Appendix H: Demand Response

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INTRODUCTION

The Council's definition of demand response (DR) is voluntary and temporary change in consumers' use of electricity when the power system is stressed. The change in use is usually a reduction, but there could be situations in which an increase in use would relieve stress on the power system and would qualify as DR.

Demand response is similar to conservation in that it occurs on the consumer's side of the meter. However, while conservation is an increase in efficiency that reduces energy use while leaving consumers' levels of service unchanged, demand response is a change in use of electricity at particular times that may change quality or level of service and may in some cases actually increase energy use overall.

This appendix reviews the treatment of demand response in the Council's Fifth Power Plan, reviews progress in understanding and implementation of demand response since that plan, and describes the work on demand response in the Sixth Power Plan.

DEMAND RESPONSE IN THE COUNCIL'S FIFTH POWER PLAN

The Council's Fifth Power Plan[1] was the first of the Council's plans to consider demand response as a resource.[2] The plan explained that concern with demand response rises from a disconnect between power system costs and consumers' prices. While costs of providing electricity vary with power system circumstances that change from hour to hour and season to season, electricity consumers seldom see prices that reflect these "real time" costs. This disconnect leads to higher consumption at high cost times than is optimal, with overinvestment in peaking capacity.

The Fifth Power Plan examined two general categories of options to remedy the disconnect, pricing and programs.

Pricing Options

The Fifth Power Plan outlined the main categories of retail pricing options that have been proposed for incenting demand response. The objective of these options is to give consumers prices that more closely approximate actual system costs through the hours of the year, leading consumers to reduce their usage appropriately when system costs are high. The plan described three main categories of time sensitive pricing structures and their advantages and disadvantages:

Real time prices vary with demand and supply conditions as they develop, so that consumers receive efficient signals to guide their usage decisions. Since real time prices will often vary from one hour to the next, they require meters that record hourly use and that can notify customers of the hourly changes in prices. These meters were less common when the fifth plan was being developed than they are now, but they are still an obstacle to universal use of real time prices. Real time prices can convey the most accurate reflection of electricity costs as events occur, but they can also be the most volatile of pricing structure, and that volatility has been a concern for many customers and regulators.

Time of use prices are set based on expected costs of serving loads in specified seasons and times of day. Time of use prices are set for a year or more at a time, so are less volatile than real time prices, but they are inherently less able to reflect the unexpected demand and supply situations that occur and that represent the greatest opportunities for demand response to benefit the power system. In short, time of use rates raise less concerns among regulators and ratepayers, but they have less potential benefits.

Critical peak prices can be viewed as a compromise between real time prices and time of use prices. Critical peak prices are usually set at mutiples (4-6 times) of ordinary retail rates, but only apply to a small part of the year, typically 1 percent of all hours (87 hours/year), limiting volatility in customers' bills. At the same time, critical peak prices have some of the efficiency

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[1] The Fifth Power Plan is posted at http://www.nwcouncil.org/energy/powerplan/5/Default.htm, with Chapter 4 on DR at http://www.nwcouncil.org/energy/powerplan/5/(04)%20Demand%20Response.pdf and Appendix H on DR at http://www.nwcouncil.org/energy/powerplan/5/Appendix%20H%20(Demand%20Response).pdf.

[2] According to the strict legal definitions of the Northwest Power Act, demand response is probably not a "resource" but a component of "reserves." For ease of exposition, the plan refers to demand as a resource in the sense of the general definition of the word - "a source of supply or support."

potential of real time prices, because utilities can call critical peak price events when the system is most in need of demand response (with previous notice, commonly 24 hours).

Program Options

The Fifth Power Plan described the main categories of program alternatives to pricing policies to achieve demand response. These program alternatives all involve some form of compensation to customers willing to modify their use, or allow the utility to modify their use, of power when it benefits the power system:

Interruptible contracts have been used for many years to help utilities manage the risk of unexpected problems. For a discount in the customer's underlying price, the utility has the right to cut service to the customer when necessary. The discount and terms of interruption vary.

