Final Report

Comprehensive Assessment of Demand-Side Resource Potentials (2008-2027)

Prepared for:
Puget Sound Energy

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This study was a large and complex undertaking. New approaches had to be devised to meet its many conceptual and analytic challenges. It also required compilation of a large amount of data from multiple sources, including multiple departments within Puget Sound Energy. It would be difficult to overstate the contributions made by Puget Sound Energy's staff throughout the nine months of planning and research it took to complete this study—from formulating concepts to identification of appropriate data sources, to compilation of data, and to reviewing the results and providing constructive feedback. We are particularly grateful to Villamor Gamponia, Phillip Popoff, Aliza Seelig, Jay Jacobson, Bob Stolarski, Joel Jackman, Gurvinder Singh, Mary Smith and Eric Brateng.

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Overview

This report summarizes the results of an independent study of the potentials for electric and natural gas demand-side management (DSM) resources in Puget Sound Energy's (PSE's) service area from 2008 to 2027. The study was commissioned by PSE as part of its biennial integrated resource planning (IRP) process.

The study builds upon previous efforts and incorporates significant improvements with respect to scope of assessment and its methodology. As in previous studies, the focus of the assessment was on electric and natural gas energy efficiency potentials. The scope of the analysis for electric DSM resource potentials was expanded to include a full range of small-scale generation resources comprised of energy efficiency, demand response, fuel conversion, distributed generation, and emerging technologies for energy efficiency and distributed generation. Significant enhancements were also made in the methodology, particularly in technical characterization and economic valuation of resources. The methods used to evaluate the technical potentials for and cost-effectiveness of resources draw upon the best practices in the utility industry and are consistent with the methodology used by the Northwest Power Planning and Conservation Council in its assessment of regional conservation potentials in the Northwest.

Summary of the Results

The results of this study indicate cumulative "technical" energy conservation potentials of 799 average megawatts (aMW) of electric and 35 million Decatherms (Dth) of natural gas over the 20-year planning horizon from 2008 to 2027, from existing, mature energy efficiency and fuel conversion technologies (Exhibit 1).[1] Approximately 471 aMW of the electric and 11.2 million Dth of the natural gas conservation resources are expected to be cost effective, based on the total resource cost (TRC) criterion. Once normal market and program delivery constraints are taken into account, about 367 aMW (80%) and 6.9 million Dth (61%) of these resources may be reasonably achievable by the end of the 20-year planning period. An additional 54 aMW of energy savings are also expected to be achievable from emerging energy efficiency technologies (14 aMW) and existing and emerging distributed generation technologies (40 a MW).

The energy savings resulting from a full implementation of the identified demand-side resources represent 17% of total electric and 6% of gas loads in 2007, offsetting 38% and 21% of the projected 20-year growth in electric and gas demand.

In the electric sector, savings from *existing* energy efficiency technologies constitute the largest share (81%) of total savings potentials. The commercial sector accounts for the largest share of achievable electricity savings (168 aMW), followed by the residential sector with an achievable

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[1] All energy savings presented in this report are at the customer meter and do not include "upstream" adjustments for T&D system losses which would increase energy savings by 6.7% for electric and 0.8% for gas.

savings potential of 157 aMW. An additional 17 aMW of electricity savings are projected to be available from the firm-load segment of the industrial sector. An additional 14 aMW of savings is expected to be achievable through the implementation of *emerging* electric energy-efficiency technologies, not include in the IRP. Discretionary resources (i.e. retrofit opportunities) account for 238 aMW (70%) of the electric and 3.2 million Dth (44%) of natural gas energy-efficiency resources. The remaining potentials are associated with "lost-opportunity" resources, namely new construction and normal replacement of existing equipment at the end of their normal life cycle.

Exhibit 1. Base-Case Electric Technical, Economic and Achievable Potentials by Resource

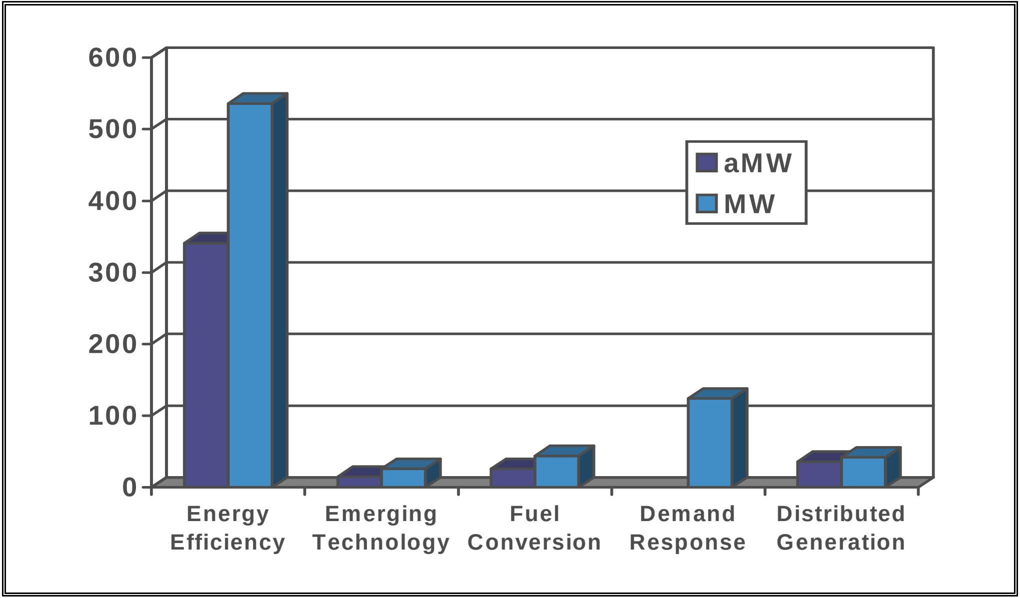
Resource	Technical Potential	Economic Potential	Achievable Potential
Electric Resources			
Energy Efficiency (aMW)	702	434	341
Energy Efficiency Emerging Technologies (aMW)	43	20	14
Fuel Conversion (aMW)	97	37	26
Demand Response (MW)	N/A	N/A	122
Distributed Generation (aMW)	N/A	N/A	36
Distributed Generation Emerging Technologies (aMW)	N/A	N/A	4
Total Energy Efficiency with Existing Technology			525
Total Energy Efficiency with Emerging Technology			543
Gas Resources			
Energy Efficiency (Dth)	35,109,050	11,181,275	6,919,508
Energy Efficiency Emerging Technologies (Dth)	526,124	464,183	377,898

Note: N/A indicates a potential was not calculated for this resource.

Conversion of residential space heating, water heating and appliances from electric to gas fuel are projected to provide the opportunity for acquiring an additional 26 aMW of electricity savings. Small-scale distributed generation technologies using fossil fuels (reciprocating engines, micro-turbines) and renewable sources (wind, solar, and biomass) are expected to offer additional load reductions of 40 aMW, about 4 aMW of which are expected to become available through emerging distributed generation technologies (Exhibit 2).

The identified electric demand-side management resources represent a significant contribution to PSE's future capacity requirements. As the results of this study suggest, if fully implemented, the energy savings from the identified resources are likely to reduce PSE's peak load by an equivalent of 648 MW by 2027, as measured at the meter. An additional reduction of 122 MW (at the meter) in peak capacity requirements may be achievable from demand-response options such as direct load control, demand buyback, curtailable tariffs, critical peak pricing and dispatchable standby generation. The combined effects of the peak impacts of energy-efficiency and demand-response resources may be expected to reduce PSE's 2027 peak capacity requirements by 11% (Exhibit 2). Additionally, due to the unique nature of DR resources, where two or more strategies can compete for the same customers and end uses, it is unlikely that all strategies can attain their individual potentials concurrently. Accounting for such interactions would lower the total available potential to 103 MW.

Exhibit 2. Year 20 Base-Case Electric Achievable Potential by Resource



Owing to the impacts of additional measures, particularly inclusion of emerging technologies, estimates of achievable electric energy efficiency potential are about 44 aMW (approximately 15%) higher than the 297 aMW from the 2005 assessment, or 30 aMW (10%) higher without emerging technologies. These results are largely in line with the regional estimates developed by the Northwest Power and Conservation Council. In its *5th Northwest Regional Electric Power and Conservation Plan*, the Council has estimated that 2,800 aMW of conservation is expected to be achievable regionally by the year 2025, which represents approximately 15% of the 2005 regional load. Based on the Council's "medium-case" forecast, regional conservation potentials represent slightly over 32% of the projected 6000 aMW growth in regional electricity demand from 2005 to 2025. Using 2005 as a basis for comparison, the achievable potentials identified in this study similarly amount to about 15% of PSE's 2005 load of 2,340 aMW. Based on the results of this study, by 2025 PSE is expected to account for approximately 14% of the regional load, and 12% of total regional achievable conservation potentials.[2]

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[2] Due to marked differences among local utilities in their customer mix, past conservation activity, load growth rate, and economic assumptions used in the determination of conservation potentials such as discount rates, a direct comparison between the regional and utility-specific estimates of conservation potentials is difficult, and may results in misleading conclusions.

The potentials for natural gas energy-efficiency resources are estimated at 7.3 million Dth, including 0.4 Dth from emerging technologies. The gas savings potentials are split almost evenly between discretionary and lost-opportunity resources. The majority of natural gas savings potentials are in the residential and commercial sectors, which together account for over 97% of total achievable energy-efficiency opportunities.

Achievable potentials for gas conservation are approximately 1,600 million Dth lower than those reported in the 2005 study, mainly as a result of lower technical potentials of 3,114 MDth due to updated end-use consumption indices based on new data, particularly in the residential sector. This difference is, however, mostly offset by the higher avoided costs and more aggressive market penetration assumptions.

Resource Costs

The total life-cycle costs for acquisition of the achievable potentials stand at approximately $1.1 billion for electric and $0.2 billion for gas resources in 2007 dollars, including 10% administrative expenses such as planning, program design, marketing, and on-going operation (Exhibit 3). Discretionary and lost-opportunity electric energy-efficiency savings from existing technologies account for the largest share (over 84%) of the total resource acquisition costs. The results of this assessment also show that the identified resources may be acquired at a weighted average levelized cost of $0.068 per kWh. Fuel conversion (at $0.03/kWh) and emerging energy-efficiency technologies (at $0.05/kWh) have the lowest levelized costs. Average levelized per-unit cost of conserved energy from energy-efficiency resources is estimated at or below $0.07 per kWh, and at a levelized per-unit cost of $0.76 per therm for gas resources (Exhibit 3). Distributed Generation has the highest levelized cost of energy (at $0.09/kWh).

Exhibit 3. Base-Case Resource Acquisition Costs (NPV and Levelized) by Resource

	Electric Resource		Natural Gas Resources	
Resource	20-Year NPV ($000)	Levelized Cost	20-Year NPV ($000)	Levelized Cost
Energy Efficiency	$ 929,762	$ 0.07 / kWh	$ 203,779	$ 0.76 / therm
Emerging Technologies	$ 21,378	$ 0.05 / kWh	$6,065	$ 0.34 / therm
Fuel Conversion	$ 21,314	$ 0.03 / kWh		
Demand Response	$ 73,881	$ 68 / kW		
Distributed Generation	$83,419	$ 0.09 / kWh		

Resource Availability under Alternative Scenarios

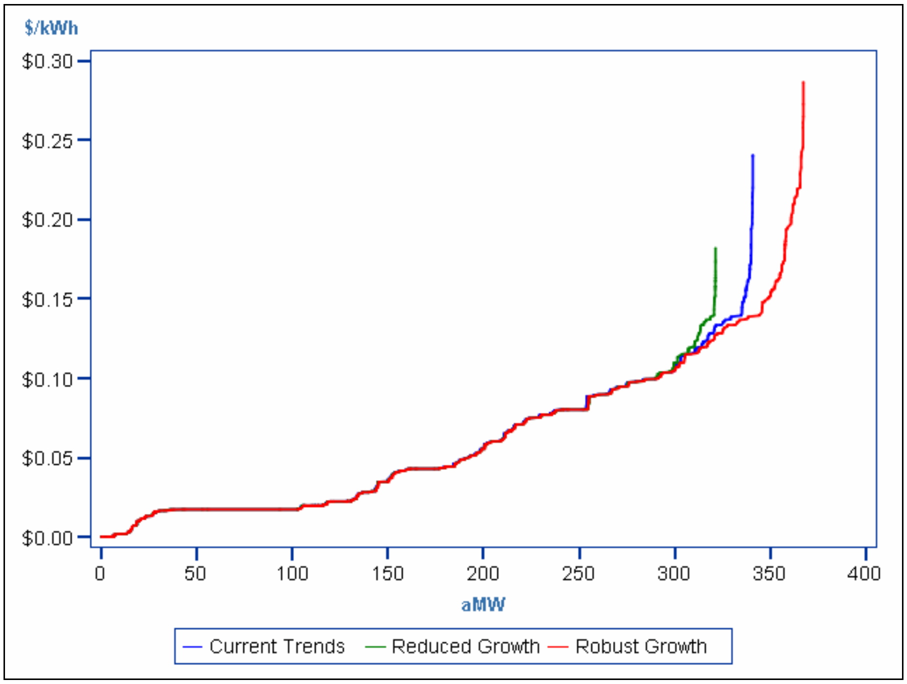
To provide additional perspective on future availability of DSM resources and to take into account uncertainties regarding future conditions in energy markets, resource potentials were estimated under alternative future scenarios with regard to their effect on resource costs. Five different scenarios were analyzed using a range of probable market prices. Estimates of energy efficiency potentials proved generally stable under various scenarios. In the electric sector, for example, a decline of nearly 20% from the highest to the lowest price scenarios was shown to result in a modest 6% decrease in energy efficiency potentials. (Exhibit 4). The results of the analysis indicates almost no effect on quantities of other DSM resources. This is largely due to the relatively low cost of many of the energy-efficiency measures.

Exhibit 4. Year 20 Electric Achievable Potential by Resource and Scenario

Resource	Base	Base + 25%	Base -10%	Green World	Low Growth
Average Avoided Cost ($/kWh)	$0.09	$0.11	$0.08	$0.10	$0.08
Energy Efficiency (aMW)	341.0	367.0	330.0	358.0	321.0
Emerging Technology (aMW)	14.0	15.0	14.0	14.0	14.0
Fuel Conversion (aMW)	26.0	26.0	25.7	26.0	22.0
Demand Response (MW)	124.0	124.0	124.0	124.0	124.0
Distributed Generation (aMW)	36.0	40.1	36.0	36.0	34.0
Distributed Generation + Emerging Tech (aMW)	40.1	40.1	40.1	36.0	40.1

Exhibit 5 shows how the electric energy-efficiency supply curve changes by scenario (the base-case book-ended by the highest and lowest scenarios). The curves are identical until about $0.11, at which point they begin to diverge. For example, if a horizontal line were drawn at $0.18, the amount of potential would vary significantly by scenario.

Exhibit 5. Electric Energy-Efficiency Supply Curves by Scenario



Examination of natural gas resources under alternative scenarios, however, indicates a more dramatic change in quantities in response to various price assumptions, particularly in energy efficiency based on existing technologies. As shown in Exhibit 6, achievable gas conservation potentials may be expected to grow by nearly 42% as a result of a 25% increase in prices above the base-case forecast. More extreme price fluctuations (for example from the low-growth scenario to 25% above the base-case) are likely to produce changes of nearly 72% in resource potentials. The impacts on fuel conversion options seem more moderate, since the base case is already high on the supply curve. For example, a 15% drop in avoided costs from the highest to the lowest case is shown to produce a less than 20% decline in the potentials for this resource. Price changes generally appear to have little effect on energy efficiency potentials from emerging technologies due to the relatively low per-unit costs of these resources (Exhibit 6).

Exhibit 6. Year 20 Gas Achievable Potential by Resource and Scenario (1000Dth)
(Represents Additional Gas Usage for Fuel Conversion)

Resource	Base	Base + 25%	Base -10%	Green World	Low Growth
Average Avoided Cost ($/therm)	$0.96	$1.20	$0.87	$1.13	$0.84
Energy Efficiency	69,195	97,926	64,843	90,308	56,989
Emerging Technology	3,779	3,530	3,807	3,692	3,675
Fuel Conversion	1,218	1,218	1,200	1,218	1,001

For gas energy efficiency, supply curves vary even more significantly than for electric. Exhibit 7 shows the base, low, and high scenarios and how much savings is attained for each at a given cost cutoff. At low costs, the high scenario actually provides lower savings than the other scenarios because some more efficient measures on the margin are included in this scenario. For example, although a high-efficiency gas furnace may have a low enough cost to pass in all scenarios, in the highest scenario, the premium-efficiency gas furnace passes the screen, and will be installed instead. The savings of this measure is greater, but the levelized cost is as well, so it is not included until higher up the supply curve, at which point the high scenario surpasses the other scenarios at a given cost cutoff.

Ramping and Deployment

For the purpose of incorporating the DSM resource potentials into the integrated resource plan, the identified electric resources were scheduled for deployment according to the timing of PSE’s resource requirements over the 20-year planning period. Given the forecast energy and capacity needs of PSE, all electric energy-efficiency and demand-response resources are scheduled for deployment during early years. Acquisition of other electric resources (fuel conversion and distributed generation) are assumed to begin slowly in the early years, then accelerate in the medium term, and level off over the latter parts of the period (Exhibit 8). Due to the common difficulties in marketing of natural gas conservation programs, natural gas conservation resources are assumed to be acquired at a rate of one-twentieth of the potential annually, without any acceleration.

Exhibit 7. Gas Energy-Efficiency Supply Curves by Scenario

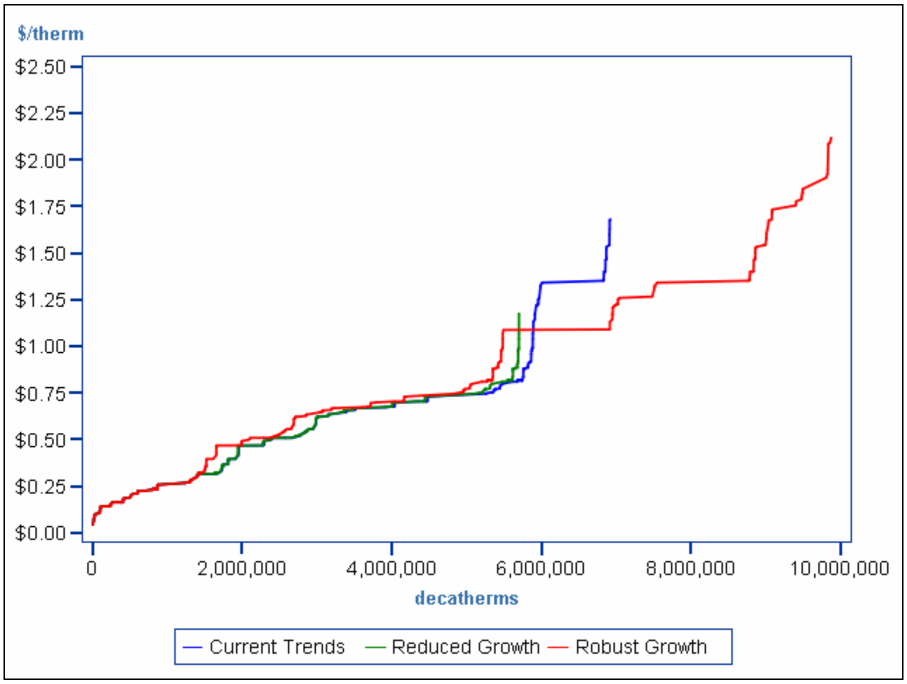
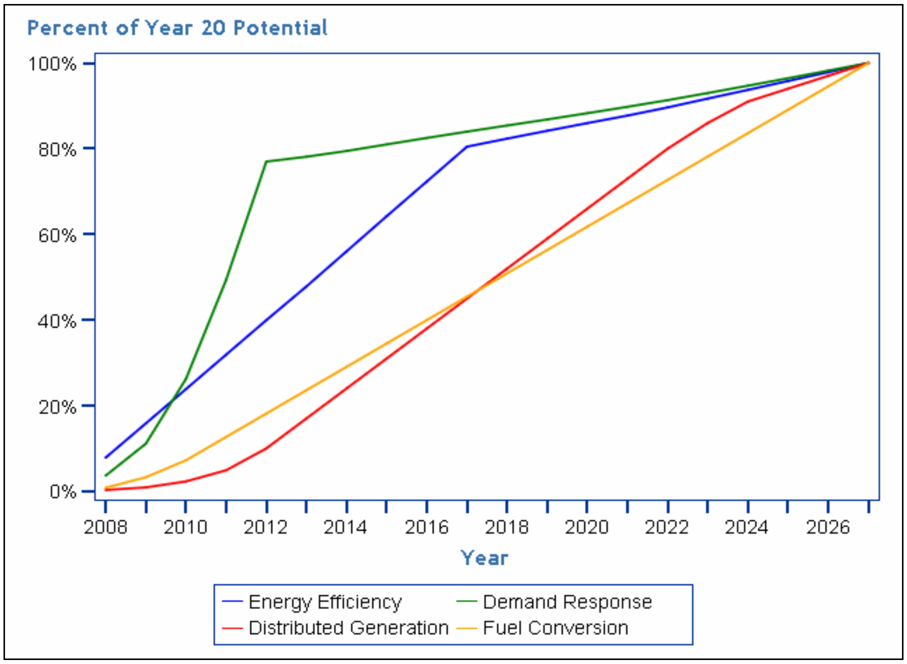


Exhibit 8. Assumed Timing of Electric DSM Resource Acquisition (Annual Rate as % of Total)



A full realization of the estimated achievable DSM potentials would require acquisition at the rate of approximately 21 aMW of electricity and 3.6 million therms per year over the 20-year planning period, assuming equal annual increments. These estimates are within a reasonable range of what PSE has been able to accomplish recently (19 aMW of electric and 2.4 million therms of natural gas savings in 2006). However, as more of the available potentials is exhausted over time, greater effort (and resources) would be needed to acquire the remaining potentials.

It is also important to note that achievable potentials represent fractions of economic potentials determined on the basis of the TRC criterion. The test is based on “total” cost of the resource, regardless of how it might be shared between the utility and program participants. Clearly, the higher the incentives paid by the utility, the greater the customers’ willingness to participate in DSM programs. The actual market penetration of DSM programs will therefore largely depend on incentives paid by the utility. This would, in turn, increase the cost burden borne by the utility, leading to higher rate impacts, with particular equity implications. These adverse effects may be at least partially mitigated by adopting alternative, low-cost resource acquisition strategies such as a greater emphasis on market transformation initiatives, promotion of new energy codes and standards, or programmatic efforts to improve compliance with existing codes.

1. Introduction

This study is a comprehensive attempt at identifying all electric and natural gas demand-side management (DSM) technologies and measures that are technically feasible, cost-effective and reasonably achievable in Puget Sound Energy's service area from 2008-2027. It is the third 20-year assessment commissioned by PSE in support of its biennial integrated resource planning (IRP) process. It builds upon the experiences of previous studies, expands their scope, and improves their methodologies in several important ways, including:

1. Extending the scope of the analysis to the full range of applicable DSM options including energy efficiency, electric-to-gas fuel conversion, demand response, small-scale distributed generation, dispatchable standby generation, and emerging energy-efficient and distributed generation technologies.

