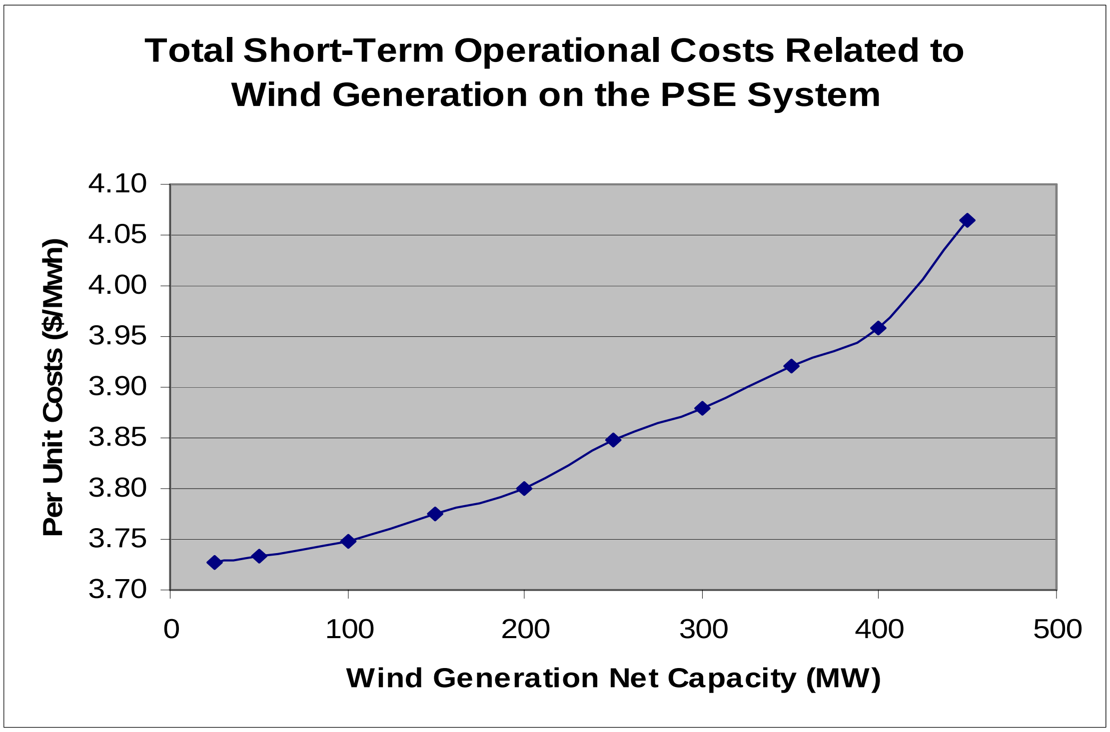
Table 13.1 below presents overall results for the four categories of short-term wind generation impacts analyzed individually in Sections 6, 7, 11 & 12 of this report:

**Table 13.1 - Summary of Probable Short-Term Operational Impacts due to the Addition of Varying Amounts of Wind Generation on the PSE System**

| Wind Generation Net Capacity (MW) | Regulation ($/Mwh) | Operating Reserves ($/Mwh) | Hour-Ahead Costs ($/Mwh) | Day-Ahead Costs ($/Mwh) | Total Costs ($/Mwh) |
|---|---|---|---|---|---|
| 25 | 0.16 | 0.00 | 2.72 | 0.84 | 3.73 |
| 50 | 0.16 | 0.00 | 2.73 | 0.84 | 3.73 |
| 100 | 0.16 | 0.00 | 2.75 | 0.84 | 3.75 |
| 150 | 0.16 | 0.00 | 2.78 | 0.84 | 3.77 |
| 200 | 0.16 | 0.00 | 2.81 | 0.83 | 3.80 |
| 250 | 0.16 | 0.00 | 2.85 | 0.84 | 3.85 |
| 300 | 0.16 | 0.00 | 2.89 | 0.83 | 3.88 |
| 350 | 0.16 | 0.00 | 2.93 | 0.83 | 3.92 |
| 400 | 0.16 | 0.00 | 2.97 | 0.82 | 3.96 |
| 450 | 0.16 | 0.00 | 3.01 | 0.89 | 4.06 |

Chart 13.1 shows the trend in per unit total operational costs as a function of wind generation net capacity:

**Chart 13.1**



### 13.2 Sensitivity of Results

In addition to the scaling studies performed to analyze the impacts of varying wind generation amounts, Golden also performed a cost sensitivity study for the 150 MW wind capacity case. Table 13.2 below presents the results of this sensitivity study; the figures shown in bold type indicate the recommended baseline results previously reported in Table 13.1.

**Table 13.2**
**Cost Sensitivity Results for 150 MW Net Capacity Wind Generation**

| Impacts Category | Low Side of Cost Range ($/Mwh) | Recommended Cost ($/Mwh) | High Side of Cost Range ($/Mwh) |
|---|---|---|---|
| Regulation | 0.01 | **0.16** | 0.19 |
| Operating Reserves | 0.00 | **0.00** | 0.00 |
| Hour-Ahead | 0.98 | **2.78** | 3.25 |
| Day-Ahead | 0.75 | **0.84** | 1.96 |
| Total | 1.74 | **3.77** | 5.40 |

For Regulation cost impacts, the low side of the indicated range was determined from the results of the Hudson and Kirby study (a regulating reserve increase of 0.22%) and the high side of the indicated range was determined from the results of the UWIG/Xcel study (a regulating reserve increase of 3.5%). For Hour-Ahead cost impacts, the low side of the indicated range was determined using a 50% confidence interval and the high side of the range was determined using a 99% confidence interval. The indicated low and high points for the Day-Ahead cost impacts were determined in a similar fashion as for the Hour-Ahead low and high points.

### 13.3 Comparison of Phase 2 versus Phase 1 Results

Table 13.3 below shows a summary cost comparison of the four short-term wind related impacts categories analyzed in both the Phase 1 and Phase 2 studies, referenced to a common wind generation amount of 136.4 MW net capacity:

**Table 13.3**
**Comparison of Phase 1 and Phase 2 Study Results – 136.4 MW Net Wind Capacity**

| Impacts Category | Phase 1 Study Results ($/Mwh) | Phase 2 Study Results ($/Mwh) |
|---|---|---|
| Regulation | 0.16 | 0.16 |
| Operating Reserves | 0.00 | 0.00 |
| Hour-Ahead | 1.54 | 2.77 |
| Day-Ahead | 2.24 | 0.84 |
| Total | 3.94 | 3.77 |

Two broad trends are evident in comparing the Phase 1 and Phase 2 results:

- The sum total cost impact for all four categories as determined in the Phase 2 studies is slightly, but not radically, lower than the total cost determined in the Phase 1 studies.

- The relative magnitude of the Hour-Ahead and Day-Ahead costs has shifted between the Phase 1 and Phase 2 studies, even though the sum total cost remain largely unchanged. This result is due to the incorporation of more sophisticated Hour-Ahead and Day-Ahead wind forecast confidence intervals in the Phase 2 studies.

### 13.4 The PSE Phase 2 Costs versus Other Reported Results

In November, 2003, UWIG released a technical paper entitled Wind Power Impacts on Electric-Power-System Operating Costs – Summary and Perspective on Work Done to Date. This paper summarized the results of six studies conducted by other entities that focused on quantifying the short-term operational impacts of integrating wind generation into large utility systems. All of the six studies except one (the so called Hirst study) evaluated Regulation, Hour-Ahead ("load following") and Day-Ahead ("unit commitment") impacts.

The results of the five UWIG reported studies (excluding Hirst) may not be directly comparable to each other or the PSE Phase 2 results since all of the studies used differing wind penetration levels. A comparison of the five UWIG reported studies and the PSE Phase 2 study does, however, provide some useful information as to the probable *range* of short-term wind integration costs. Table 13.4 below shows such a summary:

**Table 13.4 - Short-Term Operational Costs of Wind Generation On Large Utility Power Systems**

| Study | Wind Penetration Level (Percent of Peak Load) | Total Short-Term Operational Costs ($/Mwh) |
|---|---|---|
| **PSE Phase 2 (150 MW Case)** | **3.3** | **3.77** |
| UWIG/XCEL | 3.5 | 1.85 |
| Pacificorp | 20.0 | 5.50 |
| BPA | 7.0 | 1.47-2.27 |
| We Energies I | 4.0 | 1.90 |
| We Energies II | 29.0 | 2.92 |

As can be seen from Table 13.4, there is a fairly wide range of per unit cost impacts as determined in the six comparative studies. Some of the reasons for these cost differences include: 1) differing wind penetration levels, 1) differing uses of forecast versus actual wind generation quantities, 3) differing treatment of capacity and/or option value, 4) differing market price and fuel price assumptions and 5) differing power portfolio resource operating characteristics/constraints.

# Section 14 – Conclusions

## 14.1 Summary

This report has described the data sources, computational methodologies, and results developed by Golden and PSE to identify and quantify the impacts of adding wind generation into the PSE power portfolio. Specifically, Golden and PSE analyzed the impact of adding 25 MW to 450 MW of wind generation capacity to the PSE system. The analysis was based primarily on: 1) eight months of actual wind generation and wind generation forecast data derived from the CRB, and 2) an 11 ½ month record of simulated wind generation and wind generation forecasts for a future wind farm assumed to be located near Ellensburg, Washington.

Golden and PSE jointly developed two separate analytical tools to evaluate the Hour-Ahead and Day-Ahead operational impacts of wind generation on the PSE system. The first analytical model (termed the Mid-C Flex model) was based on general PSE Mid-C operating practices and incorporated a number of real-life operating constraints. The second model (termed the Virtual Storage model) utilized a virtual storage pond concept and employed sophisticated options valuation methodologies. The results of both models were then combined to produce the overall results presented in this Report.

The MW and dollar cost impacts presented herein represent reasonable, mid-point evaluations given the selected input data and stated assumptions. In particular, the confidence intervals chosen to evaluate wind forecast error impacts are believed to strike a fair balance between PSE's general desire for operational certainty versus minimizing the costs of managing wind generation variations.

The results presented are valid for the range of wind generation amounts studied, assuming PSE's current amount of Mid-C capacity. Should PSE's Mid-C generating capacity be reduced in the future, or should the amount of wind generation added to the PSE system exceed 450 MW, it would generally be expected that the per-unit operational costs of integrating wind resource onto the PSE system would be somewhat greater than what is presented herein. Additional sensitivity studies would be required to quantify these types of impacts.

Finally, as mentioned in the initial discussion of the Project Scope, there are several wind related impacts that Golden/PSE did not analyze as part of this Phase 2 study. These other issues include transmission impacts, seasonal resource planning concerns and wind generation winter capacity ratings. The 10-minute increment wind generation datasets assembled by Golden from the CRB Project data and the Ellensburg area datasets originally developed in the Phase 1 studies should be of use to PSE personnel examining these other wind related topics.

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# APPENDIX E
# RFP PROCESS AND RESULTS

PSE's April 2003 Least Cost Plan identified a need for new resources. To implement the plan's resource strategy, PSE subsequently initiated a competitive acquisition process that included requests for proposals (RFP) for wind resources, generation resources, and energy efficiency. The energy efficiency acquisition process and results are discussed in Chapter VII. This appendix summarizes the results of the competitive acquisition processes and the status of selected projects.

## A. Generation RFPs and Responses

PSE's first RFP following the release of the 2003 Least Cost Plan sought bids for wind resources (Wind RFP). The Wind RFP was issued on November 19, 2003. The RFP called for approximately 150 megawatts of wind power capacity. PSE sought proposals for long-term power purchase agreements (PPA) or PSE ownership of wind power projects. The proposals were due on January 16, 2004.

In response to the Wind RFP, PSE received 13 unique proposals for new wind development projects from 10 developers. Many of the proposals contained multiple offer options such as PPAs, asset ownership, and a combination of a PPA and a partial ownership. Considering all the options offered under each proposal, more than 40 different proposals were submitted.

Shortly thereafter, PSE issued a RFP for all generation sources (All-Source RFP), dated February 4, 2004. PSE sought proposals for a wide variety of generation projects that would provide approximately 355 aMW of energy, under long-term PPAs or PSE ownership of power projects. The proposals were due on March 12, 2004.

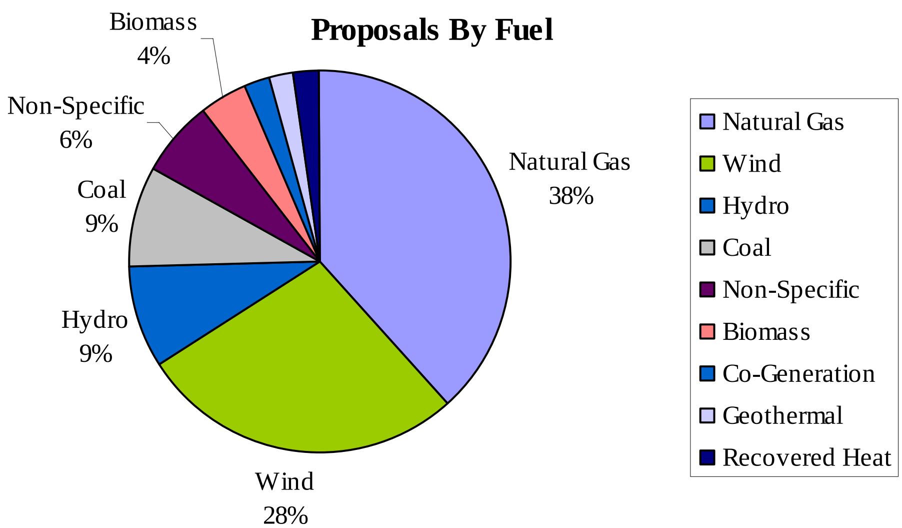
PSE received 47 unique proposals from 39 different owners/developers. Again, many of the proposals contained multiple offer options such as PPAs, asset ownership, and a combination of a PPA and a partial ownership. Considering all the options offered under each proposal, more than 88 different proposals were submitted.

All but two of the proposals submitted in response to the Wind RFP were resubmitted in response to the All-Source RFP, which included all of the short-listed proposals from the Wind

RFP. For this reason, PSE decided to merge the ongoing evaluation of the Wind RFP proposals with the evaluation of the All-Source RFP proposals.

Exhibit E-1 shows the relative proportions of the fuel sources that backed the proposals.

**Exhibit E-1**




## B. Evaluation Methodology

PSE reviewed and evaluated the proposals in a two-stage process. In Stage One, PSE screened the proposals on defined evaluation criteria and project costs, on a stand-alone basis. The most promising proposals from Stage One were evaluated in Stage Two. In addition to its own staff, PSE used outside consulting firms to evaluate the technical and environmental attributes of the proposals. Exhibit E-2 shows an overview of this process:

**Exhibit E-2**

*Stage One Evaluation*

PSE screened the proposals in Stage One using qualitative and quantitative analysis. PSE applied the defined evaluation criteria listed below:

A. Compatibility with PSE Resource Need
    1. Performance within Existing PSE Generation Portfolio
    2. Timing
    3. Resource Mix/Diversity
B. Cost
C. Risk
    1. Impact on PSE's Overall Risk Position
    2. Environmental and Permitting Risk
    3. Respondent Risk
    4. Ability to Deliver as Proposed (Development Status and Schedule)
    5. Ability to Deliver as Proposed (Experience and Qualification)
    6. Status of Transmission Rights
    7. Security and Control
D. Public Benefits
    1. Environmental Impacts
E. Strategic and Financial
    1. Guarantees and Security

PSE rated the proposals under the qualitative criteria using a rating system of "Low," "Medium," and "High," with "High" being considered more favorable and "Low" being considered less favorable.

PSE used the Acquisition Screening Model (ASM) in Stage One to summarize and compare quantitative factors on an equivalent basis. The ASM, a simplified version of the Portfolio Screening Model (PSM), is used to evaluate the relative costs of individual resource proposals. These factors included the following:

- Pro Forma with Dispatch
- 20-year Levelized Cost

- Revenue Requirements
- Mark-to-Model
- PPA Imputed Debt
- Transmission Costs, including ancillary services
- Integration Costs
- End-effects

The ASM calculated the levelized energy cost of a proposal—acquisition or PPA—over a 20-year period. With this information, PSE was able to develop a cost ranking for each proposal. The Portfolio Screening Model (PSM) was used to evaluate combinations of new resources along with PSE's existing resources, to calculate overall portfolio revenue requirements. Exhibit E-3 shows the inputs that PSE used to develop the ASM/PSM calculations.

**Exhibit E-3**
**Inputs Used in ASM/PSM Calculations**

| **PLANT CHARACTERISTICS:** | **PLANT COST DATA:** |
|---|---|
| • Capacity<br>• Heat rate<br>• Maintenance outage schedule<br>• Forced outage rate<br>• Sample 8760 hour generation profile for wind projects<br>• Book and tax depreciation rates<br>• Emission rates for SO2, NOX, and CO2 | • Capital cost including AFUDC and deal transaction costs<br>• Fixed O&M per kW of capacity<br>• Fixed A&G costs per kW of capacity (this will include property taxes and insurance)<br>• Variable O&M per MWh<br>• Fuel transportation costs including fixed pipeline and lateral charges as well as pipeline commodity charges plus fuel use (losses) and Washington state use tax<br>• Fixed and variable transmission costs including wheeling, ancillary services and imbalance or integration costs |
| **PPA COST DATA:** | **OTHER ASSUMPTIONS:** |
| • PPA fixed prices and escalation<br>• PPA variable prices, and or variable adders<br>• Transmission costs: fixed and variable<br>• Tolling: fixed and variable gas transportation, variable O&M heat rate, seasonal and maintenance outage forecast, forced outage rate | • Costs of borrowing debt and equity capital. Uses the weighted average cost of capital for levelizing costs.<br>• Natural gas price = input to AURORA<br>• Power price = hourly output from AURORA<br>• Trading values of emissions<br>• Imputed debt risk percentage<br>• Production tax credits for qualifying renewable projects |

Combining the rating system of the qualitative evaluation criteria and the ranking of the quantitative costs, PSE narrowed the proposals to a "short list". The short-listed proposals were further evaluated in Stage Two.

*Stage Two Evaluation*

In Stage Two, PSE used the Porfolio Screening Model (PSM) to evaluate short-listed proposals by calculating the portfolio impacts for a given set of resources. These portfolio analyses were also compared to updated generic portfolios similar to those that PSE evaluated in its 2003 Least Cost Plan. PSE continued to apply the Stage One evaluation criteria in the Stage Two evaluation process and placed further emphasis on the following qualitative factors:

- Transmission and Integration Alternatives
- Comparison of PPAs and Ownership Alternatives
- Ability to Deliver
- Experience of Developers
- Guarantees and Security
- Environmental and Public Benefit

As in the Stage One process, PSE again combined the quantitative cost rankings with the “High,” “Medium,” and “Low” qualitative ratings for the qualitative criteria. PSE ranked the short-listed proposals to prioritize due diligence efforts and possible commercial discussions.

## C. Detailed Evaluation Summary and Selection Results

*Stage One Evaluation*

PSE began the Stage One evaluation considering over 88 proposal options representing PPAs, asset ownership, and combinations of PPAs and partial ownership. The initial screening that PSE performed in Stage One identified some proposals that warranted lesser priority due to the lack of viability of the proposal. PSE moved these projects to the “constrained list". PSE evaluated the proposals that passed the initial screening by applying levelized cost calculations under the PSM, as well as defined qualitative criteria. Using the levelized cost from PSM, PSE was able to develop a cost ranking for each proposal that passed the initial screening. This process eliminated certain proposals with high costs, unacceptable risks, and/or feasibility constraints. PSE determined that a selection of proposals should be included in a preliminary list of "most favorable" proposals.

From that preliminary list, PSE then identified the proposals that—although attractive at some levels—faced obstacles such as transmission constraints, high fuel costs, premature development status, permitting obstacles, and other issues. PSE placed these proposals on the "continuing investigation" list. PSE continued to monitor their status through the remainder of Stage One and throughout Stage Two.

The remaining proposals from the most favorable list were placed on the short list. PSE determined that, for the most part, the short-listed proposals were both low cost under the PSM levelized-cost analysis, and low risk under the qualitative criteria.

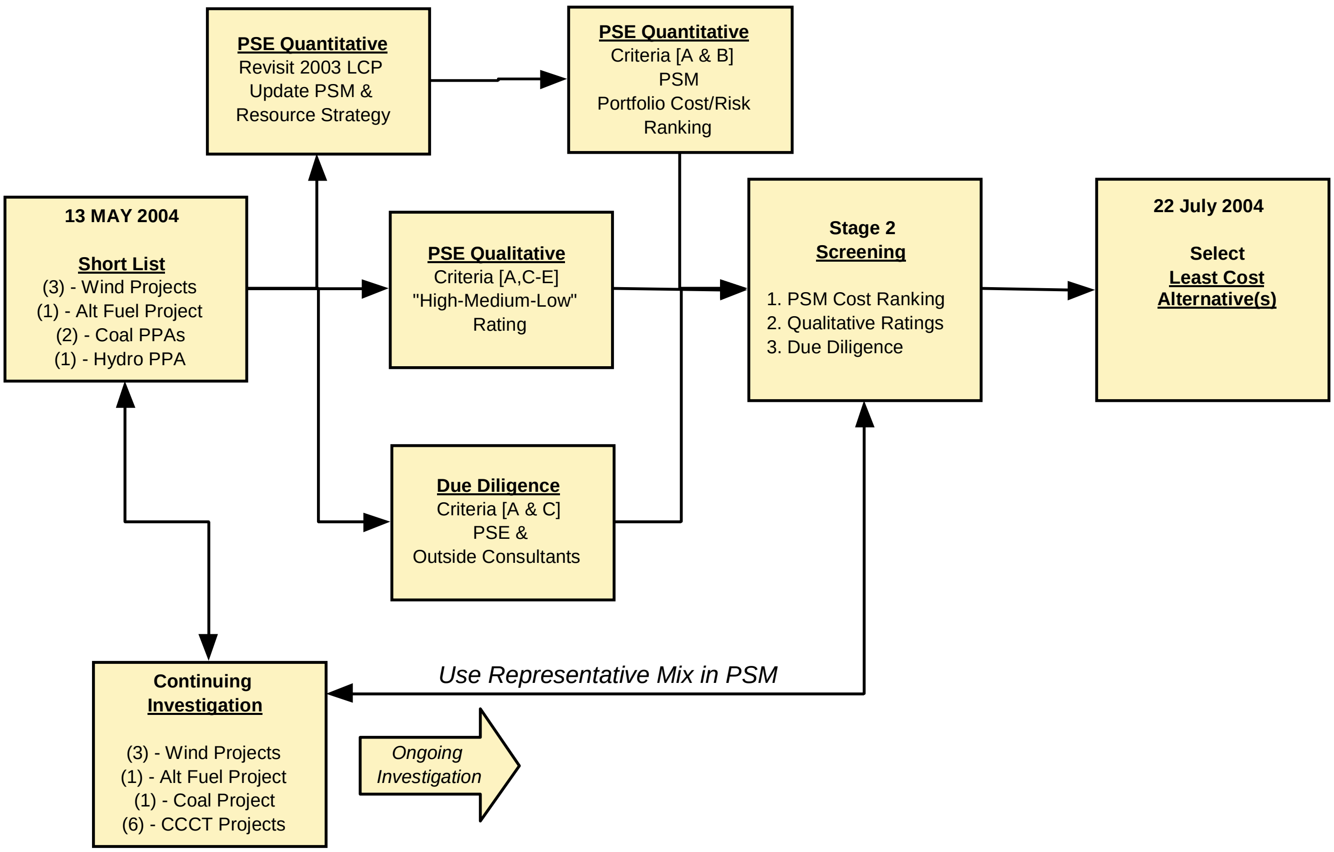
Given the high level of current and forecasted natural gas prices, no natural gas-fired projects were included in the short list. To evaluate the impacts of natural gas projects in PSE's portfolio, PSE did analyze representative natural gas proposals—drawn from the continuing investigation list—in the PSM during Stage Two.