Direct control has also been used for many years, typically applied to air conditioners. The customer is typically compensated with a seasonal discount in exchange for the utility's right to reduce air conditioning service for a specified number of times during the season.

Demand buyback has been used in the Pacific Northwest and elsewhere to enable customers who were unwilling to make the commitment called for by interruptible contracts or direct control programs to play a part in demand response. Customers participating in demand buyback programs respond on a day-ahead basis to offers from the utility or system operator of payment for load reduction. Typically the utility announces what it is willing to pay for load reduction the next day and the customer responds with an amount of reduction it is willing to make for that level of compensation. The utility notifies customers whose reductions will be compensated usually the afternoon of the day before reductions are needed.

Emergency generation installed in such facilities as hospitals, data centers and office buildings can be dispatched by the local utility, subject to environmental limitations. Arrangements between the utility and the owners of emergency generation can be anything acceptable to both parties, but may include a reservation or capacity payment and an energy payment when the generator is operated.

Estimate of Potential Demand Response

The Fifth Power Plan reviewed DR experience in the Pacific Northwest and elsewhere in the U.S. While the Pacific Northwest pursued some kinds of demand response during the 2000-01 West Coast electricity market crisis, historically the hydroelectric system of our region had made it relatively easy to meet our regional peak demands without demand response. By contrast, elsewhere in the U.S. the costs of meeting peak loads were closely related to building more thermal generation, at higher costs, creating incentives to consider demand side alternatives, i.e. demand response. As a result, demand response experience was generally more common outside the Pacific Northwest.

The Fifth Power Plan made a very simple estimation of the possible size of the demand response, arriving at about 1,600 megawatts[3] by a set of conservative assumptions, and the plan used 2,000

[3] Page H-13, Appendix H of the Fifth Power Plan

megawatts as the basis for its portfolio analysis of the effect of demand response on long run cost and risk. These estimates matched rules of thumb and experience from around the country, which suggested that demand response potential in the range of 5 percent of peak load[4] was a reasonable target.

Estimates of Cost Effectiveness of Demand Response

The plan's exploration of cost effectiveness measures of demand response examined three methods of estimating the generating cost avoided by demand response:

A simplistic estimate of the cost/MWh at an assumed number of hours of operation of a "stand-alone" peaking generator. This method resulted in estimates of $677/MWh to $1,179/MWh for generators running 100 hours/year, with higher costs for generators running fewer hours/year.[5]

The estimation of the incremental cost of electricity from peaking generators added to the existing system, with credit of operational savings and spot market sales from the new units. This estimation used the AURORA® model to simulate the operation of the interconnected power system of the entire Western U.S. along with the Canadian provinces of British Columbial and Alberta and the norther part of Baja California in Mexico. The resulting estimates of avoided cost ranged from $519/MWh to over $14,000/MWh, depending on hydro conditions and reserve margin assumptions.[6]

The simulation of the effect of demand response on the cost and risk of the power system over a range of 750 possible 20-year futures, using the Council's portfolio model. This simulation did not estimate avoided cost, but compared the cost and risk combinations of portfolios that included up to 2,000 megawatts of demand response with fixed costs of $2,260/MW-yr and variable costs of $150/MWh,[7] compared to portfolios with no demand response. The comparison showed substantial net reductions in both cost and risk when demand response was included in the portflios. These net benefits clearly indicate that demand response at these costs is cost effective.

The results of the different methods differed, but they all indicated that reductions in demand for electricity at appropriate times could avoid very significant costs, and in the case of the portfolio model method could reduce the financial risks to the system as well.

Action Plan

The Fifth Power Plan set a target of 500 megawatts of demand response to be achieved by 2009. This target was not based on detailed analysis of acquisition costs of demand response, since our experience with these costs was slim. Instead, the target was intended to encourage utilities and others in the region to gain experience with demand response, putting future programs and analysis on a firmer basis.