2. Incorporating additional measures including emerging energy-efficiency technologies and cost-saving innovations in distributed generation.

3. Using an economic screen to assess cost-effectiveness of individual measures and technologies based on the total resource cost (TRC) test criterion.

4. Evaluating resources at an hourly (rather than annual) level so that their unique energy and capacity impacts are fully taken into account. This procedure involved evaluating each measure based on its unique hourly load shape.

5. Updating end-use consumption indices for all sectors using the most recent data or estimating new indices through statistical regression techniques to disaggregate total annual consumption into its constituent end uses.

6. Revising the information on technology saturations to account for the effects of PSE's DSM activities since 2004 and resource acquisitions targeted for 2005 and 2006.

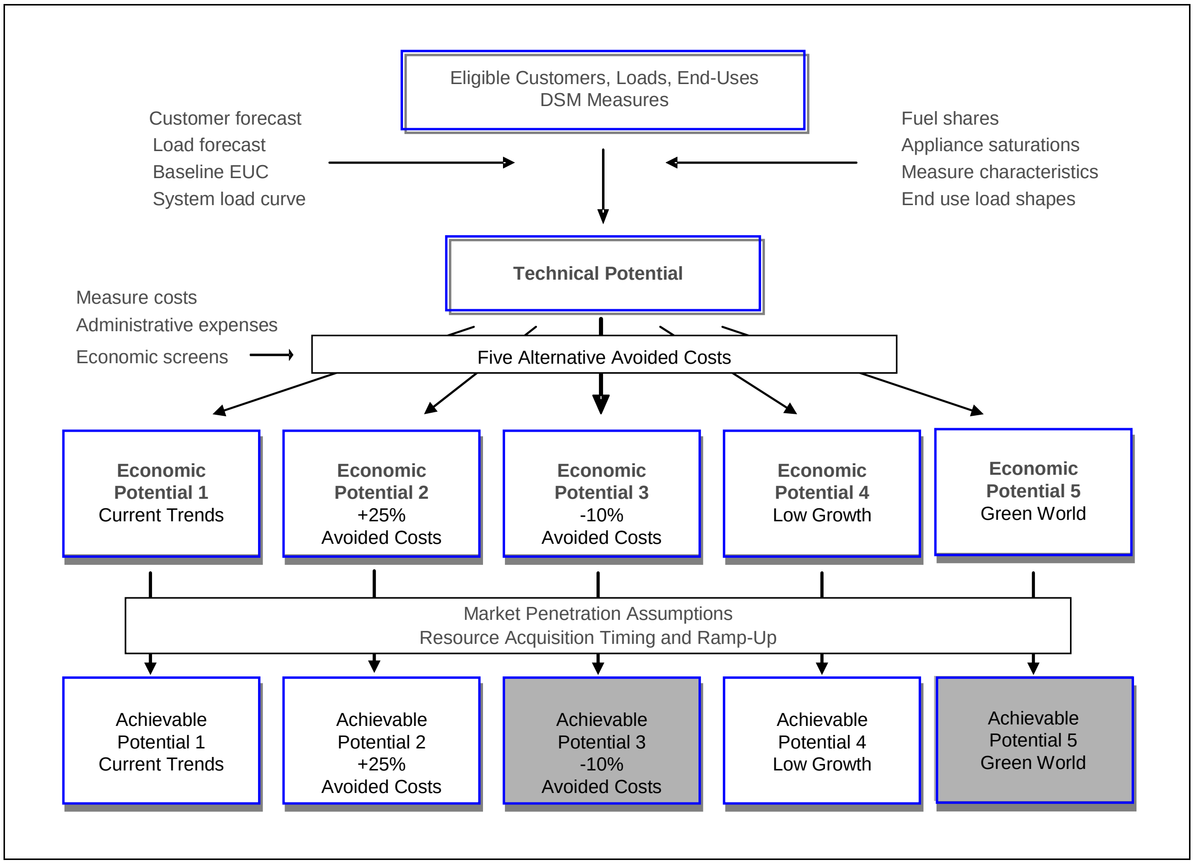
This study aims to characterize a broad range of DSM options and to provide reasonably reliable estimates of their magnitudes, costs, and the timing of their availability using the most recent data available. The conceptual framework and the analytic methods used in this study conform with standard practices in the utility industry and are consistent with the methods used by the Northwest Power Planning and Conservation Council ("the Council") in its assessment of region-wide conservation potentials.

General Approach

The five DSM resources analyzed in this study differ with respect to technology, availability, type of load impact, and target consumer markets. Analysis of their potentials, therefore, requires customized methods that can address the unique characteristics of each resource. These methods, however, spring from the same conceptual framework and the general analytic approach.

The general methodology is best described as a hybrid “top-down/bottom-up” approach. As illustrated in Figure 1, it 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 demand-side measures and practices on each end use, taking into account fuel shares, current market saturations, technical feasibility, and costs. These unique impacts are then aggregated to produce estimates of resource potentials at the end-use, customer-class, and system levels.

Figure 1. General Methodology for Assessment of Demand-Side Resource Potentials



Consistent with the accepted industry standards, the approach in this study distinguishes among four distinct, yet related, definitions of resource potential that are widely used in utility resource planning: naturally occurring conservation, “technical potential,” “economic potential,” and “achievable potential.” Naturally occurring conservation refers to gains in energy efficiency that occur as a result of normal market forces such as technological change, energy prices, market transformation efforts, and improved energy codes and standards. In this analysis, the market effects components of naturally occurring conservation are taken into account by explicitly incorporating changes to codes and standards and marginal efficiency shares in the development of the base-case forecasts.

Technical potential assumes that all demand-side resource opportunities may be captured, regardless of their costs or market barriers. For demand-side resources such as energy efficiency and fuel conversion, technical potentials further fall into two classes: “instantaneous” (retrofit) and “phased-in” (lost-opportunity) resources. It is important to note that the notion of “technical potentials” is less relevant to resources such as demand response and distributed generation—nearly all end-use loads may be subject to interruption or displacement by on-site generation from a strictly “technical” point of view. Economic potential represents a subset of technical potential consisting of only those measures that are deemed cost-effective based on a total resource cost test (TRC) criterion. For each measure, the test is structured as the ratio of the net present values of the measure’s benefits and costs. Only those measures with a benefit-to-cost ratio of equal or greater than 1.0 are deemed cost-effective and are retained.

Achievable potential is defined as that portion of economic potential that might be assumed to be achievable in the course of the planning horizon, given market barriers that may impede customer participation in demand-side management programs sponsored by the utility. The assumed levels of achievable potentials are meant to serve principally as planning guidelines. Ultimately, the actual levels of achievable opportunities will depend on the customers’ willingness and ability to participate in the demand-side programs, administrative constraints, and availability of an effective delivery infrastructure. Clearly, the customer’s willingness to participate in demand-side programs depends on the amount of incentive that is offered. Since the economic potentials in this analysis are based on a total resource cost perspective, it is implicitly assumed that PSE would bear the full cost of measures, which could raise equity concerns. Depending on the actual experience of various programs in the future, PSE may consider alternative, more efficient and cost-effective means such as market transformation and promotion of codes and standards, in order to capture portions of these resources.

A complete description of the each of the definitions of resource potentials and a discussion of methods used for their derivations are found in 7, Methodology.

Organization of this Report

This report is organized in seven sections. The next four sections (sections two through five) describe each individual resource analyzed in the study and present the results for each. Section six examines the effects of alternative economic scenarios on resource potentials. Section seven is devoted to a discussion of methodologies and assumptions used in evaluating various estimates of resource potentials. Additional technical information, descriptions of data and their sources are presented in the appendices to this document.

2. Energy Efficiency Resources

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 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 construction segments each) were considered. A comprehensive set of 145 unique electric and 61 unique gas measures—including 29 emerging electric and four emerging natural gas technologies—for all major end uses were analyzed. The results of the analysis for existing technology are described below, while emerging technology results are presented later in this section. A complete list of energy efficiency measures is provided in Appendix B.

Electric Resource Potentials

The results of this study indicate that there are 702[3] aMW of technically feasible electric energy efficiency potential (Technical Potential) by the end of the 20-year planning horizon in 2027 (Table 1). Approximately 434 aMW of these resources are cost-effective (Economic Potential) with an average levelized per unit cost of five (5) cents per kWh. Across all sectors, 341 aMW (nearly 80% of the economic potential) are deemed reasonably achievable (Achievable Potential). If fully deployed, the identified achievable potentials amount to nearly 10% of PSE's forecast load in 2027, and 30% of the projected load growth over the 20-year planning period.

Table 1. Cumulative (20-Year) Technical, Economic and Achievable Electric Energy Efficiency Potentials (aMW)

Sector	Technical Potential	Economic Potential	Achievable Potential	Achievable As Percent of Baseline Sales	Resource Cost Levelized $/kWh
Residential	310	196	157	9.3%	$0.05
Commercial	374	220	168	9.9%	$0.06
Industrial	19	19	17	9.9%	$0.03
Total	702	34	341	9.7%	$0.05

Nearly 95% (324 aMW) of the achievable potentials are in the commercial and residential sectors and 5% (17 aMW) in the industrial sector. Discretionary resources, i.e. those available

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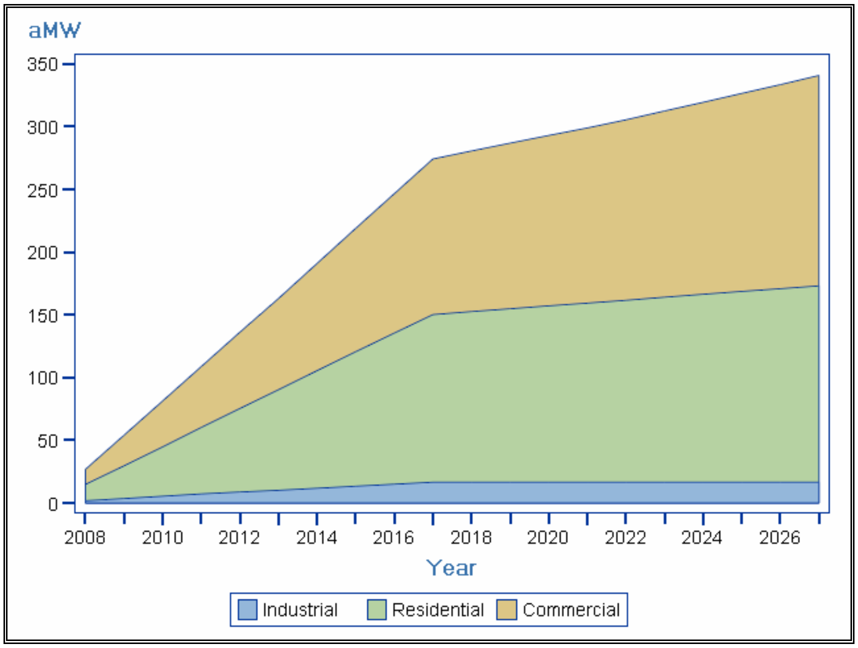
[3] All energy savings presented in this report are at the customer meter and do not include "upstream" adjustments for T&D system losses which would increase energy savings by 6.7% for electric and 0.8% for gas.

through immediate retrofit opportunities, constitute 70% (238aMW) of achievable electric potentials in the three sectors combined. All of the 17 aMW of achievable potentials in the industrial sector fall into the discretionary resource category. The large amounts of discretionary resources will allow PSE to accelerate its acquisition of energy-efficiency resources to meet its shorter term energy resource requirements. As illustrated in Figure 2, PSE is planning to pursue an aggressive acquisition strategy, seeking to obtain all discretionary[4] savings in the first ten years. All additional savings after the 10th year are from new construction and normal replacement of equipment in existing buildings.

Figure 2. Acquisition Schedule for Achievable Electric Savings by Year and Sector



Residential Sector

Achievable electric potential in the residential sector is expected to grow to 157 aMW over 20 years, corresponding to a 9.3% reduction in 2027 residential electric consumption. As shown in Figure 3, single family homes represent almost 75% (116 aMW) of total savings, followed by multifamily and manufactured homes. Additional savings of 25.2 aMW and 9.6 aMW are expected to be achievable in the multi-family and manufactured housing sectors. By far the largest (72%) of achievable saving opportunities in the residential sector are from lighting measures, owing primarily to the low cost of compact fluorescent lighting measures. Space heating and water heating applications account for the next two largest slices of achievable potentials, followed by plug loads and appliances such as energy-efficient refrigerators and freezers. (see Table 2 and Figure 4).

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[4] Discretionary savings are those that can be acquired at any point during the planning horizon. These consist primarily of lighting, building shell, and water heating measures in existing buildings.

Table 2. Residential Sector Electric Energy Efficiency Potentials by End Use

End Use	Technical Potential (aMW)	Economic Potential (aMW)	Achievable Potential (aMW)
Central AC	2.1		
Freezer	2.1		
Heat Pump	11.6	5.0	4.0
Lighting	137.9	140.4	112.3
Plug Load	30.0	9.0	7.1
Refrigeration	12.0	12.3	10.0
Room AC	0.2		
Space Heat	65.8	22.7	18.2
Water Heat	48.5	6.3	4.9
Total	310.2	195.7	156.5

Commercial Sector

The commercial sector offers the largest opportunities for electric energy-efficiency improvement. The results of this study indicate that there are 168 aMW of cumulative achievable potentials in the commercial sector. Offices and educational facilities represent the largest shares (26% and 18% respectively) of the savings potential in the commercial sector. Considerable savings opportunities are expected to exist in the retail, groceries and dry-goods stores (31 aMW), health (14 aMW) and warehouse (16 aMW) segments of the commercial sector. Moderate amounts of savings are expected to be available in lodging facilities and restaurants. Together, these sectors are expected to offer 15 aMW of cumulative saving potentials. Approximately 20 aMW of savings are estimated for miscellaneous, un-classified commercial establishments (Figure 5). Lighting efficiency represents by far the largest portion of achievable potentials in the commercial sector, followed by HVAC, which accounts for approximately 40% of the achievable potentials (Table 3 and Figure 6).

Table 3. Commercial Sector Electric Energy Efficiency Potentials by End Use

End Use	Technical Potential (aMW)	Economic Potential (aMW)	Achievable Potential (aMW)
Cooling Chillers	32.6	17.9	13.6
Cooling DX	58.1	17.8	14.2
Cooling Heat Pump	18.6	4.9	3.9
HVAC Aux	1.4	1.4	0.9
Lighting	176.6	121.2	90.3
Plug Load	4.9	2.2	1.7
Refrigeration	10.9	9.7	7.6
Space Heat	61.4	39.6	31.6
Water Heat	9.3	4.9	3.9
Total	373.8	219.8	167.8

Industrial Sector

Technical and achievable electric and gas energy-efficiency potentials were estimated for all major end uses within 15 major industrial sectors in PSE's service territory. Achievable electric energy-efficiency potentials in the industrial sector are estimated at 17 aMW, representing approximately 10% of the total industrial load in 2027, at an average levelized per-unit cost of under 3 cents per kWh. The results of this study suggests that the identified savings tend to be evenly distributed among the eight industrial sectors, strongly correlated with their shares of PSE's industrial load (Figure 7). The majority of the savings in the industrial sector (57%) are attributable to efficiency gains in motor upgrades in air compression, pumping and air distribution applications. Small amounts of savings (3.2 aMW) are also available in facility improvements, primarily HVAC and lighting retrofits. Energy efficiency improvements in refrigeration and process cooling are also expected to generate an additional 2 aMW of savings in the industrial sector (Table 4 and Figure 8).

Table 4. Industrial Sector Electric Energy Efficiency Potentials by End Use

End Use	Technical Potential (aMW)	Economic Potential (aMW)	Achievable Potential (aMW)
HVAC	2.0	2.0	1.8
Lighting	1.6	1.6	1.4
Process Cooling	1.4	1.4	1.2
Process Motors Air Compression	3.2	3.2	2.8
Process Motors Fans	1.3	1.3	1.2
Process Motors Other	2.4	2.4	2.1
Process Motors Pumps	5.9	5.9	5.3
Process Motors Refrigeration	0.8	0.8	0.7
Total	18.6	18.6	16.6

Figure 3. Residential Achievable Electric Saving Potentials by Dwelling Type

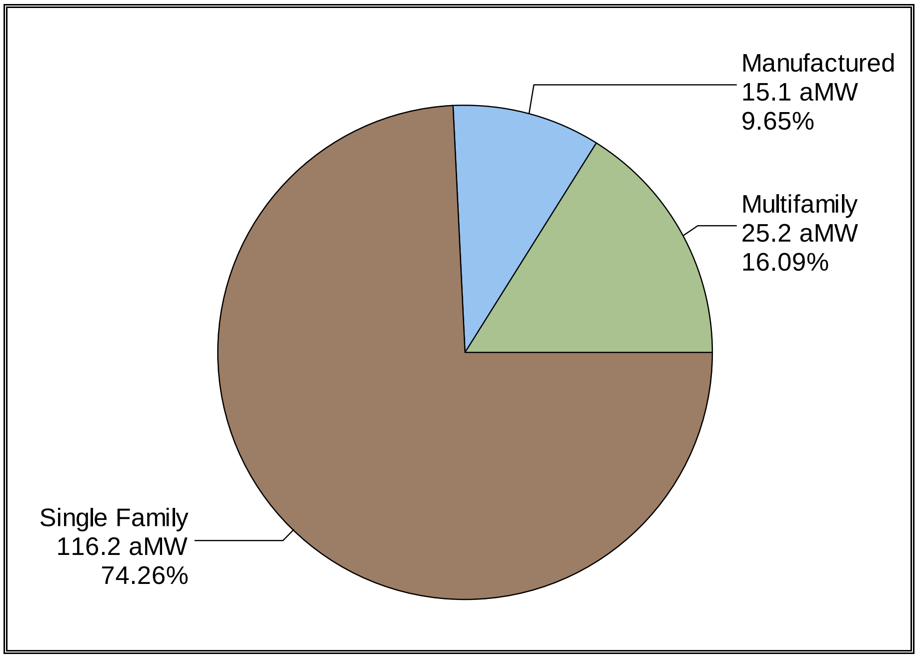


Figure 4. Residential Achievable Electric Saving Potentials by End Use

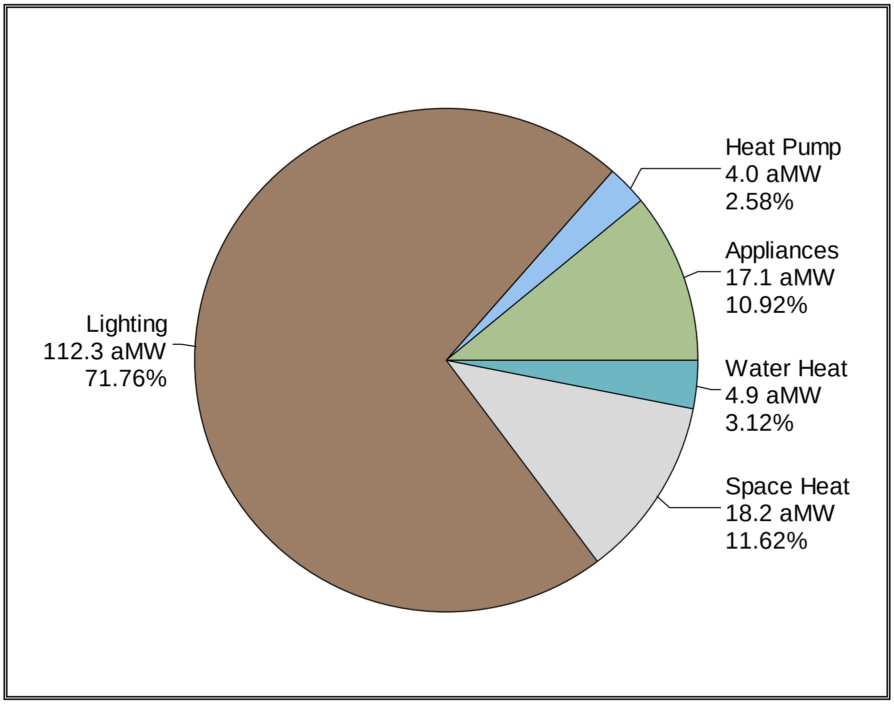


Figure 5. Commercial Sector Electric Achievable Potentials by Building Type

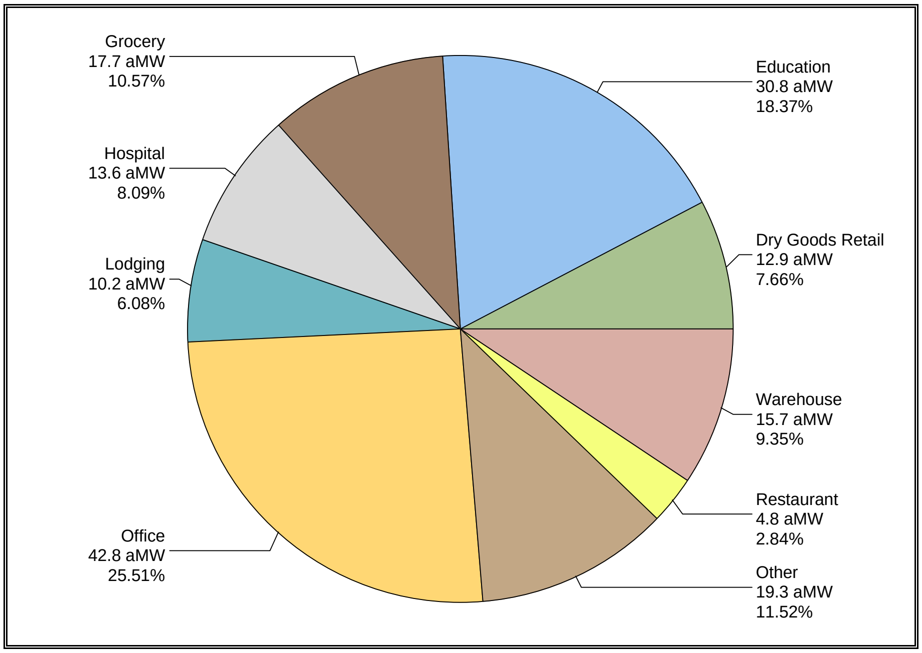


Figure 6. Commercial Sector Electric Achievable Potentials by End Use

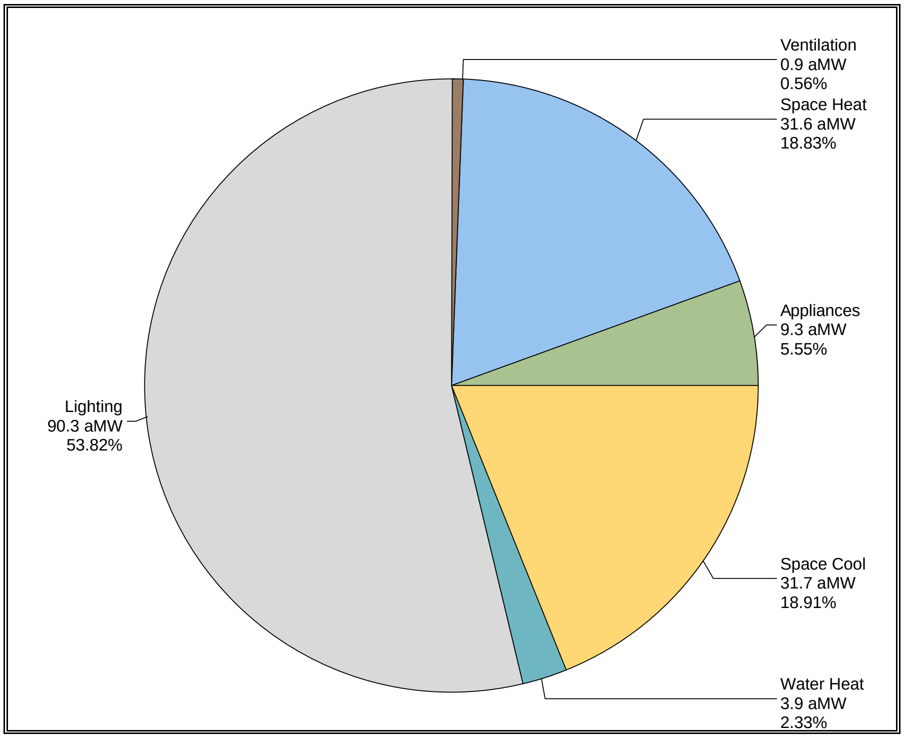


Figure 7. Industrial Sector Achievable Electric Potentials by Sector (NAICS)