*Stage Two Evaluation*

PSE continued to apply the Stage One evaluation criteria during Stage Two, in addition to using the Stage Two evaluation criteria. Moreover, PSE determined that it required additional information to further evaluate the proposals that were short-listed in Stage One. PSE sent information requests to the owners and developers of the short-listed projects.

Exhibit E-4 summarizes how PSE evaluated the short-listed proposals in Stage Two.

**Exhibit E-4**




PSE revisited the 2003 Least Cost Plan resource strategy in order to update and reaffirm the current resource assumptions and strategy. Given the time that had passed since publication of the 2003 Least Cost Plan, PSE updated its long-term planning data with new gas price forecasts and generic plant costs and types. In addition, the RFP process showed that the capital costs of new wind plants are currently higher than the generic assumption that PSE modeled in the 2003 Least Cost Plan. Further, the initial proposals that PSE received did not include seasonal joint ownership options for new gas plants as modeled in the Least Cost Plan.

For gas price forecasting in the base scenario, PSE used the CERA Rearview Mirror forecast—updated in the fourth quarter of 2003—which is approximately 17 percent higher than the gas price forecast that PSE used in the 2003 Least Cost Plan. The changed input assumptions that PSE ran in the AURORA model resulted in an average increase in electric prices of approximately 14 percent (compared to the forecast in the 2003 Least Cost Plan).

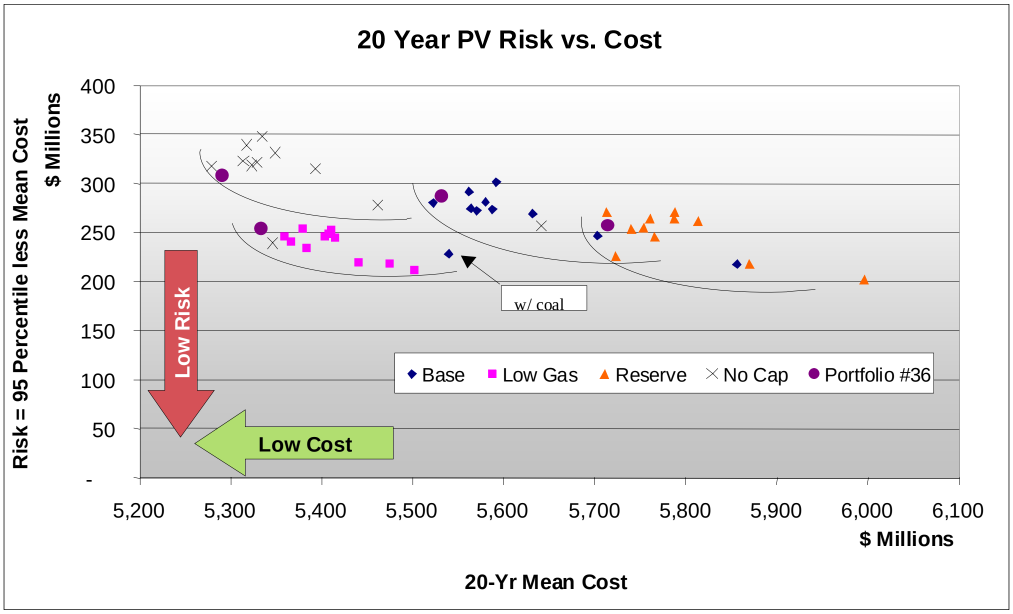
Due to increases in natural gas prices, PSE determined that the Monte Carlo approach might not provide sufficient energy price variability to adequately test the various acquisition alternatives. Instead, PSE developed three price scenarios based upon CERA's Rearview Mirror, World-in-Turmoil, and Green World long-term gas price forecasts. A fourth price scenario used the Rearview Mirror forecast with summer electricity price caps. The four price scenarios provided a more robust test of portfolio cost and risk than that which was provided by Monte Carlo simulation alone.

During this analysis, PSE observed that portfolios with a wind component generally had lower costs, whereas portfolios with a natural gas component generally had higher costs. The most uncertain portfolio involved exclusive reliance on market purchases (through the deferral of any new resource acquisitions through 2008).

PSE then analyzed the portfolio costs by developing more than 35 portfolio combinations from the short list, in addition to representative projects that PSE chose from the continuing investigation list. Using the PSM, PSE developed a portfolio cost ranking for each proposal. The PSM provided a framework in which to evaluate the long-term costs of each resource option and how those resources would perform in PSE's portfolio.

From these 35 proposals, PSE selected representative portfolios for further evaluation under the four price scenarios. PSE then calculated the present values of portfolio costs for each of the representative portfolios. Exhibit E-5 shows the present value of portfolio costs ranked from lowest costs on the left to highest costs on the right.

**Exhibit E-5**




Environmental, real estate, financial, technical, and other assessments were performed to analyze the soundness and feasibility of the proposals that were asset-based. PSE rated the short-listed proposals under the qualitative evaluation criteria using a rating system of “High,” “Medium,” and “Low,” with “High” being considered more favorable and “Low” being considered less favorable.

PSE selected a portfolio that was both low cost and low risk, which included short-listed proposals, as a group of potential acquisition opportunities. Exhibit E-6 summarizes the selected portfolio.

**Exhibit E-6**

| PROJECT NAME | OWNER / DEVELOPER | LOCATION |
|---|---|---|
| 2-yr Power Purchase Agreement | Arizona Public Service Co. | -- |
| 22-yr Seasonal On-Peak PPA | Utility PPA | System Purchase |
| Hopkins Ridge Wind Project | RES North America, LLC | Columbia Co, WA |
| Wild Horse Wind Project | Zilkha Renewable Energy | Kittitas Co, WA |
| NWPL Sumas Recovered Energy | ORMAT Nevada, Inc. | Sumas, WA |

## D. Status of Resources Selected

*Arizona Public Service PPA*

PSE determined that the short-term PPA proposed by Arizona Public Service (APS) offers significant portfolio benefits. PSE and APS signed definitive contracts on June 25, 2004. PSE began receiving energy from this contract on January 1, 2005.

*Utility PPA*

A long-term utility PPA proposal was evaluated as one of the short-listed supply options. PSE and the supplier were unable to finalize commercial terms and this resource is no longer under active discussion.

*Hopkins Ridge Wind Project*

The 150 MW Hopkins Ridge wind project was among the lowest-cost wind projects according to the quantitative analysis, and all of the project's qualitative ratings were high. In addition, the Hopkins Ridge project had the greatest potential to achieve commercial operation by the end of 2005, which would qualify the project for production tax credits.

On October 29, 2004, PSE and RES North America signed a Letter of Intent (LOI) for PSE’s acquisition of the Hopkins Ridge project, and negotiations for definitive contracts proceeded. PSE’s board of directors approved the purchase of the Hopkins Ridge project on January 11,

2005. Definitive agreements were executed on March 11, 2005 and a notice to proceed was given to RES North America to begin construction. The project is expected to reach commercial operation in December 2005.

*Wild Horse Wind Project*

PSE's due diligence showed that the Wild Horse wind project is viable, with a desirable location in Kittitas County and a strong potential for receiving timely permits. The portfolio analysis showed that the Wild Horse project lowers PSE's portfolio costs. Because the Wild Horse project requires transmission line upgrades (which involve cost and schedule risks), permitting and engineering for the upgrades are underway.

On September 1, 2004, PSE and Zilkha signed an LOI for PSE's acquisition of the Wild Horse project, and negotiations for definitive contracts are underway.

Public hearings, coordinated by the Kittitas County Planning Commission and County Commissioners, began January 25, 2005, and the Kittitas Board of County Commissioners approved the Wild Horse project on March 3, 2005. The state Energy Facility Site Evaluation Council held hearings on March 7 and 8, 2005. The Council is expected to forward its recommendation to the governor for a final decision in late May of 2005.

*NWPL Sumas Recovered Heat Project*

This project involves generating energy using recovered heat at an existing Northwest Pipeline compressor station. The NWPL Sumas recovered heat project showed an attractive 20-year levelized energy cost, and the project's qualitative ratings were also favorable. PSE entered into an LOI with ORMAT Nevada on April 14, 2005, and definitive agreements will follow by mid year. In addition, studies are underway to identify and resolve possible transmission constraints. The projected commercial operations date is the second quarter of 2007.

# APPENDIX F
# 2003 GREENHOUSE GAS EMISSIONS INVENTORY

PSE began accounting for greenhouse gas (GHG) emissions in 2003. To date, PSE has accounted for GHG's emitted during the 2002 and 2003 calendar years. These GHG inventories are based on data generated by PSE, established GHG accounting guidelines, and available Department of Energy and Environmental Protection Agency (EPA) documents. Each inventory accounts for the following:

- PSE's direct emissions from electrical generation, PSE's vehicle fleet, PSE's storage and distribution of natural gas, and PSE's use of sulfur hexafluoride as an insulating gas;
- PSE's indirect emissions associated with firm contract and non-firm (wholesale market) purchases of electricity; and
- Avoided GHG emissions due to PSE's conservation efforts and other conservation programs.

The inventories are intended to provide PSE with the information to achieve five major goals:

- Maintaining an accurate, transparent estimate of PSE's 2003 GHG emissions;
- Understanding PSE's emissions sources for relative size and importance;
- Tracking PSE's GHG emissions over time;
- Evaluating PSE's GHG emissions from electric production and purchase relative to other electric generators and electric utilities; and
- Estimating the emissions avoided through PSE's conservation programs.

## A. Accounting Process and Methodology

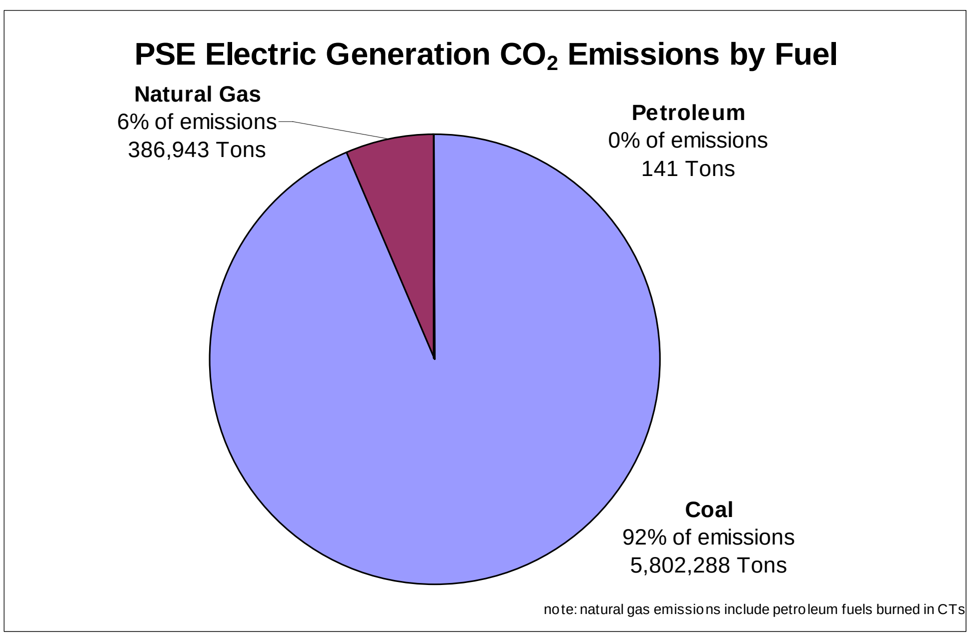
An estimate of PSE's GHG emissions for 2003 was made based on the accounting protocols developed by the World Resource Institute (WRI) and World Business Council on Sustainable Development (WBCSD), and those used from the voluntary GHG reporting program of the Energy Information Agency (EIA) and EIA Form 1605(b). WRI/WBCSD GHG accounting protocols are explained in the *GHG Protocol* (WRI/WBCSD, 2001), an accounting and reporting standard developed by a partnership between industry, non-governmental organizations, and governments. EIA 1605(b) reporting is a voluntary reporting program for GHG emissions and reductions, developed under Section 1605(b) of the Energy Policy Act of 1992. PSE submitted reports to the EIA 1605(b) reporting program for 1994 to 1996. The accounting conducted for 2003 follows the *GHG Protocol*, and is a functional equivalent of EIA 1605(b) reporting.

Data used in the compilation of the inventories comes from a number of sources. The calculation methodology used varies depending on the data available. The greenhouse gases accounted for (in each annual GHG inventory) include carbon dioxide (CO2), methane (CH4), nitrous oxide (N2O), and sulfur hexaflouride (SF6).

**B. Direct Emissions – Electric**

For all of PSE's electric generation plants, fuel use data for 2003 was available for calculating emissions. In addition, direct measurements of CO2 emissions from the Colstrip plant were available due to Colstrip's reporting requirements under the Acid Rain Program. The actual measurements were considered the most accurate data for Colstrip. For all other electric generation plants, fuel use data and standard emission factors were used to calculate emissions associated with combustion.

**Exhibit F-1**
**Direct Emissions from Electric Generation Plants**



## C. Direct Emissions – Natural Gas Operations and Fuel Use by Vehicles

Direct emissions from PSE's natural gas operations include any incidental losses or leakage from the natural gas system, or venting of natural gas to depressurize lines for service, etc. PSE used USEPA/GRI emissions factors to calculate these fugitive emissions and losses from PSE's transmission system and from PSE's gas storage at Jackson Prairie.

Another direct source of GHG emissions included in the inventory was PSE's emissions from fuel use in vehicles during 2003. This is calculated based on the fuel usage in PSE's fleet and on emissions factors.

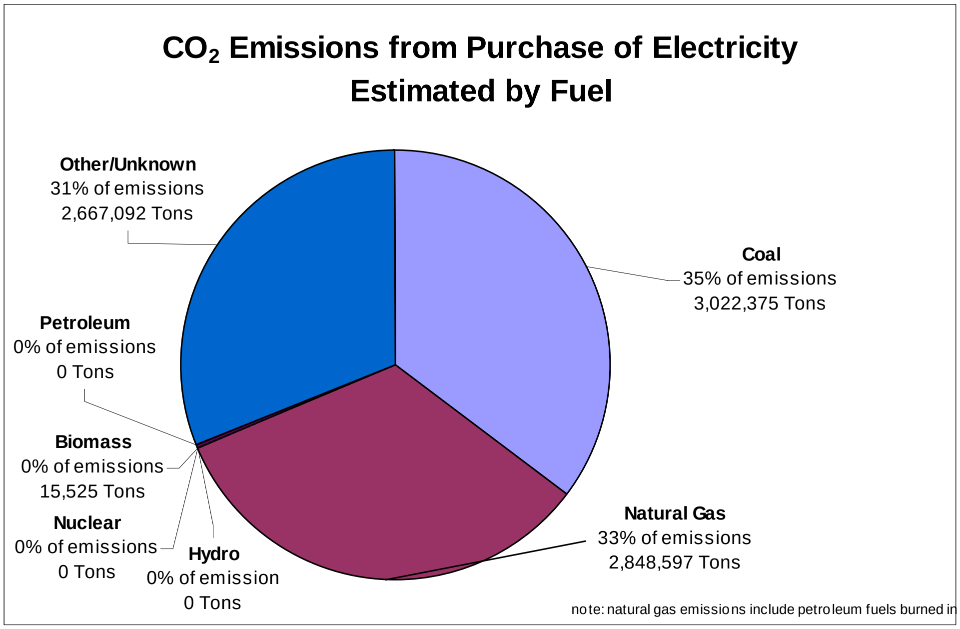
**Exhibit F-2**
**Direct Emissions from Natural Gas Operations and Vehicle Fuel Use**

| | Emissions (Tons) | | | |
|---|---|---|---|---|
| | $CO_2$ | $CH_4$ | $N_2O$ | $SF_6$ |
| ***Natural Gas Emissions*** | | | | |
| Distribution - Fugitive/Vented Natural Gas Emissions | | 5,589 | | |
| Storage - Fugitive/Vented Natural Gas Emissions | | 1,066 | | |
| Fugitive/Vented $SF_6$ Emissions | | | | 0.4025 |
| ***Fleet Emissions*** | | | | |
| Fleet Emissions | 12,702 | 2.08 | 0.02 | |
| **TOTAL EMISSIONS** | **12,702** | **6,657** | **0.02** | **0.4025** |

## D. Indirect Emissions – Electric

Indirect emissions associated with the generation of electricity that is sold to other intermediaries or to end consumers is also accounted for in the inventory. These emissions are based on the electricity purchased by PSE. PSE purchases electricity under firm (long-term) contracts, and under non-firm contracts (spot market purchases). Emissions were calculated based on the electricity purchased from each entity, the estimated generation sources used to produce the electricity purchased by PSE, and emissions factors for each generation source. Where generation source information was not available, a national emissions factor was used.

**Exhibit F-3**
**Indirect Emissions from Purchase of Electricity**




## E. Indirect Emissions – Natural Gas

Indirect emissions from natural gas systems were calculated using the same methodology as direct emissions.

**Exhibit F-4**
**Indirect Emissions from Natural Gas Operations**

| | Emissions (Tons) | | | |
|---|---|---|---|---|
| | $CO_2$ | $CH_4$ | $N_2O$ | $SF_6$ |
| ***Natural Gas Emissions (Indirect)*** | | | | |
| Distribution - Fugitive/Vented Natural Gas Emissions | | 1,435 | | |
| Storage - Fugitive/Vented Natural Gas Emissions | | 871 | | |
| **TOTAL EMISSIONS** | | **2,306** | | |

## F. Conservation Programs and Emissions Avoided

PSE runs a variety of electric and natural gas conservation programs, resulting in significant reductions in demand on electric and natural gas resources. These programs led to savings of 131,867,000 kWh of electricity and 2,175,375 therms of natural gas in 2003 amounting to avoided emissions of over 72,000 tons of CO2. PSE's natural gas conservation measures amounted to an avoidance of emissions of approximately 15 tons of methane. In addition to these conservation measures, PSE owns and operates a fleet of natural gas-fueled vehicles. Assuming that these vehicles would have operated on gasoline instead of natural gas, it is estimated that approximately 500 tons of CO2 emissions were avoided by using natural gas vehicles.

**Exhibit F-5**
**Emissions Avoided**

| ***Summary of Emissions Reductions*** | Emissions Reductions (Tons) | | | |
|---|---|---|---|---|
| | $CO_2$ | $CH_4$ | $N_2O$ | $SF_6$ |
| Electric Conservation | 72,237 | 6 | 2 | |
| Natural Gas Vehicles | 83 | -1.4 | 0.01 | |
| Gas Conservation | | 14.9 | | |
| **TOTAL REDUCTIONS** | **72,320** | **19.5** | **2.01** | |

## G. GHG Emissions Outlook

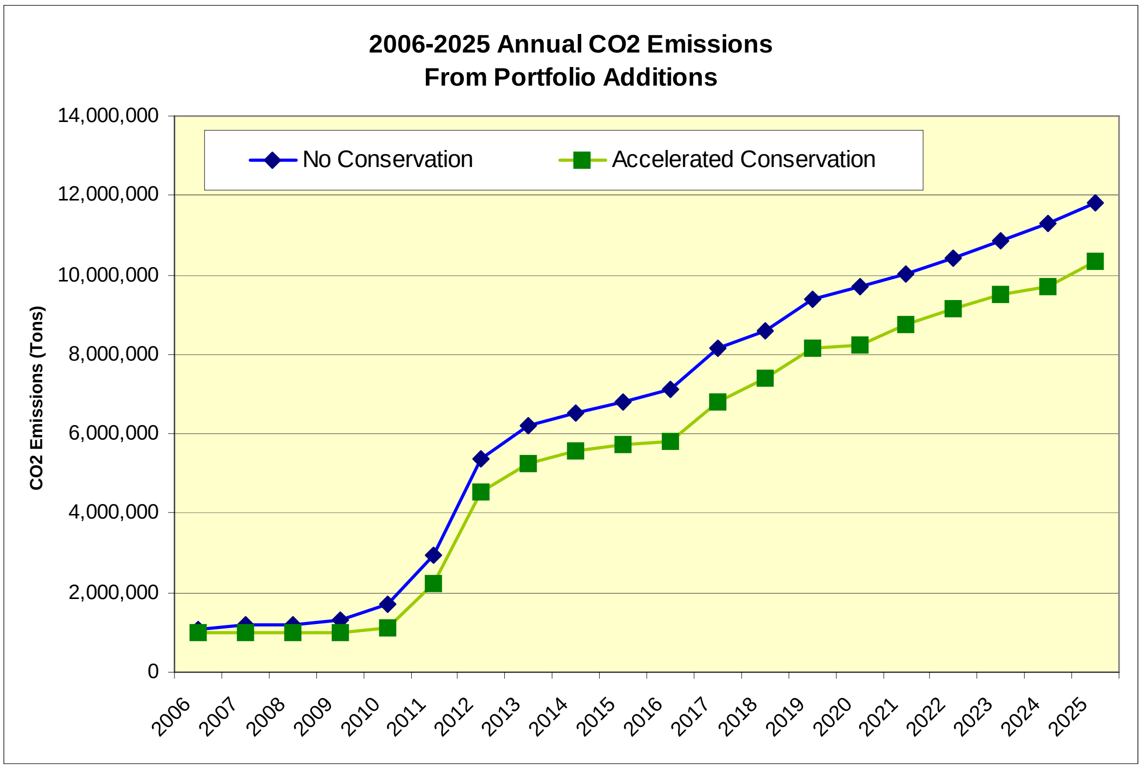
The Least Cost Plan has modeled a number of scenarios for PSE's future electricity demand, and how it means to meet that demand. This includes newly acquired wind power and plans to add more renewable resources to PSE's energy resource mix. As existing contracts expire, PSE is expected to meet electricity demand with CCGT, renewables, and conservation in the short term, and possibly through the addition of coal in the long term.