[4] The system peak load has ranged up to 36,000 megawatts in the period 1992-2007, five percent of this would be 1,800 megawatts.
[5] Page H-16, Appendix H of the Fifth Power Plan
[6] Table H-2, Appendix H of the Fifth Power Plan
[7] Page H-21, Appendix H of the Fifth Power Plan

Finally, the Fifth Power Plan also included eight action items for the region to accomplish by 2009:

1. Expand and refine existing programs.

2. Develop cost effectiveness methodology for demand response.

3. Incorporate demand response in utilities' integrated resource plans.

4. Evaluate the cost and benefits of improved metering and communication technologies.

5. Monitor cost and availability of emerging demand response technologies.

6. Explore ways to make price mechanisms more acceptable.

7. Transmission grid operators should consider demand response for the provision of ancillary services, on an equal footing with generation.

8. The Council will host several workshops to identify and coordinate efforts to accomplish these action items.

PROGRESS SINCE THE FIFTH PLAN

Action Plan Items

Since the release of the Council's Fifth Power Plan there have been a number of developments related to demand response. Several of these developments are related to the action items just listed:

Action Item 1. A number of existing demand response programs have been expanded. Idaho Power and PacifiCorp have expanded programs that allow them to interrupt air conditioning and irrigation. Portland General Electric has substantially increased the number of their customers' standby generators that PGE can dispatch when necessary.

Action Items 2, 6, and 8. Council staff held 3 workshops in 2005 and 2006. These workshops focused mainly on cost effectiveness methodology. Beginning in 2007 the Council, along with the Regulatory Assistance Project (RAP) and Lawrence Berkeley National Laboratory (LBNL),[8] formed the Pacific Northwest Demand Response Project (PNDRP).

The objective of the PNDRP is to provide suggestions to the region's regulators to help encourage the development of demand response. Consultation with the regulators resulted in narrowly focusing the topics to be taken up by the PNDRP: cost effectiveness methodology, pricing strategies, and the integration of demand response into transmission and distribution planning. By December of 2008 PNDRP had succeeded in agreeing on a set of cost effectiveness guidelines, and began to examine pricing strategies. These cost effectiveness guidelines provide an initial valuation framework for demand response resources and should be

[8] The participation of the RAP and LBNL is supported by the U.S. Department of Energy.

considered as a screening tool by state commissions and utilities in the Pacific Northwest. The cost effectiveness guidelines are at the end of this Appendix in Appendix H-1.

The PNDRP is expected to continue work on pricing strategies in the spring of 2010.

Council staff is also working on incorporating risk into the evaluation of cost effectiveness of demand response, using the Council's portfolio model. Progress in this work is described below, in the "Portfolio Analysis of Demand Response since the Fifth Plan" section.

Action Item 3. Utilities are including demand response in their integrated resource plans, and further expansions of demand response programs are planned.

Action Item 4. Portland General Electric and Idaho Power have begun to install advanced metering for all their customers. In addition, with funding from the American Recovery and Reinvestment Act (ARRA) the U.S. Department of Energy has awarded grants to Avista Utilities, Central Lincoln People's Utility District, Idaho Power Company, Pacific Northwest Generating Cooperative, and Snohomish Public Utility District to support the purchase and installation of smart grid technologies, which will include improved metering and communication. U.S. DOE has also awarded a grant to the Western Electricity Coordinating Council (WECC) for similar purposes, which will involve the participation of three regional utilities, Bonneville Power Administration, Idaho Power Company, and PacifiCorp. These grants require negotiations between the recipients and U.S. DOE to finalize details, so that the final list of projects that will proceed was not known when this was written.

Bonneville, Battelle and 12 partners also have submitted a proposal to U.S. DOE to demonstrate the practicality and value of smart grid technologies. This project had not been approved when this was written, but the proposers hope to hear about funding before the end of 2009.