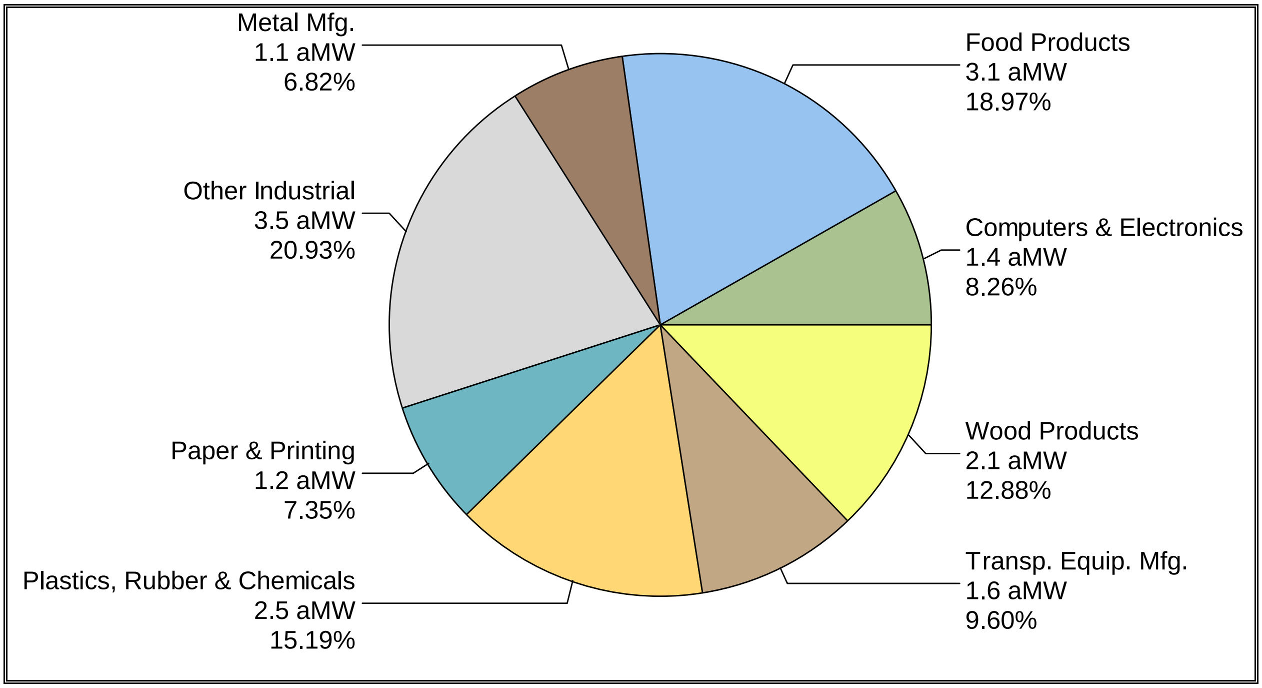
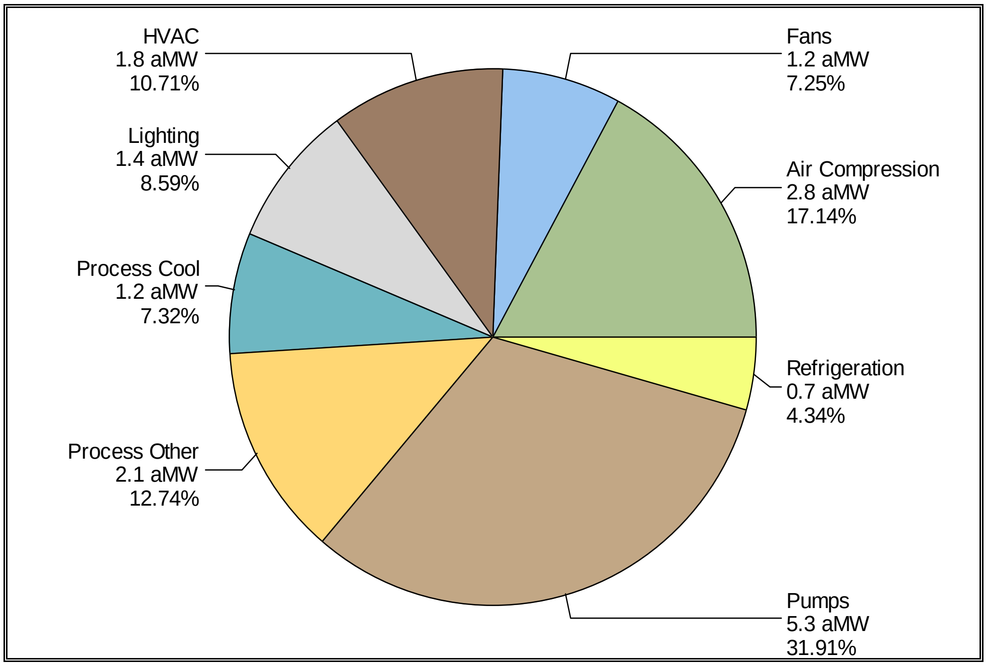


Figure 8. Industrial Sector Achievable Electric Potentials by End Use



Natural Gas Resource Potentials

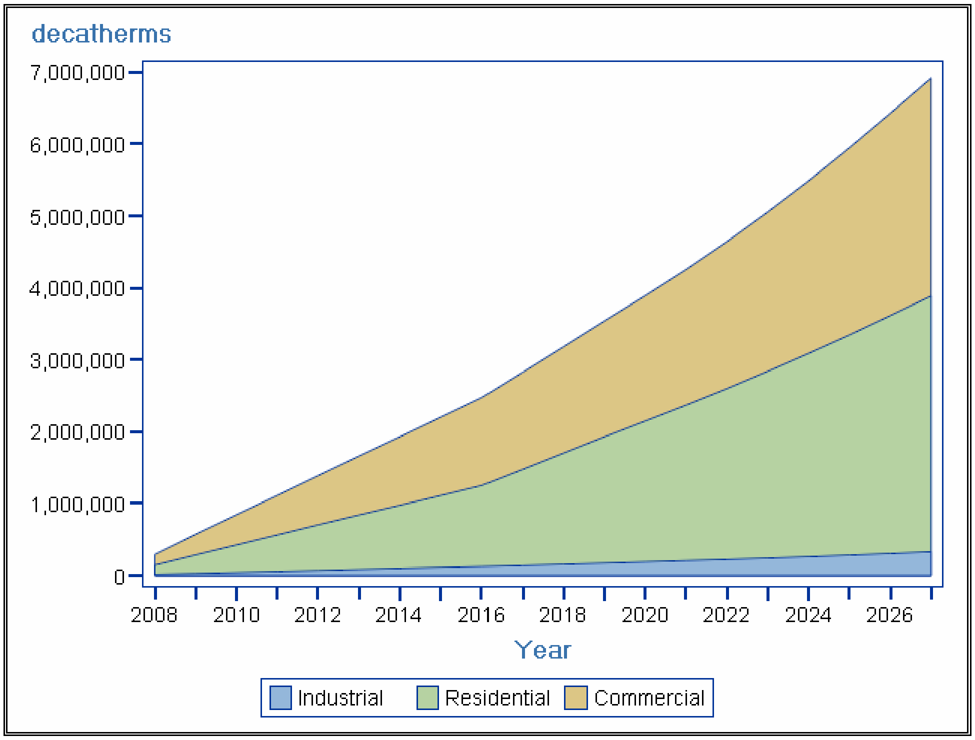
Table 5 shows the total decatherm (Dth) savings in the 20th year of the planning horizon by the type of potential. Across all sectors, cumulative natural gas savings potentials of nearly 70 million Dth are likely to be achievable over the planning horizon at a cost of 78 cents per therm or less. The estimated achievable potential represents about 32% of the technical and 62% of the economic potential. The residential and commercial sectors account for nearly 97% (10.7 million Dth) of the total achievable potential in all sectors. The industrial sector shows relatively small, though inexpensive, potentials for natural gas savings (Table 5).

Table 5. Cumulative (20-Year) Technical, Economic and Achievable Natural Gas Energy Efficiency Potentials (Dth)

Sector	Technical Potential	Economic Potential	Achievable Potential	Achievable As Percentage of Baseline Sales	Resource Cost ($/therm)
Residential	21,938,914	5,496,224	3,560,793	7.5%	$0.78
Commercial	12,732,958	5,247,873	3,030,831	4.4%	$0.53
Industrial	437,178	437,178	327,884	6.8%	$0.33
Total	35,109,050	11,181,275	6,919,508	5.3%	$0.65

Approximately 46% of the achievable natural gas savings potentials consist of retrofit measures and 54% are from lost opportunities. Due to the relatively large share of lost opportunity resources; and unique challenges in marketing of gas energy-efficiency programs, an aggressive, accelerated strategy does not appear feasible. It is, therefore, assumed that natural gas energy-efficiency resources would be acquired more gradually than electric resources. Achievable potentials for natural gas measures were assumed to begin at 55% (for existing buildings) and 35% (for new construction) of economic potentials during the early years of planning through 2016, and gradually ramp up to 75% and 55% for existing and new buildings respectively in the future.

Figure 9. Resource Acquisition Schedule Natural Gas Savings by Year and Sector



Residential Sector

Achievable natural gas savings potential in the residential sector grows to about 3.6 million Dth over 20 years. Figure 10 shows the distribution of this savings by home type. Because manufactured homes tend to have a higher saturation of electric equipment, these homes account for a smaller percentage of natural gas savings than they do for electric. There are far fewer natural gas end uses than electric, and only two prove to have cost-effective savings in the residential sector. Space heat accounts for over 60% of savings (Table 6 and Figure 11).

Table 6. Residential Sector Gas Energy Efficiency Potentials by End Use

End Use	Technical Potential (Dth)	Economic Potential (Dth)	Achievable Potential (Dth)
Space Heating	18,106,136	3,077,238	2,159,835
Water Heating	3,832,779	2,418,986	1,400,958
Total	21,938,914	5,496,224	3,560,793

Commercial Sector

Slightly over 3 million Dth of cumulative savings are expected to be achievable in this sector. Distribution of achievable natural gas savings across the ten modeled commercial segments are shown in Figure 12. Because the "Other" segment comprises the largest part of PSE's base year sales (over 30%), it is not surprising that it also represents the largest slice of potential, followed by office buildings with expected achievable potentials of nearly 0.5 million Dth. The largest amounts of achievable potentials are expected to be in energy-efficiency improvements in space heating and water heating, each accounting for approximately 1.5 million Dth of achievable potential (Table 7 and Figure 13).

Table 7. Commercial Sector Gas Energy Efficiency Potentials by End Use

End Use	Technical Potential (Dth)	Economic Potential (Dth)	Achievable Potential (Dth)
Cooking	152,067	23,088	17,316
Pool Heating	73,097	41,269	29,938
Space Heating	9,232,169	2,674,514	1,515,566
Water Heating	3,275,625	2,509,002	1,468,012
Total	12,732,958	5,247,874	3,030,831

Industrial Sector

Long-term cumulative achievable gas energy-efficiency potentials are estimated at 328,000 Dth. Food products and "other," unclassified industrials are the largest sources of achievable potential. With an average levelized per unit cost of under 33 cents per therm, energy-efficiency improvements in the industrial sector are the lowest cost gas savings. Food products and "other," unclassified industrial industries are the largest sources of achievable potential, combining for nearly 60% of the total (Figure 14). In the industrial sector, natural gas is almost exclusively used for process heating (boilers) and space heating. Nearly 80% of savings potentials are in boiler efficiency upgrades and 20% in space heating improvements (Table 8 and Figure 15).

Table 8. Industrial Sector Gas Energy Efficiency Potentials by End Use

End Use	Technical Potential (Dth)	Economic Potential (Dth)	Achievable Potential (Dth)
HVAC	89,470	89,470	67,103
Process Boiler	347,708	347,708	260,781
Total	437,178	437,178	327,884