A preliminary estimate of PSE's CO2 emission rate going forward was made based on the projected preferred electric resource mix in 2015. For the market purchases of power (indirect emissions), emissions are shown as net values. The net sales approach was used to provide consistency, as it is not known what PSE's future market transactions will be. This future emissions estimate does not differentiate between future direct and indirect emissions.

*Emissions from Portfolio Additions*

An estimate of PSE's CO2 emissions was made based on the projected preferred electric resource mix for these resource additions and the conservation scenarios considered (see Exhibit F-6). Note that this future emissions estimate does not differentiate between future direct and indirect emissions. The market purchases of power (indirect emissions) included in this analysis are calculated as values. This is different than the accounting protocols (GHG Inventory), which advocate reporting total indirect emissions, and separate accounting of market sales and associated indirect emissions. This approach was used to provide consistency, as it is not known what PSE's future market transactions will be.

**Exhibit F-6**
**Emissions from Portfolio Additions**




The estimate of emissions from portfolio additions shows that for both the No Conservation and Accelerated Conservation scenarios, $CO_2$ emissions will increase. Under an accelerated conservation scenario, emissions increase from approximately 100,000 tons $CO_2$ starting in 2006 to just over 10,000,000 tons $CO_2$ by 2025. With no conservation, emissions increase from approximately 100,000 tons $CO_2$ starting in 2006 to nearly 12,000,000 tons $CO_2$ by 2025. Considerable $CO_2$ emissions savings under the accelerated conservation scenario begin in 2014, just before new coal resources are brought online.

This analysis of PSE's future CO2 emissions is a very simple analysis based on fixed assumed factors.  A more detailed analysis could include assumptions related to PSE's sources of energy, improvements in generation and emissions control technology (such as IGCC), and projected resource availability from the Northwest Power Planning Council and Department of Energy.

# APPENDIX G
# ELECTRIC RESULTS

The following appendix includes input details and results for each supply portfolio and scenario discussed in Chapter X of the Least Cost Plan. There were 22 supply-side portfolios and scenario combinations tested in PSM. The following table provides a matrix of the combinations. This appendix also summarizes the leading demand-side case, and the energy savings attributed to the accelerated energy efficiency and early fuel conversion programs. The final page provides the details behind the 2006-2025 Resource Strategy with demand-side programs.

| Static and Dynamic PSM Analysis | Business as Usual | Current Momentum | Green World | Transmission Solution | Low Growth | Robust Growth |
|---|---|---|---|---|---|---|
| 10% Renewable and 50/50 Coal & Gas | X | X | | X | X | X |
| 15% Renewable and 50/50 Coal & Gas | X | X | X | X | X | X |
| 15% Renewable and Coal | X | X | | X | X | X |
| 15% Renewable and Gas | X | X | X | X | X | X |

The first section of supply-side results depicts the annual generic portfolio additions, the available generation mix from new and existing resources based upon availability not economic dispatch, and the static and dynamic 20-year portfolio costs. The next section summarizes the selected least cost demand-side programs, the energy savings from the programs, and the new 20-year portfolio cost for the integrated resource strategy. The final section shows the cumulative energy additions by year for the 2006-2025 resource strategy and the percentage mix of additions over the 20 years.

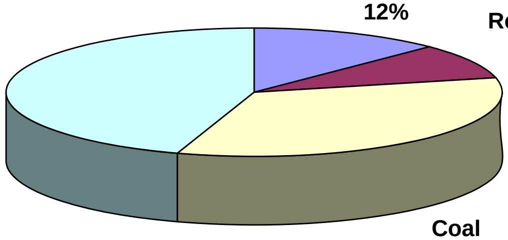
# Electric Supply-Side Results

**Scenario:** Business As Usual
**Portfolio:** 10% Renewable and 50/50 Gas & Coal
**Time Period 1:** 2006-2015
**Time Period 2:** 2016-2025
**Transmission:** Participant Funded

| Time Period 1 | Supply Additions (Nameplate Capacity in MW) | | | | | | | | | | Total Period Additions | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | MW | Percent |
| CCGT | 125 | | | 25 | 75 | 100 | 250 | 75 | 50 | 25 | 725 | 20% |
| Coal | | | | | | | | | | | - | 0% |
| Wind | | 100 | 100 | 100 | | | | | | | 300 | 8% |
| Biomass | | | | | | 25 | 25 | 25 | | | 75 | 2% |
| PBAs | 125 | | | | 25 | 175 | 275 | 100 | 25 | 25 | 750 | 21% |
| Duct Fired | 17 | | | 3 | 10 | 14 | 34 | 10 | 7 | 3 | 98 | 3% |
| Winter Call Option | 988 | 56 | 39 | 31 | 163 | 191 | 77 | 21 | 5 | 32 | 1,603 | 45% |
| Total | 1,255 | 156 | 139 | 159 | 273 | 505 | 661 | 231 | 87 | 85 | 3,551 | 100% |

| Time Period 2 | Supply Additions (Nameplate Capacity in MW) | | | | | | | | | | Total Period Additions | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | MW | Percent |
| CCGT | 425 | 75 | 25 | 75 | 25 | 50 | 25 | 25 | 50 | 50 | 825 | 37% |
| Coal | 425 | 75 | 50 | 75 | 25 | 25 | 50 | 25 | 25 | 50 | 825 | 37% |
| Wind | 100 | | | | | | | | | | 100 | 5% |
| Biomass | | | | | | 25 | | | | | 25 | 1% |
| PBAs | | | | | | | | | | | - | 0% |
| Duct Fired | 57 | 10 | 3 | 10 | 3 | 7 | 3 | 3 | 7 | 7 | 111 | 5% |
| Winter Call Option | | | 18 | 79 | 46 | 1 | 30 | 56 | 84 | 21 | 335 | 15% |
| Total | 1,007 | 160 | 96 | 239 | 99 | 108 | 108 | 109 | 166 | 128 | 2,221 | 100% |

**2025 Available Generation from New and Existing Resources (Annual Average)**




**Analytic Results**

| Static | $/MWh | $ (Millions) |
|---|---|---|
| Revenue from Power Sales | | (414) |
| Cost of Power Purchase | | 1,079 |
| Generic Revenue Requirement | | 6,021 |
| Variable Cost of Existing Fleet | | 959 |
| End Effects | | 498 |
| Expected Cost | 36.21 | 8,143 |

| Dynamic - 100 Trials | $/MWh | $ (Millions) |
|---|---|---|
| Mean | 35.26 | 7,929 |
| 95% | 38.46 | 8,649 |
| 5% | 32.27 | 7,256 |
| Avg. > 90% | 38.43 | 8,642 |

Exhibit No. ___(EMM-6)
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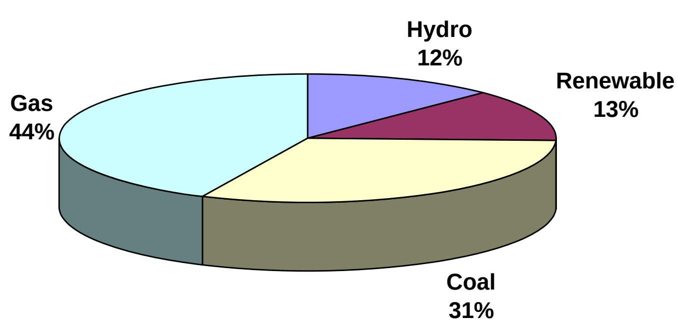
**Scenario:** Business As Usual
**Portfolio:** 15% Renewable 50/50 Gas & Coal
**Time Period 1:** 2006-2015
**Time Period 2:** 2016-2025
**Transmission:** Participant Funded

| Time Period 1 | Supply Additions (Nameplate Capacity in MW) | | | | | | | | | | Total Period Additions | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | MW | Percent |
| CCGT | 125 | | | 25 | 75 | 100 | 250 | 75 | 50 | 25 | 725 | 20% |
| Coal | | | | | | | | | | | - | 0% |
| Wind | | 100 | 100 | 100 | | | | | | | 300 | 8% |
| Biomass | | | | | | 25 | 25 | 25 | | | 75 | 2% |
| PBAs | 125 | | | | 25 | 175 | 275 | 100 | 25 | 25 | 750 | 21% |
| Duct Fired | 17 | | | 3 | 10 | 14 | 34 | 10 | 7 | 3 | 98 | 3% |
| Winter Call Option | 988 | 56 | 39 | 31 | 163 | 191 | 77 | 21 | 5 | 32 | 1,603 | 45% |
| Total | 1,255 | 156 | 139 | 159 | 273 | 505 | 661 | 231 | 87 | 85 | 3,551 | 100% |

| Time Period 2 | Supply Additions (Nameplate Capacity in MW) | | | | | | | | | | Total Period Additions | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | MW | Percent |
| CCGT | 400 | 50 | 25 | 50 | 25 | 25 | 50 | 50 | 25 | 50 | 750 | 31% |
| Coal | 400 | 75 | | 75 | | 25 | 25 | 25 | 50 | 50 | 725 | 30% |
| Wind | 100 | 100 | 100 | | | | | | | | 300 | 13% |
| Biomass | 25 | 25 | 25 | 25 | 25 | 25 | | | | | 150 | 6% |
| PBAs | | | | | | | | | | | - | 0% |
| Duct Fired | 54 | 7 | 3 | 7 | 3 | 3 | 7 | 7 | 3 | 7 | 101 | 4% |
| Winter Call Option | 1 | | 36 | 107 | 25 | 29 | 25 | 28 | 89 | 21 | 361 | 15% |
| Total | 980 | 257 | 189 | 264 | 78 | 107 | 107 | 110 | 167 | 128 | 2,387 | 100% |

**2025 Available Generation from New and Existing Resources (Annual Average)**




**Analytic Results**

| Static | $/MWh | $ (Millions) |
|---|---|---|
| Revenue from Power Sales | | (413) |
| Cost of Power Purchase | | 1,051 |
| Generic Revenue Requirement | | 6,098 |
| Variable Cost of Existing Fleet | | 959 |
| End Effects | | 497 |
| Expected Cost | 36.43 | 8,192 |

| Dynamic - 100 Trials | $/MWh | $ (Millions) |
|---|---|---|
| Mean | 35.51 | 7,986 |
| 95% | 38.74 | 8,712 |
| 5% | 32.50 | 7,309 |
| Avg. > 90% | 38.65 | 8,692 |

Exhibit No. ___(EMM-6)
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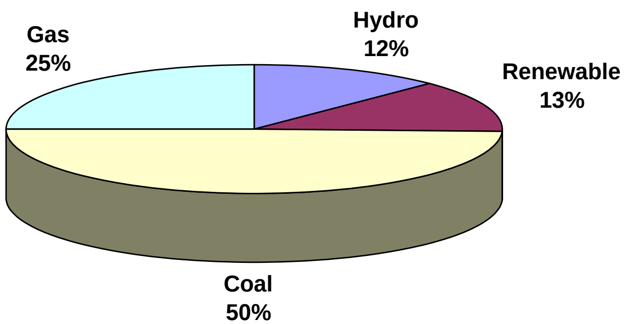
**Scenario:** Business As Usual
**Portfolio:** 15% Renewable and Coal
**Time Period 1:** 2006-2015
**Time Period 2:** 2016-2025
**Transmission:** Participant Funded

| Time Period 1 | Supply Additions (Nameplate Capacity in MW) | | | | | | | | | | Total Period Additions | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | MW | Percent |
| CCGT | 125 | | | 25 | 75 | 100 | 250 | 75 | 50 | 25 | 725 | 20% |
| Coal | | | | | | | | | | | - | 0% |
| Wind | | 100 | 100 | 100 | | | | | | | 300 | 8% |
| Biomass | | | | | | 25 | 25 | 25 | | | 75 | 2% |
| PBAs | 125 | | | | 25 | 175 | 275 | 100 | 25 | 25 | 750 | 21% |
| Duct Fired | 17 | | | 3 | 10 | 14 | 34 | 10 | 7 | 3 | 98 | 3% |
| Winter Call Option | 988 | 56 | 39 | 31 | 163 | 191 | 77 | 21 | 5 | 32 | 1,603 | 45% |
| Total | 1,255 | 156 | 139 | 159 | 273 | 505 | 661 | 231 | 87 | 85 | 3,551 | 100% |

| Time Period 2 | Supply Additions (Nameplate Capacity in MW) | | | | | | | | | | Total Period Additions | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | MW | Percent |
| CCGT | | | | | | | | | | | - | 0% |
| Coal | 825 | 125 | 25 | 125 | 25 | 75 | 75 | 75 | 75 | 75 | 1,500 | 62% |
| Wind | 100 | 100 | 100 | | | | | | | | 300 | 12% |
| Biomass | 25 | 25 | 25 | 25 | 25 | 25 | | | | | 150 | 6% |
| PBAs | | | | | | | | | | | - | 0% |
| Duct Fired | | | | | | | | | | | - | 0% |
| Winter Call Option | 52 | | 49 | 95 | 51 | 11 | 35 | 130 | 53 | | 476 | 20% |
| Total | 1,002 | 250 | 199 | 245 | 101 | 111 | 110 | 205 | 128 | 75 | 2,426 | 100% |

**2025 Available Generation from New and Existing Resources (Annual Average)**




**Analytic Results**

| **Static** | **$/MWh** | **$ (Millions)** |
|---|---|---|
| **Revenue from Power Sales** | | (419) |
| **Cost of Power Purchase** | | 908 |
| **Generic Revenue Requirement** | | 6,283 |
| **Variable Cost of Existing Fleet** | | 959 |
| **End Effects** | | 396 |
| **Expected Cost** | 36.14 | 8,127 |

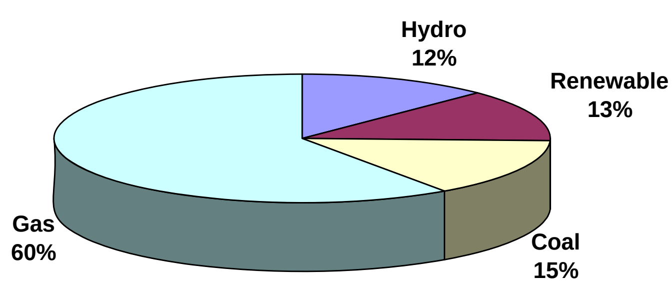
| **Dynamic - 100 Trials** | **$/MWh** | **$ (Millions)** |
|---|---|---|
| **Mean** | 35.58 | 8,002 |
| **95%** | 38.72 | 8,708 |
| **5%** | 32.57 | 7,326 |
| **Avg. > 90%** | 38.87 | 8,741 |

**Scenario:** Business As Usual
**Portfolio:** 15% Renewable and Gas
**Time Period 1:** 2006-2015
**Time Period 2:** 2016-2025
**Transmission:** Participant Funded

| Time Period 1 | Supply Additions (Nameplate Capacity in MW) | | | | | | | | | | Total Period Additions | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | MW | Percent |
| CCGT | 125 | | | 25 | 75 | 100 | 250 | 75 | 50 | 25 | 725 | 20% |
| Coal | | | | | | | | | | | - | 0% |
| Wind | | 100 | 100 | 100 | | | | | | | 300 | 8% |
| Biomass | | | | | | 25 | 25 | 25 | | | 75 | 2% |
| PBAs | 125 | | | | 25 | 175 | 275 | 100 | 25 | 25 | 750 | 21% |
| Duct Fired | 17 | | | 3 | 10 | 14 | 34 | 10 | 7 | 3 | 98 | 3% |
| Winter Call Option | 988 | 56 | 39 | 31 | 163 | 191 | 77 | 21 | 5 | 32 | 1,603 | 45% |
| Total | 1,255 | 156 | 139 | 159 | 273 | 505 | 661 | 231 | 87 | 85 | 3,551 | 100% |

| Time Period 2 | Supply Additions (Nameplate Capacity in MW) | | | | | | | | | | Total Period Additions | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | MW | Percent |
| CCGT | 775 | 125 | 25 | 125 | 25 | 50 | 75 | 75 | 75 | 75 | 1,425 | 61% |
| Coal | | | | | | | | | | | - | 0% |
| Wind | 100 | 100 | 100 | | | | | | | | 300 | 13% |
| Biomass | 25 | 25 | 25 | 25 | 25 | 25 | | | | | 150 | 6% |
| PBAs | | | | | | | | | | | - | 0% |
| Duct Fired | 105 | 17 | 3 | 17 | 3 | 7 | 10 | 10 | 10 | 10 | 192 | 8% |
| Winter Call Option | | | | 46 | 47 | 24 | 21 | 24 | 79 | 39 | 280 | 12% |
| Total | 1,005 | 267 | 153 | 213 | 100 | 106 | 106 | 109 | 164 | 124 | 2,347 | 100% |

**2025 Available Generation from New and Existing Resources (Annual Average)**




**Analytic Results**

| Static | $/MWh | $ (Millions) |
|---|---|---|
| Revenue from Power Sales | | (442) |
| Cost of Power Purchase | | 1,214 |
| Generic Revenue Requirement | | 5,936 |
| Variable Cost of Existing Fleet | | 959 |
| End Effects | | 568 |
| Expected Cost | 36.62 | 8,235 |

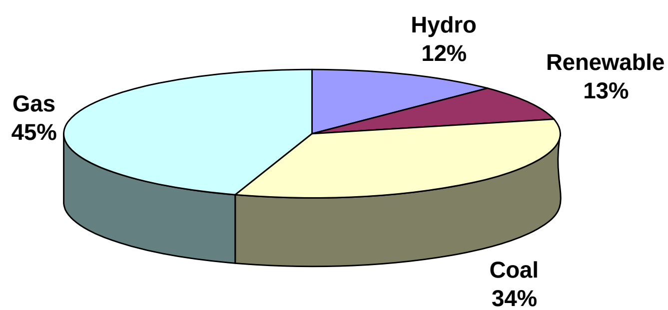
| Dynamic - 100 Trials | $/MWh | $ (Millions) |
|---|---|---|
| Mean | 35.38 | 7,956 |
| 95% | 38.49 | 8,657 |
| 5% | 32.36 | 7,278 |
| Avg. > 90% | 38.75 | 8,715 |

| | |
|---|---|
| **Scenario:** | **Current Momentum** |
| **Portfolio:** | **10% Renewable and 50/50 Gas & Coal** |
| **Time Period 1:** | **2006-2015** |
| **Time Period 2:** | **2016-2025** |
| **Transmission:** | **Participant Funded** |

| **Time Period 1** | **Supply Additions (Nameplate Capacity in MW)** | | | | | | | | | | Total Period Additions | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **2006** | **2007** | **2008** | **2009** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | MW | Percent |
| CCGT | 125 | | | 25 | 75 | 100 | 250 | 75 | 50 | 25 | 725 | 20% |
| Coal | | | | | | | | | | | - | 0% |
| Wind | | 100 | 100 | 100 | | | | | | | 300 | 8% |
| Biomass | | | | | | 25 | 25 | 25 | | | 75 | 2% |
| PBAs | 125 | | | | 25 | 175 | 275 | 100 | 25 | 25 | 750 | 21% |
| Duct Fired | 17 | | | 3 | 10 | 14 | 34 | 10 | 7 | 3 | 98 | 3% |
| Winter Call Option | 988 | 56 | 39 | 31 | 163 | 191 | 77 | 21 | 5 | 32 | 1,603 | 45% |
| Total | 1,255 | 156 | 139 | 159 | 273 | 505 | 661 | 231 | 87 | 85 | 3,551 | 100% |

| **Time Period 2** | **Supply Additions (Nameplate Capacity in MW)** | | | | | | | | | | Total Period Additions | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **2016** | **2017** | **2018** | **2019** | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** | MW | Percent |
| CCGT | 425 | 75 | 25 | 75 | 25 | 50 | 25 | 25 | 50 | 50 | 825 | 37% |
| Coal | 425 | 75 | 50 | 75 | 25 | 25 | 50 | 25 | 25 | 50 | 825 | 37% |
| Wind | 100 | | | | | | | | | | 100 | 5% |
| Biomass | | | | | | 25 | | | | | 25 | 1% |
| PBAs | | | | | | | | | | | - | 0% |
| Duct Fired | 57 | 10 | 3 | 10 | 3 | 7 | 3 | 3 | 7 | 7 | 111 | 5% |
| Winter Call Option | | | 18 | 79 | 46 | 1 | 30 | 56 | 84 | 21 | 335 | 15% |
| Total | 1,007 | 160 | 96 | 239 | 99 | 108 | 108 | 109 | 166 | 128 | 2,221 | 100% |

**2025 Available Generation from New and Existing Resources (Annual Average)**




**Analytic Results**

| **Static** | **$/MWh** | **$ (Millions)** |
|---|---|---|
| **Revenue from Power Sales** | | (460) |
| **Cost of Power Purchase** | | 1,086 |
| **Generic Revenue Requirement** | | 6,264 |
| **Variable Cost of Existing Fleet** | | 1,291 |
| **End Effects** | | 565 |
| **Expected Cost** | 38.89 | 8,746 |

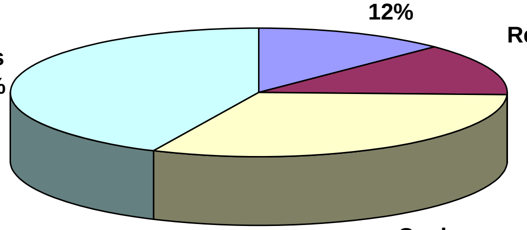
| **Dynamic - 100 Trials** | **$/MWh** | **$ (Millions)** |
|---|---|---|
| **Mean** | 38.00 | 8,545 |
| **95%** | 40.04 | 9,005 |
| **5%** | 36.01 | 8,098 |
| **Avg. > 90%** | 40.26 | 9,054 |

**Scenario:** Current Momentum
**Portfolio:** 15% Renewable 50/50 Gas & Coal
**Time Period 1:** 2006-2015
**Time Period 2:** 2016-2025
**Transmission:** Participant Funded

| Time Period 1 | Supply Additions (Nameplate Capacity in MW) | | | | | | | | | | Total Period Additions | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | MW | Percent |
| CCGT | 125 | | | 25 | 75 | 100 | 250 | 75 | 50 | 25 | 725 | 20% |
| Coal | | | | | | | | | | | - | 0% |
| Wind | | 100 | 100 | 100 | | | | | | | 300 | 8% |
| Biomass | | | | | | 25 | 25 | 25 | | | 75 | 2% |
| PBAs | 125 | | | | 25 | 175 | 275 | 100 | 25 | 25 | 750 | 21% |
| Duct Fired | 17 | | | 3 | 10 | 14 | 34 | 10 | 7 | 3 | 98 | 3% |
| Winter Call Option | 988 | 56 | 39 | 31 | 163 | 191 | 77 | 21 | 5 | 32 | 1,603 | 45% |
| Total | 1,255 | 156 | 139 | 159 | 273 | 505 | 661 | 231 | 87 | 85 | 3,551 | 100% |

| Time Period 2 | Supply Additions (Nameplate Capacity in MW) | | | | | | | | | | Total Period Additions | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | MW | Percent |
| CCGT | 400 | 50 | 25 | 50 | 25 | 25 | 50 | 50 | 25 | 50 | 750 | 31% |
| Coal | 400 | 75 | | 75 | | 25 | 25 | 25 | 50 | 50 | 725 | 30% |
| Wind | 100 | 100 | 100 | | | | | | | | 300 | 13% |
| Biomass | 25 | 25 | 25 | 25 | 25 | 25 | | | | | 150 | 6% |
| PBAs | | | | | | | | | | | - | 0% |
| Duct Fired | 54 | 7 | 3 | 7 | 3 | 3 | 7 | 7 | 3 | 7 | 101 | 4% |
| Winter Call Option | 1 | | 36 | 107 | 25 | 29 | 25 | 28 | 89 | 21 | 361 | 15% |
| Total | 980 | 257 | 189 | 264 | 78 | 107 | 107 | 110 | 167 | 128 | 2,387 | 100% |