Action Item 5. Council staff and others in the region have continued to monitor potential new demand response technologies. Perhaps the most significant development in this area is the growth of demand response aggregators. These aggregators are not really new technology, rather a combination of existing communication and control technology, together with a business model that calls makes the aggregator the intermediary between the utility and the customer when demand response is needed. The aggregator enlists customers, installs controls on selected equipment on the customers' premises, and guarantees reductions to utilities or system operators when needed. Utilities, both in our region and elsewhere, can "pay for performance" without developing all the program capability themselves, which is attractive to many utilities.

Action Item 7. In the last year or so the combination of increasing demand for electricity together with the necessity to accommodate increasing amounts of wind generation has focused attention on ancillary services, in particular regulation and load following.[9] Bonneville's balancing authority has been the one most affected by wind development in the region, and Bonneville has done significant analysis on the cost of incremental ancillary services. Bonneville also distributed a Request for Information (RFI) in August of 2008, asking for information on generation or loads that could provide regulation or load following to help integrate wind generation.

[9] More complete discussion of regulation and load following is in Chapter 11.

Achievement of 500 megawatts of demand response by 2009: The achievement of the 500 megawatt target for demand response developed by 2009 depends on how the megawatts are counted. Regional utilities have at least 700 megawatts of demand response acquired or planned by the end of 2009. Significant parts of this demand response are outside our region in the eastern part of PacifiCorp's service territory, though this demand response benefits the western part of PacifiCorp's system (in our region) as well. While we cannot precisely allocate the share of total demand response that is in our region, it is less than the 500 megawatts target.

Some of the details of these accomplishments are proprietary, but the major components are: reductions in air conditioning and irrigation by Idaho Power and PacifiCorp, curtailable industrial loads, dispatchable standby generation by Portland General Electric,[10] and day-ahead demand buyback programs by PacifiCorp and Portland General Electric.

While our region as a whole is winter peaking, much of the 2005-2009 experience with demand response affects summer loads. However, even though summer demand response may not reduce the region's absolute peak loads it could have as much or more value than winter demand response. Analysis by the Adequacy Forum[11] suggests that summer peaking capacity may become short before winter peaking capacity. Further, regional spot prices for electricity, heavily influenced by summer peaking loads in California and the Southwest, already tend to be higher in the summer than in the winter. As a result, the experience with summer demand response programs has significant value for the region.

There have also been developments that were not anticipated by the Fifth Power Plan’s action items. Several utilities have contracted estimates of supply curves for demand response.[12] This work, based on our current level of experience, cannot foresee all the demand response measures we will eventually discover, or foresee all the means of obtaining demand response we will eventually devise, but the estimates are steps forward in our understanding of demand response.

Portfolio Analysis of Demand Response since the Fifth Plan

Compared to no demand response, including demand response in the Fifth Plan reduced both cost and risk all along the “efficient frontier” of possible portfolios. Since the release of the Fifth Power Plan Council staff have conducted additional portfolio analysis of the effects of demand response. Much of this analysis explored the cost effectiveness of demand response. The work estimated combinations of fixed and variable costs that that result in power system costs and risks that are equivalent to no demand response at all.[13] At these combinations of costs, the costs of the demand response program just balance the reductions in other resource costs. These combinations of costs can be characterized as the “cost effectiveness frontier” and can be illustrated by Figure H-1.

[10] Other utilities have called on customers’ standby generation on an ad hoc basis in special circumstances.
[11] See the 2008 Assessment at http://www.nwcouncil.org/energy/resource/Adequacy%20Assessment%20Final.doc
[12] Including Bonneville, PacifiCorp, Puget Sound Energy and Portland General Electric
[13] See Appendix H-3 for a detailed description of the work and findings.