Figure 10. Residential Sector Achievable Gas Potentials by Dwelling Type

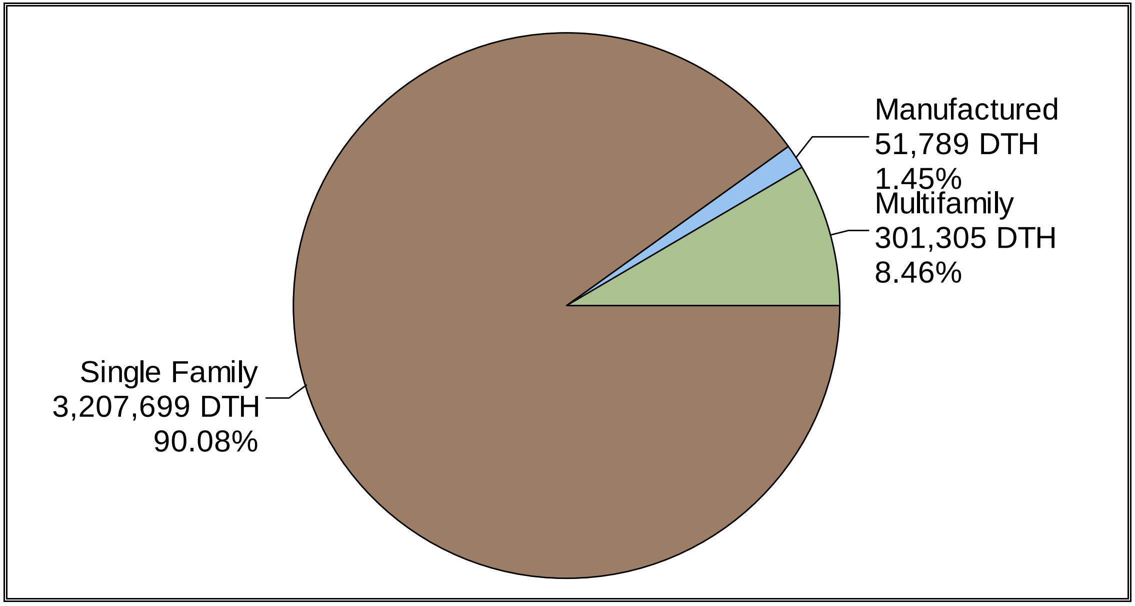


Figure 11. Residential Sector Achievable Gas Potentials by End Use

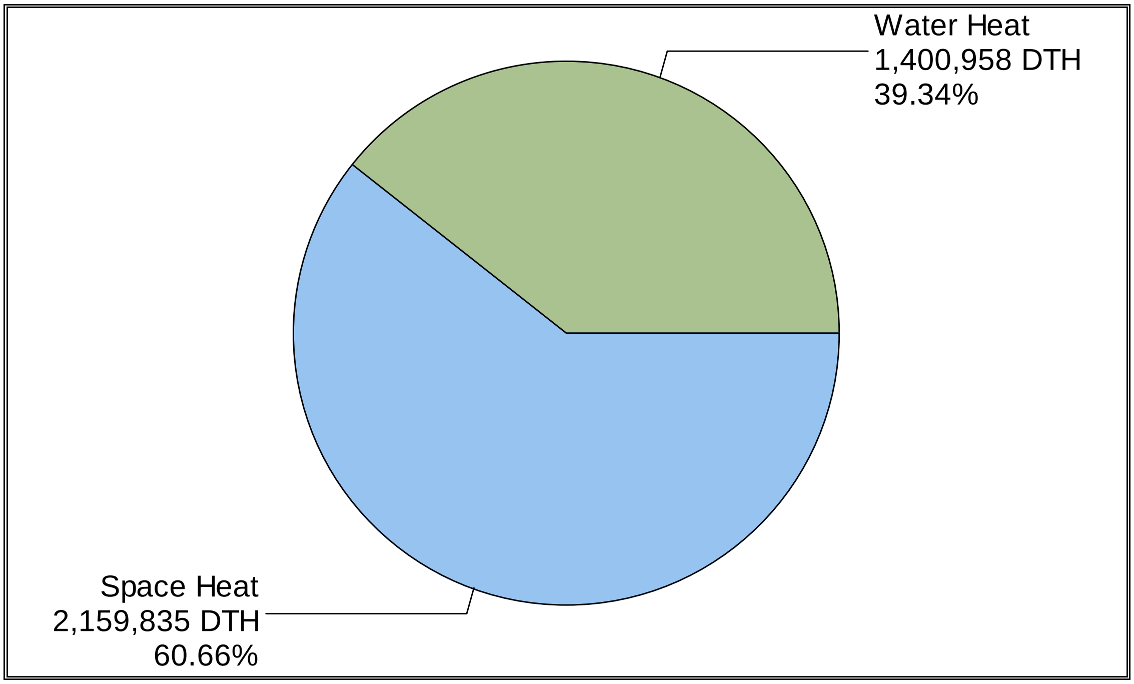


Figure 12. Commercial Sector Achievable Gas Potentials by Building Type

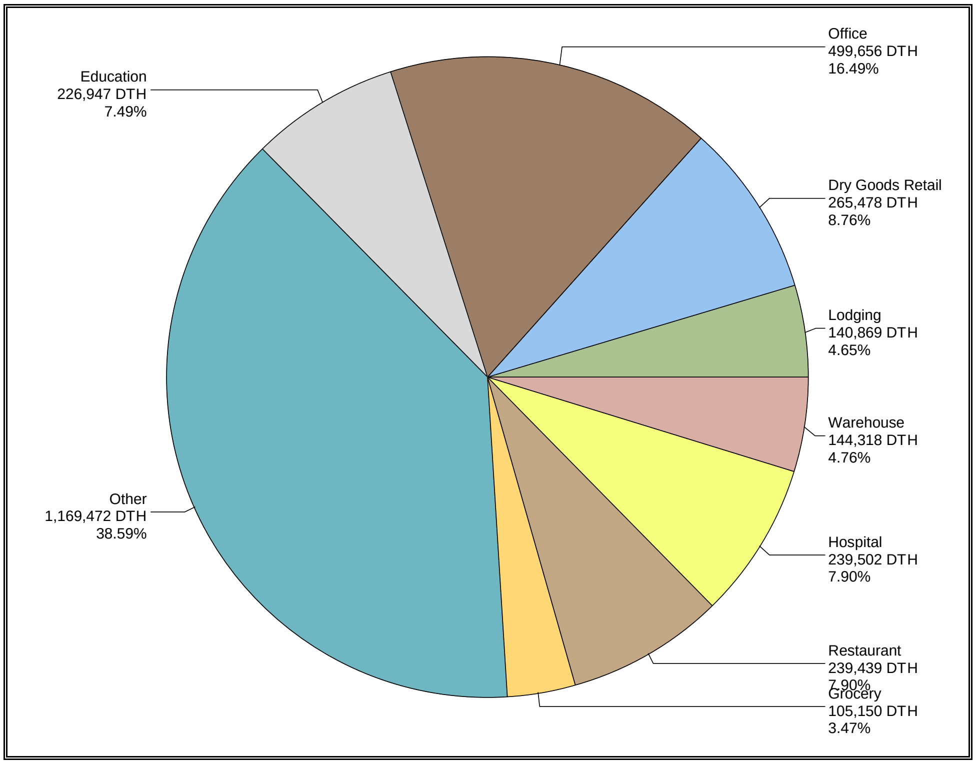


Figure 13. Commercial Sector Achievable Gas Potentials by End Use

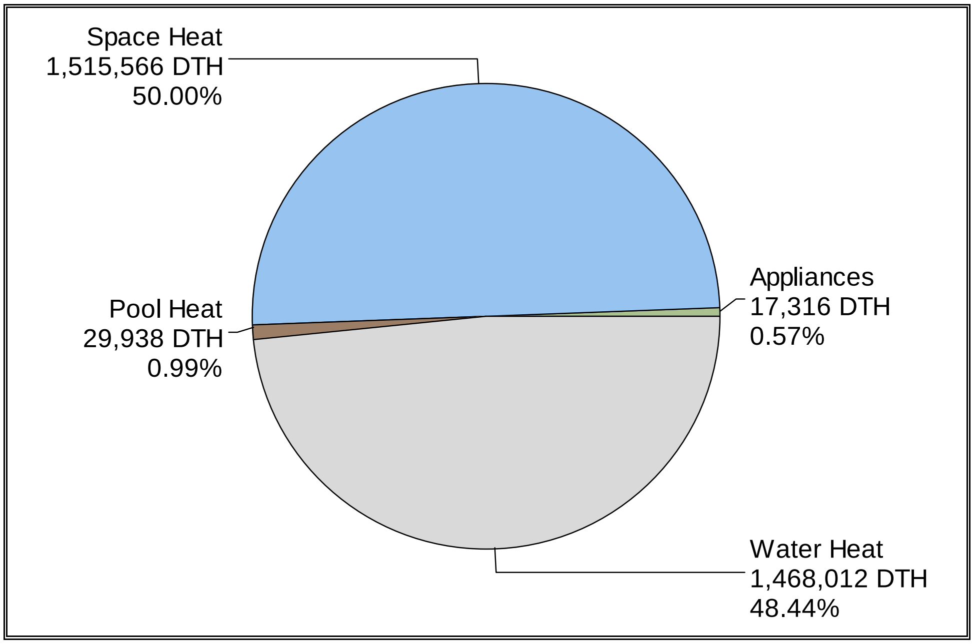


Figure 14. Industrial Sector Achievable Gas Potentials Industry

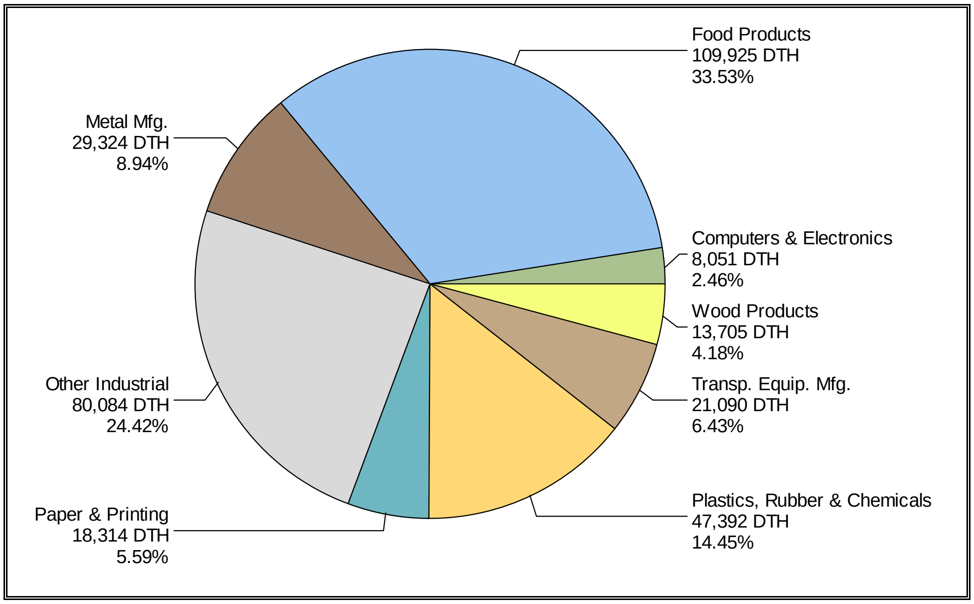
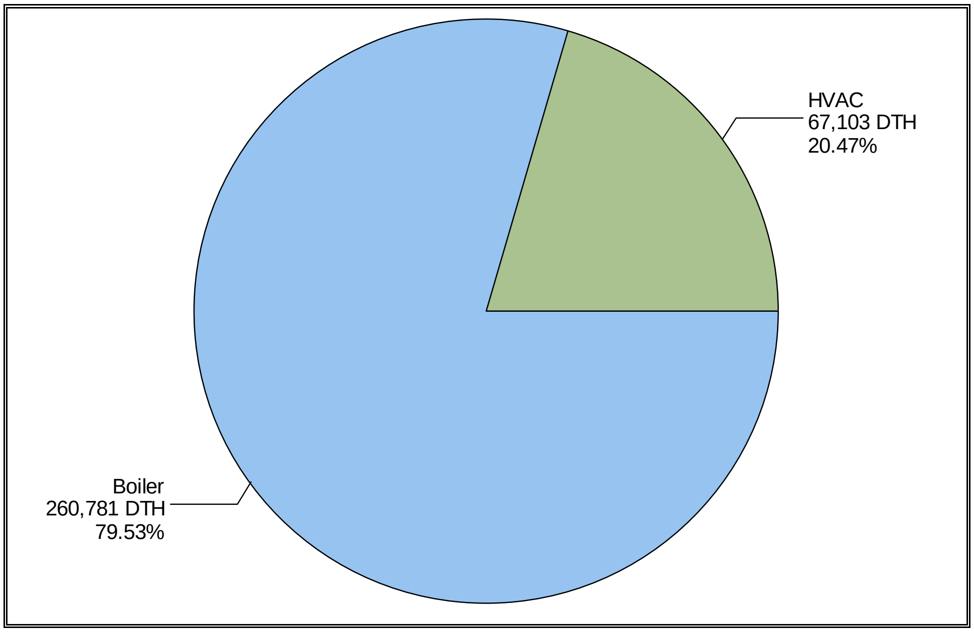


Figure 15. Industrial Sector Achievable Gas Potentials by End Use



Emerging Energy Efficiency Technologies

Scope of Analysis

In this study, explicit consideration was given to a number of emerging energy-efficiency technologies, including the deliberate modeling of conditions where new technologies gradually supplant existing ones. The emerging technology measures are energy-efficiency measures that are not readily available in the current market, but are expected to be so within the 20-year planning horizon. The potential energy savings from Emerging Technologies were not included in PSE's IRP.

The assessment of emerging technologies began with an initial list of 40 residential and 50 commercial measures. After applying several screens, the list was narrowed to a final set of 15 commercial and 13 residential measures. The first screen removed measures for which there was a lack of reliable quantitative data or that were otherwise inappropriate for PSE territory. Second, a rough economic screen was used to eliminate the highly expensive measures that had a levelized cost greater than $0.20/kWh as a first approximation of whether such measures were likely to be cost-effective. Finally, measures were screened for their stage of "market-readiness."[5] Measures that are now beginning to be introduced into the market are expected to become more commonplace and have a noticeable impact on energy use in about five years. There are also measures that are based of proven technologies, but for which no marketing or mass production has begun. These are expected to enter the market in about 10 years. Finally, there are those measures that represent a promising technology, but require more development and are thus not likely to have any market penetration for 15 years. Any measure that is not expected to penetrate the market in more than 15 years was not considered for this 20-year potential study. A table of these emerging technology measures is given in Chapter 7 and a more complete description is in Appendix A.

The emerging technology (ET) measures may or may not be competing with an existing measure. For example, LED white lighting would compete for market share with compact fluorescent lights (CFLs), where LEDs would gradually become more competitive over time. To account for this, the total number of energy-efficient fixtures installed would remain the same, but a portion of those fixtures with CFLs would decrease as the number of LEDs increased. Since LEDs are more efficient than CFLs, the overall savings potential would increase given the same number of fixtures. In other cases, the ET measures do not compete with existing measures and thus simply increase the overall savings potential as they are introduced.

Resource Potentials

Because there are no industrial ET measures and many of the measures in the commercial sector did not pass the cost-effectiveness threshold, the residential sector dominates the ET savings. Table 9 shows the year-20 achievable electric potential by sector and end use bundle. The largest

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[5] "Emerging Energy Efficient Technologies and Practices for the Building Sector as of 2004," ACEEE, Davis Energy Group, and Marbek Resource Consultants, Report A042, October 2004.

potential appears in residential lighting, while there are also opportunities for HVAC measures in the commercial sector. For gas, the only cost-effective emerging technology measures are those applying to the heating end use. Again, most of the potential lies in the residential sector.

Table 9. Emerging Technology Electric and Gas Achievable Potentials (Year 20)

Sector	HVAC	Lighting	Other	Total
Electric (aMW)				
Residential	0.9	8.9	0.7	10.5
Commercial	3.3	0.2	0.1	3.6
Total Electric	4.1	9.2	0.8	14.0
Gas (Dth)				
Residential	332,320			332,320
Commercial	45,578			45,578
Total Gas	377,899			377,899

Figure 16 shows the annual savings by sector for electric ET measures. As can be seen, there is no ET savings until the first measures come online in year five. Due to PSE’s aggressive approach in the first 10 years for electric resource acquisition, the slope of savings is greater from 2012 to 2016 than beyond, but savings continue to grow due to increased market acceptance. Figure 17 shows the gas measure savings (Dth) by year for each sector. The shape is much different than electric, due to the difference in resource acquisition strategies.

Figure 16. Emerging Technology Annual Electric Achievable Potential by Sector

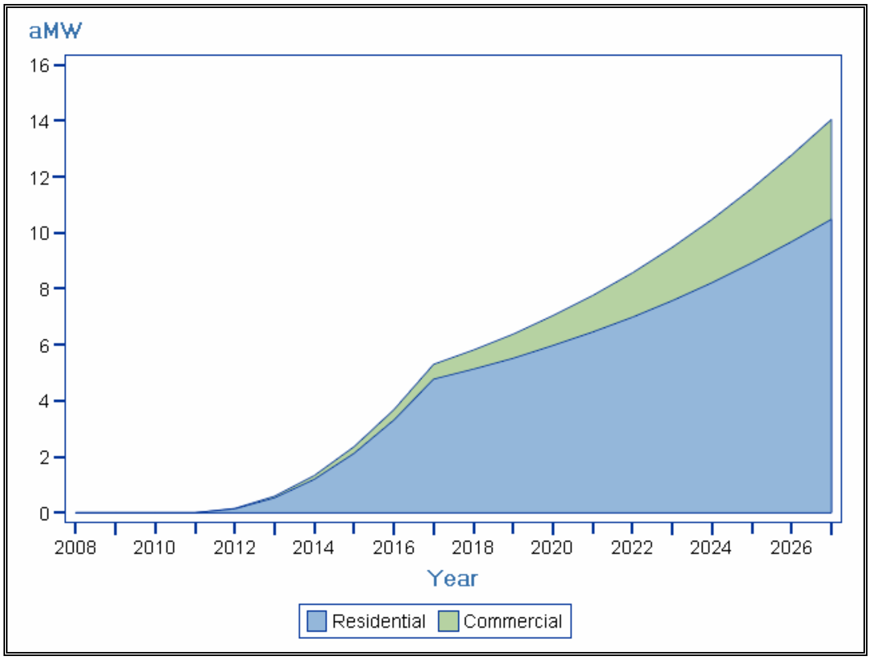
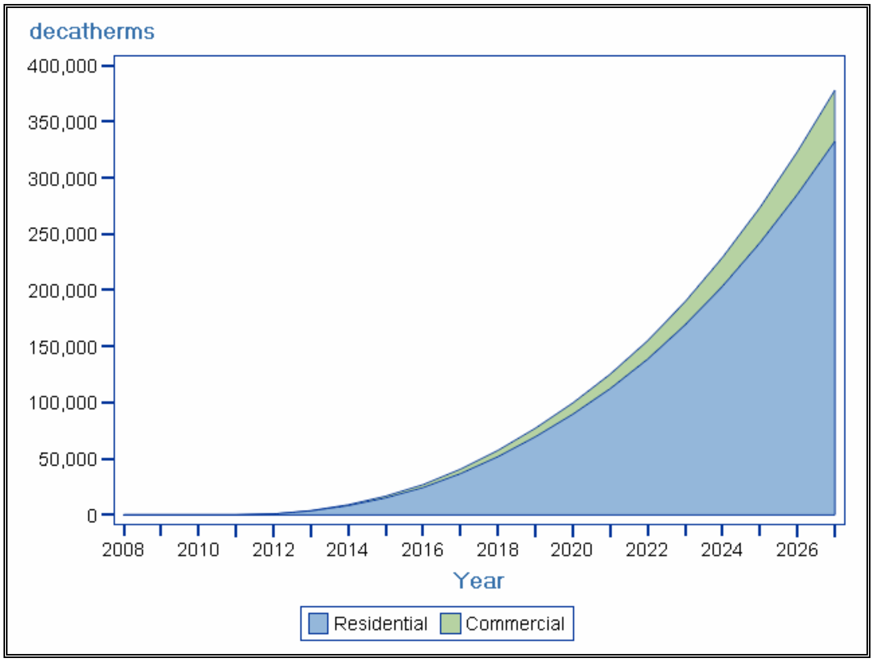


Figure 17. Emerging Technology Annual Gas Achievable Potential by Sector



3. Fuel Conversion Potentials

Scope

In the context of this study, “fuel conversion” refers to electricity saving opportunities involving substitution of natural gas for electricity through a replacement of space heating systems, water heating equipment and appliances. Fuel conversion potentials were examined for the residential single-family homes in parts of PSE’s service area where both electricity and gas are being served. Multi-Family and manufactured homes were not considered due to low saturation of natural gas in the existing stock, as well as technical and market constraints (for example venting issues and a high percentage of renters). Four end uses were considered: (1) space heating, (2) zonal heating, (3) water heating, and (4) appliances (clothes dryer and cooking range).

Methodology

The methodology for determining fuel conversion potential consisted of four steps:

1. Evaluate alternative technologies in terms of their life cycle costs (including full fixed installation and variable expenses) and benefits as measured in terms of the avoided cost value of displaced electricity

2. Estimate market potentials by determining the number of potential customers and applicable end uses

3. Establish cost-effectiveness of different technologies and “measure bundles” (economic potential)

4. Calculate achievable potential based on percentage of economic potential and assumed resource acquisition rate.

Measures Considered

The analysis of fuel conversion considered opportunities in four major end uses in single-family dwellings only: space heating, zonal heating, water heating and appliances (clothes dryer and cooking range). Applicable measures and their assumed technical specifications are shown in Table 10. Minimum efficiency thresholds for the gas equipment were set at the highest efficiency levels that met the cost-effective criteria in the gas energy efficiency potentials assessment. In other words, it was assumed that only the highest efficiency gas measures would be used in all conversions.

Examination of zonal (or room) heating assumed conversion to strictly similar gas-fired equipment such as gas wall heaters (rather than central systems). Dryers and cooking ranges were the only appliances considered in the study. Although the range of efficiencies for dryers tends to be narrow, a moisture sensor can be installed that will automatically shut off the dryer once the moisture level drops below a certain level. This can result in a 15% decrease in energy usage over a standard dryer, due to reduced run-time.[6] Similarly, there are minor differences in the efficiency level of ranges. However, a 20% energy savings can be achieved by using a convection oven.[7] A convection oven includes a fan within the oven cavity that results in air circulation around the food, increasing the overall heat transfer to the food. This allows for lowered oven temperatures and shortened cooking times. A fuller technical description of fuel conversion measures can be found in Appendix C.

Table 10. List of End Uses and Measures Used

End Use	Gas Measure	Electric Baseline
Space heating	90 AFUE condensing furnace	Electric furnace
	96 AFUE condensing furnace	
Zone heating	84% efficient wall heater	Electric wall/ baseboard
Water heating	EF=0.64 storage water heater	Electric water heater
	EF=0.82 tank-less water heater	
Appliances	Gas dryer w/ moisture sensor	Electric dryer w/ moisture sensor
	Convection gas range	Convection electric range

Gas Availability and Market Potentials

For the purpose of this study, it was assumed that the market potential would depend on two factors: (1) service availability and (2) customers' expressed interest and willingness to participate in a fuel conversion program.

Gas availability and its implications in terms of service extension costs is an important consideration in determining the market and economic potentials for fuel conversion. Based on the most recent data available from PSE's 2004 Residential Energy Study (RES), PSE currently serves gas to approximately 49% of single-family homes in its electric service area (Figure 18). Since these customers use at least one or more piece of gas-using equipment, they are considered as candidates for only *additional* gas-using equipment, without imposing additional line extension costs. As shown in Figure 18, under the normal conversion scenario, these customers represent nearly three-quarters of the potential market (293,000 customers) for fuel conversion.

A relatively small proportion of the fuel conversion market potential is attributable to extension of service to new customers. The survey results have shown that about 32% of these customers are within PSE's gas service area. Based on the latest data available from PSE, delivery of gas service to these customers would require either a main extension (76%) or service line extension (24%). About 30% of customers in the former group may be served by short extensions.

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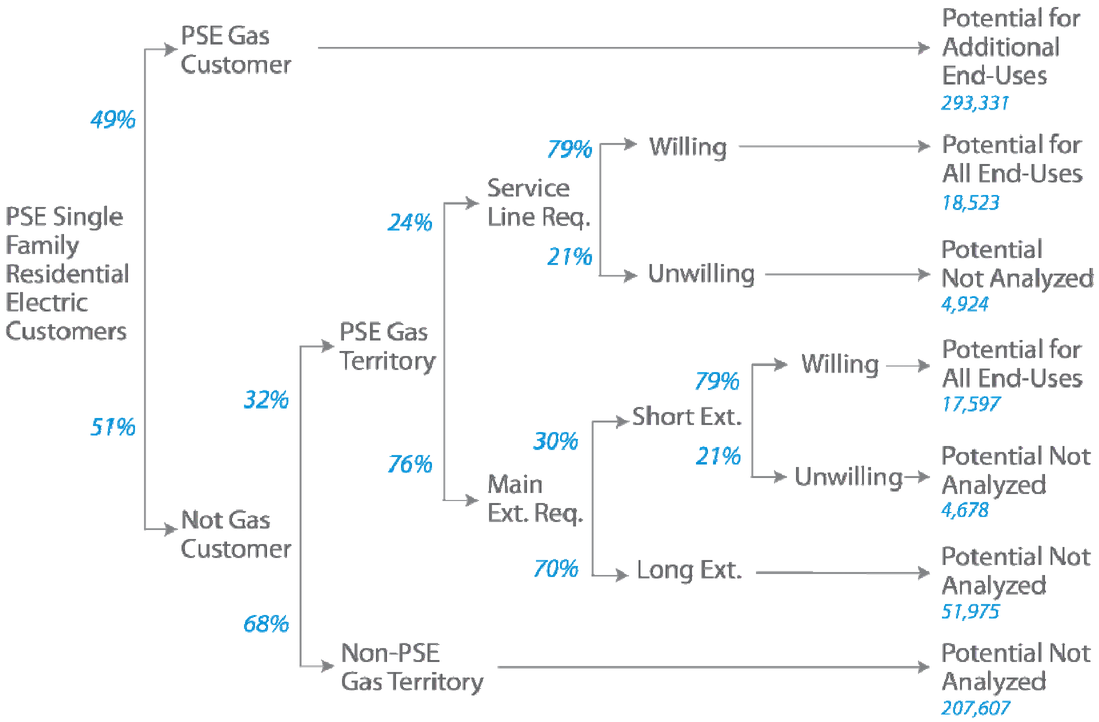
[6] http://www.aceee.org/consumerguide/topwash.htm

[7] http://www.aceee.org/consumerguide/cooking.htm

Customer's willingness to participate in fuel conversion is a second major determinant of market potential for fuel conversion opportunities. Based on a recent survey of customers within PSE's gas service area, 79% of customers who are already on main or may be served with short line extensions expressed an interest in fuel conversion. This represents an additional market opportunity of 36,000 cases for implementation of *all* fuel conversion measures.[8]

Figure 18. Customers Available for Fuel Conversion



Conversion Costs and Benefits

To determine costs, only normal replacement was considered; that is, the assumed installed cost of the gas measure is incremental to that of the alternative electric measure. Thus, the cost to install a new gas furnace, for example, would include the cost of the gas unit itself, less the cost of the equivalent electric unit, plus any additional installation costs, including additional piping required to either extend the piping in the house (for current gas customers), or to deliver gas to the house (for electric-only customers), and gas fuel costs. For electric-only customers, connecting a house to the gas main is assumed to require either a service-line extension (no charge) or a short main extension (approximately $2000). Since it's expected that current electric customers would at least install a gas furnace, the cost to add the gas line to the house is only added to the furnace. Other end uses will have an additional cost only for interior piping ($200,

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[8] The customer shares for the various branches in Figure 18 were derived from PSE Customer Information System and mapping of zip+4 census track codes to PSE's gas distribution system.

as determined through interviews with local HVAC contractors on PSE's Contract Referral Service List). Detailed assumptions on various cost elements are described in Appendix C.

Conversion costs were estimated based on electric and gas avoided costs and the assumed levels of unit energy consumption (UEC). The avoided cost benefits were calculated from a net present value of the first year electric ($/kWh) or gas ($/therm) avoided cost hourly data for the different end-use load shapes and measure lives. Electric UECs (kWh/yr) used in the energy-efficiency model for an existing single-family home were used for a baseline electric value. The equivalent gas UEC (therms/yr) was calculated from the electric usage for the water heater, range, and dryer, based on different efficiency levels for the different measures. For space heat, however, there was a significant disparity between the calculated gas UEC and that found from PSE tariffs. As a result, the tariff gas UEC was used for the stock gas heating measure (AFUE=80), with lower UECs calculated for high-efficiency furnaces. Zone heating UECs are assumed to be about 50% lower than in central units.

Calculation of benefits included avoided electric energy costs, avoided capacity costs ($35/kW/year through 2012 and $90/kW/yr after 2012), avoided transmission and distribution losses (6.7% for electricity and 0.8% for gas), and deferred T&D investment ($32/kW/yr). Since fuel conversion implies replacing an electric measure with a gas-fueled one, the true benefit needs to take this additional gas use into account.

Resource Potentials

To calculate the economic potential, the total resource cost (TRC) test was used to screen measures for cost-effectiveness. The economic screening was conducted assuming alternative bundles of measures, to account for cost savings resulting from joint installation of measures. All possible combinations of different bundling scenarios were considered in determining economic potentials. However, not all bundles are equally likely to be adopted. For new gas customers, it was assumed 5% will convert a space heater only, 80% will convert space and water heaters, 5% will convert space and water heaters and a range or dryer, and the remaining 5% will convert all four end uses. For existing gas customers, for which there are three possible end uses (water heater, range, dryer), it is assumed 85% will convert a water heater, 5% will convert two end uses (water + dryer or range) while 10% will convert all three. With zone heating, 5% will convert only a zone heater, 80% will convert a zone heater as well as a water heater, and 5% will convert a zone and water heater and one or two other end use(s) (dryer and/or range). These distributions are based on previous PSE experience. The TRC-based benefit/cost ratios for the different measures and bundles for the base case scenario is given with a 15% administration cost adder in Table 11 for electric-only and current gas customers. Only one end use (zonal heating) was not cost-effective in this scenario; however, the bundles including zonal heaters were.

Fuel conversion technical potentials were calculated by assuming that all measures for end uses for all willing customers are converted. At the meter, the technical potential was found to be 97 aMW for the base-case scenario. Acquisition of the indicated electricity savings would, however, result in an increased gas consumption at the meter of about 4,181,000 Dth in year 20 for the base-case scenario. Approximately 40% (36 aMW) of the technical potential was determined to be cost-effective after the application of economic screens.