**2025 Available Generation from New and Existing Resources (Annual Average)**




**Analytic Results**

| **Static** | $/MWh | $ (Millions) |
|---|---|---|
| Revenue from Power Sales | | (459) |
| Cost of Power Purchase | | 1,056 |
| Generic Revenue Requirement | | 6,322 |
| Variable Cost of Existing Fleet | | 1,291 |
| End Effects | | 576 |
| Expected Cost | 39.07 | 8,786 |

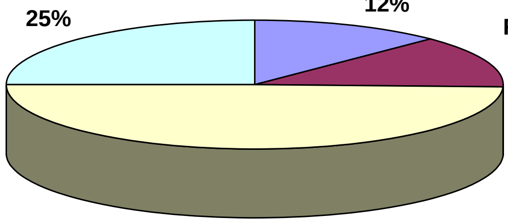
| **Dynamic - 100 Trials** | $/MWh | $ (Millions) |
|---|---|---|
| Mean | 38.20 | 8,591 |
| 95% | 40.25 | 9,051 |
| 5% | 36.29 | 8,161 |
| Avg. > 90% | 40.45 | 9,097 |

**Scenario:** Current Momentum
**Portfolio:** 15% Renewable and Coal
**Time Period 1:** 2006-2015
**Time Period 2:** 2016-2025
**Transmission:** Participant Funded

| Time Period 1 | Supply Additions (Nameplate Capacity in MW) | | | | | | | | | | Total Period Additions | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | MW | Percent |
| CCGT | 125 | | | 25 | 75 | 100 | 250 | 75 | 50 | 25 | 725 | 20% |
| Coal | | | | | | | | | | | - | 0% |
| Wind | | 100 | 100 | 100 | | | | | | | 300 | 8% |
| Biomass | | | | | | 25 | 25 | 25 | | | 75 | 2% |
| PBAs | 125 | | | | 25 | 175 | 275 | 100 | 25 | 25 | 750 | 21% |
| Duct Fired | 17 | | | 3 | 10 | 14 | 34 | 10 | 7 | 3 | 98 | 3% |
| Winter Call Option | 988 | 56 | 39 | 31 | 163 | 191 | 77 | 21 | 5 | 32 | 1,603 | 45% |
| Total | 1,255 | 156 | 139 | 159 | 273 | 505 | 661 | 231 | 87 | 85 | 3,551 | 100% |

| Time Period 2 | Supply Additions (Nameplate Capacity in MW) | | | | | | | | | | Total Period Additions | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | MW | Percent |
| CCGT | | | | | | | | | | | - | 0% |
| Coal | 825 | 125 | 25 | 125 | 25 | 75 | 75 | 75 | 75 | 75 | 1,500 | 62% |
| Wind | 100 | 100 | 100 | | | | | | | | 300 | 12% |
| Biomass | 25 | 25 | 25 | 25 | 25 | 25 | | | | | 150 | 6% |
| PBAs | | | | | | | | | | | - | 0% |
| Duct Fired | | | | | | | | | | | - | 0% |
| Winter Call Option | 52 | | 49 | 95 | 51 | 11 | 35 | 130 | 53 | | 476 | 20% |
| Total | 1,002 | 250 | 199 | 245 | 101 | 111 | 110 | 205 | 128 | 75 | 2,426 | 100% |

**2025 Available Generation from New and Existing Resources (Annual Average)**




**Analytic Results**

| Static | $/MWh | $ (Millions) |
|---|---|---|
| Revenue from Power Sales | | (468) |
| Cost of Power Purchase | | 901 |
| Generic Revenue Requirement | | 6,580 |
| Variable Cost of Existing Fleet | | 1,291 |
| End Effects | | 430 |
| Expected Cost | 38.83 | 8,733 |

| Dynamic - 100 Trials | $/MWh | $ (Millions) |
|---|---|---|
| Mean | 38.26 | 8,603 |
| 95% | 40.48 | 9,103 |
| 5% | 36.04 | 8,105 |
| Avg. > 90% | 40.79 | 9,173 |

Exhibit No. ___(EMM-6)
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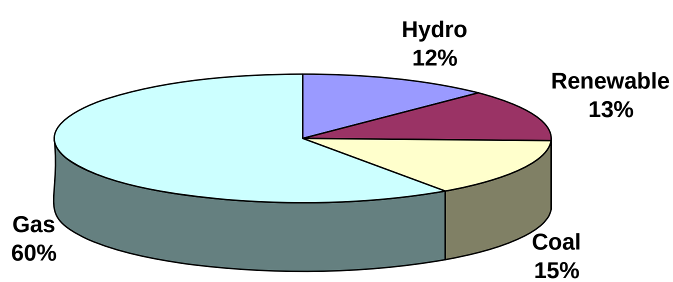
**Scenario:** Current Momentum
**Portfolio:** 15% Renewable and Gas
**Time Period 1:** 2006-2015
**Time Period 2:** 2016-2025
**Transmission:** Participant Funded

| Time Period 1 | Supply Additions (Nameplate Capacity in MW) | | | | | | | | | | Total Period Additions | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | MW | Percent |
| CCGT | 125 | | | 25 | 75 | 100 | 250 | 75 | 50 | 25 | 725 | 20% |
| Coal | | | | | | | | | | | - | 0% |
| Wind | | 100 | 100 | 100 | | | | | | | 300 | 8% |
| Biomass | | | | | | 25 | 25 | 25 | | | 75 | 2% |
| PBAs | 125 | | | | 25 | 175 | 275 | 100 | 25 | 25 | 750 | 21% |
| Duct Fired | 17 | | | 3 | 10 | 14 | 34 | 10 | 7 | 3 | 98 | 3% |
| Winter Call Option | 988 | 56 | 39 | 31 | 163 | 191 | 77 | 21 | 5 | 32 | 1,603 | 45% |
| Total | 1,255 | 156 | 139 | 159 | 273 | 505 | 661 | 231 | 87 | 85 | 3,551 | 100% |

| Time Period 2 | Supply Additions (Nameplate Capacity in MW) | | | | | | | | | | Total Period Additions | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | MW | Percent |
| CCGT | 775 | 125 | 25 | 125 | 25 | 50 | 75 | 75 | 75 | 75 | 1,425 | 61% |
| Coal | | | | | | | | | | | - | 0% |
| Wind | 100 | 100 | 100 | | | | | | | | 300 | 13% |
| Biomass | 25 | 25 | 25 | 25 | 25 | 25 | | | | | 150 | 6% |
| PBAs | | | | | | | | | | | - | 0% |
| Duct Fired | 105 | 17 | 3 | 17 | 3 | 7 | 10 | 10 | 10 | 10 | 192 | 8% |
| Winter Call Option | | | | 46 | 47 | 24 | 21 | 24 | 79 | 39 | 280 | 12% |
| Total | 1,005 | 267 | 153 | 213 | 100 | 106 | 106 | 109 | 164 | 124 | 2,347 | 100% |

**2025 Available Generation from New and Existing Resources (Annual Average)**




**Analytic Results**

| Static | $/MWh | $ (Millions) |
|---|---|---|
| Revenue from Power Sales | | (491) |
| Cost of Power Purchase | | 1,237 |
| Generic Revenue Requirement | | 6,091 |
| Variable Cost of Existing Fleet | | 1,291 |
| End Effects | | 688 |
| Expected Cost | 39.20 | 8,816 |

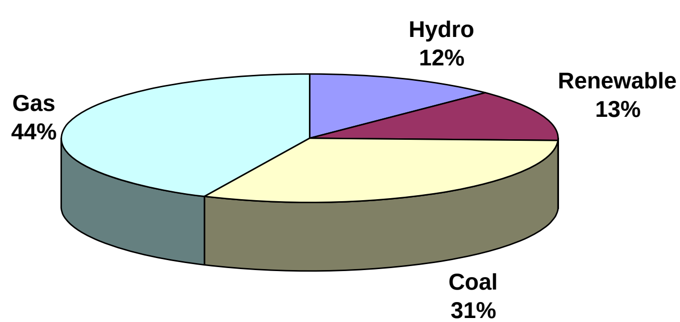
| Dynamic - 100 Trials | $/MWh | $ (Millions) |
|---|---|---|
| Mean | 38.08 | 8,563 |
| 95% | 40.46 | 9,098 |
| 5% | 35.99 | 8,093 |
| Avg. > 90% | 40.77 | 9,169 |

**Scenario:** Green World
**Portfolio:** 15% Renewable 50/50 Gas & Coal
**Time Period 1:** 2006-2015
**Time Period 2:** 2016-2025
**Transmission:** Participant Funded

| Time Period 1 | Supply Additions (Nameplate Capacity in MW) | | | | | | | | | | Total Period Additions | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | MW | Percent |
| CCGT | 125 | | | 25 | 75 | 100 | 250 | 75 | 50 | 25 | 725 | 20% |
| Coal | | | | | | | | | | | - | 0% |
| Wind | | 100 | 100 | 100 | | | | | | | 300 | 8% |
| Biomass | | | | | | 25 | 25 | 25 | | | 75 | 2% |
| PBAs | 125 | | | | 25 | 175 | 275 | 100 | 25 | 25 | 750 | 21% |
| Duct Fired | 17 | | | 3 | 10 | 14 | 34 | 10 | 7 | 3 | 98 | 3% |
| Winter Call Option | 988 | 56 | 39 | 31 | 163 | 191 | 77 | 21 | 5 | 32 | 1,603 | 45% |
| Total | 1,255 | 156 | 139 | 159 | 273 | 505 | 661 | 231 | 87 | 85 | 3,551 | 100% |

| Time Period 2 | Supply Additions (Nameplate Capacity in MW) | | | | | | | | | | Total Period Additions | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | MW | Percent |
| CCGT | 400 | 50 | 25 | 50 | 25 | 25 | 50 | 50 | 25 | 50 | 750 | 31% |
| Coal | 400 | 75 | | 75 | | 25 | 25 | 25 | 50 | 50 | 725 | 30% |
| Wind | 100 | 100 | 100 | | | | | | | | 300 | 13% |
| Biomass | 25 | 25 | 25 | 25 | 25 | 25 | | | | | 150 | 6% |
| PBAs | | | | | | | | | | | - | 0% |
| Duct Fired | 54 | 7 | 3 | 7 | 3 | 3 | 7 | 7 | 3 | 7 | 101 | 4% |
| Winter Call Option | 1 | | 36 | 107 | 25 | 29 | 25 | 28 | 89 | 21 | 361 | 15% |
| Total | 980 | 257 | 189 | 264 | 78 | 107 | 107 | 110 | 167 | 128 | 2,387 | 100% |

**2025 Available Generation from New and Existing Resources (Annual Average)**




**Analytic Results**

| Static | $/MWh | $ (Millions) |
|---|---|---|
| Revenue from Power Sales | | (506) |
| Cost of Power Purchase | | 1,326 |
| Generic Revenue Requirement | | 6,881 |
| Variable Cost of Existing Fleet | | 1,658 |
| End Effects | | 543 |
| Expected Cost | 44.03 | 9,902 |

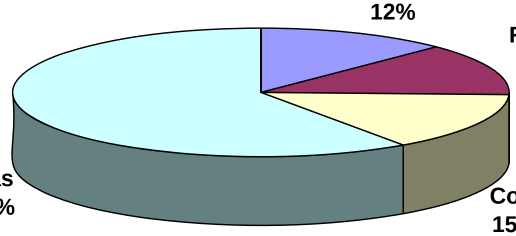
| Dynamic - 100 Trials | $/MWh | $ (Millions) |
|---|---|---|
| Mean | 43.25 | 9,726 |
| 95% | 46.48 | 10,453 |
| 5% | 39.51 | 8,886 |
| Avg. > 90% | 46.46 | 10,449 |

**Scenario:** Green World
**Portfolio:** 15% Renewable and Gas
**Time Period 1:** 2006-2015
**Time Period 2:** 2016-2025
**Transmission:** Participant Funded

| Time Period 1 | Supply Additions (Nameplate Capacity in MW) | | | | | | | | | | Total Period Additions | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | MW | Percent |
| CCGT | 125 | | | 25 | 75 | 100 | 250 | 75 | 50 | 25 | 725 | 20% |
| Coal | | | | | | | | | | | - | 0% |
| Wind | | 100 | 100 | 100 | | | | | | | 300 | 8% |
| Biomass | | | | | | 25 | 25 | 25 | | | 75 | 2% |
| PBAs | 125 | | | | 25 | 175 | 275 | 100 | 25 | 25 | 750 | 21% |
| Duct Fired | 17 | | | 3 | 10 | 14 | 34 | 10 | 7 | 3 | 98 | 3% |
| Winter Call Option | 988 | 56 | 39 | 31 | 163 | 191 | 77 | 21 | 5 | 32 | 1,603 | 45% |
| Total | 1,255 | 156 | 139 | 159 | 273 | 505 | 661 | 231 | 87 | 85 | 3,551 | 100% |

| Time Period 2 | Supply Additions (Nameplate Capacity in MW) | | | | | | | | | | Total Period Additions | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | MW | Percent |
| CCGT | 775 | 125 | 25 | 125 | 25 | 50 | 75 | 75 | 75 | 75 | 1,425 | 61% |
| Coal | | | | | | | | | | | - | 0% |
| Wind | 100 | 100 | 100 | | | | | | | | 300 | 13% |
| Biomass | 25 | 25 | 25 | 25 | 25 | 25 | | | | | 150 | 6% |
| PBAs | | | | | | | | | | | - | 0% |
| Duct Fired | 105 | 17 | 3 | 17 | 3 | 7 | 10 | 10 | 10 | 10 | 192 | 8% |
| Winter Call Option | | | | 46 | 47 | 24 | 21 | 24 | 79 | 39 | 280 | 12% |
| Total | 1,005 | 267 | 153 | 213 | 100 | 106 | 106 | 109 | 164 | 124 | 2,347 | 100% |

**2025 Available Generation from New and Existing Resources (Annual Average)**




**Analytic Results**

| Static | $/MWh | $ (Millions) |
|---|---|---|
| Revenue from Power Sales | | (547) |
| Cost of Power Purchase | | 1,578 |
| Generic Revenue Requirement | | 6,626 |
| Variable Cost of Existing Fleet | | 1,658 |
| End Effects | | 546 |
| Expected Cost | 43.84 | 9,860 |

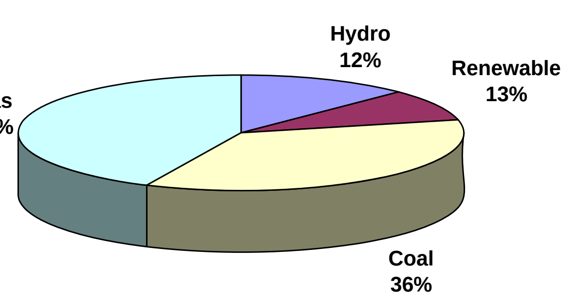
| Dynamic - 100 Trials | $/MWh | $ (Millions) |
|---|---|---|
| Mean | 42.73 | 9,610 |
| 95% | 46.16 | 10,380 |
| 5% | 39.15 | 8,805 |
| Avg. > 90% | 46.27 | 10,405 |

**Scenario:** Transmission Solution
**Portfolio:** 10% Renewable and 50/50 Gas & Coal
**Time Period 1:** 2006-2012
**Time Period 2:** 2013-2025
**Transmission:** System-Wide Rates

| Time Period 1 | Supply Additions (Nameplate Capacity in MW) | | | | | | | Total Period Additions | |
|---|---|---|---|---|---|---|---|---|---|
| | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | MW | Percent |
| CCGT | 125 | | | 25 | 50 | 125 | 275 | 600 | 19% |
| Coal | | | | | | | | - | 0% |
| Wind | | 100 | 100 | 100 | | | | 300 | 10% |
| Biomass | | | | | | | 25 | 25 | 1% |
| PBAs | 125 | | | | 50 | 150 | 275 | 600 | 19% |
| Duct Fired | 17 | | | 3 | 7 | 17 | 37 | 81 | 3% |
| Winter Call Option | 988 | 56 | 39 | 31 | 166 | 209 | 50 | 1,539 | 49% |
| Total | 1,255 | 156 | 139 | 159 | 273 | 501 | 662 | 3,145 | 100% |

| Time Period 2 | Supply Additions (Nameplate Capacity in MW) | | | | | | | | | | | | | Total Period Additions | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | MW | Percent |
| CCGT | 400 | 25 | 25 | 25 | 100 | 25 | 75 | 25 | 25 | 25 | 50 | 25 | 50 | 425 | 32% |
| Coal | 425 | 25 | 25 | 25 | 75 | 50 | 50 | 25 | 25 | 50 | 25 | 50 | 50 | 425 | 32% |
| Wind | | 100 | | | | | | | | | | | | - | 0% |
| Biomass | 25 | | | | | | 25 | | 25 | | | | | 50 | 4% |
| PBAs | | | | | | | | | | | | | | - | 0% |
| Duct Fired | 54 | 3 | 3 | 3 | 14 | 3 | 10 | 3 | 3 | 3 | 7 | 3 | 7 | 57 | 4% |
| Winter Call Option | | 1 | 34 | 36 | | 19 | 80 | 46 | 29 | 30 | 28 | 88 | 21 | 377 | 28% |
| Total | 904 | 154 | 87 | 89 | 189 | 97 | 240 | 99 | 107 | 108 | 110 | 166 | 128 | 1,334 | 100% |

**2025 Available Generation from New and Existing Resources (Annual Average)**




**Analytic Results**

| Static | $/MWh | $ (Millions) |
|---|---|---|
| Revenue from Power Sales | | (400) |
| Cost of Power Purchase | | 1,121 |
| Generic Revenue Requirement | | 5,926 |
| Variable Cost of Existing Fleet | | 959 |
| End Effects | | 242 |
| Expected Cost | 34.90 | 7,848 |

| Dynamic - 100 Trials | $/MWh | $ (Millions) |
|---|---|---|
| Mean | 34.69 | 7,802 |
| 95% | 36.08 | 8,113 |
| 5% | 33.15 | 7,454 |
| Avg. > 90% | 36.20 | 8,142 |

Exhibit No. ___(EMM-6)
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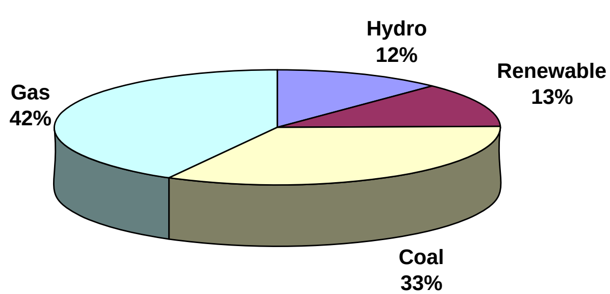
**Scenario:** Transmission Solution
**Portfolio:** 15% Renewable 50/50 Gas & Coal
**Time Period 1:** 2006-2012
**Time Period 2:** 2013-2025
**Transmission:** System-Wide Rates

| Time Period 1 | Supply Additions (Nameplate Capacity in MW) | | | | | | | Total Period Additions | |
|---|---|---|---|---|---|---|---|---|---|
| | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | MW | Percent |
| CCGT | 125 | | | 25 | 50 | 125 | 275 | 600 | 19% |
| Coal | | | | | | | | - | 0% |
| Wind | | 100 | 100 | 100 | | | | 300 | 10% |
| Biomass | | | | | | | 25 | 25 | 1% |
| PBAs | 125 | | | | 50 | 150 | 275 | 600 | 19% |
| Duct Fired | 17 | | | 3 | 7 | 17 | 37 | 81 | 3% |
| Winter Call Option | 988 | 56 | 39 | 31 | 166 | 209 | 50 | 1,539 | 49% |
| Total | 1,255 | 156 | 139 | 159 | 273 | 501 | 662 | 3,145 | 100% |

| Time Period 2 | Supply Additions (Nameplate Capacity in MW) | | | | | | | | | | | | | Total Period Additions | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | MW | Percent |
| CCGT | 400 | 25 | | | 50 | 25 | 75 | 25 | 25 | 50 | 25 | 50 | 50 | 375 | 24% |
| Coal | 425 | 50 | 75 | | 50 | | 50 | | 25 | 25 | 50 | 25 | 50 | 275 | 17% |
| Wind | | | | 100 | 100 | 100 | | | | | | | | 300 | 19% |
| Biomass | 25 | | | 25 | 25 | 25 | 25 | 25 | 25 | | | | | 150 | 10% |
| PBAs | | | | | | | | | | | | | | - | 0% |
| Duct Fired | 54 | 3 | | | 7 | 3 | 10 | 3 | 3 | 7 | 3 | 7 | 7 | 51 | 3% |
| Winter Call Option | | | 15 | 44 | | 58 | 81 | 47 | 28 | 26 | 33 | 83 | 21 | 421 | 27% |
| Total | 904 | 78 | 90 | 169 | 232 | 211 | 241 | 100 | 106 | 108 | 111 | 165 | 128 | 1,572 | 100% |

**2025 Available Generation from New and Existing Resources**
**(Annual Average)**




**Analytic Results**

| **Static** | $/MWh | $ (Millions) |
|---|---|---|
| **Revenue from Power Sales** | | (404) |
| **Cost of Power Purchase** | | 1,081 |
| **Generic Revenue Requirement** | | 6,030 |
| **Variable Cost of Existing Fleet** | | 959 |
| **End Effects** | | 261 |
| **Expected Cost** | 35.25 | 7,928 |

| **Dynamic - 100 Trials** | $/MWh | $ (Millions) |
|---|---|---|
| **Mean** | 35.06 | 7,885 |
| **95%** | 36.49 | 8,206 |
| **5%** | 33.34 | 7,498 |
| **Avg. > 90%** | 36.59 | 8,229 |