Figure H-1: Cost Effectiveness Frontier of Demand Response

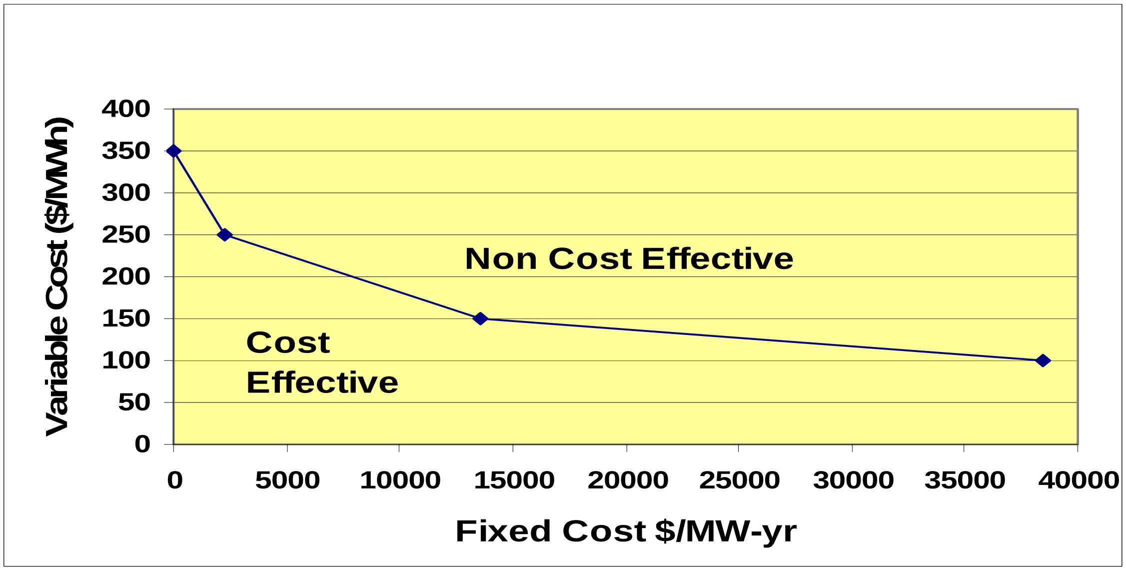

Figure H-1 shows combinations of fixed costs, graphed on the horizontal axis, and variable costs, graphed on the vertical axis. The cost effectiveness frontier divides all possible combinations of fixed and variable costs into two sets, combinations above the frontier and combinations below it. Combinations whose costs graph below the frontier are cost effective; that is, demand response with these costs reduces system costs and risks.

The cost effectiveness frontier offers some advantages to regulators and utility program designers, compared to alternative indicators of cost effectiveness. Since it is based on the Council's portfolio analysis, the effects of demand response not only on cost but also on risk are incorporated. The frontier takes into account the tradeoff between fixed costs and variable costs of demand response, and provides a rough measure of effectiveness that helps identify programs that are worthy of more detailed analysis.

But this cost effectiveness frontier has shortcomings. It represents a single, simplified "generic" demand response program that is available in all seasons at the same cost and capacity, and it is modeled in the portfolio as a resource to help the power system meet peak demand. As has been discussed earlier, we're coming to appreciate that demand response may be able to provide a range of services to the power system, from peak load service, to contingency reserves, to reguation and load following. Some loads may be able to provide more than one of these services. To reflect this world, several demand response programs will need to be simulated in the portfolio model. In addition, the portfolio model currently cannot simulate ancillary services, so the cost effectiveness frontier cannot reflect reflect benefits from ancillary services provided by demand response.

For the time being, the cost-effectiveness frontier approach to identifying cost effective demand response is a work in progress, and is not proposed as a proven and mature measure for decision making.

DEMAND RESPONSE IN THE SIXTH PLAN

Estimation of Available Demand Response

The Fifth Power Plan used estimated short-term price elasticities to arrive at a very rough estimate of the potential size of the demand response resource.[14] The estimate was presented not as being accurate within 10 or 20 percent, but as supporting the potential significance of a resource that we were just beginning to understand. While there is now more experience with demand response, there is still a great deal to learn about how much demand response is possible and how best to achieve it.