Table 11. Measure Bundles for Electric-Only and Existing Gas Customers

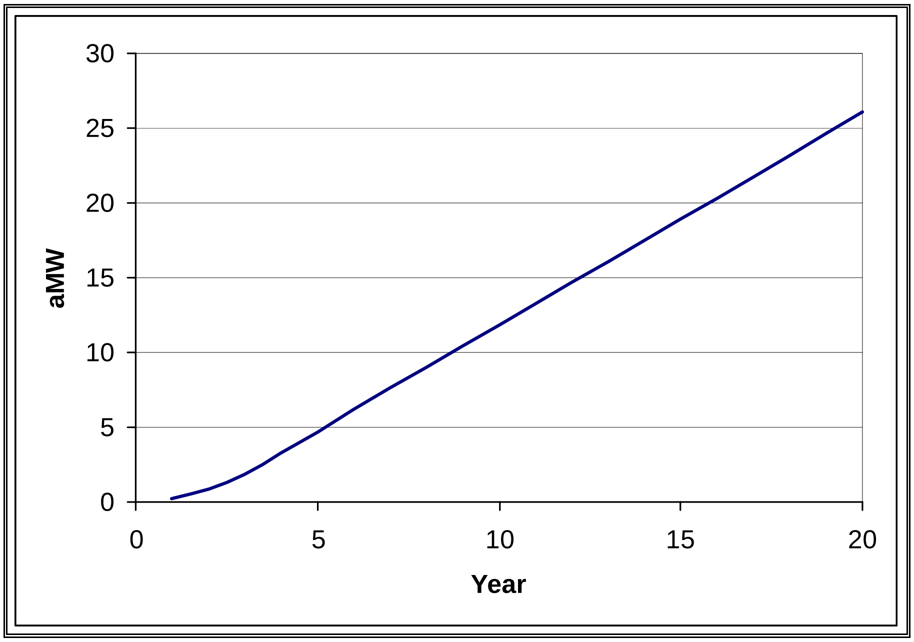
End Use	Measure//Measure Bundle	Cost ($)	Net Benefit ($)	Benefit/ Cost Ratio	Electric Savings (aMW)	Additional Gas Usage (1000 Dth)
Electric-Only Customers						
Space Heating	90 AFUE condensing furnace	1,840	2,504	1.4	0.2	10
	96 AFUE condensing furnace	2,243	2,817	1.3		
Space + Water	90 AFUE + 0.64 EF	2,369	3,887	1.6	7.5	495
Space + Water + Dryer	90 AFUE + 0.64 EF + moisture sensor	2,668	4,500	1.7	0.5	27
Space + Water + Range	90 AFUE + 0.64 EF + convection	2,714	4,239	1.6	0.5	27
Space + Water + Dryer + Range	90 AFUE + 0.64 EF + moisture sensor + convection	3,013	4,852	1.6	0.5	28
Existing Gas Customers						
Water Heating	EF=0.64 storage water heater	529	1,383	2.6	13	558
	EF=0.82 tank-less water heater	932	1,672	1.8		
Water + Dryer	0.64 EF + moisture sensor	828	1,996	2.4	0.5	20
Water + Range	0.64 EF + convection	874	1,734	2.0	0.5	20
Water + Dryer + Range	0.64 EF + moisture + convection	1,173	2,348	2.0	2.3	97
Zone Heating	84% efficient wall heater	1,725	957	0.6	0	0
Zone + Water	84% + 0.64 EF	2,254	2,340	1.0	0.3	17
Zone + Water + Dryer	84% + 0.64 EF + moisture sensor	2,553	2,953	1.2	0.01	0.6
Zone + Water + Range	84% + 0.64 EF + convection	2,599	2,691	1.0	0.01	0.6
Zone + Water Dryer + Range	84% + 0.64 EF + moisture + convection	2,898	3,304	1.1	0.02	1.3

The total achievable electric savings potential of fuel conversion in year 20 for the base case scenario was estimated at 26 aMW, which corresponds to an increase in gas use of 1,218,000 Dth, as measured at the meter. A summary of all potentials is given in Table 12. The achievable potential, by end use, is given in Table 11. In calculating the achievable potentials, it was assumed that 75% of the economic potential is likely to be achievable over the course of the planning period. As shown in Figure 19, deployment of fuel conversion resources would begin with a slow growth during the first three years, allowing for program development, and a strong, linear growth for the remainder of the planning horizon.

Table 12. Summary of Fuel Conversion Potentials

	Electric-Only Customers	Existing Gas Customers	Total
Technical Potential			
Electric Savings (aMW)	29	68	97
Additional Gas Usage (1000Dth)	2846	1335	4181
Economic Potential			
Electric Savings (aMW)	10	26	36
Additional Gas Usage (1000Dth)	547	1210	1757
Achievable Potential			
Electric Savings (aMW)	9	17	26
Additional Gas Usage (1000Dth)	501	717	1218

Figure 19. Assumed Ramp Rate for Fuel Conversion



4. Demand Response Potentials

Scope

Demand-response (or demand-responsive) resources (DR) 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 pursued for either reliability or economic/market objectives. These objectives 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 buyback, demand bidding, and dispatchable stand-by generation) strategies. In this assessment, five DR options were considered.

1. Direct Load Control

Direct load control (DLC) programs are designed to interrupt specific end-use loads at customer facilities through directed control by the utility. When deemed necessary, the utility is authorized to cycle or shut off participating appliances or equipment for a limited number of hours on a limited number of occasions. Customers usually do not have to pay for the equipment or installation of control systems and are given incentives that are usually paid through monthly credits on their utility bills. For this type of program, receiver systems are installed on the customer equipment to enable communications from the utility and to execute controls. Typically, DLC programs are mandatory once a customer elects to participate; however, voluntary participation is now an option for some programs with more intelligent control systems and override capabilities at the customer facility. Direct load control is assumed to be applicable to residential (space heating and water heating), large commercial and industrial customers (with loads larger than 250 kW), primarily through coordination with existing energy management systems. In the residential sector, space heating includes central forced air electric and heat pumps, assuming a 50% cycling strategy.

2. Dispatchable Standby Generation

Dispatchable standby generation involves an agreement between the utility and customers with existing on-site generation (generally back-up units), where the utility assumes responsibility for the operation, maintenance and fuel costs in exchange for the ability to dispatch the units for a pre-specified number of hours during system emergencies or high-price periods. Generally, the generating unit is a reciprocating diesel or dual-fuel engine. Given the pollution concerns of running a stationary diesel engine, there are limits to the number of hours in a year the engine can be operated. The Puget Sound Clean Air Agency allows a permitting exemption if the unit is less than 10 MMBtu/hr (~3000 kW) and runs for less than 500 hours per year. Given increased availability of bio-diesel fuel, it may be feasible to retrofit regular diesel stand-by generators to run on bio-diesel, thereby reducing greenhouse gas impacts of these units. Dispatchable standby generation programs are assumed to target multiple industrial and commercial sectors such as hospitals, hotels/motels, offices, warehouses and industrial high-tech facilities with generation units of 500 kW on average.

3. Curtailable Load Program

Curtailable load programs refer to contractual arrangements between the utility and its large customers who agree to curtail or interrupt their operations, in whole or in part, for a predetermined period when requested by the utility. In this study it was assumed that only those customers with a minimum monthly demand of at least 250 kW would be eligible for such a program. In most cases, mandatory participation is required once the customer enrolls in the program; however, the number of curtailment requests both in total as well as on a daily basis are limited by the terms of the contract.

Customers are generally not paid for individual events, but compensated in the form of a fixed monthly amount per kW of pledged curtailable load or in the form of a rate discount. Typically, contracts require customers to curtail their connected load by the greater of a set percentage (e.g., 15-20%) or a predetermined level (e.g., 100 kW). These types of strategies often involve long-term contracts and have penalties for non-compliance, which range from simply dropping the customer from the program to more punitive actions such as requiring the customer to repay the utility for the committed (but not curtailed) energy at market rates. PSE currently has a limited number of customers on interruptible tariffs.

4. Critical Peak Pricing

Critical peak (CPP) or extreme-day pricing refers to incentive-based, DR strategies that aim to reduce system demand by encouraging customers to curtail their loads for a limited number of hours during the year. During such events, customers have the option of curtailing their usage or paying substantially higher than standard retail rates.

Under a CPP program, customers receive a discount on the normal retail rates during non-critical peak periods in exchange for paying premium prices during critical peak events. However, the peak price is determined in advance, providing customers with some degree of certainty about the costs of participation. The basic rate structure is a time-of-use tariff where a rate with fixed prices for usage during different blocks of time (typically on- and off-peak prices by season). TOU rates are designed to reflect the typical costs of generating and delivering power during those time periods. When a critical peak pricing (CPP) element is added, the normal peak price under a TOU rate structure is replaced with a much higher event price, which is intended to reflect the utility's higher cost of supply during critical peak events.

Most CPP programs provide advance notice along with event criteria, such as a threshold for forecasted weather temperatures, to help customers plan their operations. One of the attractive features of the CPP program is the absence of a mandatory curtailment requirement. Residential and small commercial customers (<30 kW) are assumed to be eligible for this program.

5. Demand Buyback

Under demand buyback (DBB) arrangements, the utility offers payments to customers for reducing their demand when requested by the utility. Under these programs, the customer remains on a standard rate but is presented with options to bid or propose load reductions in response to utility requests. 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. PSE operated a demand buy-back program in 2000 and 2001, but currently has no active participants.

Demand buyback is a mechanism that enables consumers to actively participate in electricity trading by offering to undertake changes in their normal patterns of consumption. Participation requires the flexibility to make changes to their normal electricity demand profile and install the necessary control and monitoring technology to execute the bids and demonstrate bid delivery. One of several Internet-based programs is generally used to disseminate information on buyback rates to potential customers who then can take the appropriate actions to manage their peak loads during the requested events. The strategy in this analysis targets the largest commercial and industrial customers (>250kW).

Methodology

Demand-response resources differ from other DSM options, particularly energy efficiency, in at least three important respects, which affect how DR potentials are calculated. First, they depend on customer choice. That is, they require that customers enroll in an on-going program (annually or periodically). Second, unlike energy-efficiency resources, demand response, by definition, affects the quality and availability of service to the customer albeit with the customer's consent. Finally, while energy-efficiency measures continue to provide savings over the normal life of the measure, the impacts of DR depend on the customer's ability and willingness to participate in individual events; and hence depend largely on program design features such as incentives levels, number of events, and whether the program is assumed to be mandatory or voluntary.

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 hybrid, "top-down"/"bottom-up" approach. As in the case of energy efficiency and fuel conversion, demand-response opportunities began with a "technical" assessment. However, the emphasis was on "market potential" as the determining factor in what is achievable. As illustrated graphically in Figure 20, the assessment involved four principal steps as follows.

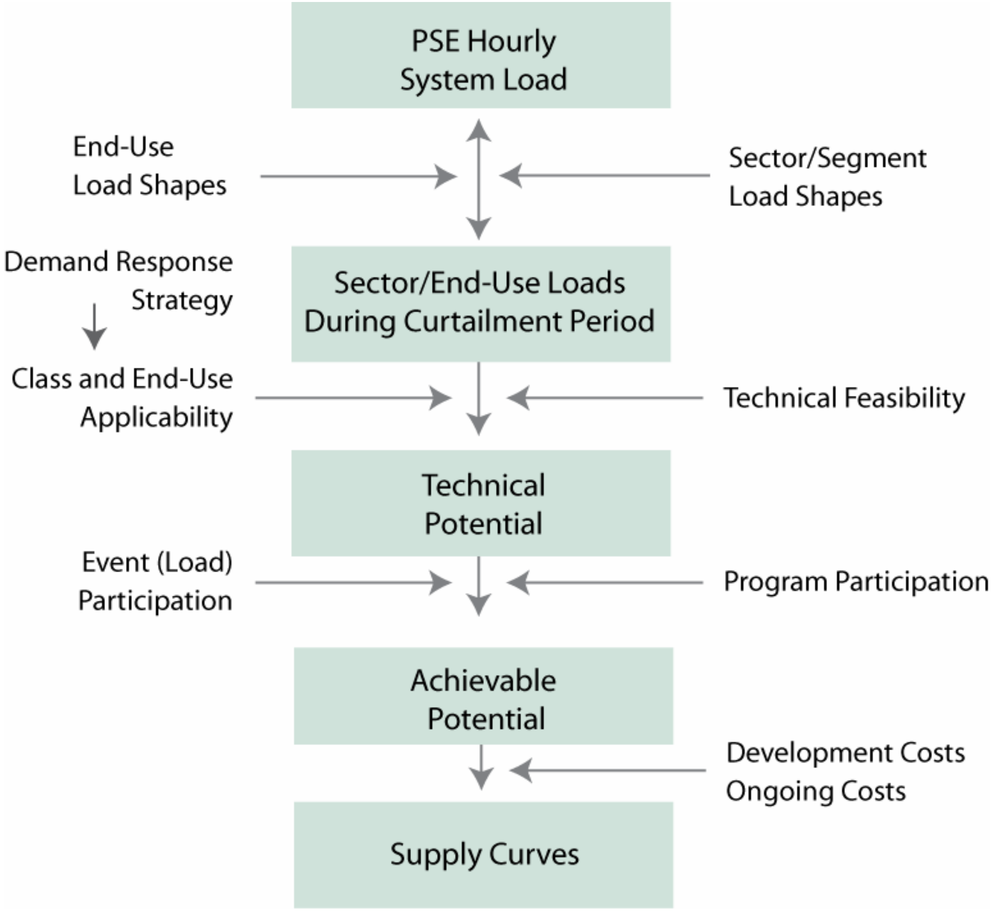
Estimating Total Load During Curtailment Periods. Using total energy sales by customer class and market sector in combination with end-use and sector hourly load profiles, the first step in the analysis was to calculate the class, sector and end-use loads during the likely curtailment periods. Maximum available loads for demand response were calculated based on the highest one-percentile (87 hours) of the system load duration curve.

Determining Technical Potentials. In all demand-response options, in general it may be technically feasible to shed all load during a demand-response event, but the potential would then equal system load, which is not useful for planning purposes and not possible for any single demand-response program. Therefore, technical potentials were estimated by adjusting total load to account for those customer classes and market segments deemed eligible for participation and the applicability and technical constraints of specific end uses. Technical potential is first estimated for the base year, then increased annually to 2027 by the annual peak forecast and assumes a 6.7% avoided line loss.

Estimating Achievable Potentials. Achievable potential is a subset of technical potential and takes into account the customers' ability and willingness to participate in DR programs subject to their unique business priorities, operating requirements, and economic (price) considerations. Estimates of achievable potential were derived by adjusting technical potential by two factors: expected rates of *program* participation, and expected rates of *event* participation. For each demand-response program, the assumed rates of program and event participation were derived 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.

Development of Supply Curves. Finally, supply curves, which represents the quantity of resources (cumulative achievable MW) that can be achieved at or below the cost at any point, are developed using assumptions of development and ongoing costs for each DR strategy, as well as program attrition rates. The assumptions and data used in the analysis are described in greater detail in Appendix D.

Figure 20. General Methodology for Calculation of Demand Response Potentials



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Resource Potentials

The results of the technical potential assessment, as summarized in Table 13, show that in 2027, the highest *technical* potential can be found in residential water heating DLC and critical peak pricing, followed by curtailable load. Yet, due to significant market barriers; such as, customers being disinclined to enroll in programs which require significant behavioral changes, it is unlikely that a program can attain this level of load reduction. Table 14 provides an estimate of that portion of technical potential that is likely to be achieved, once actual market potentials for various strategies are taken into account. Program participation rates are based on experience of regional and national utilities in enrolling customers into demand response programs. Historically, the rates of acceptance by customers have been quite low.

The results indicate that residential water heating DLC and standby generation, with achievable potentials of 34 MW (0.5 percent of system peak) and 31 MW (0.5 percent of system peak) respectively, offer the largest opportunities for demand-response interventions. Achievable peak reductions from curtailable load are estimated at 25 MW, representing 0.4 percent of system peak. Opportunities resulting from critical peak pricing, DLC space heating and large C&I and demand buyback are expected to be relatively small. Because these results do not incorporate the interaction among programs or with energy efficiency, it is expected that the actual cumulative potentials would be somewhat lower than 122 MW although this may be used as an upper bound for planning purposes.

Table 13. Technical Potential (in 2027)

Sector	DLC – Water Heating	DLC - Space Heating	DLC – Large C&I	Demand Buyback	Curtailable Load	Critical Peak Pricing	Standby Generation
Industrial	-	-	18	48	48	-	-
Commercial	-	-	51	128	135	6	68
Residential	381	111	-	-	-	273	-
Total	**381**	**111**	**70**	**176**	**183**	**280**	**68**
Potential as % of PSE Peak	5.8%	1.7%	1.1%	2.7%	2.8%	4.2%	1.0%

Table 14 also displays the per-unit costs for each resource based on a dollar-per-kW-year basis. Standby generation, at $31/kW/year, is expected to be the least expensive option. Demand buyback though relatively inexpensive, at $46/kW/year, is much less reliable than standby generation due to the voluntary nature of the program and the rather low energy price forecasts for the foreseeable future. Curtailable load and critical peak pricing are both estimated at $50/kW/year, while the direct load control programs are all in the range of $100/kW/year due to the high cost of equipment and installation costs. These program costs can vary widely, depending on factors such as incentive levels and costs to recruit customers to participate in these programs.

Table 14. Achievable Potential (in 2027)

Sector	DLC – Water Heating	DLC – Space Heating	DLC – Large C&I	Demand Buyback	Curtailable Load	Critical Peak Pricing	Standby Generation
Industrial	-	-	1	1	6	-	-
Commercial	-	-	3	4	18	0	31
Residential	34	10	-	-	-	12	-
Total	34	10	5	5	25	13	31
Potential as % of PSE Peak	0.5%	0.2%	0.1%	0.1%	0.4%	0.2%	0.5%
Per-Unit Costs ($/kW-year)	$106	$95	$100	$46	$50	$50	$31

The supply curve is constructed from estimated achievable resource potentials and per-unit costs of each resource option. The demand response supply curve, shown in Figure 21, represents the quantity of each resource (cumulative achievable MW) that can be achieved at or below the cost at any point. Cumulative MW is created by summing the achievable potentials along the horizontal axis sequentially, in the order of their levelized costs. For example, the demand buyback program has 5 MW available, and its cost is the second lowest. Therefore, its quantity is added to the 31 MW of standby generation, showing that in total, 36 MW of resources are available at prices equal to or less than $46/kW. The dotted horizontal lines show PSE's total expected cost of capacity at various points in the planning horizon. Until 2012, it is expected that capacity will cost $67/kW/year, which includes $35 for generation capacity and $32 for the deferral value of transmission and distribution investments. After 2012, avoided capacity costs rise to $90, totaling $122/kW/year for capacity, rendering options such as direct load control cost-effective at that point.

Resource Acquisition Ramping Scenario

For demand response, it is expected that the all programs will ramp up at an increasing rate over the first 5 years of the planning period, such that only 5% of the total market potential will be in place in 2008, 35% in 2010, and 100% in year 2012, as shown in Figure 22. This five-year ramp-up is intended to coincide with PSE's projected timing of the need to build peaking resources. Additional resource potential will become available at the same rate as the growth in PSE's peak load.

Due to the unique nature of DR potentials, where two or more strategies can compete for the same customers and end uses, it is not likely that all strategies can attain their individual potentials concurrently. One way to account for such interactions is to rank the competing strategies by their levelized per-unit costs and assume that the lowest cost resources would be deployed first. For example, a 25% reduction in potentials for curtailable load and residential direct load control programs, and a 50% reduction in the C&I direct load control program would lower the total available potential to 103 MW.

Figure 21. Supply Curve for Demand-Response Options

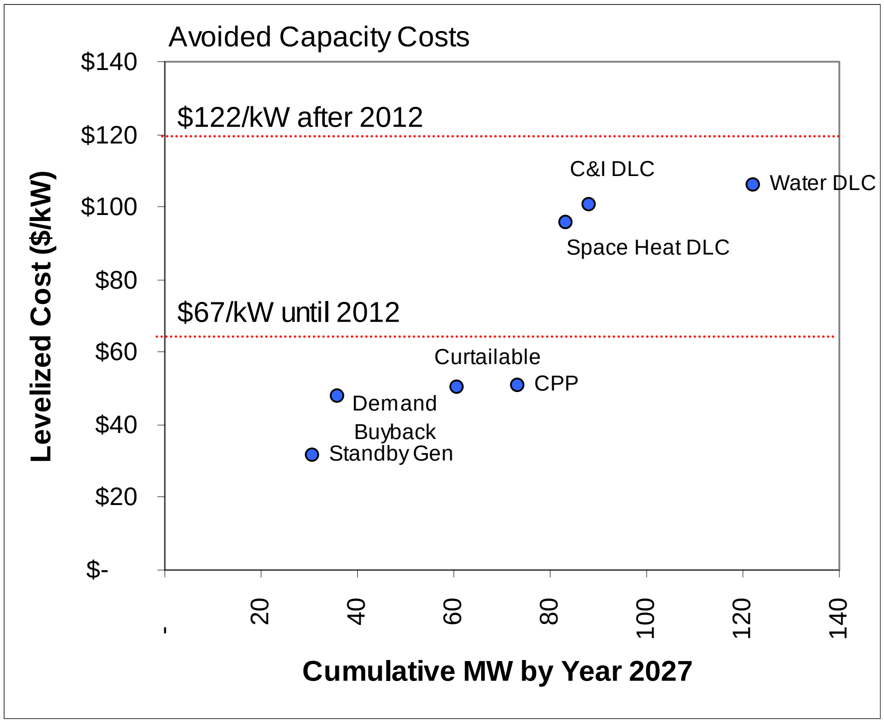
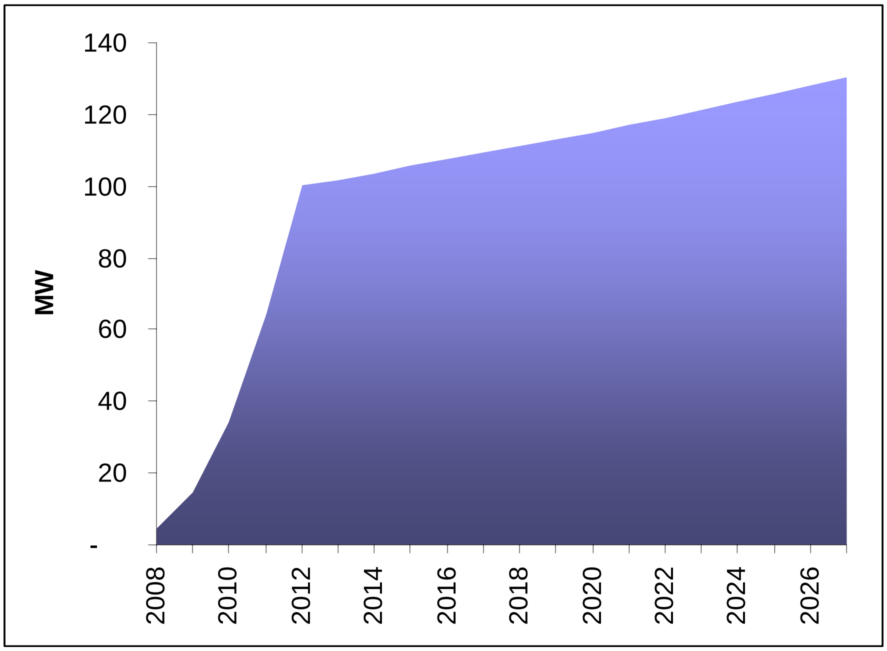


Figure 22. Demand-Response Ramping



5. Distributed Generation

Scope

Distributed generation (DG) encompasses all resources that generate electricity on-site at customers' facilities. For the purposes of this study, this type of power is used for baseline loads, but not as peak load reduction. Peak load reduction, or standby distributed generation, is treated under demand response. The DG technologies explored in this study fall into two primary categories: non-renewable generation and renewable generation. Only those technologies with less than five MW of rated capacity were considered as a demand-side resource.

Non-Renewable Generation

Non-renewable generation includes all technologies that require burning a hydrocarbon fuel, e.g., natural gas, in a generator to produce electricity. The three primary generator technologies are, in order of increasing cost, (1) reciprocating engines (either spark-ignition or compression-ignition), (2) turbines (gas or steam for larger capacity (>1 MW) or microturbines for smaller capacity (<1 MW)), and (3) fuel cells, primarily those using phosphoric acid as the electrolyte, although other types of fuel cells are now becoming commercially viable.