Exhibit No. ___(EMM-6)
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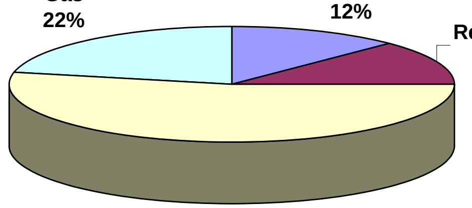
**Scenario:** Transmission Solution
**Portfolio:** 15% Renewable and Coal
**Time Period 1:** 2006-2012
**Time Period 2:** 2013-2025
**Transmission:** System-Wide Rates

| Time Period 1 | Supply Additions (Nameplate Capacity in MW) | | | | | | | Total Period Additions | |
|---|---|---|---|---|---|---|---|---|---|
| | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | MW | Percent |
| CCGT | 125 | | | 25 | 50 | 125 | 275 | 600 | 19% |
| Coal | | | | | | | | - | 0% |
| Wind | | 100 | 100 | 100 | | | | 300 | 10% |
| Biomass | | | | | | | 25 | 25 | 1% |
| PBAs | 125 | | | | 50 | 150 | 275 | 600 | 19% |
| Duct Fired | 17 | | | 3 | 7 | 17 | 37 | 81 | 3% |
| Winter Call Option | 988 | 56 | 39 | 31 | 166 | 209 | 50 | 1,539 | 49% |
| Total | 1,255 | 156 | 139 | 159 | 273 | 501 | 662 | 3,145 | 100% |

| Time Period 2 | Supply Additions (Nameplate Capacity in MW) | | | | | | | | | | | | | Total Period Additions | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | MW | Percent |
| CCGT | | | | | | | | | | | | | | - | 0% |
| Coal | 850 | 75 | 75 | | 125 | | 125 | 25 | 75 | 75 | 75 | 75 | 100 | 675 | 42% |
| Wind | | | | 100 | 100 | 100 | | | | | | | | 300 | 19% |
| Biomass | 25 | | | 25 | 25 | 25 | 25 | 25 | 25 | | | | | 150 | 9% |
| PBAs | | | | | | | | | | | | | | - | 0% |
| Duct Fired | | | | | | | | | | | | | | - | 0% |
| Winter Call Option | 38 | 17 | 17 | 43 | | 72 | 95 | 52 | 10 | 35 | 38 | 93 | 30 | 468 | 29% |
| Total | 913 | 92 | 92 | 168 | 250 | 197 | 245 | 102 | 110 | 110 | 113 | 168 | 130 | 1,593 | 100% |

**2025 Available Generation from New and Existing Resources (Annual Average)**




**Analytic Results**

| Static | $/MWh | $ (Millions) |
|---|---|---|
| Revenue from Power Sales | | (428) |
| Cost of Power Purchase | | 899 |
| Generic Revenue Requirement | | 6,038 |
| Variable Cost of Existing Fleet | | 959 |
| End Effects | | (47) |
| Expected Cost | 32.99 | 7,420 |

| Dynamic - 100 Trials | $/MWh | $ (Millions) |
|---|---|---|
| Mean | 32.95 | 7,411 |
| 95% | 34.75 | 7,814 |
| 5% | 30.63 | 6,887 |
| Avg. > 90% | 34.88 | 7,845 |

Exhibit No. ___(EMM-6)
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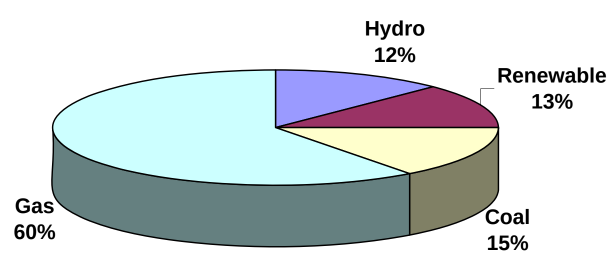
**Scenario:** Transmission Solution
**Portfolio:** 15% Renewable and Gas
**Time Period 1:** 2006-2012
**Time Period 2:** 2013-2025
**Transmission:** System-Wide Rates

| Time Period 1 | Supply Additions (Nameplate Capacity in MW) | | | | | | | Total Period Additions | |
|---|---|---|---|---|---|---|---|---|---|
| | **2006** | **2007** | **2008** | **2009** | **2010** | **2011** | **2012** | MW | Percent |
| CCGT | 125 | | | 25 | 50 | 125 | 275 | 600 | 19% |
| Coal | | | | | | | | - | 0% |
| Wind | | 100 | 100 | 100 | | | | 300 | 10% |
| Biomass | | | | | | | 25 | 25 | 1% |
| PBAs | 125 | | | | 50 | 150 | 275 | 600 | 19% |
| Duct Fired | 17 | | | 3 | 7 | 17 | 37 | 81 | 3% |
| Winter Call Option | 988 | 56 | 39 | 31 | 166 | 209 | 50 | 1,539 | 49% |
| Total | 1,255 | 156 | 139 | 159 | 273 | 501 | 662 | 3,145 | 100% |

| Time Period 2 | Supply Additions (Nameplate Capacity in MW) | | | | | | | | | | | | | Total Period Additions | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** | MW | Percent |
| CCGT | 800 | 75 | 75 | | 100 | 25 | 125 | 25 | 50 | 75 | 75 | 75 | 75 | 625 | 42% |
| Coal | | | | | | | | | | | | | | - | 0% |
| Wind | | | | 100 | 100 | 100 | | | | | | | | 300 | 20% |
| Biomass | 25 | | | 25 | 25 | 25 | 25 | 25 | 25 | | | | | 150 | 10% |
| PBAs | | | | | | | | | | | | | | - | 0% |
| Duct Fired | 108 | 10 | 10 | | 14 | 3 | 17 | 3 | 7 | 10 | 10 | 10 | 10 | 84 | 6% |
| Winter Call Option | | | | | | 33 | 71 | 47 | 25 | 20 | 24 | 79 | 39 | 338 | 23% |
| Total | 933 | 85 | 85 | 125 | 239 | 186 | 238 | 100 | 107 | 105 | 109 | 164 | 124 | 1,497 | 100% |

**2025 Available Generation from New and Existing Resources**
**(Annual Average)**




**Analytic Results**

| **Static** | **$/MWh** | **$ (Millions)** |
|---|---|---|
| **Revenue from Power Sales** | | (448) |
| **Cost of Power Purchase** | | 1,320 |
| **Generic Revenue Requirement** | | 6,055 |
| **Variable Cost of Existing Fleet** | | 959 |
| **End Effects** | | 553 |
| **Expected Cost** | 37.53 | 8,440 |

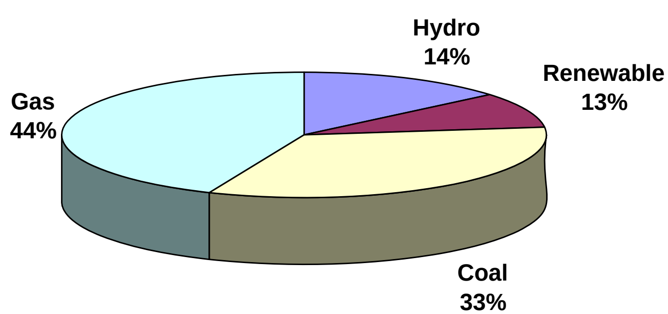
| **Dynamic - 100 Trials** | **$/MWh** | **$ (Millions)** |
|---|---|---|
| **Mean** | 37.19 | 8,364 |
| **95%** | 38.48 | 8,653 |
| **5%** | 35.51 | 7,986 |
| **Avg. > 90%** | 38.73 | 8,711 |

**Scenario:** Low Growth
**Portfolio:** 10% Renewable and 50/50 Gas & Coal
**Time Period 1:** 2006-2015
**Time Period 2:** 2016-2025
**Transmission:** Participant Funded

| Time Period 1 | Supply Additions (Nameplate Capacity in MW) | | | | | | | | | | Total Period Additions | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | MW | Percent |
| CCGT | 100 | 25 | | | 25 | 125 | 225 | 100 | 25 | 25 | 650 | 18% |
| Coal | | | | | | | | | | | - | 0% |
| Wind | | 100 | 100 | 100 | | | | | | | 300 | 8% |
| Biomass | | | | | | 25 | 25 | 25 | | | 75 | 2% |
| PBAs | 100 | | 25 | | | 125 | 275 | 75 | 50 | | 650 | 18% |
| Duct Fired | 14 | 3 | | | 3 | 17 | 30 | 14 | 3 | 3 | 88 | 2% |
| Winter Call Option | 1,041 | 28 | 14 | 58 | 243 | 213 | 104 | 20 | 7 | 57 | 1,785 | 50% |
| Total | 1,255 | 156 | 139 | 158 | 271 | 505 | 659 | 234 | 85 | 85 | 3,548 | 100% |

| Time Period 2 | Supply Additions (Nameplate Capacity in MW) | | | | | | | | | | Total Period Additions | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | MW | Percent |
| CCGT | 400 | 25 | 50 | 25 | 75 | | | 25 | 25 | 25 | 650 | 32% |
| Coal | 400 | 50 | 25 | 75 | 50 | | | 25 | | 25 | 650 | 32% |
| Wind | | | | | | | | | | | - | 0% |
| Biomass | | | | | | 25 | | | | | 25 | 1% |
| PBAs | | | | | | | | | | | - | 0% |
| Duct Fired | 54 | 3 | 7 | 3 | 10 | | | 3 | 3 | 3 | 88 | 4% |
| Winter Call Option | | | 59 | 133 | 48 | 102 | | 55 | 134 | 70 | 601 | 30% |
| Total | 854 | 78 | 141 | 236 | 183 | 127 | - | 108 | 162 | 123 | 2,014 | 100% |

**2025 Available Generation from New and Existing Resources (Annual Average)**




**Analytic Results**

| Static | $/MWh | $ (Millions) |
|---|---|---|
| Revenue from Power Sales | | (399) |
| Cost of Power Purchase | | 885 |
| Generic Revenue Requirement | | 5,129 |
| Variable Cost of Existing Fleet | | 933 |
| End Effects | | 454 |
| Expected Cost | 32.76 | 7,001 |

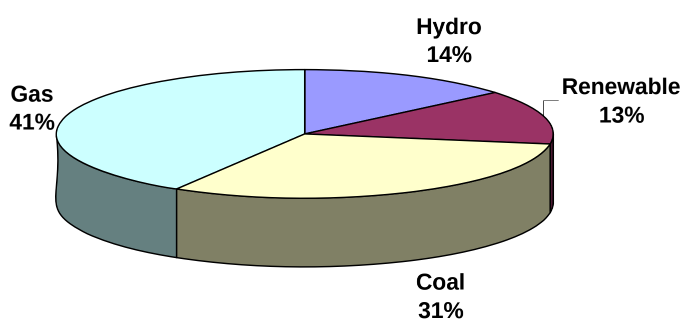
| Dynamic - 100 Trials | $/MWh | $ (Millions) |
|---|---|---|
| Mean | 31.80 | 6,798 |
| 95% | 34.29 | 7,330 |
| 5% | 29.36 | 6,276 |
| Avg. > 90% | 34.45 | 7,363 |

**Scenario:** Low Growth
**Portfolio:** 15% Renewable 50/50 Gas & Coal
**Time Period 1:** 2006-2015
**Time Period 2:** 2016-2025
**Transmission:** Participant Funded

| Time Period 1 | Supply Additions (Nameplate Capacity in MW) | | | | | | | | | | Total Period Additions | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | MW | Percent |
| CCGT | 100 | 25 | | | 25 | 125 | 225 | 100 | 25 | 25 | 650 | 18% |
| Coal | | | | | | | | | | | - | 0% |
| Wind | | 100 | 100 | 100 | | | | | | | 300 | 8% |
| Biomass | | | | | | 25 | 25 | 25 | | | 75 | 2% |
| PBAs | 100 | | 25 | | | 125 | 275 | 75 | 50 | | 650 | 18% |
| Duct Fired | 14 | 3 | | | 3 | 17 | 30 | 14 | 3 | 3 | 88 | 2% |
| Winter Call Option | 1,041 | 28 | 14 | 58 | 243 | 213 | 104 | 20 | 7 | 57 | 1,785 | 50% |
| Total | 1,255 | 156 | 139 | 158 | 271 | 505 | 659 | 234 | 85 | 85 | 3,548 | 100% |

| Time Period 2 | Supply Additions (Nameplate Capacity in MW) | | | | | | | | | | Total Period Additions | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | MW | Percent |
| CCGT | 400 | | 25 | 25 | 50 | | | | 25 | 50 | 575 | 26% |
| Coal | 400 | | | 75 | 50 | | 25 | | | 25 | 575 | 26% |
| Wind | 100 | 100 | 100 | | | | | | | | 300 | 13% |
| Biomass | | | 25 | 25 | 25 | 25 | | | | | 100 | 4% |
| PBAs | | | | | | | | | | | - | 0% |
| Duct Fired | 54 | | 3 | 3 | 7 | | | | 3 | 7 | 78 | 3% |
| Winter Call Option | | | 99 | 113 | | | 132 | 106 | 133 | 43 | 626 | 28% |
| Total | 954 | 100 | 252 | 241 | 132 | 25 | 157 | 106 | 161 | 125 | 2,254 | 100% |

**2025 Available Generation from New and Existing Resources (Annual Average)**




**Analytic Results**

| Static | $/MWh | $ (Millions) |
|---|---|---|
| Revenue from Power Sales | | (408) |
| Cost of Power Purchase | | 854 |
| Generic Revenue Requirement | | 5,262 |
| Variable Cost of Existing Fleet | | 933 |
| End Effects | | 475 |
| Expected Cost | 33.29 | 7,115 |

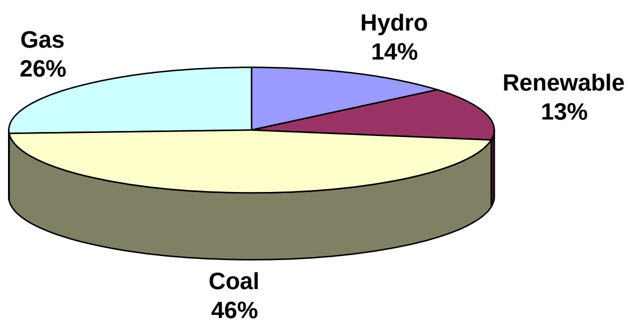
| Dynamic - 100 Trials | $/MWh | $ (Millions) |
|---|---|---|
| Mean | 32.38 | 6,921 |
| 95% | 34.82 | 7,443 |
| 5% | 29.95 | 6,402 |
| Avg. > 90% | 35.00 | 7,482 |

**Scenario:** Low Growth
**Portfolio:** 15% Renewable and Coal
**Time Period 1:** 2006-2015
**Time Period 2:** 2016-2025
**Transmission:** Participant Funded

| Time Period 1 | Supply Additions (Nameplate Capacity in MW) | | | | | | | | | | Total Period Additions | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | MW | Percent |
| CCGT | 100 | 25 | | | 25 | 125 | 225 | 100 | 25 | 25 | 650 | 18% |
| Coal | | | | | | | | | | | - | 0% |
| Wind | | 100 | 100 | 100 | | | | | | | 300 | 8% |
| Biomass | | | | | | 25 | 25 | 25 | | | 75 | 2% |
| PBAs | 100 | | 25 | | | 125 | 275 | 75 | 50 | | 650 | 18% |
| Duct Fired | 14 | 3 | | | 3 | 17 | 30 | 14 | 3 | 3 | 88 | 2% |
| Winter Call Option | 1,041 | 28 | 14 | 58 | 243 | 213 | 104 | 20 | 7 | 57 | 1,785 | 50% |
| Total | 1,255 | 156 | 139 | 158 | 271 | 505 | 659 | 234 | 85 | 85 | 3,548 | 100% |

| Time Period 2 | Supply Additions (Nameplate Capacity in MW) | | | | | | | | | | Total Period Additions | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | MW | Percent |
| CCGT | | | | | | | | | | | - | 0% |
| Coal | 800 | 25 | 25 | 100 | 100 | | | 50 | | 75 | 1,175 | 51% |
| Wind | 100 | 100 | 100 | | | | | | | | 300 | 13% |
| Biomass | | | 25 | 25 | 25 | 25 | | | | | 100 | 4% |
| PBAs | | | | | | | | | | | - | 0% |
| Duct Fired | | | | | | | | | | | - | 0% |
| Winter Call Option | | 41 | 114 | 117 | | 63 | 102 | 60 | 161 | 52 | 710 | 31% |
| Total | 900 | 166 | 264 | 242 | 125 | 88 | 102 | 110 | 161 | 127 | 2,285 | 100% |

**2025 Available Generation from New and Existing Resources (Annual Average)**




**Analytic Results**

| **Static** | $/MWh | $ (Millions) |
|---|---|---|
| Revenue from Power Sales | | (410) |
| Cost of Power Purchase | | 760 |
| Generic Revenue Requirement | | 5,438 |
| Variable Cost of Existing Fleet | | 933 |
| End Effects | | 488 |
| Expected Cost | 33.72 | 7,208 |

| **Dynamic - 100 Trials** | $/MWh | $ (Millions) |
|---|---|---|
| Mean | 33.11 | 7,077 |
| 95% | 35.60 | 7,610 |
| 5% | 30.61 | 6,543 |
| Avg. > 90% | 35.67 | 7,625 |

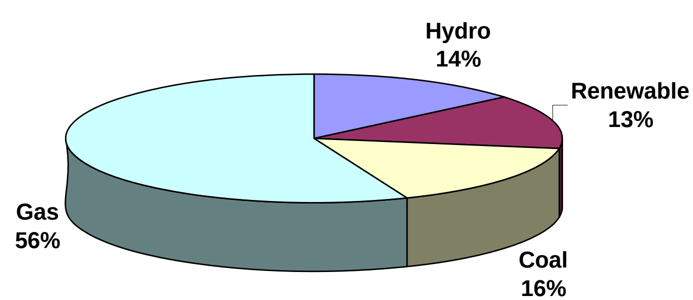
Exhibit No. ___(EMM-6)
Page 748 of 784

**Scenario:** Low Growth
**Portfolio:** 15% Renewable and Gas
**Time Period 1:** 2006-2015
**Time Period 2:** 2016-2025
**Transmission:** Participant Funded

| Time Period 1 | Supply Additions (Nameplate Capacity in MW) | | | | | | | | | | Total Period Additions | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | MW | Percent |
| CCGT | 100 | 25 | | | 25 | 125 | 225 | 100 | 25 | 25 | 650 | 18% |
| Coal | | | | | | | | | | | - | 0% |
| Wind | | 100 | 100 | 100 | | | | | | | 300 | 8% |
| Biomass | | | | | | 25 | 25 | 25 | | | 75 | 2% |
| PBAs | 100 | | 25 | | | 125 | 275 | 75 | 50 | | 650 | 18% |
| Duct Fired | 14 | 3 | | | 3 | 17 | 30 | 14 | 3 | 3 | 88 | 2% |
| Winter Call Option | 1,041 | 28 | 14 | 58 | 243 | 213 | 104 | 20 | 7 | 57 | 1,785 | 50% |
| Total | 1,255 | 156 | 139 | 158 | 271 | 505 | 659 | 234 | 85 | 85 | 3,548 | 100% |

| Time Period 2 | Supply Additions (Nameplate Capacity in MW) | | | | | | | | | | Total Period Additions | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | MW | Percent |
| CCGT | 775 | | 25 | 100 | 75 | | | 50 | 25 | 75 | 1,125 | 51% |
| Coal | | | | | | | | | | | - | 0% |
| Wind | 100 | 100 | 100 | | | | | | | | 300 | 13% |
| Biomass | | | 25 | 25 | 25 | 25 | | | | | 100 | 4% |
| PBAs | | | | | | | | | | | - | 0% |
| Duct Fired | 105 | | 3 | 14 | 10 | | | 7 | 3 | 10 | 152 | 7% |
| Winter Call Option | | | 52 | 99 | | 71 | 102 | 51 | 133 | 39 | 547 | 25% |
| Total | 980 | 100 | 205 | 238 | 110 | 96 | 102 | 108 | 161 | 124 | 2,224 | 100% |

**2025 Available Generation from New and Existing Resources (Annual Average)**




**Analytic Results**

| Static | $/MWh | $ (Millions) |
|---|---|---|
| Revenue from Power Sales | | (429) |
| Cost of Power Purchase | | 980 |
| Generic Revenue Requirement | | 5,075 |
| Variable Cost of Existing Fleet | | 933 |
| End Effects | | 480 |
| Expected Cost | 32.93 | 7,038 |

| Dynamic - 100 Trials | $/MWh | $ (Millions) |
|---|---|---|
| Mean | 31.74 | 6,783 |
| 95% | 34.56 | 7,387 |
| 5% | 29.22 | 6,245 |
| Avg. > 90% | 34.60 | 7,396 |

Exhibit No. ___(EMM-6)
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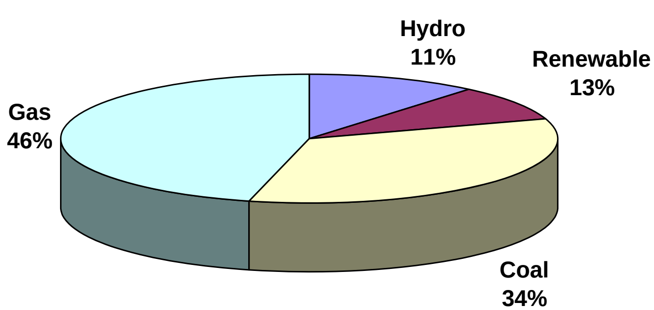
**Scenario:** Robust Growth
**Portfolio:** 10% Renewable and 50/50 Gas & Coal
**Time Period 1:** 2006-2015
**Time Period 2:** 2016-2025
**Transmission:** Participant Funded

| Time Period 1 | Supply Additions (Nameplate Capacity in MW) | | | | | | | | | | Total Period Additions | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | MW | Percent |
| CCGT | 125 | 25 | 25 | | 50 | 150 | 275 | 100 | 25 | 50 | 825 | 23% |
| Coal | | | | | | | | | | | - | 0% |
| Wind | | 100 | 100 | 100 | | | | | | | 300 | 8% |
| Biomass | | | | | | | 25 | 25 | 50 | | 100 | 3% |
| PBAs | 150 | | 50 | | 50 | 150 | 275 | 100 | 25 | 25 | 825 | 23% |
| Duct Fired | 17 | 3 | 3 | | 7 | 20 | 37 | 14 | 3 | 7 | 111 | 3% |
| Winter Call Option | 963 | 29 | | 20 | 165 | 183 | 50 | | | | 1,410 | 39% |
| Total | 1,255 | 157 | 178 | 120 | 272 | 503 | 662 | 239 | 103 | 82 | 3,571 | 100% |

| Time Period 2 | Supply Additions (Nameplate Capacity in MW) | | | | | | | | | | Total Period Additions | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | MW | Percent |
| CCGT | 525 | 50 | 50 | 75 | 75 | | 50 | 75 | 50 | 50 | 1,000 | 43% |
| Coal | 525 | 50 | 50 | 75 | 100 | | 25 | 50 | 50 | 75 | 1,000 | 43% |
| Wind | | 100 | | | | | | | | | 100 | 4% |
| Biomass | | | | | | 25 | 25 | | | | 50 | 2% |
| PBAs | | | | | | | | | | | - | 0% |
| Duct Fired | 71 | 7 | 7 | 10 | 10 | | 7 | 10 | 7 | 7 | 135 | 6% |
| Winter Call Option | | | | | | | | | 31 | | 31 | 1% |
| Total | 1,121 | 207 | 107 | 160 | 185 | 25 | 107 | 135 | 138 | 132 | 2,316 | 100% |