The concept of a supply curve for demand response is very attractive -- the region has worked (and still works) on supply curves for conservation, arranging conservation measures and programs in order of increasing costs, to help identify which measures are most attractive and to help identify where to draw the line for cost effectiveness. We'd like similar help with demand response, but some qualities of demand response make the estimation of supply curves for it more complicated:

1. The amount of available demand response varies with season, time of day, and power system conditions. For example, on an August afternoon customers can accept higher temperatures to reduce air-conditioning load, but that response is not available when there is little or no air-conditioning load, such as the cool night hours in most months.

2. Demand response can provide a variety of services to the power system (e.g. peak load service, contingency reserves, regulation, load following) as described later in this Appendix. Each of these services will have its own supply, which will vary over time. To estimate a supply curve for demand response to help meet peak loads we must consider whether some of the same customers and actions will be providing contingency reserves or load following services as well -- otherwise we run the risk of counting the same actions twice in separate supply curves.

3. The costs of demand response are more complex than those of conservation. The costs of conservation are generally fixed, as are the amount and schedule of energy savings. In contrast, demand response often comes with fixed and variable cost components, and requires a "dispatch" decision (by the utility or the customer) to reduce energy use at a particular time. The variable cost of demand response is the major factor in that decision.

4. Displaying demand response in the normal cost vs. quantity format of a supply curve requires some sort of aggregation of the fixed and variable costs into a single measure, such as the "average cost per megawatt of a demand response program that operates 100 hours per year." But a supply curve displaying such aggregated costs may distort critical information about a demand response program. In this example, depending on the variable cost of the program, it may or may not make sense to operate it the assumed 100 hours per year.

[14] Page A-8, Chapter 4 of the Fifth Power Plan

5. Estimates of conservation potential have depended on understanding the performance of "hardware" such as insulation and machinery, predictable by engineering analysis. Estimates of demand response, on the other hand, depend more on understanding the behavior of consumers exchanging comfort or convenience for compensation. This behavior is not so predictable without actual experience, which so far is quite limited.

6. The economics of demand response will be powerfully influenced by technological change, particularly the development of "Smart Grid" technologies,[15] which promise to make more and cheaper demand response available. Such technological change is impossible to predict in specifics, but it seems inevitable that there will be significant change over the next 20 years, and that the change will make demand response more attractive.

With the limited experience available now, a balance must be struck between the precision and the comprehensiveness of estimates of potential demand response. Precise estimates need to be limited to customers, end uses, and incentives where there is experience. These estimates necessarily exclude some possibilities that are virtually certain to have significant demand potential, eventually. Comprehensive estimates avoid this tendency to underestimate potential by including possibilities where there is less experience, but the estimates are therefore less precise.

Each of these approaches has its place. An estimate for a near-term implementation plan must focus on the "precise" end of this spectrum. An estimate for a long run planning strategy, such as the Council's, should focus on the "comprehensive" end. The long term goal should be to expand experience with various forms of demand response to the point that a precise estimate of available demand response is also comprehensive. It's fair to say this goal has been reached in the estimation of conservation potential, but has not yet been reached for demand response, at least for the region as a whole.

Studies of Potential

With these caveats about the limitations of estimating potential demand response based on limited experience, the regional discussions and analysis since the Fifth Power Plan have advanced our understanding of the resource. In our region, Bonneville, PacifiCorp, Portland General Electric, and Puget Sound Energy have contracted studies of potential.

Global Energy Partners and The Brattle Group performed Bonneville's study. The study estimated demand response available through 2020 and included direct load control of residential and small commerical customers, an "Emergency Demand Response"[16] program for medium and large commercial and industrial customers, capacity market options,[17] customers' participation in a market for ancillary services, and two pricing options. The study estimated potential demand response for each of theses options. The estimates took each option alone, with no attempt to estimate the interactions among them -- as a result, adding the estimates together risks double counting some demand response.