A more energy-efficient use of a standard non-renewable generation unit is as a combined heat and power (CHP) plant. CHP includes a standard non-renewable generator, but improves the overall utility by capturing the waste heat produced by the generator and using it for other purposes. For example, a typical spark-ignition engine has an electrical efficiency of about only 35%. The "lost" energy is primarily waste heat. A CHP unit will capture much of this waste heat and use it for space heating or hot water, achieving an overall efficiency of up to 80%. Thus, savings become available for space/water heating in addition to electricity being generated. All of the same generator technologies used for non-renewable generation are applicable for CHP, except that, in the case of fuel cells, not all types operate at a high enough temperature for efficient capture of the waste heat.

Renewable Generation

Renewable generation encompasses all generation that uses a renewable energy source. Three renewable energy sources are considered: (1) biomass, (2) wind, and (3) photovoltaics (PV). Biomass is further categorized into two subgroups: industrial biomass and anaerobic digesters. Industrial biomass includes the waste product from industries such as lumber mills or pulp and paper manufacturing, while anaerobic digesters create methane gas (biogas) by breaking down municipal solid waste, wastewater or dairy farm waste. The same generators used for non-renewable generation can be used with biomass, and may also be used in a CHP configuration. Industrial biomass is generally large scale, using generators such as steam or gas turbines of >1 MW capacity, while anaerobic digesters are coupled with smaller scale generators, such as reciprocating engines, microturbines or fuel cells.

The other renewable generation technologies are unique in that they do not require a hydrocarbon fuel for power generation and are thus zero-emission generators. For wind, a turbine is used to convert wind energy into electricity; photovoltaics (PV) convert solar radiation into electricity. These technologies do not create significant amounts of heat as a by-product, and thus are electricity-only technologies (not CHP).[9]

Methodology

Traditionally, when determining market potentials for energy-efficiency technologies, the first step is to calculate a "technical potential." This potential assumes all technologies will be adopted in all available applications, regardless of cost or other market barriers. However, for distributed generation technologies, determining a technical potential is not practical. From a purely "technical" point of view, DG can be implemented at any site, resulting in a technical potential of nearly 100%. This type of penetration is unrealistic, however,[10] and thus, for these technologies, only the "market" potential was calculated. The market potentials for different technologies were based, when available, on program successes in the Northwest and in other regions of the country. Details on the methodology for calculating market potentials for DG technology is discussed below.

Non-Renewable Generation

For the DG study, all non-renewable generation technologies include CHP. Standard non-renewable generation (without CHP) is only considered under standby distributed generation, a subset of demand response. In addition, natural gas is assumed to be the main fuel used, as it is throughout the year and is cleaner-burning than diesel[11].

Combined Heat and Power

CHP is assumed to always be utilized for two principal reasons:

1. Based on levelized cost comparison between the available technologies (reciprocating engines, microturbines, fuel cells) of similar capacities in non-CHP vs. CHP applications, the cost for CHP is uniformly less due to fuel savings in heating energy use.

2. Because CHP captures the otherwise waste heat of a stand-alone generator, the overall efficiency of a CHP system is greater. Thus, to make this DG resource portfolio as "green" as possible, all non-renewable generation includes CHP.

The market potential for CHP is based upon California's success of increasing CHP

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[9] Note that one can have a concentrated solar collector that does generate heat; however, those generally operate at much larger scales than are considered in this project, and are thus not discussed.

[10] See, for example, EEA Report No. B-REP-05-5427-013, Sept 2005.

[11] Depending on the metrics used, biodiesel could be considered clean burning, but storage issues make it less available than natural gas.

installations within the Self-Generation Incentive Program (SGIP). This program, funded by the investor-owned utilities of California, provides varying levels of incentives for individual customers to install various DG technologies. This program has been in effect since 2001. The results of SGIP was used as an expected generation outcome for the PSE base case, normalized by the PSE load compared to the load of the participating SGIP utilities. Since SGIP has been in effect for five years, this amount of generation achieved can occur for PSE after a similar five-year period. The three primary technologies (reciprocating engines, microturbines and fuel cells) were all included in SGIP and treated distinctly.

Renewable Generation

Wind

The results from California's SGIP were also used as a base for implementation of small-scale wind capacity (<1 MW). Note that in California, only four small-wind turbines have been adopted, so the sample size is quite small, but nevertheless representative of market penetration. Again, the capacities are normalized by the load ratio, as done with CHP.

Biomass

Industrial

Industrial biomass includes key industrial markets (e.g. lumber, food, pulp & paper) where sufficient internally generated biomass waste can be used for power generation. The projected growth in U.S. electricity generation from industrial biomass was used as the basis for growth in generation by biomass within PSE's industrial sector.[12] Again, the PSE industrial biomass growth is normalized by the ratio of the PSE industrial electrical load to the US load.

One weakness in this analysis is that the U.S. data does not differentiate between large- and small-scale generators. It is possible that much of this generation is larger than 5 MW. (A capacity of 1 MW was chosen as a typical generator size for relatively small scale applications.) To try to compensate for this, an upper limit on capacity was determined through a secondary study.[13] This work indicates that there are 268 MW of technical CHP potential in small-scale (<5 MW) industrial applications in Washington. Since PSE has 6.7% of the WA industrial sales, it is assumed to have a technical potential of 18 MW. This is taken as an upper limit of industrial biomass capacity.

Anaerobic Digesters

This category includes generators utilizing methane gas produced by dairy farms, municipal solid waste and wastewater treatment facilities. The capacity of 250 kW was chosen as a typical generator size. The type of unit used is variable (fuel cell, microturbine, reciprocating engine), and thus there is a wide range in associated cost. Generally, the generator is used in a CHP

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[12] From Energy Information Administration (EIA).

[13] Energy and Environmental Analysis Report No. B-REP-04-5427-004r, Aug 2004.

application, where the captured heat is used to help maintain the digester at the necessary elevated temperatures. Although anaerobic digesters are included within California's SGIP, the availability of the users of these digesters are area-specific, and thus the SGIP was not used as a basis. Instead, the potential was based on information from the Washington Department of Community, Trade and Economic Development[14] and, in particular, the Northwest CHP Application Center[15] databases.

Photovoltaics

Similarly, SGIP's success with PV was not used in this study due to California's significantly different solar profile, and as such, the penetration under SGIP would likely over-predict what might be feasible in PSE territory. Instead, the market penetration rate of the Energy Trust of Oregon[16] within Portland General Electric's territory for the past four years is used as a basis for PSE. Given the similarity in PGE and PSE territories, the same growth is projected for PSE.

Technical Data

In order to determine the costs for the different technologies, an assumed capacity is used. For the three CHP technologies and wind, this assumed capacity is based on the weighted average of the units installed through California's SGIP. For PV, the average size of a typical array in Oregon is used.[17] Typical capacities for industrial biomass vary widely, and typically tend to be larger than other DG technologies. Thus, a 1 MW unit is used as a proxy. Finally, for anaerobic digesters, a rough average of existing and planned generators at various facilities with these digesters was used for the average capacity.[15] These values are summarized in Table 15 below. Also shown in the table is the fuel heat rate, measure life and capacity factors (CF) for the different generators. Heat rates are based on a weighted average of CHP units from the SGIP data. The measure life and CF were obtained from secondary published sources, except the CF for PV, wind and biomass. For PV and wind, the CF is based on PSE's experience, and for biomass, it is based on the actual capacity factor of the Renton Wastewater Treatment biomass unit.[15]

With these prototypical generating units, the associated costs and heat rates, if applicable, can be determined from literature values. For PV and biomass, the costs were based on a unit of the capacity given. It should be noted that for generators used with anaerobic digesters, any of the three CHP technologies could be used; thus, the costs can vary widely. In this analysis, a weighted average levelized cost of the technologies, based on adoption proportions in California is assumed. These costs are reported in Table 16. Administration costs of 10% of the capital expense are included in O&M cost. The heat rate can be used to calculate a fuel cost. Note that even though some of the references from which this cost information was obtained may be

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[14] Personal discussions with Tim Stearns, Senior Energy Policy Specialist, Washington Department of Community, Trade and Economic Development, June 2006.

[15] http://www.chpcenternw.org/

[16] Personal communication with Kacia Brockman of the Energy Trust of Oregon.

[17] "Oregon Photovoltaic Characterization," Prepared for the Energy Trust of Oregon by EMI, October 2003.

somewhat dated, the decrease in the cost of technology is roughly equivalent to the rate of inflation (2.5%). As a simplifying assumption, the 2007 costs are assumed to be the same as in the cited reference.

Table 15. Prototypical Generating Unit

Technology	Capacity (kW)	Fuel Heat Rate (MMBTU/MWh)	Measure Life (years)	Capacity Factor
Reciprocating Engine (RE)	419	4.8	20	0.9
Microturbine (MT)	183	7.4	15	0.95
Fuel Cell (FC)	696	5.8	10	0.95
Wind	663	N/A	25	0.15
Photovoltaics (PV)	0.65	N/A	25	0.12
Industrial Biomass	1,000	N/A	20	0.8
Anaerobic Digesters	250	N/A	15	0.8

Table 16. Costs for Technologies Considered (2007 Dollars)

Technology	Installed Cost ($000/MW)	Annual O&M Costs ($000/MW)	Heat Rate (MMBTU/MWh)
Reciprocating Engine (RE)	1,087	210	5.0
Microturbine (MT)	1,634	272	7.4
Fuel Cell (FC)	5,314	546	5.8
Wind	2,598	347	0
Photovoltaics (PV)	6,700	687	0
Industrial Biomass	1,600	272	0
Anaerobic Digesters	3,906	487	0

Market Potentials

The results of this analysis indicate a cumulative market potentials of 42.2 aMW from all DG technologies. The largest potentials are in reciprocating engine and micro-turbine CHP applications (23.9 aMW) and industrial biomass (10.1 aMW). An additional 6.1 aMW is also expected to be available through the installation of anaerobic digesters. The potential for renewables is small with a total of 0.11 aMW for wind and PV combined (Table 17).

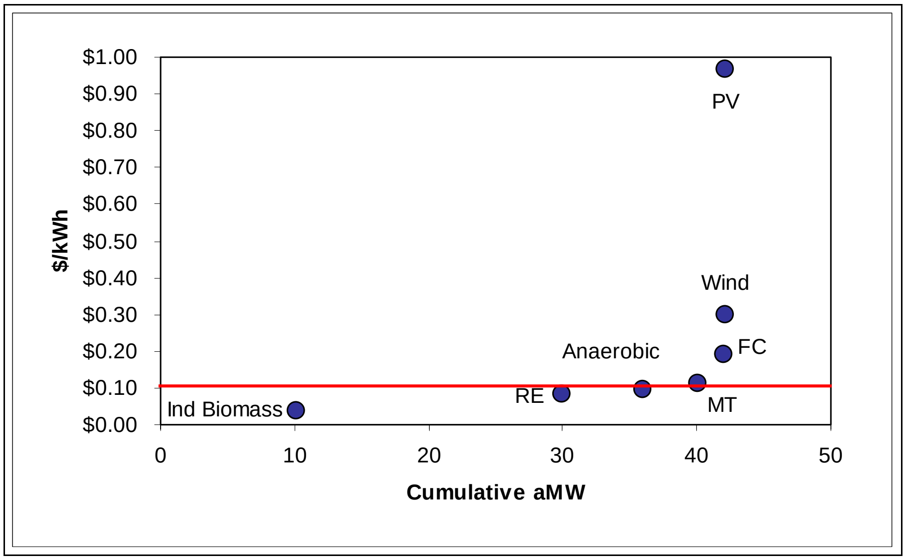
Table 17. Market Potential (aMW) for DG Technologies in Year 2027

Sector	Industrial Biomass	Reciprocating Engine	Anaerobic Digesters	Micro Turbine	Fuel Cell	Wind	Photo Voltaic	Total
Industrial	10.1	6.9	0.0	1.4	0.7	0.00	0.00	19.1
Commercial	0.0	12.9	6.1	2.7	1.3	0.03	0.04	23.1
Residential	0.00	0.00	0.00	0.00	0.00	0.01	0.04	0.1
Total	**10.1**	**19.8**	**6.1**	**4.1**	**2.0**	**0.04**	**0.07**	**42.3**
% of 2027 PSE sales	0.29%	0.56%	0.17%	0.12%	0.06%	0.00%	0.00%	1.2%
Levelized Cost ($/kWh)	$0.04	$0.08	$0.10	$0.11	$0.19	$0.30	$0.97	

Also shown in the table are the levelized costs ($/kWh), calculated using a nominal discount rate of 8.4%. These levelized costs were calculated from the total cost, and also include savings based on deferred transmission and distribution (T&D, $32/kW/yr) and avoided generation ($35/kW/yr through 2012 and $90/kW/yr after 2012).

As is made evident by their levelized costs, not all of these technologies are cost-effective. A cost cutoff, based on the levelized cost for a generic supply-side resource, was used to provide an economic screen. In other words, only technologies that are equal to or less than the cost of a generic supply-side resource are considered. This cutoff is $0.1104/kWh for the base case. Figure 23 gives the cumulative supply curve for the DG base case scenario, where the red line represents this cutoff. Thus, only industrial biomass, reciprocating engines, and anaerobic digesters are cost-effective, resulting in a total economic achievable potential of 36 aMW.

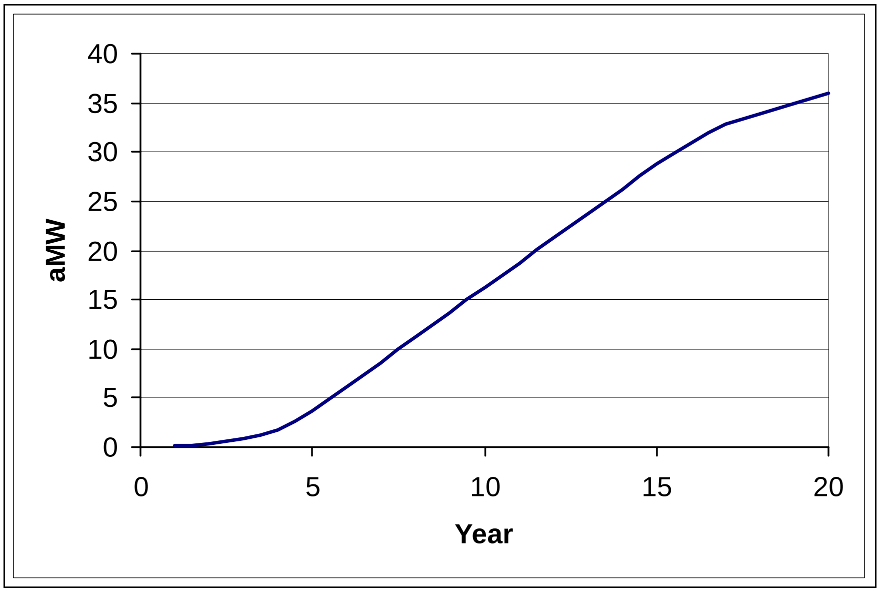
Figure 23. Cumulative Supply Curve for DG in Base Case Scenario



PV-Photovoltaics, FC- Fuel Cell, MT-Microturbine, RE-Reciprocating Engine

The assumed ramp rate of potential is given in Figure 24. This ramp rate allows for a slow buildup of programs over the first five years, significant growth in years 6-15, and a final slowdown in years 16-20 as most of the potential is realized.

Figure 24. Market Penetration Curve for All DG Technologies



Emerging Distributed Generation Technologies

Since a number of these technologies (specifically, PV, Wind, Microturbines and Fuel Cells) are continually developing, there is a good possibility that within the 20-year timeframe there will be significant technological advancements leading to a decrease in cost or increase in capacity factor (specifically for small wind). In addition, it is thought that CHP might break into the residential market, based on pilot programs in other parts of the country.[18] It is assumed that 2% of the total potential will be added to the residential sector.

To account for this, a separate DG resource bundle including an emerging technologies (ET) component was evaluated. This bundle assumes these technological changes will occur in year 10, resulting in a capital cost reduction of 50% (2007$) for PV, MT and FC. Anaerobic digesters, which can be run using a RE, MT or FC, have a 30% reduction in price, to account for the lack of price reduction with reciprocating engines. Wind turbines are assumed to have a 50% increase (to 23%) in the capacity factor, since smaller turbines, more suited to PSE territory, are beginning to be developed.

When emerging technologies assumptions are included, the penetration by sector changes, since CHP is now also within the residential sector (Table 18). However, the total potential is

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[18] For example, Climate Energy (www.climate-energy.com), has recently begun selling a CHP-RE unit for residential use in New England.

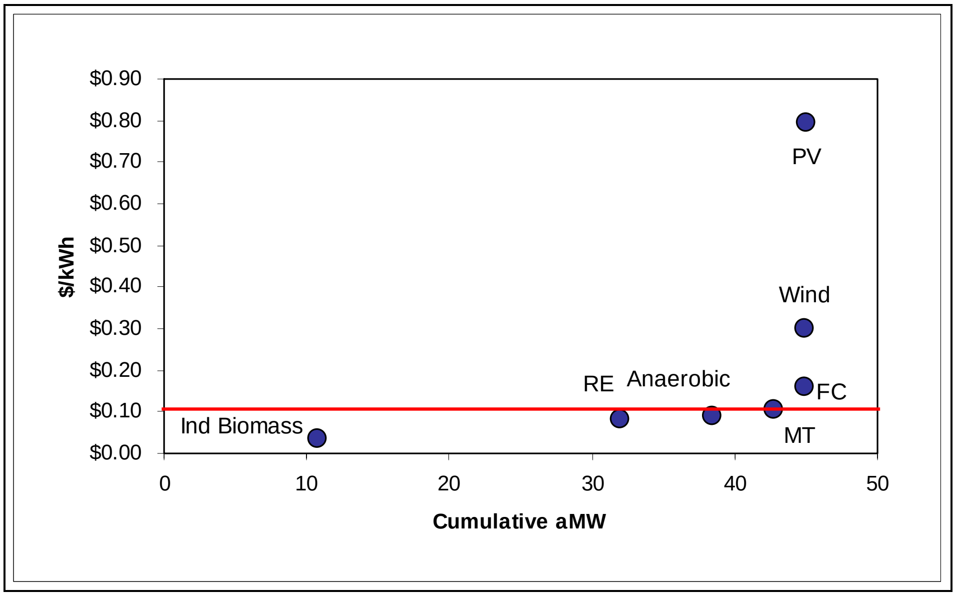
basically the same, though slightly higher, for the additional residential CHP and the increase in capacity factor for installations in years 10 and later for wind. Also included in this table are the levelized costs ($/kWh), calculated using a nominal discount rate of 8.4%.

Table 18. Market Potential (aMW) for DG+ET in Year 2027 Scenario by Sector

Sector	Industrial Biomass	RE	Anaerobic Digesters	MT	FC	Wind	PV	Total
Industrial	10.1	6.9	0.0	1.4	0.7	0.00	0.00	19.1
Commercial	0.0	12.9	6.1	2.7	1.3	0.03	0.04	23.1
Residential	0.0	1.1	0.0	0.1	0.1	0.01	0.04	1.3
Total	10.1	20.9	6.1	4.2	2.1	0.05	0.07	43.5
% of PSE Sales	0.29%	0.59%	0.17%	0.12%	0.06%	0.00%	0.00%	1.2%
Levelized Cost ($/kWh)	$0.04	$0.08	$0.09	$0.11	$0.16	$0.30	$0.79	

The levelized costs of some of technologies decrease with the emerging technology assumptions, as described above. With these reductions, CHP-MT will now fall below the economic cutoff. The total economic achievable potential for DG with ET increases to 40 aMW. The supply curve for DG with ET is given in Figure 25 below. The assumed ramp rate is the same as with the standard DG technology bundle.

Figure 25. Cumulative Supply Curve for DG + ET in Base Case Scenario



6. Resource Potentials Under Alternative Scenarios

In additional to the base case scenario, four additional scenarios for electric and gas potentials under alternative assumptions on future load growth and natural gas prices were considered: (1) current trends with a 10% decrease in avoided cost, (2) current trends with a 25% increase in avoided cost, (3) low growth, and (4) green world. (Natural gas scenario designations are shown in parentheses). Since these scenarios change the avoided cost, they only affect the economic potentials. The key assumptions underlying the five scenarios (gas indicated parenthetically) are:

1. ***Current Trends (Base Case)***
    a. Theme: best estimate of current resource costs and characteristics, fuel prices, state laws and moderate federal environmental policies
    b. Annual load growth: 1.6%
    c. Gas price: forward marks for 2008-2011, and Global Insights long-run fundamental forecast.
    d. Generic supply-side resource cost: $0.11/kWh
2. ***Current Trends + 25% (Base Case +25%)***
    a. Theme: upper bound on reference avoided costs
    b. Annual load growth: Upper bound on reference avoided costs
    c. Gas price: reference + 25%
    d. Generic supply-side resource cost: $0.14/kWh
3. ***Current Trends – 10% (/Base Case -10%)***
    a. Theme: lower bound on reference avoided costs
    b. Load growth: lower bound on reference avoided costs
    c. Gas price: reference – 10%
    d. Generic supply-side resource cost: $0.10/kWh
4. ***Low Growth (Reduced Growth)***
    a. Theme: lower regional and PSE load growth based on lower long-term economic growth
    b. Load demand: Low 1.3%
    c. Gas price: forward marks for 2008-2009, and Global Insights long run low forecast
    d. Generic supply-side resource cost: $0.09/kWh
5. ***Green World (Robust Growth)***
    a. Theme: support for stronger environmental legislation at the federal level, with continuation of state level RPS
    b. Load demand: lower
    c. Gas price: forward marks for 2008-2009, and Global Insights long run high case forecast.
    d. Generic supply-side resource cost: $0.13/kWh

Economic potentials for each of the five DSM resources under these scenarios were recalculated to reflect the effects of these scenarios on avoided costs. Total costs for each resource show the net-present value of the 20-year life cycle costs in 2007 dollars, based on a discount rate of 8.4%. Achievable potentials were then estimated using identical methodology as in the base case. The results are shown in Table 19 and

Table 20.