**2025 Available Generation from New and Existing Resources (Annual Average)**




**Analytic Results**

| Static | $/MWh | $ (Millions) |
|---|---|---|
| Revenue from Power Sales | | (136) |
| Cost of Power Purchase | | 2,599 |
| Generic Revenue Requirement | | 5,481 |
| Variable Cost of Existing Fleet | | 1,013 |
| End Effects | | 224 |
| Expected Cost | 36.06 | 9,182 |

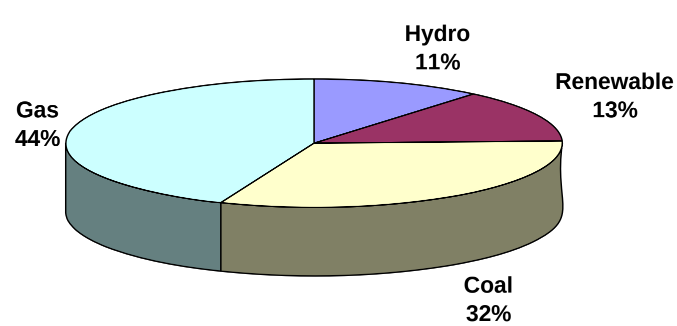
| Dynamic - 100 Trials | $/MWh | $ (Millions) |
|---|---|---|
| Mean | 35.15 | 8,950 |
| 95% | 38.22 | 9,733 |
| 5% | 31.89 | 8,121 |
| Avg. > 90% | 38.44 | 9,789 |

**Scenario:** Robust Growth
**Portfolio:** 15% Renewable 50/50 Gas & Coal
**Time Period 1:** 2006-2015
**Time Period 2:** 2016-2025
**Transmission:** Participant Funded

| Time Period 1 | Supply Additions (Nameplate Capacity in MW) | | | | | | | | | | Total Period Additions | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | MW | Percent |
| CCGT | 125 | 25 | 25 | | 50 | 150 | 275 | 100 | 25 | 50 | 825 | 23% |
| Coal | | | | | | | | | | | - | 0% |
| Wind | | 100 | 100 | 100 | | | | | | | 300 | 8% |
| Biomass | | | | | | | 25 | 25 | 50 | | 100 | 3% |
| PBAs | 150 | | 50 | | 50 | 150 | 275 | 100 | 25 | 25 | 825 | 23% |
| Duct Fired | 17 | 3 | 3 | | 7 | 20 | 37 | 14 | 3 | 7 | 111 | 3% |
| Winter Call Option | 963 | 29 | | 20 | 165 | 183 | 50 | | | | 1,410 | 39% |
| Total | 1,255 | 157 | 178 | 120 | 272 | 503 | 662 | 239 | 103 | 82 | 3,571 | 100% |

| Time Period 2 | Supply Additions (Nameplate Capacity in MW) | | | | | | | | | | Total Period Additions | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | MW | Percent |
| CCGT | 500 | 25 | 25 | 50 | 100 | | 50 | 25 | 50 | 75 | 900 | 35% |
| Coal | 500 | 50 | | 75 | 75 | | 50 | 50 | 50 | 50 | 900 | 35% |
| Wind | 100 | 100 | 100 | 100 | | | | 100 | | | 500 | 20% |
| Biomass | 25 | 25 | 25 | | 25 | 25 | | | | | 125 | 5% |
| PBAs | | | | | | | | | | | - | 0% |
| Duct Fired | 68 | 3 | 3 | 7 | 14 | | 7 | 3 | 7 | 10 | 122 | 5% |
| Winter Call Option | | | | | | | | | | | - | 0% |
| Total | 1,193 | 203 | 153 | 232 | 214 | 25 | 107 | 178 | 107 | 135 | 2,547 | 100% |

**2025 Available Generation from New and Existing Resources**
**(Annual Average)**




**Analytic Results**

| Static | $/MWh | $ (Millions) |
|---|---|---|
| Revenue from Power Sales | | (134) |
| Cost of Power Purchase | | 2,567 |
| Generic Revenue Requirement | | 5,587 |
| Variable Cost of Existing Fleet | | 1,013 |
| End Effects | | 270 |
| Expected Cost | 36.54 | 9,303 |

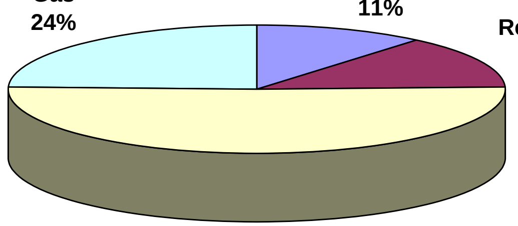
| Dynamic - 100 Trials | $/MWh | $ (Millions) |
|---|---|---|
| Mean | 35.68 | 9,086 |
| 95% | 38.66 | 9,845 |
| 5% | 32.48 | 8,271 |
| Avg. > 90% | 38.94 | 9,916 |

**Scenario:** Robust Growth
**Portfolio:** 15% Renewable and Coal
**Time Period 1:** 2006-2015
**Time Period 2:** 2016-2025
**Transmission:** Participant Funded

| Time Period 1 | Supply Additions (Nameplate Capacity in MW) | | | | | | | | | | Total Period Additions | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | MW | Percent |
| CCGT | 125 | 25 | 25 | | 50 | 150 | 275 | 100 | 25 | 50 | 825 | 23% |
| Coal | | | | | | | | | | | - | 0% |
| Wind | | 100 | 100 | 100 | | | | | | | 300 | 8% |
| Biomass | | | | | | | 25 | 25 | 50 | | 100 | 3% |
| PBAs | 150 | | 50 | | 50 | 150 | 275 | 100 | 25 | 25 | 825 | 23% |
| Duct Fired | 17 | 3 | 3 | | 7 | 20 | 37 | 14 | 3 | 7 | 111 | 3% |
| Winter Call Option | 963 | 29 | | 20 | 165 | 183 | 50 | | | | 1,410 | 39% |
| Total | 1,255 | 157 | 178 | 120 | 272 | 503 | 662 | 239 | 103 | 82 | 3,571 | 100% |

| Time Period 2 | Supply Additions (Nameplate Capacity in MW) | | | | | | | | | | Total Period Additions | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | MW | Percent |
| CCGT | | | | | | | | | | | - | 0% |
| Coal | 1,025 | 75 | 25 | 150 | 175 | | 75 | 75 | 125 | 125 | 1,850 | 69% |
| Wind | 100 | 100 | 100 | 100 | | | | 100 | | | 500 | 19% |
| Biomass | 25 | 25 | 25 | | 25 | 25 | | | | | 125 | 5% |
| PBAs | | | | | | | | | | | - | 0% |
| Duct Fired | | | | | | | | | | | - | 0% |
| Winter Call Option | | | 29 | 74 | | | 29 | 18 | 48 | 7 | 205 | 8% |
| Total | 1,150 | 200 | 179 | 324 | 200 | 25 | 104 | 193 | 173 | 132 | 2,680 | 100% |

**2025 Available Generation from New and Existing Resources (Annual Average)**




**Analytic Results**

| Static | $/MWh | $ (Millions) |
|---|---|---|
| Revenue from Power Sales | | (126) |
| Cost of Power Purchase | | 2,475 |
| Generic Revenue Requirement | | 5,685 |
| Variable Cost of Existing Fleet | | 1,013 |
| End Effects | | 189 |
| Expected Cost | 36.28 | 9,237 |

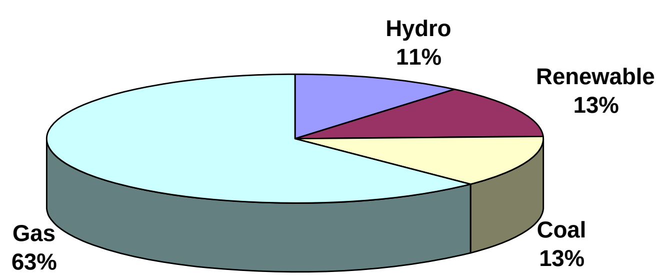
| Dynamic - 100 Trials | $/MWh | $ (Millions) |
|---|---|---|
| Mean | 35.70 | 9,091 |
| 95% | 38.65 | 9,841 |
| 5% | 32.39 | 8,247 |
| Avg. > 90% | 38.96 | 9,921 |

**Scenario:** Robust Growth
**Portfolio:** 15% Renewable and Gas
**Time Period 1:** 2006-2015
**Time Period 2:** 2016-2025
**Transmission:** Participant Funded

| Time Period 1 | Supply Additions (Nameplate Capacity in MW) | | | | | | | | | | Total Period Additions | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | MW | Percent |
| CCGT | 125 | 25 | 25 | | 50 | 150 | 275 | 100 | 25 | 50 | 825 | 23% |
| Coal | | | | | | | | | | | - | 0% |
| Wind | | 100 | 100 | 100 | | | | | | | 300 | 8% |
| Biomass | | | | | | | 25 | 25 | 50 | | 100 | 3% |
| PBAs | 150 | | 50 | | 50 | 150 | 275 | 100 | 25 | 25 | 825 | 23% |
| Duct Fired | 17 | 3 | 3 | | 7 | 20 | 37 | 14 | 3 | 7 | 111 | 3% |
| Winter Call Option | 963 | 29 | | 20 | 165 | 183 | 50 | | | | 1,410 | 39% |
| Total | 1,255 | 157 | 178 | 120 | 272 | 503 | 662 | 239 | 103 | 82 | 3,571 | 100% |

| Time Period 2 | Supply Additions (Nameplate Capacity in MW) | | | | | | | | | | Total Period Additions | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | MW | Percent |
| CCGT | 975 | 75 | 25 | 125 | 175 | | 75 | 75 | 100 | 125 | 1,750 | 67% |
| Coal | | | | | | | | | | | - | 0% |
| Wind | 100 | 100 | 100 | 100 | | | | 100 | | | 500 | 19% |
| Biomass | 25 | 25 | 25 | | 25 | 25 | | | | | 125 | 5% |
| PBAs | | | | | | | | | | | - | 0% |
| Duct Fired | 132 | 10 | 3 | 17 | 24 | | 10 | 10 | 14 | 17 | 236 | 9% |
| Winter Call Option | | | | | | | | | | | - | 0% |
| Total | 1,232 | 210 | 153 | 242 | 224 | 25 | 85 | 185 | 114 | 142 | 2,611 | 100% |

**2025 Available Generation from New and Existing Resources (Annual Average)**




**Analytic Results**

| Static | $/MWh | $ (Millions) |
|---|---|---|
| Revenue from Power Sales | | (146) |
| Cost of Power Purchase | | 2,656 |
| Generic Revenue Requirement | | 5,498 |
| Variable Cost of Existing Fleet | | 1,013 |
| End Effects | | 352 |
| Expected Cost | 36.81 | 9,374 |

| Dynamic - 100 Trials | $/MWh | $ (Millions) |
|---|---|---|
| Mean | 35.70 | 9,091 |
| 95% | 39.02 | 9,935 |
| 5% | 32.44 | 8,259 |
| Avg. > 90% | 39.19 | 9,980 |

Exhibit No. ___(EMM-6)
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# Electric Demand-Side Results

## Conservation Screening Model Analytic Results
**Scenario: Accelerated Energy Efficiency and Early Fuel Conversion**

**Selected Programs and Cost Level for Accelerated Energy Efficiency and Early Fuel Conversion Scenario**

| | < $45/MWh | $45 - $55/MWh | $55 - $65/MWh | $65 - $75/MWh | $75 - $85/MWh | $85 - $95/MWh | $95 - $105/MWh | $105 - $115/MWh |
|---|---|---|---|---|---|---|---|---|
| **Bundle** | **Cost Level A** | **Cost Level B** | **Cost Level C** | **Cost Level D** | **Cost Level E** | **Cost Level F** | **Cost Level G** | **Cost Level H** |
| **COM_EC_APPLIANCES** | 1 | 1 | 1 | 1 | NA | NA | 0 | 0 |
| **COM_EC_HVAC** | 1 | 1 | 1 | 1 | 1 | 1 | NA | 0 |
| **COM_EC_LIGHTING** | 1 | 1 | 1 | 1 | 1 | NA | 0 | 0 |
| **COM_EC_WATERHEAT** | 1 | 1 | 1 | 1 | NA | NA | NA | 0 |
| **COM_NC_APPLIANCES** | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 |
| **COM_NC_HVAC** | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 |
| **COM_NC_LIGHTING** | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 |
| **COM_NC_WATERHEAT** | 1 | 1 | 1 | 1 | NA | NA | 0 | 0 |
| **IND_EC_GENERAL** | 1 | NA | NA | NA | NA | NA | NA | NA |
| **RES_EC_APPLIANCES** | 1 | 1 | 1 | 1 | NA | 0 | 0 | 0 |
| **RES_EC_HVAC** | 1 | 1 | 1 | 1 | 1 | 0 | NA | 0 |
| **RES_EC_LIGHTING** | 1 | 1 | 1 | 1 | NA | NA | 0 | 0 |
| **RES_EC_WATERHEAT** | 1 | 1 | 1 | 1 | NA | 0 | 0 | 0 |
| **RES_NC_APPLIANCES** | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 |
| **RES_NC_HVAC** | NA | NA | NA | NA | NA | NA | 0 | 0 |
| **RES_NC_LIGHTING** | 1 | 1 | 1 | 1 | 1 | NA | 0 | 0 |
| **RES_NC_WATERHEAT** | 1 | 1 | 1 | 1 | NA | 0 | 0 | 0 |

**KEY**
**COM- Commercial**
**RES - Residential**
**EC- Existing Construction**
**NC- New Construction**
**0- Excluded (Non cost effective)**
**1- Included (Cost effective)**
**NA- No program at this cost level**

**Energy Savings (AMW)**

| Accelerated Energy Efficiency Early Fuel Conversion | | |
|---|---|---|
| **Year** | **Yearly** | **Cumulative** |
| **2006** | **35.5** | **35.5** |
| **2007** | **33.1** | **68.6** |
| **2008** | **31.1** | **99.6** |
| **2009** | **29.6** | **129.3** |
| **2010** | **28.7** | **158.0** |
| **2011** | **27.1** | **185.1** |
| **2012** | **25.6** | **210.7** |
| **2013** | **24.2** | **234.9** |
| **2014** | **22.9** | **257.8** |
| **2015** | **21.3** | **279.1** |
| **2016** | **2.6** | **281.6** |
| **2017** | **2.7** | **284.3** |
| **2018** | **2.9** | **287.2** |
| **2019** | **3.1** | **290.4** |
| **2020** | **3.3** | **293.7** |
| **2021** | **3.5** | **297.2** |
| **2022** | **3.7** | **300.9** |
| **2023** | **3.9** | **304.9** |
| **2024** | **4.2** | **309.1** |
| **2025** | **4.3** | **313.4** |

### Incremental 20 Year Portfolio Cost

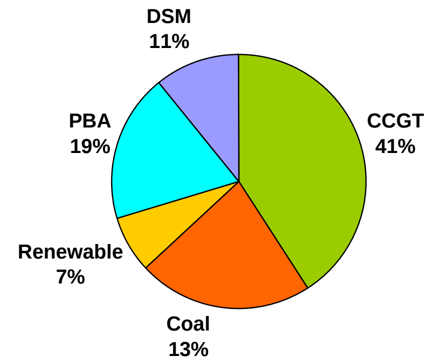
| Static | $ (Millions) |
|---|---|
| **Revenue from Power Sales** | (379) |
| **Cost of Power Purchase** | 994 |
| **EE and Fuel Conv Revenue Requirement** | 588 |
| **Generic Revenue Requirement** | 4,983 |
| **Variable Cost of Existing Fleet** | 959 |
| **End Effects** | 425 |
| **Expected Cost** | 7,569 |

| Dynamic- 100 Trials | $ (Millions) |
|---|---|
| **Mean** | 7,497 |
| **95%** | 7,765 |
| **5%** | 7,126 |
| **Avg. > 90%** | 7,804 |

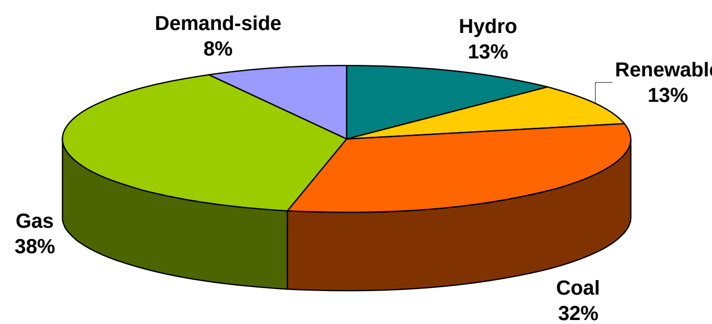
# 2006-2025 Resource Strategy

| Year | 2006-2025 Resource Strategy Cumulative AMW | | | | |
|---|---|---|---|---|---|
| | Renewable | DSM | Coal | PBA | CCGT |
| 2006 | 0 | 35 | 0 | 94 | 94 |
| 2007 | 32 | 69 | 0 | 94 | 94 |
| 2008 | 64 | 100 | 0 | 94 | 94 |
| 2009 | 96 | 129 | 0 | 94 | 94 |
| 2010 | 96 | 158 | 0 | 94 | 94 |
| 2011 | 117 | 185 | 0 | 188 | 188 |
| 2012 | 139 | 211 | 0 | 428 | 428 |
| 2013 | 160 | 235 | 0 | 499 | 499 |
| 2014 | 160 | 258 | 0 | 537 | 537 |
| 2015 | 160 | 279 | 0 | 553 | 553 |
| 2016 | 192 | 282 | 263 | 0 | 816 |
| 2017 | 192 | 284 | 345 | 0 | 898 |
| 2018 | 192 | 287 | 397 | 0 | 950 |
| 2019 | 192 | 290 | 460 | 0 | 1,013 |
| 2020 | 192 | 294 | 467 | 0 | 1,020 |
| 2021 | 213 | 297 | 511 | 0 | 1,064 |
| 2022 | 213 | 301 | 543 | 0 | 1,096 |
| 2023 | 213 | 305 | 571 | 0 | 1,124 |
| 2024 | 213 | 309 | 583 | 0 | 1,136 |
| 2025 | 213 | 313 | 641 | 0 | 1,194 |

**2006-2025 Resource Addition Mix as Percentage of AMW**




**2025 Available Generation Existing and New Resources (Annual Average)**



# APPENDIX H
# GAS MODELS

## A. Gas Resource Modeling Capability

PSE has enhanced its ability to model gas resources for long-term planning and long-term gas resource acquisition since the 2003 Least Cost Plan filing. In August 2004, the Company acquired SENDOUT® and VectorGas™ from New Energy Associates. 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. VectorGas™ is an add-in that facilitates the ability to model price and load uncertainty. These valuable new tools enhance the Company's ability to ensure robust long-term resource planning and acquisition activities. The following provides a description of SENDOUT® and VectorGas™ followed by a detailed explanation of the uncertainty factors PSE modeled for VectorGas™.

## B. System Overview--SENDOUT® and VectorGas™

The SENDOUT® and VectorGas™ software products are an integrated tool set for gas resource analysis. SENDOUT® models the gas supply network and the portfolio of supply, storage, and transportation to meet demand requirements. VectorGas™ simulates uncertainties regarding weather and commodity prices using Monte Carlo methods. It then runs the SENDOUT® portfolio over many draws to provide a probability distribution of results from which to make decisions.

## C. SENDOUT®

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. Alternatively, 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). SENDOUT® 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 capacities and fixed costs in addition to 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 optimize the size of energy efficiency programs on an integrated basis with supply-side alternatives in a long-run resource mix analysis.

*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, and either natural or production gas) 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.

## D. VectorGas™

Monte Carlo modeling set-up, simulation (running just the draws for weather and price inputs), and optimizations (running each of the draws through SENDOUT®) is accomplished in the VectorGas™ module. In VectorGas™, the assumptions for weather and price uncertainty are defined below. Scenario data from SENDOUT® is exported to VectorGas™ which produces simulations and generates optimizations.

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. VectorGas™ utilizes the SENDOUT® network optimizer to provide a detailed dispatch for each Monte Carlo draw.

The advanced probability-based metrics yield a more insightful picture of the portfolio, and form the basis for risk-based resource decisions. The most common of these probability measures include: Expected Value (μ) - EV is then more meaningful than the traditional deterministic measure (total system costs, for example) for a normal scenario since it directly and proportionately captures the portfolio's response to the whole range of weather and price events. Variability (σ) – the level of variance for critical objectives (e.g., cost exposure) should be a key component when comparing portfolios. Probability (P) – measures the likelihood of a key event (10 percent to exceed $500 million annual costs, for example).

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.

Performing Monte-Carlo analysis in conjunction with the level of detail included in SENDOUT® for long-term resource planning requires a considerable degree of computing power. In addition to the SENDOUT® and VectorGas™ software, PSE also acquired additional hardware. VectorGas™ essentially runs on a server that is connected to 5 personal computers that are grid machines, all of which run the SENDOUT® linear programming model. VectorGas™ creates the Monte Carlo draws. Then, through distributed processing, it sends each draw to one of the 5 grid computers. When the grid machines complete analysis of a Monte Carlo draw, results are posted back to VectorGas™ and another process job is sent to the grid machine. This is a flexible system that operates over PSE's IT network.

*VectorGas™ Uncertainty Inputs*

VectorGas'™ 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 (thus demands) 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 needed for VectorGas™ and explains the analysis used to define each factor.

*Uncertainty Factors for VectorGas™*

The following is a list and brief description of each input needed for Vector Gas to create reasonable sets of scenarios:

- 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 65 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 HDDs 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, this measure can be considered the average of daily gas prices prior to factoring in effects of daily temperature.
- Standard Deviation of Monthly Price Draw: This is a measure of the variability of prices at each basin, such as at AECO. VectorGas™ uses standard deviation expressed in dollars. A different standard deviation can be assigned to each month for the planning period.
- Temperature to Price Correlations at each basin: Ensures that a reasonable relationship exists between prices and temperatures in each Monte Carlo scenario. Linear/simple temperature to price correlation coefficients are used in VectorGas™ and a different value can be assigned to each month.
- Price to Price Correlations between basins: Ensures reasonable relationships for prices between each basin for the Monte Carlo scenarios. Linear/simple temperature to price correlation coefficients are used in VectorGas™.
- Daily Price to Temperature Coefficients: Daily temperatures drive changes from the monthly price draw. Daily price is modeled as an exponential function of daily temperature and has the ability to include a second level of sensitivity to model a price “blow-out” due to an extreme temperature.