[15] See Appendix K
[16] Customers are offered payment for load reductions during system events, but are not penalized if their usage does not change.
[17] Customers are paid to commit to reduce loads when required by the power system, and receive additional payment when they are actually called to reduce load.

Council staff extended this study's results for direct load control, emergency demand response, and capacity market options proportionally to the entire region by assuming that these programs did not double count potential so that they could be summed. The upper end of the range of regional estimates resulting from this extension amounted to about 1.4 percent of peak load in the winter and 2.2 percent of peak load in the summer in 2020.

Puget Sound Energy (PSE) commissioned a study by Cadmus in 2009 that is still being revised. Preliminary results indicate that about demand response equal to about 3 percent of 2029 forecast peak load will be available.

The studies of demand response potential for PacifiCorp and Portland General Electric had not been completed at the time the Council approved the Sixth Power Plan.

Experience

In addition to estimates of demand response available in the future, there is considerable experience around the country with demand response that has been acquired or is in the last stages of acquisition by utilities and system operators. This experience gives some idea of the total amount of demand response that can be expected when utilities pursue it aggressively over a period of time.

In the Pacific Northwest, PacifiCorp has been quite active in acquiring demand response. By 2009, PacifiCorp expected to have over 500 megawatts of demand response, including direct load control of air conditioning and irrigation, dispatchable standby generation, and interruptible load. PacifiCorp also calls on demand buy back and "Power Forward."[18] These last two components are considered non-firm resources, but have combined to provide reductions in the 100 to 200 megawatts range in addition to the 500 megawatts of firm megawatts. The demand response, compared to PacifiCorp's forecasted peak load of 9,800 megawatts for 2009, means that PacifiCorp has more than 5 percent of peak load in firm demand response, and another 1-2 percent in non-firm demand response.

Idaho Power had about 60 megawatts of demand response in 2008, made up of direct load control of residential air conditioning and timers on irrigation pumps. The company is committeed to expand their demand response to 293 megawatts by 2013 by converting much of their irrigation demand response to dispatchable[19] and adding demand response from the commercial and industrial sectors. This level would be 7.7 percent of their projected peak demand in 2013 of 3,800 megawatts. In the longer run the company is planning on reaching 500 megawatts of demand response by 2021, which would make demand response equal to 11.4 percent of its 2021 forecasted peak demand of about 4,400 megawatts.

Portland General Electric expects to have 125 megawatts of dispatchable standby generation (DSG) in place by 2012. While this generation is licenced to operate 400 hours per year, PGE is using it to provide contingency reserves, which means it only operates when another resource is unexpectedly unavailable, or a much smaller number of hours per year. PGE also has received

[18] Power Forward is a program coordinated with the governor's office in Utah that makes public service announcements asking for voluntary reductions from the general public when the power system is stressed. Estimated response varies, but has been as much as 100 megawatts.

[19] Instead of having reductions on fixed schedules, some customers on Monday, some on Tuesday, etc., the company would be able to call on all of the participating customers at the same time when the need arises.

responses from a Request for Proposals (RFP) asking for proposals to provide demand response up to 50 megawatts by 2012. These responses make the company confident that it can actually secure 50 megawatts of new demand response by 2012. PGE also has 10 megawatts that is interruptible. The sum of these three resources, 185 megawatts, is equal to 4.1 percent of the company's projected peak load of 4,500 megawatts in 2012.

Elsewhere in the country, the New York Independent System Operator (NYISO) has been enlisting and using demand response in its operations for several years. The NYISO currently has about 2,300 megawatts of demand response participating in their programs. About 2,000 megawatts of that total are subject to significant penalties if they don't deliver promised reductions when called upon, so should be considered firm resources. About 300 megawatts of the total are voluntary and are better counted as nonfirm, although the typical response of these resources is around 70 percent, according to NYISO staff. The 2,000 megawatts of firm demand response amount to about 5.9 percent of the NYISO's expected 2009 peak load of 34,059 megawatts. Adding the expected 70 percent of the 300 megawatts of non firm demand response would raise the expected total demand response to 2,210 megawatts, or 6.5 percent of peak load.