Table 19. Electric Achievable Resource Potentials Under Alternative Scenarios

Scenario	Energy Efficiency	Emerging Technology	Fuel Conversion	Demand Response	Distributed Generation	Distributed Generation Emerging Tech
Current Trends						
Potential	341 aMW	14 aMW	26.0 aMW	122 MW	36.0 aMW	40.1 aMW
Cost ($000)	$929,762	$21,378	$21,314	$73,881	$72,695	$ 83,419
Current Trends + 25%						
Potential	367 aMW	15 aMW	26.0 aMW	122 MW	40.1 aMW	40.1 aMW
Cost ($000)	$1,127,198	$22,947	$21,314	$73,881	$92,488	$ 91,063
Current Trends -10%						
Potential	330 aMW	14 aMW	25.7 aMW	122 MW	36.0 aMW	40.1 aMW
Cost ($000)	$841,791	$20,988	$20,917	$73,881	$70,355	$80,362
Low Growth						
Potential	321 aMW	14 aMW	22.0 aMW	122 MW	34.0 aMW	40.1 aMW
Cost ($000)	$766,316	$21,001	$17,673	$73,881	$60,864	$76,379
Green World						
Potential	358 aMW	14 aMW	26.0 aMW	122 MW	36.0 aMW	36.0 aMW
Cost ($000)	$1,029,508	$21,953	$21,314	$73,881	$79,156	$78,266

Table 20. Gas Achievable Potential Under Alternative Scenarios

Scenario	Energy Efficiency	Emerging Technology	Fuel Conversion (Additional Gas Use)
Base Case			
Achievable Potential (1000Dth)	69,195	3,779	1,218
Cost ($000)	$203,779	$6,065	$21,314
Base Case + 25%			
Achievable Potential (1000Dth)	97,926	3,530	1,218
Cost ($000)	$403,461	$5,819	$21,314
Base Case -10%			
Achievable Potential (1000Dth)	64,843	3,807	1,200
Cost ($000)	$171,600	$6,073	$20,917
Robust Growth/Green World			
Achievable Potential (1000Dth)	90,308	3,692	1,218
Cost ($000)	$352,399	$5,782	$21,314
Reduced Growth			
Achievable Potential (1000Dth)	56,989	3,675	1,001
Cost ($000)	$141,236	$5,684	$17,673

Price changes generally appear to have no appreciable effect on electric energy efficiency potentials, particularly for emerging technologies, due to the relatively low per-unit costs of these resources. Electric resource levels proved generally stable under all scenarios. For example, a decline of nearly 20% from the highest to the lowest price scenario was shown to result in a modest 6% decrease in potentials. The results of the analysis indicate almost no effect on quantities of demand response potentials.

Examination of natural gas resources under alternative scenarios (

Table 20) however, indicates a more dramatic change in quantities in response to various price assumptions, particularly in energy efficiency based on existing technologies. (Note that fuel conversion figures in

Table 20 indicate an increase in gas consumption and not a savings potential.) As shown in

Table 20, achievable gas conservation potentials may be expected to grow by nearly 42% as a result of a 25% increase in prices above the base-case forecast. More extreme price fluctuations (for example from the low-growth scenario to 25% above the base-case) are likely to produce changes of nearly 72% in resource potentials.

The impacts on fuel conversion options seem more moderate, since the base case is already high on the supply curve. For example, a 15% drop in avoided costs from the highest to the lowest case is shown to produce a less than 20% decline in the potentials for this resource.

7. Methodology for Estimating Potentials

1- Technical Potentials

Technical potential assumes that all demand-side resource opportunities may be captured, regardless of their costs or market barriers. For demand-side resources such as energy efficiency and fuel conversion, technical potentials further fall into two classes: “instantaneous” (retrofit) and “phased-in” (lost-opportunity) resources. The assessment of technical potentials in this study were based on an end-use modeling approach. Simply stated, the approach involves first producing an end-use level forecast assuming “frozen” end-use efficiencies, which is then calibrated to the Company’s system load forecast. A second forecast is then generated, taking into account the impacts of technically feasible demand-side measures. Technical resource potentials are then calculated as the difference between the two forecasts. The methodology underlying the estimation of technical potentials was based on an end-use modeling approach, consisting of two main steps as follows.

1. ***Baseline forecasts***. The development of an accurate baseline—including the present stock of equipment efficiency characteristics and expected changes in stock equipment efficiencies over the planning horizon due to codes, standards, and naturally-occurring conservation—was an essential step to accurately portray the size of conservation resources.
2. ***Estimation of technical, economic, and achievable potential***. The incorporation of technical measure data, economic analysis, and market constraints into the end use forecasting framework allowed the development of alternative scenarios that provided traditional estimates of technical, economic, and achievable potential.

Market Segmentation

The first step in segmentation was to determine the appropriate building types within each sector. These designations came from PSE’s end-use equipment survey for the residential sector, and from PSE’s classification of 2005 sales by building type for the commercial and industrial sectors. Next, appropriate end uses for each sector were determined and mapped to building types within each. Not all end uses within a sector were mapped to every building type (cooking was not mapped to warehouses, e.g.). Table 21 to Table 23 show the building types and end uses for both gas and electric for each sector.

Within each segment, inputs were analyzed separately for different construction vintages. For residential customers, four vintages were analyzed: homes built before 1980, from 1980 to 2000, from 2000 to 2007, and new construction over the planning horizon. For commercial customers, the three vintages were: buildings constructed before 1995, from 1995 to 2007, and new construction over the planning horizon. Industrial customers were split into two vintages: those constructed before 2007 and those constructed over the planning horizon.

Table 21. Residential Sector Dwelling Types and End-Uses

Residential Segments	Electric End Uses	Gas End Uses
Single Family	Space Heat	Space Heat
Multifamily	Heat Pump	Water Heat
Manufactured Home	Central AC	Cooking
	Room AC	Dryer
	Lighting	
	Water Heat	
	Refrigeration	
	Freezer	
	Cooking	
	Dryer	
	Plug Load	

Table 22. Commercial Sector Building Types and End-Uses

Commercial Segments	Electric End Uses	Gas End Uses
Office	Space Heat	Space Heat
Dry Goods Retail	Cooling Chillers	Water Heat
Restaurant	Cooling DX	Cooking
Grocery	Cooling Heat Pump	Pool Heat
Warehouse	HVAC Aux	
School	Lighting	
University	Water Heat	
Hospital	Refrigeration	
Hotel Motel	Cooking	
Other	Plug Load	

Table 23. Industrial Segments and End-Uses

Industrial Segments	Electric End Uses	Gas End Uses
Food Manufacturing	HVAC	HVAC
Wood Product Manufacturing	Indirect Boiler	Process - Boiler
Paper Manufacturing	Lighting	Process - Heat
Printing Related Support	Process Electro-Chemical	Process - Other
Chemical Manufacturing	Process Heat	
Petroleum and Coal Products	Process Other	
Plastics and Rubber Products	Process Cooling	
Nonmetallic Mineral Products	Process Motors - Fans	
Primary Metal Manufacturing	Process Motors - Pumps	
Fabricated Metal Products	Motors – Air Compression	
Industrial Machinery	Motors - Refrigeration	
Electrical Equipment Manufacturing	Process Motors - Other	
Transportation Equipment Manufacturing		
Computer Electronic Manufacturing		
Miscellaneous Manufacturing		

Baseline Forecasts

Before potentials could be estimated, an appropriate and accurate baseline end use forecast for each of PSE’s fuels sectors needed to be created. The purpose of these baseline forecasts was to partition PSE’s customers and sales by:

- Fuel: natural gas and electric
- Customer sector: residential, commercial, and industrial;
- Customer segments: dwellings, business types, and industries within the residential, commercial, and industrial sectors, respectively, for both existing and new construction vintages; and
- End uses: all major end uses applicable for each customer segment.

The breakdown of PSE’s customers and sales into the three sectors was based on an analysis of detailed customer account information. Sales and customer forecasts were provided at the sector level, and 2005 sales data and PSE’s Residential Appliance Saturation Survey (RASS) were used to distribute these forecasts into the various building types for each sector. For each customer segment, appropriate end uses were defined based on available data.

Once the appropriate segmentation was selected for each sector, baseline end-use forecasts were developed by combining current and forecasted customer counts with key market and equipment usage data. For commercial and residential sectors, the end-use-model-derived annual baseline end-use electricity consumption was calculated in each market segment as shown in equation (1) as follows:

$$EUSE_{ij} = \Sigma_e\, ACCTS_i * UPA_i * SAT_{ij} * FSH_{ij} * ESH_{ije} * EUI_{ije} \qquad (1)$$

where:

$EUSE_{ij}$ = total energy consumption for end use j in building type i;

$ACCTS_i$ = the number of accounts/customers in segment i;

UPA_i = the units per account in segment i (UPA_i is generally the average square feet per customer in commercial segments and 1.0 in residential dwellings);

SAT_{ij} = the share of customers in segment i with end use j;

FSH_{ij} = the share associated with electricity in end use j in segment i;

ESH_{ije} = the market share of efficiency level e in the equipment segment ij;

EUI_{ije} = energy consumption per customer (per square foot for commercial) use by the equipment configuration ije.

Total annual consumption in each sector was then determined by summing $EUSE_{ij}$ across the end uses and customer segments. The key to ensuring accuracy of the baseline forecasts was to calibrate the end-use model estimates of total consumption to forecasted PSE sales in 2007. This calibration to base year sales was based on making appropriate adjustments to the data where necessary to conform to known information about customer counts, appliance and equipment saturations, and fuel shares from a variety of sources.

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, the breakdown of the industrial segments were analyzed using an alternative approach. Instead of using such detailed data, the total industrial loads were broken into major end uses within each class using data from the U.S. Department of Energy's Energy Information Administration.

Based on the segmentation design and end use data, a baseline forecast is created for each fuel and sector combination. This forecast is then calibrated to each year of PSE's econometric sales forecast so that potential estimates will be consistent with PSE's expected sales. The baseline forecasts for electric and gas for each sector are shown in Figure 26 and Figure 27, respectively.

Figure 26. 20-Year Electric Sales Forecast by Sector

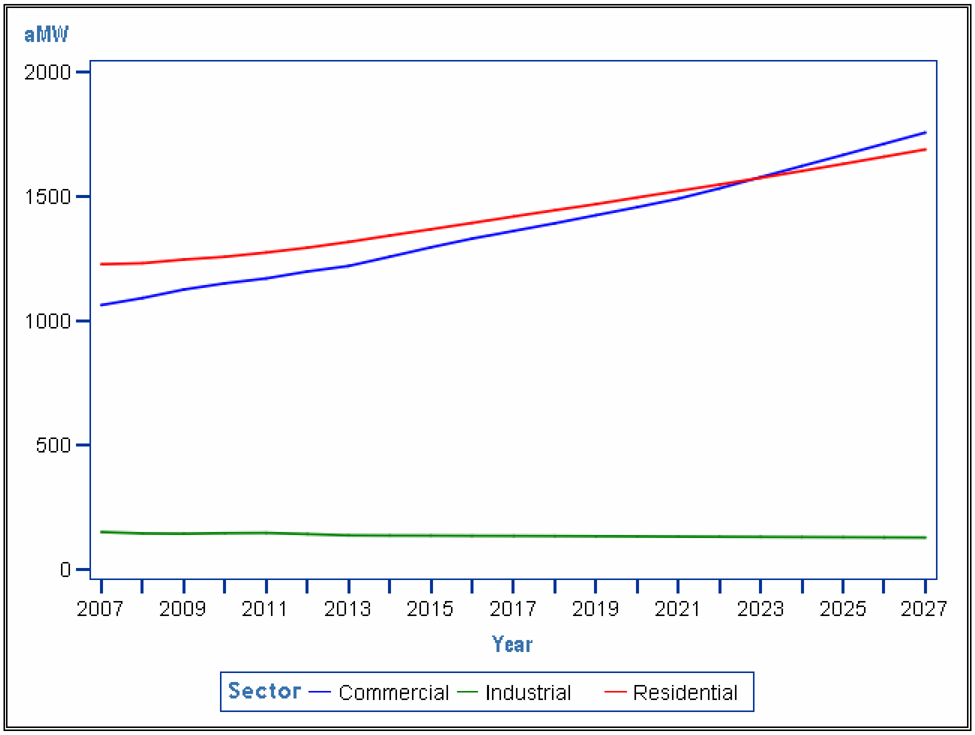
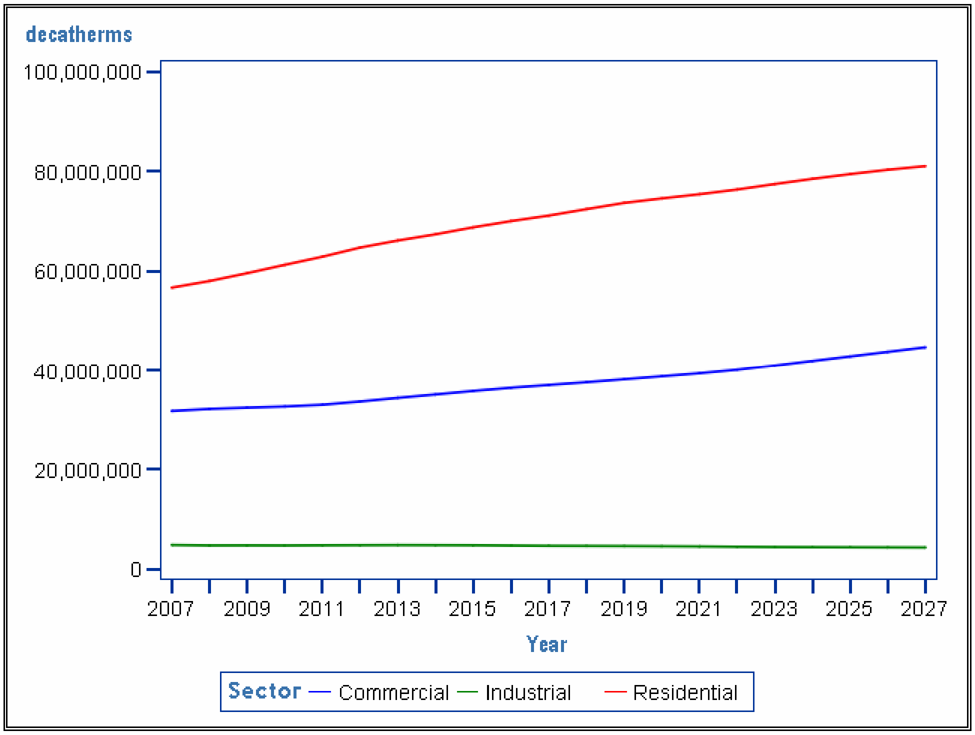


Figure 27. 20-Year Natural Gas Sales Forecast by Sector



Derivation of End-Use Consumption Estimates

Unit Energy Consumption (UEC) and End-Use Indices (EUI) are used to calibrate the End Use Forecasts for residential and commercial sectors, respectively. These represent the amount of energy that goes toward a specific end use in a year. The UEC is given in kWh or therms per year, while the EUI is given in kWh or therms per sq. ft. per year. The choice of UEC or EUI is critical to determine the overall EE potential. Baseline values are typically sourced from previous studies, by building simulation models, from statistical analysis, and/or from engineering experience, and are based on existing prototypical building types within the region. UECs are appropriate in the residential sector because of the homogeneity of energy use within each segment. However, due to the diversity within a particular segment of the commercial sector, UECs are not as appropriate and EUIs are used instead. Estimates of average square footages by commercial building segment were obtained from the 2003 Commercial Building Stock Assessment (CBSA) and PSE's 1994 Commercial End Use Survey.

Residential Sector

For the residential sector, the UECs and sources for single-family (SF) homes are given in Table 24 and Table 25 below for existing and new construction. The sources for the UECs are either from the 2005 IRP or from Conditional Demand Analysis (CDA). More details on the results of CDA analysis are given in Appendix G.

Table 24. Single-Family Electric UECs

End Use	UEC (kWh/yr)		Source
	Existing	New	
Central AC	384	370	Single-family conditional demand model
Cooking	890	761	PSE gas facilities extensions tariff - converted to electric.
Dryer	1275	868	Single-family conditional demand model or PSE gas extensions tariff - converted to electric.
Freezer	823	593	2005 IRP.
Heat Pump	4990	3272	2005 IRP
Lighting	2240	2240	2005 IRP
Plug Load	3389	3389	2005 IRP
Refrigeration	848	676	2005 IRP
Room AC	248	230	Multi-Family conditional demand model normalized by SF to MF number of occupants ratio.
Space Heat	8008	3817	2005 IRP
Water Heat	3510	2908	Single-family conditional demand model

Table 25. Single-Family Gas UECs

End Use	UEC (therms/yr)		Source
	Existing	New	
Cooking	50	43	PSE facilities extensions tariff.
Dryer	49	33	PSE facilities extensions tariff
Space Heat	670	515	Single-family Conditional demand model calibrated to existing use
Water Heat	259	304	Single-family conditional demand model calibrated to existing use

In the cases where the SF UEC was recalculated (not taken from the earlier IRP study), the UEC for multi-family and manufactured homes was found by normalizing the SF UEC by the ratio of the number of occupants or by square footage between it and the SF home. Otherwise, the source was the 2005 IRP, as for SF homes. Table 26 through 29 show the UEC values and their sources for each fuel, dwelling type and construction vintage.

Table 26. Multi-Family Electric UECs

End Use	UEC (kWh/yr)		Source
	Existing	New	
Central AC	212	205	Apply square footage ratio to SF UECs.
Cooking	670	574	Apply number of occupants ratio to SF UECs.
Dryer	960	654	Apply number of occupants ratio to SF UECs.
Freezer	599	431	2005 IRP
Heat Pump	1985	1302	MF new building type normalized by SF new and existing UECs
Lighting	1514	1514	2005 IRP
Plug Load	1534	1534	2005 IRP
Refrigeration	654	638	2005 IRP
Room AC	186	177	Multi-Family conditional demand model.
Space Heat	2773	1519	2005 IRP
Water Heat	2644	2191	Apply number of occupants ratio to SF UECs.

Table 27. Multi-Family Gas UECs

End Use	UEC (therms/yr)		Source
	Existing	New	
Cooking	36	30	PSE facilities extensions tariff. Apply number of occupants ratio to SF UECs.
Dryer	35	24	PSE facilities extensions tariff. Apply number of occupants ratio to SF UECs.
Space Heat	315	245	Calibrated SF conditional demand model UEC to MF new and existing use
Water Heat	184	216	Calibrated SF conditional demand model UEC to MF. Apply occupants ratio to SF UECs.

Table 28. Manufactured Home Electric UECs

End Use	UEC (kWh/yr)		Source
	Existing	New	
Central AC	531	433	Apply square footage ratio to SF UECs.
Cooking	747	639	Apply number of occupants ratio to SF UECs.
Dryer	1070	729	Apply number of occupants ratio to SF UECs.
Freezer	808	579	2005 IRP
Heat Pump	5320	3489	MH new building type normalized by SF new and existing UECs
Lighting	2227	2227	2005 IRP
Plug Load	1266	1266	2005 IRP
Refrigeration	854	680	2005 IRP
Room AC	208	208	Multi-Family conditional demand model normalized by MH to MF number of occupants ratio.
Space Heat	9184	4070	2005 IRP
Water Heat	2947	2441	Apply number of occupants ratio to SF UECs.

Table 29. Manufactured Home Gas UECs

End Use	UEC (therms/yr)		Source
	Existing	New	
Cooking	41	35	PSE facilities extensions tariff. Apply number of occupants ratio to SF UECs.
Dryer	40	27	PSE facilities extensions tariff. Apply number of occupants ratio to SF UECs.
Space Heat	405	311	Calibrated SF conditional demand model UEC to MF new and existing use
Water Heat	211	248	Calibrated SF conditional demand model UEC to MF. Apply occupants ratio to SF UECs.

Commercial Sector

For this study, the majority of the data is sourced from the PSE 2005 IRP as well as from professional engineering judgment. Table 30 and Table 31 represent the electric and gas EUIs for existing commercial buildings. Note that for the Gas EUIs, all the numbers are taken from the earlier IRP filing.

Table 30. Electric EUIs for Commercial Sector by Building Type (kWh/sq. ft. per Year)

Building Type	Space Heat	Cooling DX	Vent / HVAC Aux	Lighting	Water Heating	Cooking	Refrigeration	Misc. Equip
Office	4.5	6.5	2.3	5.0	0.3	-	-	1.6
Grocery	1.4	11.6	5.4	12.1	1.7	5.2	24.2	0.4
Retail	0.9	2.1	0.7	5.7	0.2	-	-	0.1
Restaurant	7.2	9.0	4.0	8.6	4.2	52.4	5.8	0.2
Warehouse	0.8	2.7	1.7	2.9	0.0	-	-	0.1
Hotel Motel	4.8	2.6	0.6	2.9	3.9	-	-	0.1
School	9.7	0.5	0.8	2.2	0.7	-	-	0.1
University	4.0	6.5	1.0	4.4	0.6	-	-	0.3
Hospital	4.6	15.5	2.7	10.2	2.1	-	-	0.5
Other	4.6	4.4	1.9	2.0	0.3	-	-	0.1

Sources: PSE 2005 IRP, except for all Water Heating end use, and Space Heat end use for Office and University building types (shaded blue), where engineering expertise determined an appropriate EUI based on analysis and previous project experience.

Table 31. Gas EUIs for Commercial Buildings by End Use (therms/sq. ft. per Year)

Building Type	Space Heat	Water Heating	Cooking	Pool Heat
Office	0.2	0.1	-	-
Grocery	0.2	0.3	0.7	-
Retail	0.1	0.0	-	-
Restaurant	0.1	0.8	1.7	-
Warehouse	0.1	0.0	-	-
Hotel Motel	0.1	0.8	-	0.11
School	0.2	0.3	0.0	0.17
University	0.3	0.4	0.0	0.14
Hospital	0.5	0.4	0.1	0.03
Other	0.2	0.2	-	-

Source: PSE 2005 IRP .

For new construction, most of the EUIs are identical except for lighting (electric) and pool heat (gas). The new EUIs reflect changes in building code requiring more efficient light fixtures and advances in pool heaters. The values for new construction are given in Table 32 below.

Table 32. EUIs for Commercial New Construction

Building Type	Lighting (kWh/yr)	Pool Heat (therms/yr)
Office	3.9	-
Grocery	9.6	-
Retail	4.4	-
Restaurant	7.5	-
Warehouse	2.4	-
Hotel Motel	2.8	0.06
School	1.9	0.03
University	4.0	0.05
Hospital	8.5	0.02
Other	1.7	-

Industrial Sector

In the industrial sector, a top-down approach was employed to allocate consumption to end uses. Industry-specific data were gathered to distribute the total building load into the major end uses within that industry. The percentage of load that falls into each end use is shown in Table 33 and Table 34, for electric and gas, respectively. The end-use breakout for the industrial building types was taken from the Energy Information Agency’s 2002 Manufacturing Energy Consumption Survey (MECS).