*Basis of Each Uncertainty Factor*

Expected Monthly HDD: PSE is using the average monthly HDD for each month based on temperature data going back to January of 1950, in VectorGas™. 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 back to 1950 noted 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 from the coldest month in the historical period. The next version of VectorGas™ is scheduled to have a matching feature to select the daily pattern from the period that best fits the monthly HDD draw—a feature included at PSE's request.

Expected Monthly Price Draw: CERA's Rearview Mirror gas price forecast was used as the expected monthly price draw in VectorGas™ for AECO, Sumas, Rockies, and San Juan price points.

Standard Deviation of Monthly Price Draw: Historical data was used to establish the range of variability for each price basin. For 2004, standard deviations were calculated based on the average daily gas price, as published in Gas Daily through 1999. The average daily price at Sumas for December 2000 was adjusted based on the historical correlation of Sumas to Rockies prices, as Sumas prices during that period were more than double Rockies prices and would significantly increase assumed variability. Gas Daily price data for all four supply basins was readily available back to 1999, and daily prices at some points was available further back. Selecting a consistent time period for all four basins provides a reasonably consistent basis for calculating the standard deviation.

Temperature to Price Correlations: Historic price correlations for each supply basin to SeaTac HDD were calculated. There are a number of different ways such correlations could reasonably be calculated. For VectorGas™, the correlation between HDD and prices was calculated based on daily temperatures and daily prices by season. Then the strongest positive seasonal correlation was selected. As one would expect, the correlations produced using this approach shows a positive, but weak correlation of prices at Sumas, AECO, Rockies, and San Juan to SeaTac temperatures. Additional analysis of temperatures in other locations may show a tighter correlation, such as temperatures in Chicago and prices at AECO. This is an issue that will be investigated as part of the Company's two year action plan.

Price Correlations between Basins: Similar to the price to weather correlations, price to price correlations were calculated seasonally. As described in the section on price standard deviations, correlations between average daily gas prices by month for the winter and non-winter seasons were correlated using daily price information back to 1999, including the adjustment for Sumas prices during December 2000. Price correlations between supply basins are strongly positive, which is to be expected given the infrastructure in the Pacific Northwest.

Temperature Effects on Daily Price-Normal Variation: Deviations between daily price and monthly price draw in VectorGas™ are driven solely by daily HDD, which is a combination of the monthly HDD draw and daily shape, as noted above. Effects of daily temperatures are modeled as an exponential effect on prices, as daily temperature moves up and down relative to the average daily temperature. A different daily price/temperature factor was calculated for each month of the year and applied to the full 20-year period. To calculate the daily price-temperature factor, a target standard deviation of daily prices was selected. Then the factor estimated that, when applied to expected daily temperatures and the 20-year average monthly price, it would result in Vector Gas daily prices exhibiting the target standard deviation. The target standard deviation was calculated as the average standard deviation of daily prices, by month, with the December 2000 price adjustment as noted above in the standard deviation discussion.

Temperature Effects on Daily Price-Jump Statistics: The jump statistics to estimate a price blow-out require defining the temperature threshold at which such daily price events can occur, the probability of occurrence if that temperature threshold is exceeded, and the magnitude of the blow-out. Using daily price data back to 1999 as discussed above, the first step was to develop a definition of "price blow-out." Analysis of the data shows a few instances where daily prices exceed the daily average price by more than 40 percent. This was used as the definition of a blow-out event. The warmest temperature at which daily prices exceeded the average daily price for the month occurred at 21 HDD (39 degrees average daily temperature). The probability of a jump event occurring was calculated by examining the number of days that a jump event occurred at each basin, divided by the total number of days in the historic period with HDD at 21 HDD or higher. For example, during the period, there were 257 days where HDD was 21 HDD or greater. Daily prices were 40 percent or greater on 9 of those days. Thus, at the HDD threshold of 21 HDD, the probability of a jump event occurring was calculated to be 9/257= 3.5 percent. If the jump occurred, the magnitude was calculated as follows: When the spread between daily prices exceeded average daily prices by 40 percent or more, the average percentage increase was used. For Sumas, this was a jump multiplier of 1.53.

# APPENDIX I
# GAS PLANNING STANDARD

In its 2003 Least Cost Plan, PSE changed its gas supply peak day planning standard from 55 heating degree days (HDD)[1], which is equivalent to 10ºF or a coldest day on record standard, to 51 HDD, which is equivalent to 14ºF 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 Least Cost Plan.

PSE has completed a detailed cost-benefit analysis that considers customers' value of reliability of service with the incremental costs of the resources necessary to provide that reliability at various temperatures. Based on the analysis, described below, PSE has determined that it would be appropriate to increase its planning standard from 51 HDD (14ºF) to 52 HDD (13ºF).

## A. Overview of Analytical Method

PSE performed a comprehensive cost-benefit analysis, examining the level at which the cost of added reliability exceeds the benefit. To do this, the incremental costs and benefits of planning standards ranging from 47 to 55 HDD were estimated using 20-year model runs from U-Plan-G. These model runs incorporated assumptions from the August 2003 Least Cost Plan update.[2]

## B. Estimating Incremental Benefit of Reliability Standards

The benefit of an increased peak day planning standard is outage costs avoided. Outage cost estimates are comprised of the following components:

1. Loss of Consumer Surplus

   Consumer surplus refers to the value that firm customers lose in the event of an outage.[3]

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[1] The concept of heating degree days (HDD) was developed by engineers as an index of heating fuel requirements. They found that when the daily mean temperature is lower than 65 degrees, most buildings require heat to maintain an inside temperature of 70 degrees. Thus, an HDD number represents the following equation: 65 – the average daily temperature = HDD.

[2] See *Sensitivities* section at the end of this discussion.

[3] In Washington Natural Gas's (WNG) 1995 Least Cost Plan, the Company reported market research into the value that residential customers place on reliability. This analysis uses the results of that research. See discussion beginning on page IV-41, WNG's 1995 Least Cost Plan.

2. Cost of Re-lights

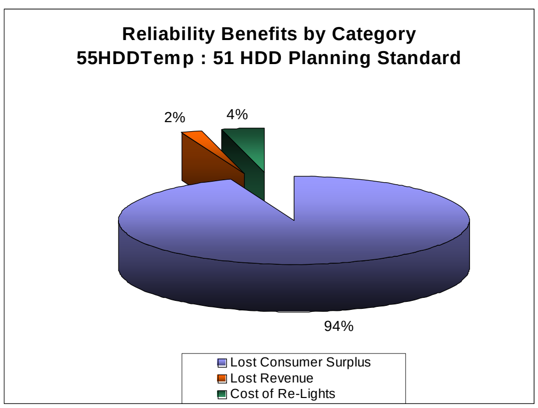
   When service to firm customers is interrupted, the Company is required to dispatch a representative to each customer's location to re-light pilot lights prior to reinstating service. This can increase the duration of an outage.[4]

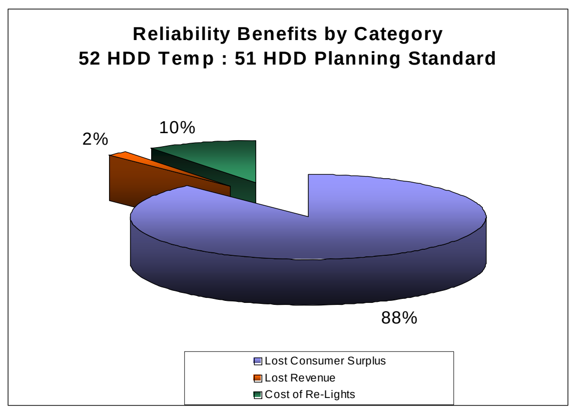
3. Lost Revenue

   When service is curtailed, customers are not paying per-therm charges.

Exhibit I-1 illustrates the makeup of outage costs at 52 and 55 HDD when planning is based on a 51 HDD standard.

**Exhibit I-1**
**Components of Outage Costs**




Once expected outage costs have been calculated, the incremental benefit of reliability is obtained by multiplying the expected cost of an outage at each planning standard by the likelihood of its occurrence. The difference in expected cost from one planning level to the next is the incremental benefit of reliability.[5] Exhibit I-2 displays these results.

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[4] The cost and rate of re-lights used for this analysis were discussed with and verified by PSE's Operations department.

[5] i.e., the benefit of outage costs avoided

**Exhibit I-2**
**Outage Costs and Incremental Benefit of Reliability**

| Planning Standard | Levelized Expected Cost of Outages | Levelized Incremental Benefit of Increasing One Planning Level |
|---|---|---|
| 47 HDD (18° F) | $ 12,404,590 | |
| 48 HDD (17° F) | $ 7,208,714 | $ 5,195,876 |
| 49 HDD (16° F) | $ 3,876,392 | $ 3,332,322 |
| 50 HDD (15° F) | $ 1,849,700 | $ 2,026,693 |
| 51 HDD (14° F) | $ 680,449 | $ 1,169,251 |
| 52 HDD (13° F) | $ 145,373 | $ 535,076 |
| 53 HDD (12° F) | $ - | $ 145,373 |
| 54 HDD (11° F) | $ - | $ - |
| 55 HDD (10° F) | $ - | $ - |

## C. Estimating Incremental Cost of Reliability Standards

Each planning standard has a corresponding optimal portfolio. The cost of reliability is the combined cost of resources and how they are dispatched within the portfolios needed to meet different planning levels. U-Plan-G was used to estimate optimal, 20-year levelized portfolio costs at each planning criterion. The model ran incrementally using a 47 HDD planning criterion, a 48 HDD planning criterion and so on, through a 55 HDD planning criterion.[6] Exhibit I-3 shows the incremental cost of reliability at each planning standard.

**Exhibit I-3**
**20-Year Portfolio Costs at Different Reliability Levels**

| | 20-Year Levelized Portfolio Cost | Incremental Cost to Increase One Planning Standard |
|---|---|---|
| 47 HDD (18° F) | $526,212,391 | |
| 48 HDD (17° F) | $526,451,036 | $238,645 |
| 49 HDD (16° F) | $526,711,834 | $260,798 |
| 50 HDD (15° F) | $527,134,870 | $423,036 |
| 51 HDD (14° F) | $527,344,659 | $209,789 |
| 52 HDD (13° F) | $527,799,812 | $455,153 |
| 53 HDD (12° F) | $529,484,590 | $1,684,778 |
| 54 HDD (11° F) | $532,016,091 | $2,531,502 |
| 55 HDD (10° F) | $534,847,249 | $2,831,158 |

[6] Resource and cost assumptions are consistent with PSE's August 2003 LCP Update. Updating market prices would affect the total but would not affect incremental costs.

## D. Cost vs. Benefit of Reliability

Comparing incremental benefits with incremental costs at various planning levels reveals that the benefit of increasing PSE's planning standard from 51 (14º F) HDD to 52 (13º F) HDD is greater than the cost. As indicated in Exhibit I-4, the benefit increases by $535,076, while cost increases by $455,153.[7]

Beyond 52 HDD, the added costs would exceed the benefits. Therefore, PSE has elected to adopt a 52 HDD standard.

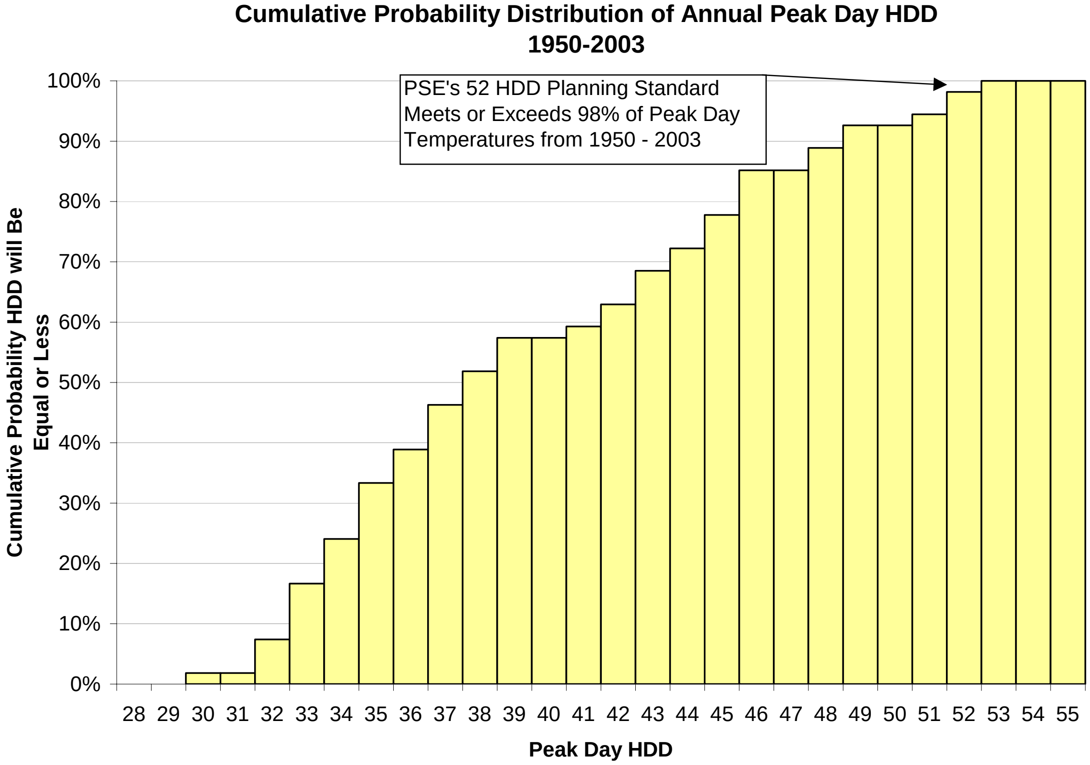
**Exhibit I-4**
**Incremental Benefits and Costs of Reliability**

| Planning Standard | Incremental Benefit | Incremental Cost | Benefit/Cost Ratio |
|---|---|---|---|
| 48 HDD (17° F) | $ 5,195,876 | $238,645 | 21.8 |
| 49 HDD (16° F) | $ 3,332,322 | $260,798 | 12.8 |
| 50 HDD (15° F) | $ 2,026,693 | $423,036 | 4.8 |
| 51 HDD (14° F) | $ 1,169,251 | $209,789 | 5.6 |
| 52 HDD (13° F) | $ 535,076 | $455,153 | 1.2 |
| 53 HDD (12° F) | $ 145,373 | $1,684,778 | 0.1 |
| 54 HDD (11° F) | $ - | $2,531,502 | - |
| 55 HDD (10° F) | $ - | $2,831,158 | - |

The 52 HDD planning standard provides a reasonable degree of planning cushion for firm customers. Exhibit I-5 illustrates that based on temperature data at Seatac from 1950-2003, the 52 HDD planning standard will meet or exceed 98 percent of historic peak day temperatures.

[7] This added cost translates to an increase in consumer rates of approximately $0.50 per customer per year.

**Exhibit I-5**




## E. Sensitivities

PSE tested three variables for sensitivity to ensure that the value of reliability was not overstated.

- Value of reliability to customer (consumer surplus)
- Impact of lost margin
- Effect of the cost and timeliness of re-lights

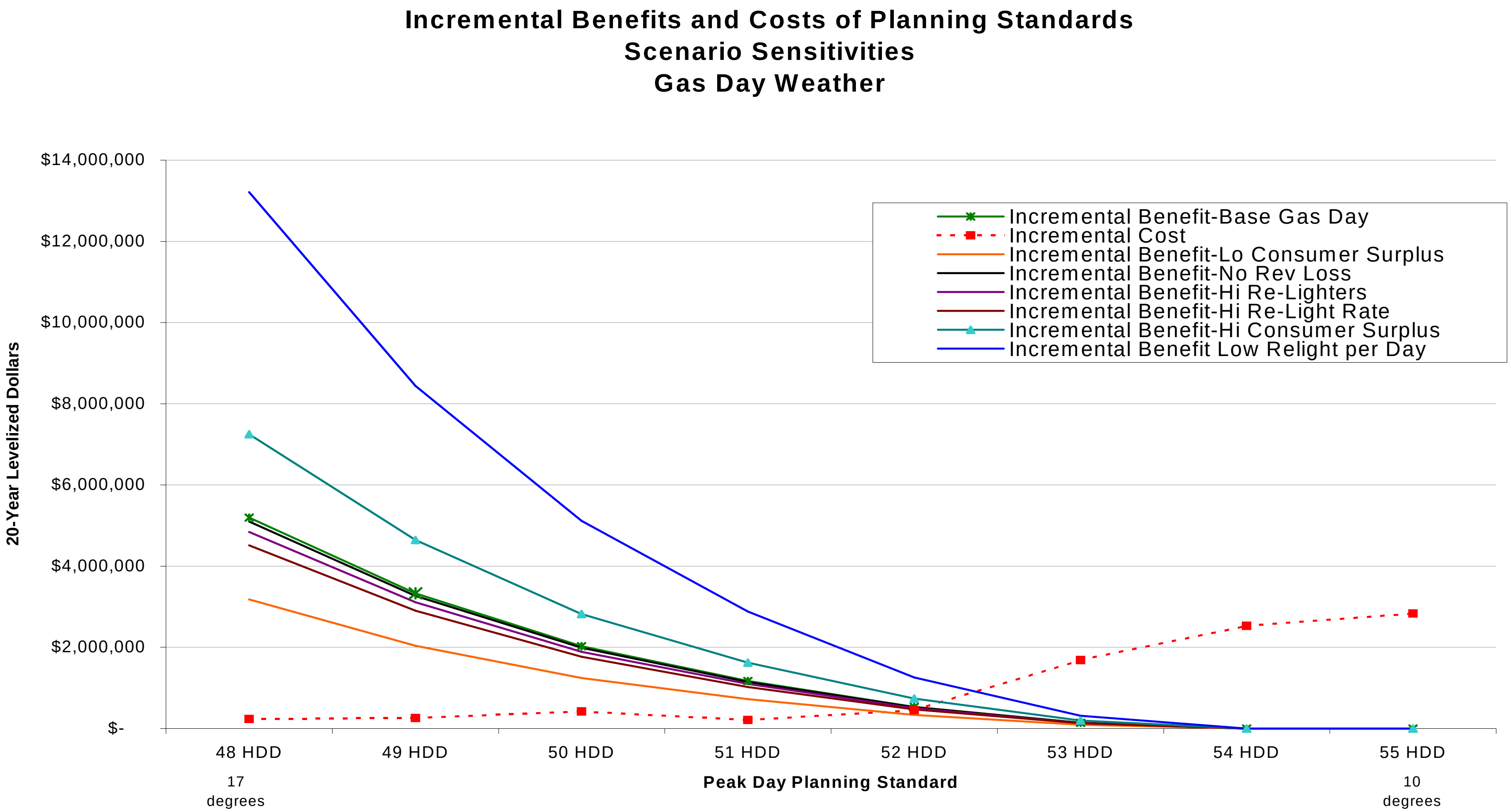
Exhibit I-6 illustrates the results of this testing, which support a decision to increase PSE's planning standard from 51 to 52 HDD.

**Exhibit I-6**
**Efficient Standards for Sensitivity Variables**

| SENSITIVITIES/ASSUMPTIONS | EFFICIENT STANDARD |
|---|---|
| Base Case | 52 HDD |
| High Consumer Surplus | 52 HDD |
| Low Consumer Surplus | 51 HDD |
| No Lost Revenue | 52 HDD |
| Fast Rate of Re-lights and Low Cost | 52 HDD |

Only the Low Consumer Surplus variable indicates that the benefit of moving to a 52 HDD standard falls slightly below the cost. Exhibit I-7 is a chart that illustrates the incremental benefits and costs of the various sensitivities. Given that the magnitude of the shortfall in the Low Consumer Surplus is minimal, it did not affect PSE’s decision to adopt a 52 HDD planning standard.

## Exhibit I-7

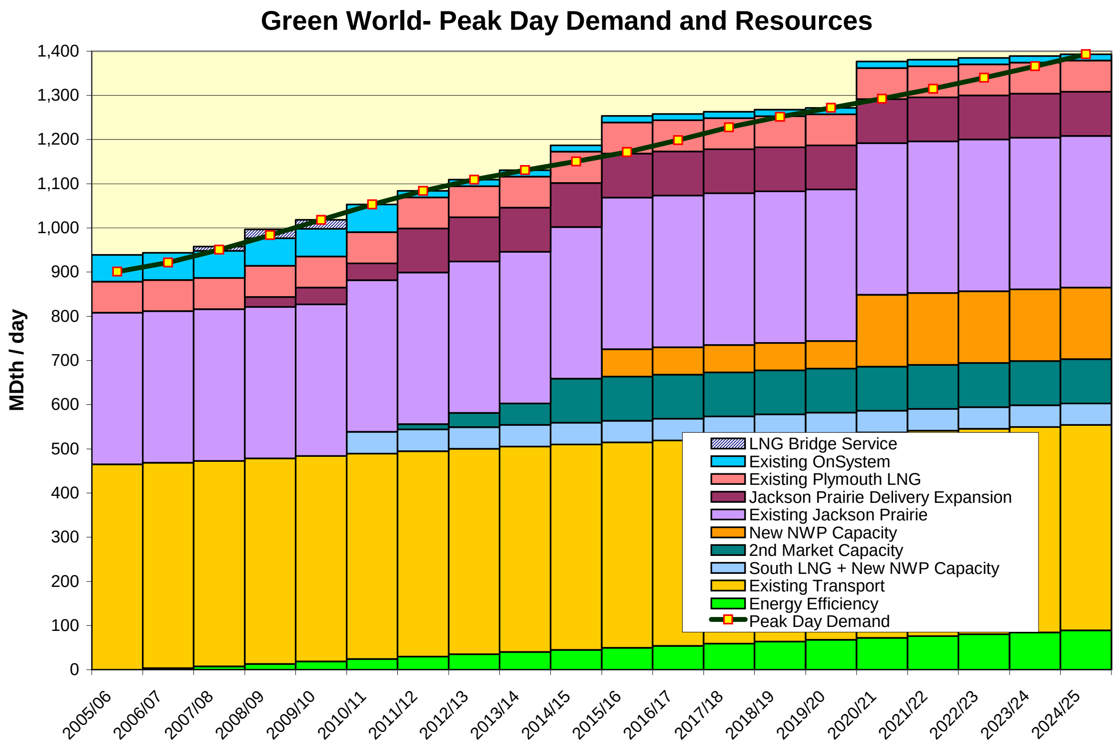



This chart indicates increasing PSE's peak-day planning standard to 52 HDD is supported by all scenarios except the Low Consumer Surplus scenario. The Low Consumer Surplus scenario falls just short of the 52 HDD threshold and supports the current 51 HDD standard.