Table 33. Industrial Electric Consumption by Industry Type and End Use

Industry Type	HVAC	Lighting	Indirect Boiler	Process Heat	Process Cool	Process Electro Chemical	Process Motors Fans	Process Motors Pumps	Process Motors Refrigeration	Process Motors Air Compression	Process Motors Other	Process Other	Other
Chemical Manufacturing	6%	4%	1%	3%	9%	18%	7%	15%	4%	16%	15%	0%	2%
Computer Electronic Manufacturing	29%	13%	0%	11%	9%	1%	5%	7%	1%	1%	9%	3%	11%
Electrical Equipment Manufacturing	17%	13%	0%	19%	4%	3%	4%	9%	3%	10%	10%	1%	8%
Fabricated Metal Products	10%	9%	0%	23%	3%	1%	6%	11%	3%	7%	17%	0%	9%
Food Manufacturing	7%	7%	1%	3%	25%	0%	4%	8%	15%	4%	19%	0%	7%
Industrial Machinery	18%	14%	0%	7%	3%	1%	7%	12%	3%	8%	19%	1%	7%
Miscellaneous Manufacturing	20%	15%	9%	9%	6%	0%	6%	3%	0%	5%	22%	0%	4%
Nonmetallic Mineral Products	6%	5%	0%	20%	3%	0%	8%	15%	4%	9%	23%	1%	4%
Paper Manufacturing	4%	4%	3%	2%	1%	2%	16%	25%	4%	4%	32%	0%	2%
Petroleum Coal Products	3%	2%	1%	6%	6%	0%	11%	20%	5%	13%	31%	0%	1%
Plastics Rubber Products	10%	8%	0%	15%	8%	0%	7%	13%	4%	9%	21%	1%	3%
Primary Metal Manufacturing	4%	3%	0%	28%	1%	31%	5%	3%	0%	5%	20%	0%	1%
Printing Related Support	18%	11%	0%	2%	4%	0%	7%	12%	3%	8%	19%	0%	14%
Transportation Equipment Manufacturing	19%	15%	0%	10%	5%	1%	5%	11%	3%	12%	12%	1%	4%
Wood Product Manufacturing	7%	7%	1%	5%	1%	0%	10%	18%	5%	11%	28%	0%	8%

Table 34. Industrial Gas Consumption by Industry Type and End Use

Industry Type	HVAC	Process Boiler	Process Heat	Process Other	Other
Chemical Manufacturing	2%	55%	35%	6%	2%
Computer Electronic Manufacturing	32%	41%	14%	2%	11%
Electrical Equipment Manufacturing	29%	12%	53%	0%	6%
Fabricated Metal Products	21%	16%	62%	1%	0%
Food Manufacturing	7%	51%	38%	5%	0%
Industrial Machinery	37%	18%	37%	3%	6%
Miscellaneous Manufacturing	33%	30%	27%	0%	10%
Nonmetallic Mineral Products	5%	3%	86%	0%	6%
Paper Manufacturing	4%	61%	26%	5%	5%
Petroleum Coal Products	1%	33%	60%	2%	4%
Plastics Rubber Products	19%	38%	29%	2%	11%
Primary Metal Manufacturing	7%	11%	80%	0%	2%
Printing Related Support	34%	20%	41%	2%	2%
Transportation Equipment Manufacturing	32%	26%	32%	2%	7%
Wood Product Manufacturing	13%	27%	49%	4%	7%

Measures Considered

For the residential and commercial sectors, the study began with a broad range of energy-efficiency measures for possible inclusion in the study. These measures were screened to include only measures that are commonly available, based on well-understood technology, and applicable to PSE's buildings and end uses. The industrial sector, in contrast, was based on general categories of process improvements. Table 35, Table 37, and Table 39 show the types of energy efficiency measures that were assessed in the residential, commercial, and industry sectors, respectively. Table 36 and Table 38 show the types of emerging technology measures that were assessed in the residential and commercial sectors, respectively. Equipment measures are those that replace end use equipment (e.g. high efficiency central air conditioners), while retrofit measures are those that reduce end use consumption without replacing end use equipment (insulation, e.g.) A complete list of all electric and gas measures, with descriptions, is given in Appendix A.

Table 35. Residential Energy-Efficiency Measures

End-Use	Measure Types
Heating and Cooling	• Retrofit: air-to-air heat exchangers; ceiling, wall (above and below grade), floor and rim joist insulation; insulated exterior doors; infiltration reduction; duct sealing and insulation; programmable thermostats; tune-up; windows; Northwest ENERGY STAR Manufactured and Single Family homes (shell measures included only). • Equipment:: high-efficiency heat pumps; high-efficiency central AC; ENERGY STAR room AC; high-efficiency gas furnaces.
Lighting	• Retrofit: CFLs; CFL fixtures.
Water Heating	• Retrofit: hot water pipe insulation; faucet aerators; low flow showerheads; temperature setback; ENERGY STAR dishwashers and clothes washers; solar water heaters; drain water heat recovery. • Equipment:: high efficiency water heaters; heat pump water heaters; solar water heaters.
Appliances	• Retrofit: removal of old (inefficient) appliances; ENERGY STAR DVD systems; ENERGY STAR digital set top receiver; ENERGY STAR HDTV; ENERGY STAR office equipment (copiers, monitors, printers and computers); external power adaptors; power strip with occupancy sensor. • Equipment:: ENERGY STAR freezers and refrigerators.

Table 36. Residential Emerging Technology Measures

End-Use	Measure Types
Heating and Cooling	• Retrofit: 'Check Me' and PTCS aerosol-based duct sealing; green roof (eco-roof); leak proof duct fittings; micro channel heat exchangers; small scale absorption cooling; solid state refrigeration cool chips (heat pump only). • Equipment:: advanced cold-climate heat pump
Lighting	• Retrofit: LED interior lighting.
Appliances	• Retrofit: advanced appliance motor (ECM) for a dryer; 1-Watt standby power; solid state refrigeration. • Equipment:: 1 kWh/day refrigerator.

Table 37. Commercial Energy Efficiency Measures

End Use	Measure Types
HVAC	• Retrofit: ceiling and floor insulation; duct sealing and insulation; programmable thermostats; windows; equipment tune-up; pipe insulation; automated ventilation control; evaporative cooling; DDC system (installation and optimization); fan and pump motors; terminal HVAC units; constant air to VAV conversion; cooling tower improvements; economizers; exhaust air to ventilation air heat recovery; retro-commissioning; chilled water / condenser water settings-optimization; chilled water piping loop w/ VSD control; cooling tower approach temperature; cooling tower (two speed and variable speed); pipe insulation for chillers; terminal HVAC units-occupancy sensor control. • Equipment:: high-efficiency heat pumps; high-efficiency chillers and DX packages; high-efficiency gas furnace/boiler.
Lighting	• Retrofit: reduce power density; CFLs; continuous dimming and stepped dimming controls; occupancy sensors; refrigeration lighting and exit signs; integrated classroom lighting; bi-level control stairwell lighting; low-wattage ceramic metal halide; induction lighting.
Water Heating	• Retrofit: hot water pipe insulation; temperature setback; chemical dishwashing systems; demand controlled circulating systems; showerheads; faucet aerators; commercial clothes washers; chemical dishwashers.

End Use	Measure Types
	• Equipment:: high-efficiency water heaters (gas only); solar water heaters (electric and gas); and tank-less water heaters.
Refrigeration	• Retrofit: high-efficiency compressors; demand control defrost; humidistat controls; display case night covers; commissioning; strip curtains; floating condenser heads; case fans; reduced speed or cycling of evaporator fans.
Other	• Power burner fryer; solar pool/spa heating system; swimming pool/spa covers; optimized variable volume lab hood; ENERGY STAR office equipment (copiers, computers, monitors and printers); vending machines (optimization of controls and equipment).

Table 38. Commercial Emerging Technology Measures

End Use	Measure Types
HVAC	• Retrofit: active window insulation; automated building diagnostics SW; green roof; hotel key card room energy control system; leak proof duct fittings.
Lighting	• Retrofit: advanced HID lighting; advanced daylighting controls; cost-effective load shed ballast and controller; hospitality lighting; hybrid solar lighting; LED solid state white lighting; low-wattage ceramic metal halide; scotopic lighting;
Refrigeration	• Retrofit: high-efficiency fan w/ECM motors.
Other	• Under floor ventilation with low static pressure.

Again, due to the more complex nature of the industrial sector, the measures used are not at the same level of detail. Instead, the industrial measures are aggregates, such that often only one or two measures correspond to an end use. The savings and cost information were found by relying on available data from energy-efficiency programs in the Northwest and California, the Department of Energy, and market information on PSE’s customers available from industrial accounts representatives.

Table 39. Industrial Conservation Measures

Electric Measure Types	Gas Measure Types
Lighting Improvements	Process Boiler Upgrades
Process Cooling Improvements	Process Boiler O&M
Fan System Improvements	Steam Distribution Systems
Pump System Improvements	HVAC Improvements
Air Compressor Improvements	
Air Compressor O&M	
Refrigeration Improvements	
Other Motor System Improvements	
HVAC Improvements	

Estimating Technical Potentials

As described in previous sections, once the baseline forecasts are established, the next step is estimating technical potential. This consists of creating an alternative forecast where all possible measures are installed, and subtracting this forecast from the baseline to calculate savings by end use, building type, sector, and fuel.

The following steps were required to develop the inputs underlying this alternative forecast scenario:

1. ***Determine measure impacts.*** The starting point in the assessment of measure impacts was the collection of a variety of inputs necessary to perform the analysis:

   Measure savings: The energy savings associated with a measure as a percentage of the total end-use consumption. Sources include engineering calculations, secondary data sources (case studies), previous studies, and the California DEER database.

   Measure costs: The per-unit cost (either full or incremental, depending on the application) associated with installation of the measure. Sources include merchant websites (Lowes, Home Depot, Sears, Trane, etc.), DEER database, RS Means, and previous studies.

   Measure life: The expected lifetime of the measure. Sources include DEER database and previous studies.

   Measure applicability: A general term that encompasses a number of factors, including the technical feasibility of installation, the current or naturally occurring saturation of the measure, as well as factors to allocate the savings associated with mutually exclusive measures.

   For equipment measures, the savings were estimated based on a shift of all baseline shares to the highest efficiency level. That is, each of the efficiency levels has some baseline share associated with it. These shares include the impacts of federal codes and standards and the small penetration of high-efficiency equipment that occurs without market intervention. In the technical potential scenario, the baseline shares were overridden by shares where 100% of the new or replaced equipment goes to the highest efficiency level. The savings associated with equipment, then, are calculated as the difference between the baseline and equipment replacement scenarios. That is, the estimated savings are essentially an output of the end-use modeling process.

   For non-equipment (or “retrofit”) measures, the estimated savings are better characterized as an input to the model. More specifically, for each end use in each segment, the cumulative effect of the bundle of eligible measures was incorporated into the end-use model as a percentage adjustment to the usage associated with that segment and end-use combination.

   Where there is only one measure that affected an end use, this percentage adjustment would simply be the measure’s percentage savings. However, in nearly every instance in this study there were multiple measures affecting the end use, so a specific methodology was employed to assess the cumulative impacts of all the measures in the bundle.

Table 40. Measure Applicability Factors

	Measure Impact	Explanation	Sources
All Measures	Fuel Saturation	The percentage of customers that use a particular fuel (gas or electric) in PSE's territory for the specific end use (e.g., water heat, space heat, etc.).	• Residential-RES • Commercial-CBSA
	End-Use Saturation	The percentage of customers that have the specific end use. (If not all residential customers had a central AC unit, for example, the end-use saturation would be less than 100%.)	• Residential-RES • Commercial-CBSA
	Measure Share	Used to distribute the percentage of market shares for competing measures (e.g., solar water heater and heat pump water heater both have a 50% measure share of the market share).	• Engineering Judgment • Secondary Data Sources
	Measure Incomplete Factor	Represents the percentage of buildings that do not have the specific measure currently installed.	• 2003 PSE Data Tracking System • Engineering Judgment
	Technical Feasibility	Accounts for the percentage of buildings that can physically install the measure. A couple of factors that may affect this percentage include whether the building already has the baseline measure (e.g., dishwasher), as well as limitations on installation (e.g., size of unit and space available to install the unit).	• Secondary Data Sources • Engineering Judgment
	Measure Interaction	Only considered for lighting. This percentage accounts for additional heating required by the HVAC system because of a reduction in heating produced by more energy-efficient lighting	• Energy Simulation Modeling (eQuest) • Engineering Judgment
Emerging Technology (ET) Measures and Those Measures Competing w/ ET	Year Introduced	Shows the year that the measure is expected to be commercially available (varies from five, to ten, to 15 years).	• ACEEE 2004 • Engineering Judgment
	Initial Share	Shows the initial impact of the measure in a percentage of the market acceptance of the emerging technology measure. All ET measures are assumed to have a 1% share in the year introduced. If the ET measure has a competing measure, that competing measure's share will be reduced to 99% (100% minus the initial share of the ET measure).	• ACEEE 2004 • Engineering Judgment
	Year of Final Share	Always year 20. The relationship between the initial year introduced and year 20 is assumed to be a linearly increasing function for ET measures.	• ACEEE 2004 • Engineering Judgment
	Final Share	This factor takes into account increasing market acceptance for the ET measure.	• ACEEE 2004 • Engineering Judgment

NOTES: RES: Residential Energy Survey; CBSA: Commercial Building Stock Assessment; ACEEE 2004: Emerging Energy-Savings Technologies and Practices for the Buildings Sector as of 2004 (Report A042).

For the single measure case, Equation (2) below shows the basic equation for estimating *retrofit* or *new construction shell/plumbing measure* savings, where the impact is defined as a measure that changes the annual consumption of an end use without affecting the basic end-use equipment. The classic example of this is additional insulation in existing or new buildings. The insulation reduces consumption without changing the basic HVAC equipment in the building.

$$SAVE_{ijm} = EUI_{ije} * PCTSAV_{ijem} * APP_{ijem} \tag{2}$$

where:

$SAVE_{ijm}$ = annual energy savings for measure *m* for end use *j* in building type *i*;

EUI_{ije} = calibrated annual end-use energy consumption for the equipment configuration *ije*;

$PCTSAV_{ijem}$ = the percentage savings of measure *m* relative to the base usage for the equipment configuration *ije*, and takes into account interactions among measures such as lighting and HVAC calibrated to annual end-use energy consumption;

APP_{ijem} = a fraction that represents a combination of different factors that determine a measure's overall applicability, including the technical feasibility, existing measure saturation, end-use interaction, and any adjustments needed to allocate savings with other mutually-exclusive measures.

As stated previously, however, the study dealt almost exclusively with cases where multiple measures affected a single end use. In such instances, the assessment of cumulative impact had to account for the interaction among the various measures, a treatment referred to as "measure stacking." The primary means to account for stacking effects is to establish a rolling, reduced baseline that is applied iteratively as measures in the stack are assessed. This is shown in equations (3) through (5), where measures 1, 2, and 3 are applied to end use life:

$$SAVE_{ij1} = EUI_{ij\,e} * PCTSAV_{ije1} * APP_{ije1} \tag{3}$$

$$SAVE_{ij2} = (EUI_{ije} - SAVE_{ij1}) * PCTSAV_{ije2} * APP_{ije2} \tag{4}$$

$$SAVE_{ij3} = (EUI_{ije} - SAVE_{ij1} - SAVE_{ij2}) * PCTSAV_{ije3} * APP_{ije3} \tag{5}$$

The result of this process was that a measure's absolute savings as part of a bundle of measures was less than its savings on its own. These two measures of absolute savings were referred to as "stand-alone" and "stacked" savings. Note that a measure's order in the stack had an effect on its absolute savings. For this study, the order was based on ascending levelized cost of each measure, which ensured that the least expensive resources were incorporated first.

2. ***Estimate phased-in technical potential.*** Estimates of technical conservation potential were developed by incorporating the measure impacts into four alternative scenarios to the baseline forecast that reflect the four resource categories presented in the introductory section:

1) Equipment in existing construction
2) Retrofit measures in existing construction
3) Equipment in new construction
4) Shell and plumbing upgrades in new construction

As described above, for each of the equipment measure scenarios, the baseline efficiency shares were shifted from the baseline to 100% for the highest efficiency. In effect, any equipment either in new construction or replacement on burnout was shifted to the highest efficiency. For non-equipment measure scenarios, the measure impacts were incorporated to develop revised estimates of baseline consumption across all efficiency levels for a given end-use.

2- Economic Potential

Economic potential represents a subset of technical potential and includes only those measures that are deemed cost-effective based on a total resource cost test (TRC) criterion. For each measure, the test is structured as the ratio of the net present values of the measure's benefits and costs. Only those measures with a benefit-to-cost ratio of equal or greater than 1.0 are deemed cost-effective and are retained. That is, for each measure, we have:

$$\frac{TRCBenefits}{TRCCosts} \geq 1$$

where:

$$TRCBenefits = NPV\left(\sum_{year=1}^{measurelife}\left(\sum_{i}^{i=8760}(impact_i \times avoided\cos t_i)\right)\right)$$

and

$$TRCCosts = MeasureCost$$

Benefits include the value of time- and seasonally-differentiated energy and capacity savings, transmission and local distribution cost savings, deferred-transmission system expansion costs and the conservation credit granted by the Northwest Power Act.[19] In order to capture the full value of time- and seasonally-differentiated impacts of each measure, a unique hourly benefits profile was calculated for each measure as the product of the measure's hourly end-use load

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[19] The Pacific Northwest Power Planning and Conservation Act mandates that "the "estimated incremental system cost" of any conservation measure or resource shall not be treated as greater than that of any non-conservation measure or resource unless the incremental system cost of such conservation measure or resource is in excess of 110 per centum of the incremental system cost of the non-conservation measure or resource." [Northwest Power Act, §3(4)(D), 94 Stat. 2699.]

shape and hourly avoided costs. This approach in effect produces a unique hourly (8760) avoided cost benefit for each measure. The measure costs include the total installed cost of the measure, and applicable operation and maintenance costs (or savings) associated with ensuring the measure's proper functioning over its expected life. The present value of total measure benefits and costs are calculated by discounting future streams at PSE's weighted average cost of capital. The basis and assumptions underlying the calculation of resource benefits and costs are summarized below.

Resource Benefit Components

- Avoided hourly generation (energy) costs: Variable, a function of measure load shape
- Avoided annual generation (capacity) costs: \$35/kW/year until 2012, and \$90/kW/year thereafter
- Avoided line losses: 6.7% for electricity and 0.8% for natural gas
- Avoided transmission system expansion costs: \$32/kW/year
- NW regional conservation credit: 10% (energy efficiency and demand response only)
- Discount Rate: weighted average cost of capital (8.4% per year)
- Administration Costs: 10% of measure costs

Resource Cost Components

- Capital measure costs: Variable by measure
- Installation labor costs: Variable by measure
- On-going O&M costs: Variable by measure
- Additional "other" fuel costs: Fuel conversion and distributed generation
- Discount Rate: weighted average cost of capital (8.4% per year)

There are three important considerations in interpreting the results of economic screening as it relates to the assessment of conservation potentials. First, the analysis is based on a total resource cost (TRC) perspective and as such no conclusions may be drawn as to how the measure costs might accrue to the utility and participants in energy efficiency programs. Indeed, it is implicitly assumed in the analysis that PSE would bear the full cost of measures. This consideration has important implications in terms of achievable potentials, since in most DSM programs the utility seldom pays the full incremental cost of the measure.

Second, the outcomes of the screening procedure described above depends on assumptions that will likely change over time. Measure costs, for example are likely to decline over time as the demand for energy efficient technologies increases. More important are the assumptions concerning the avoided costs. Clearly, as avoided costs change, so would the value of savings resulting from the installation of energy efficient technologies. So a measure failing the economic screen in earlier years of the planning period may become cost effective in later years if avoided costs increase. The third consideration is that the economic analysis is based on assumptions intended to reflect the "average" or "typical" customer. This means that while a measure might not pass the economic screen within the context of the study, there could well be instances where the measure would be cost-effective.

3- Achievable Potential

Achievable potential is defined as that portion of economic potential that is expected to be reasonably achievable in the course of the planning horizon. Developing accurate estimates of achievable levels of conservation are a critical element in utility integrated resource planning. Understating achievable potential could lead to significant lost opportunities to the utility's resource acquisition process. On the other hand, if achievable potentials are overstated, unrealized conservation potentials would create gaps in the resource plan.[20]

Unfortunately, there are no standard methods for predicting actual levels of achievable potentials with certainty. In the majority of conservation potential studies, estimation of achievable potentials generally tends to be based on either arbitrary expectations of market penetration or the utility's past experience with energy efficiency programs. In the Northwest, for example, the Northwest Power and Conservation Council has historically assumed that 85% of the estimated economic potential is likely to be achievable.[21] In its 2004 IRP, PSE assumed that 50% of the economic potentials would be achievable.

In practice, levels of cost-effective conservation potentials that may be assumed achievable, depend on several factors, including customers' willingness to participate in conservation programs (or market potential), which is itself a function of incentive levels offered by the utility, energy prices, and non-price factors such as specific operational constraints that may prevent the customer from participating in conservation programs. It is, however, difficult to identify all such factors and to quantify their likely impacts without rigorous and systematic market studies.

In this study, we decided to rely on the experience and expert judgment of PSE's professional energy services staff. The energy services staff were surveyed in a modified Delphi framework to arrive at a consensus view on what would be a "reasonable" and "realistic" expectation for market penetration rates in various customer sectors and market segments. These estimates were developed by surveying PSE's energy services staff. Based on the results of this survey, summarized in Table 41, it was assumed that 85% and 65% of the economic electric energy efficiency potential in existing buildings and new construction markets respectively, are likely to be achievable in the course of the planning period. Achievable potentials for natural gas

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[20] Accurate estimates of achievable potentials are particularly relevant in the context of Washington's Clean Energy Initiative, which directs utilities to pursue all cost-effective and "feasible" conservation with penalty provisions should utilities fail to meet such targets.

[21] The 85% figure might have its origin in Northwest's Hood River Conservation Project, a direct installation program implemented in Hood River, Oregon between 1983 and 1985. The project succeeded in achieving a market penetration of 85% of eligible households in the area. For a summary description of the project see Hood River Conservation Project Profile # 12, 1992, Bonneville Power Administration.

measures were assumed to begin at 55% (for existing buildings) and 35% (for new construction) of economic potentials during the early years of planning, and gradually ramp up to 75% and 55% for existing and new buildings respectively.

Rates for achievable potentials are assumed to be lower in the new construction market due mainly to issues concerning the concept of economically favorable “windows of opportunity” for equipment purchase decisions. The basic idea here is that the economic viability of investments in efficient equipment varies with the type and timing of construction activity. The size of economic windows varies depending on the specific equipment in question and on the timing of equipment purchase and installation. Although conservation resources in the new construction markets may be available at a lower cost than in retrofit markets, in order for the utility to intervene, it must synchronize its efforts with the normal cycle of new construction activity and act within limited windows of opportunity as they become available. This would require additional effort—and expenditures—for timely coordination with participants in the new construction market such as developers and A&A firms.

Table 41. 20 Year Market Penetration Rates by Fuel and Sector

	Electric		Gas	
Sector	Existing Construction	New Construction	Existing Construction	New Construction
Residential	85%	65%	75%	55%
Commercial	85%	65%	75%	55%
Industrial	85%	65%	75%	55%

The assumed levels of achievable potentials are meant to serve principally as planning guidelines. Ultimately, realizing these levels of demand-side opportunities will depend on the “market potentials” for various demand-side resources, which depend largely on factors beyond the Company’s control. Such factors include, among others, the customers’ willingness and ability to participate in the demand-side programs, administrative constraints, and availability of an effective delivery infrastructure. Clearly, the customer’s willingness to participate in demand-side programs depends on the amount of incentive that is offered. Depending on the actual experience of various programs in the future, PSE may consider alternative, more efficient and cost-effective means such as market transformation and promotion of codes and standards, in order to capture portions of these resources.