# APPENDIX J

# ADDITIONAL GAS ANALYSIS RESULTS

## Exhibit J-1
## Optimal Resource Mix: Green World Scenario



# Exhibit J-2
# Optimal Resource Mix: Strong Economy Scenario

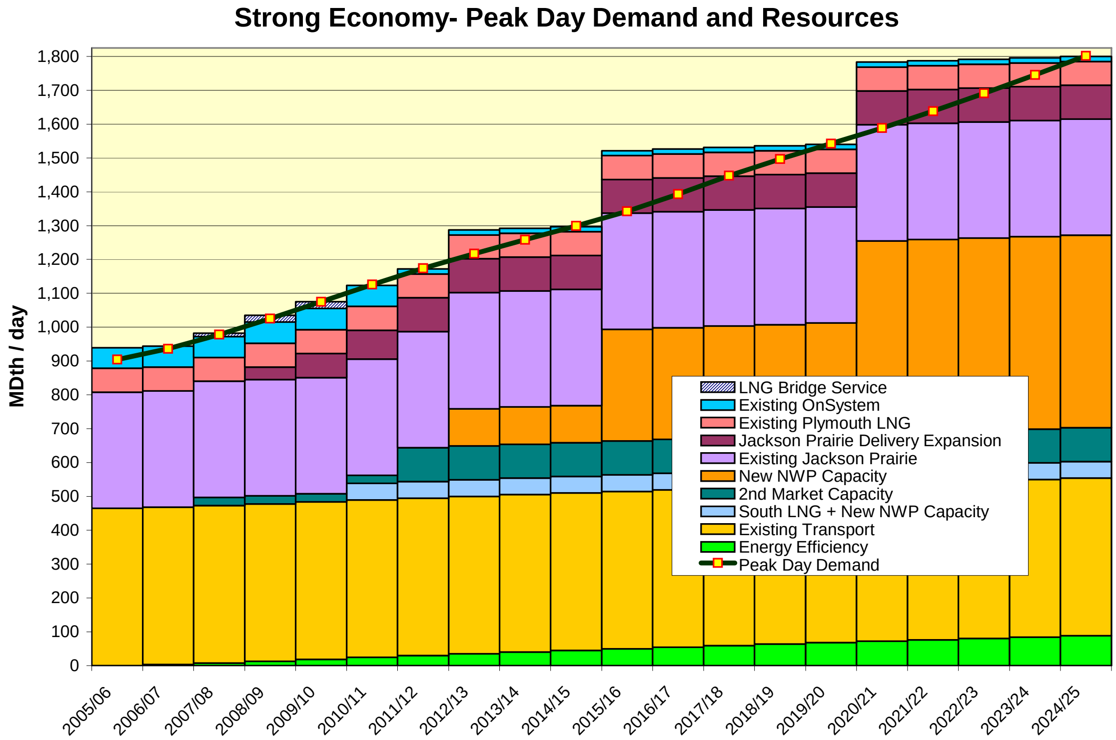
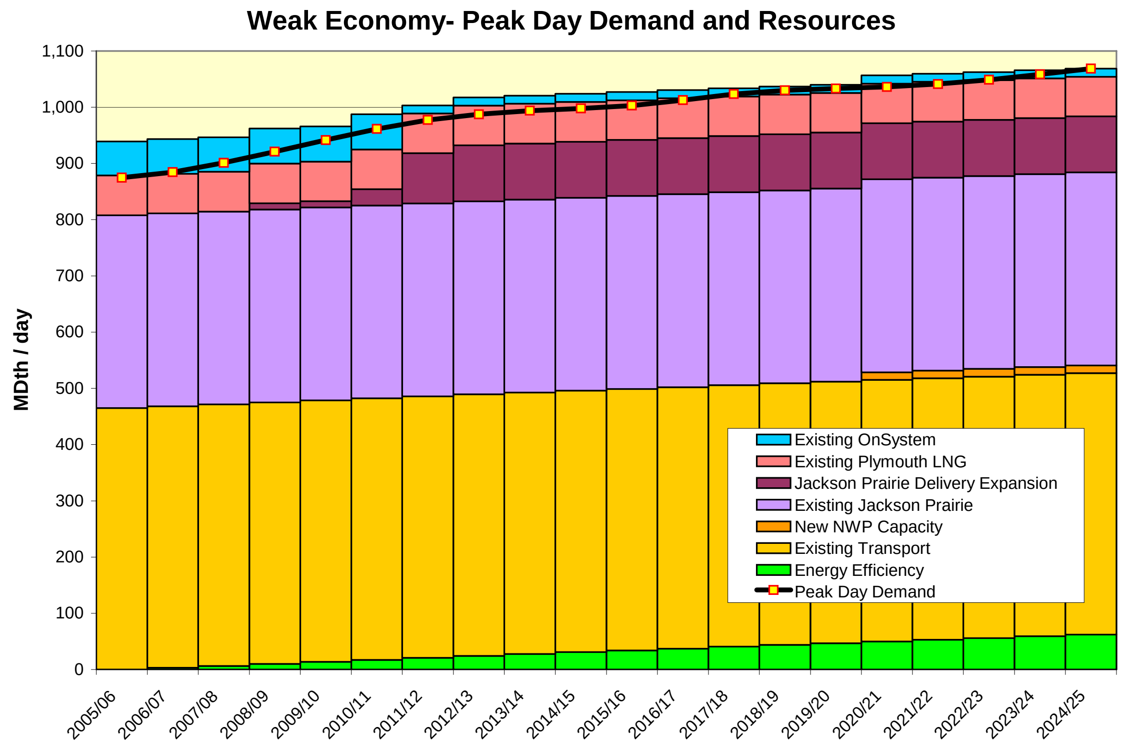


**Exhibit J-3**
**Optimal Resource Mix: Weak Economy Scenario**



## Exhibit J-4
## Optimal Resources: Generation Fuel Portfolio

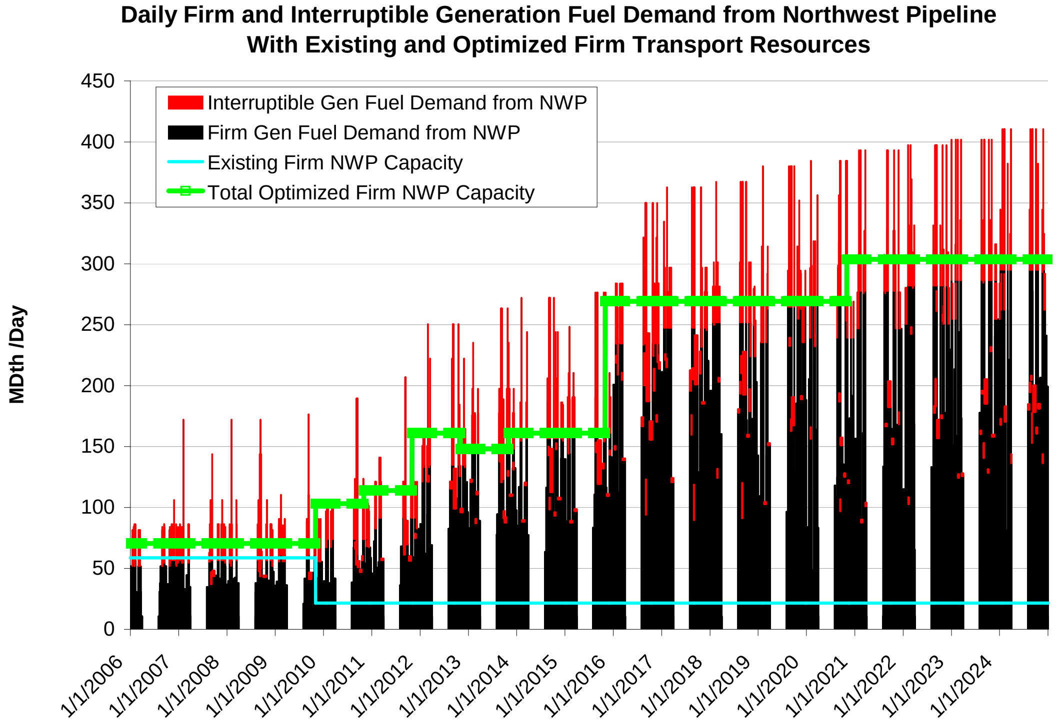
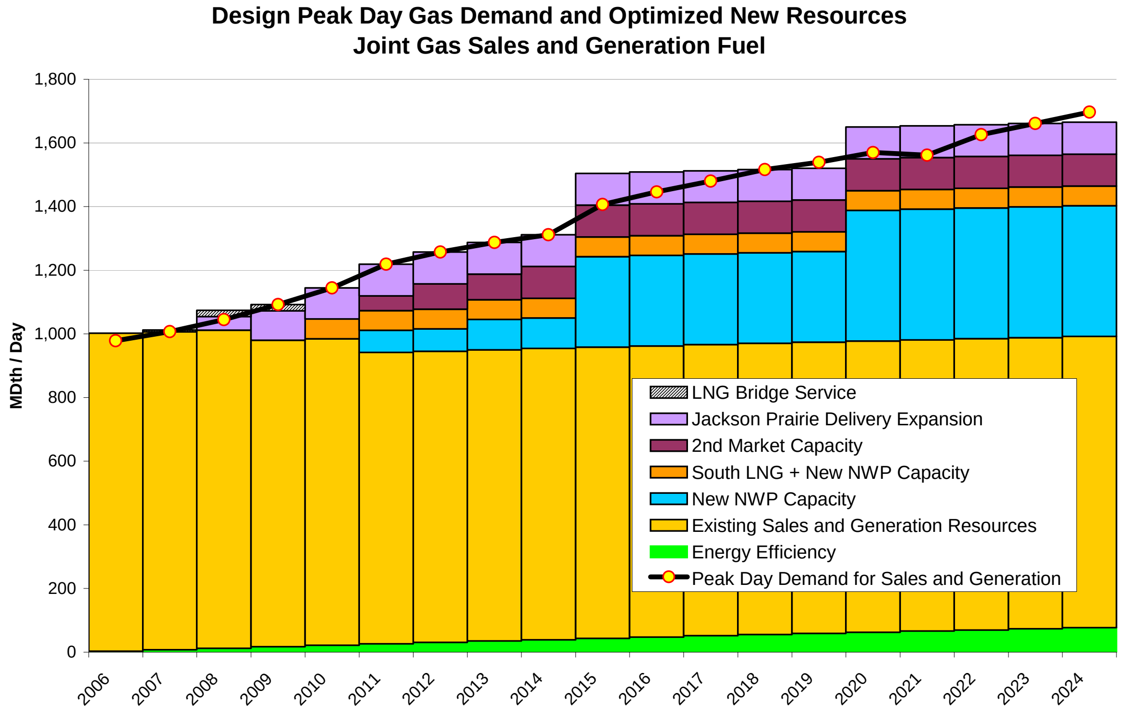


**Exhibit J-5**
**Optimal Resource Mix: Joint Sales and Generation Fuel Portfolio**

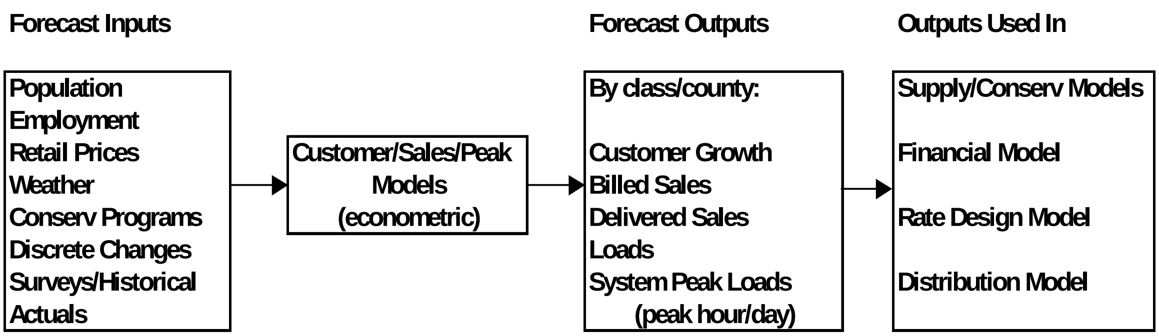


# APPENDIX K
# DESCRIPTION OF THE LOAD FORECASTING MODELS

This appendix provides a more detailed technical description of the three econometric methodologies used to forecast a) billed energy sales and customer counts, b) system peak loads for electric and gas and c) hourly distribution of loads. The econometric approaches for billed sales, customer counts and peak loads for electric and gas are presented in section 1, while the hourly distribution of loads approach is presented in section 2.

*Section 1: Billed Sales, Customer Count and Peak Load Forecast Methodologies*

**Exhibit K-1**
**PSE ECONOMETRIC FORECASTING MODEL**




For the 2005 LCP, PSE made two types of enhancements to the model over the 2003 LCP version. The enhancements improved the equation formulation or estimation method, and added capabilities to the model. Following is a summary of these enhancements:

- Distinguished electric temperature sensitivity by season, revised all equations
- Improved peak hour/day equations for electric and gas, respectively
- Revised definition of normal weather from average of 30-year hourly temperatures to average of 30-year daily heating or cooling degree days
- Converted “electric billed” to “delivered sales by class” in order to account for unbilled
- Geographically allocated sales/customers into counties
- Accounted for forecast risks/uncertainties using scenarios for sales and Monte Carlo simulations of peaks for weather risks

The first three bullets are enhancements to the equation formulation and estimation method, which improved the accuracy and relevance of the forecast outputs, while the last three bullets are added capabilities to the model to enable PSE to produce delivered sales forecasts for peak load forecasting and to determine where load growth is occurring in the service territory.

*Equations for Electric or Gas Billed Sales*

The following use-per-customer and customer equations were estimated using historical data from January 1990 to December 2003, depending on the sector and fuel type. The forecast of billed sales uses the estimated equations, normal weather assumptions together with the forecasts of rates, and various economic and demographic inputs.

$$\mathbf{UsePerCust_{c,m} = f(RetailRates_{c,m}, Weather_{c,m}, EcoDemo_{c,m}, MonDummies)}$$

$$\mathbf{CustCount_{c,m} = f(EcoDemo_{c,m}, MonDummies)}$$

where $\mathbf{UsePerCust_{c,m}}$ = use (billed sales) per customer for class c, month m

$\mathbf{CustCount_{c,m}}$ = customer counts for class c, month m

$\mathbf{RetailRates_{c,m}}$ = effective real retail rates for class c in polynomial distributed lag form of various lengths

$\mathbf{Weather_{c,m}}$ = class appropriate weather variable, cycle adjusted HDD/CDD using base temps of 65, 60, 45, 35 for HDD and 75 for CDD; cycle adjusted HDDs/CDDs are created to fit consumption period implied by the billing cycles

$\mathbf{EcoDemo_{c,m}}$ = class appropriate economic and demographic variables; variables could be income, household size, population, employment levels or growth, building permits

**MonDummies** = monthly binary variables

Given the forecast of use per customer and customer counts above, the billed sales forecast for each customer class is the product of two components: use per customer and number of customers for each class, as shown below.

$$\mathbf{BilledSales_{c,m}} = \mathbf{UsePerCust_{c,m} \times CustCount_{c,m}}$$

Different functional forms were used depending on the customer class. For the electric residential use-per-customer equation, a semi-log form was used with the explanatory variables (prices and demographic variables) entering in polynomial distributed lagged form. The length of the lag depends on the customer class equation, with residential having the longest lags. A double log form was used for the other sectors, again with explanatory variables entering in a lagged form. Lagged explanatory variables in the equations account for changes in prices or economic variables that have both short-term and long-term effects on energy consumption. For gas, most of the use-per-customer equations have a linear form with prices or economic variables entering in polynomial distribution lagged form again.

Exhibit K-2, based on the estimated coefficients for the retail prices in the use-per-customer equations, provides the computed long-term price elasticity for the major customer classes for electric and gas.

**Exhibit K-2**
**Long-Term Price Elasticity for Major Customer Classes**

| | Electric | Gas |
|---|---|---|
| Residential | -.19 | -.09 |
| Commercial | -.16 | -.08 |
| Industrial | -.19 | -.10 |

*All of the estimated price coefficients are also statistically significant.*

Electric customer forecasts by county were also generated by estimating an equation relating customer counts by class/county, and population or employment levels in that county. In producing the county level forecasts, a restriction was imposed so that the sum of forecasted customers across all counties equaled the total service area customer counts forecast. This projection is an input into the distribution planning process.

The billed sales forecast was further adjusted for discrete additions and deletions not accounted for in the forecast equations. These adjustments include the company's forecast of new programmatic conservation savings for each customer class, known large additions/deletions or fuel switching, and schedule switching. Finally, total system loads were obtained by distributing monthly billed sales into cycle sales, then allocating the 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 PSE to compute the unbilled volumes each month

*Electric Peak-Hour Load Forecast*

PSE uses an hourly regression equation to obtain monthly peak load forecasts. This equation provides "normal" and "extreme" peak loads for both residential and non-residential sectors. 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, are all variable conditions modeled by the equation. PSE estimated the equation using monthly data from January 1991 to February 2004. The historical data includes a period when large industrial customers opted to leave firm customer classes to join the transportation-only rate class the equation also accounts for this change in historical series. Finally, PSE allows the impact of peak temperature on peak loads to vary by month. This specification allows for different effects of residential and non-residential loads on peak demand by season, with and without conservation. It also allows PSE to account for the effects of different customer classes on peak loads. The functional form of the electric peak-hour equation is displayed below:

$$\textbf{Peak MW} = \sum_i a_i \text{*Resid aMW*MoDum}_i + \text{b*Non-Resid aMW}$$
$$+ \sum_{i \neq 7,8} c1_i \text{*(Normal Mly Temp-Peak Hr Temp)*(WeathSensitv aMW)*MoDum}_i$$
$$+ \sum_{i = 7,8} c2_i \text{*(Normal Mly Temp-Peak Hr Temp)*(Coml aMW)*MoDum}_i$$
$$+ \text{d*Sched48Dummy} + \sum_i e_i \text{*WkDayDum}_i + \text{f*ColdSnapDummy}$$

where a, b, c1,c2, d, e, f are coefficients to be estimated.

Peak MW = monthly system peak-hour load in MW
ResidaMW = residential delivered sales in the month in aMW
Non-ResidaMW = commercial plus industrial delivered sale in the month in aMW
Normal Mly Temp-Peak Hr Temp = deviation of actual peak-hour temp from monthly normal temp
WeathSensitv = residential plus a % of commercial delivered loads
Sched48Dummy = dummy variable for when customers in schedule 48 became transport
WkDayDum = day of the week dummy
MoDum = monthly dummy

ColdSnapDummy = 1 if the min temp the day before peak day is less than 32 degrees

These equations are estimated to account for truncation or censoring effects due to some customers being out of service during cold events. To obtain the normal and extreme peak load forecasts, PSE factors the appropriate design temperatures into the equation for either condition. For PSE, these design temperatures are 23 degrees for "normal" peak and 13 degrees for "extreme" peak. Peak hourly loads are also produced for 16 degrees Fahrenheit.

*Gas Peak-Day Load Forecast*

Gas peak day is assumed to be a function of the weather sensitive delivered sales, the deviation of actual peak day average temperature from the monthly normal average temperature, and other weather events. The following equations were estimated using monthly historical data from October 1996 to March 2004, to represent peak day firm requirements:

**Peak DThm** = a*FirmDThm + b*(Normal Mly Temp-Peak Day AvgTemp)*(Firm DThm)

+ c*ElNino + d*WinterDum + e*SummerDum + f*ColdSnapDummy

where a, b, c, d, e, and f are coefficients to be estimated.

Peak DThm = monthly system gas peak day load in decatherms
FirmDThm = monthly delivered loads by firm customers
Normal Mly Temp-Peak Day AvgTemp = deviation of actual peak day aver daily temp from monthly normal temp
ElNino = dummy for when ElNino is present during the winter
ColdSnapDummy = binary variable for when the peak occurred within a cold snap period lasting more than one day, multiplied by the minimum temps for the day
WinterDum, SummerDum = winter or summer dummy variable to account for seasonal effects

This formulation for gas peak-day load accounts for changes in use per customer consistent with those use-per-customer changes in the billed sales equation. This feature was not available in the last Least Cost Plan because the base and weather sensitive use per customer in that equation were not a function of the key demand drivers such as economic inputs, retail rate inputs and conservation. The other advantage of this formulation is the ability to account for the effects of conservation on peak loads, and for the contribution of customer classes to peak loads. The estimation method further accounts for truncation biases to recognize that some firm customers may have been out of service during some cold events.

The design peak day requirements for this forecast are based on meeting a 52 heating degree day (13°F average temperature for the day), based on the analysis of the costs and benefits of meeting a higher or lower design day temperature. Thus, using the projected delivered loads by class and this design temperature, a forecast of gas peak day load can be estimated.

*Section 2: Creation of an Hourly Electricity Demand Profile*

PSE updated its hourly (8760 hours) load profile of electricity demand to be used for the Least Cost Plan, Power Cost calculation, and other AURORA analysis. This hourly profile replaces a previous electricity demand profile developed in 2002 with use of the hourly electricity demand modeling program: HELM (Hourly Electric Load Model). The new distribution makes use of actual observed temperatures, recent load data, the latest customer counts, and improved statistical modeling.

<u>Data:</u> Hourly observed temperatures from 1/1/1950 to 12/31/2003 were used to develop a representative distribution of hourly temperatures. PSE’s actual hourly delivered electricity loads from 1/1/1994 to 12/16/2004 were used to develop the statistical relationship between temperatures and loads for use in estimating the hourly electricity demand based on the representative distribution of hourly temperatures.

<u>Methodology for distribution of hourly temperatures</u>

The above described temperature data was sorted and ranked to provide two separate data sets: 1) For each year, a ranking of the hourly temperatures by month: coldest to warmest. The average for 54 years' worth of monthly temperature data, ranked coldest to warmest, is calculated. 2) A ranking of the times when the temperatures occurred by month: coldest to warmest. These hourly time rankings were averaged to provide an expected time of occurrence.

The next step was to find the hours most likely to have the coldest temperatures (based on the observed averages of the rankings of coldest to warmest hour times) and match them up with the average coldest to warmest temperatures, by month. Sorting this information into a traditional time series then gives us the representative hourly profile of temperature.

Methodology for hourly distribution of load

For the time period 1/1/1994 to 12/31/2003, the following statistical regression equation was developed:

$Load_h = \alpha_w + \beta_1 * Load_{h-1} + \beta_2 * (Load_{h-2} + Load_{h-3} + Load_{h-4})/3 + \beta_3 * Month_m * temp_h$
$+\beta_4 * Month_m * (temp_h)^2 + \beta_5 * Holiday + \beta_6 * Linear\ Trend + AR(1)$

w = 1 to 7 (weekday)
h = 1 to 24 (hours)
m = 1 to 12 (months)
Holiday = NERC holidays

Using this regression equation, the load shape can be developed from the representative hourly temperature profile. The calendar variables for the load profile are derived to follow that of calendar year 2005.