The New England Independent System Operator (ISO-NE) cites 1,678 megawatts of demand response without dispatchable standby generation and 2,278 megawatts of demand response with dispatchable standby generation in 2007. These figures are 6.1 and 8.3 percent of ISO-NE's average weather summer peak load of 27,400 megawatts, (winter 22,775 megawatts).[20]

PJM Interconnection (PJM) is a Regional Transmission Organization that manages a wholesale market and the high-voltage transmission system for 13 mid-Atlantic Coast and Midwest states and the District of Columbia. PJM estimates 4,460 megawatts of demand response in its control area in 2008 compared to a forecasted peak load of 137,950 megawatts[21] or about 3.2 percent of peak load. There may be some demand response in the utilities of states that have been recently added to PJM (Illinois, Ohio, Michigan, and Kentucky) that is not included in this total.

California dispatched 1,200 megawatts of interruptible load on July 13, 2006, to help meet a record peak load of 50,270 megawatts. California had 1,200 megawatts more of DR available if it had been needed.[22] The 2,400 megawatts of total demand response used and available amounted to 4.8 percent of actual peak load. By 2011 the three investor-owned utilities expect to have at least 3,500 megawatts of demand response available, or 6.5 percent of the California Energy Commission's forecast of the three utilities' peak loads total for 2011 (53,665 megawatts).[23]

Portfolio Analysis of Demand Response in the Sixth Plan

In the development of the Sixth Power Plan, staff considered possible refinements in the treatment of demand response in the portfolio model. The fifth plan treated demand response

[20] http://www.iso-ne.com/trans/rsp/2008/rsp08_final_101608_public_version.pdf Table 5-7 page 47, Table 5-8 page 49, and Table 3-3 pg 25

[21] http://www.pjm.com/documents/~/media/documents/presentations/pjm-summer-2008-reliability-assessment.ashx

[22] "Harnessing the Power of Demand How ISOs and RTOs Are Integrating Demand Response into Wholesale Electricity Markets" Markets Committee of the ISO/RTO Council October 16, 2007

[23] The California Energy Commission's forecast of the three utilities peak demands can be found at http://www.energy.ca.gov/2007publications/CEC-200-2007-015/CEC-200-2007-015-SF2.PDF, in the Form 4 table for each utility.

very much like a peaking generator, with especially low fixed costs and high variable costs, but available at all times for as many hours per year as necessary. In fact most demand response is not available at all times (e.g. demand response from irrigation pumping is only available in the summer,) and there is generally some fairly low number of hours that customers are willing to tolerate reduced service. To better reflect this reality, the sixth plan analyzed demand response programs that are only available seasonally and have a maximum number of hours per season they can be exercised.

The analysis also simulated more than one kind of demand resource program, which will allow examination of the effect of demand response programs with varying proportions of fixed and variable costs on system costs and risks.

Council Assumptions

Based on the studies of demand response potential and experience elsewhere described above, the Council adopted cost and availability assumptions for several demand response programs. For this analysis of long-term planning strategies, the assumptions lean more toward the comprehensive end of the “precise/comprehensive” spectrum. These assumptions were used in the regional portfolio model to analyze the impact on expected system costs and risk of alternative resource strategies. Accordingly, they can be regarded as achievable technical potential, with the portfolio model analysis determining the programs and amounts that are cost- and risk- effective.[24]

The Council based its assumptions in part on the evidence that demand response of at least 5 percent of peak load has been accomplished by a number of utilities and system operators in periods of five to ten years, so that accomplishing a similar level of total demand response over 20 years in our region is reasonable. The total assumed potential brackets the 5 percent level, depending on whether the dispatchable standby generation is included or not. Without dispatchable standby generation, the assumed potential is 1,550 megawatts in the winter and 1,750 megawatts in the summer (about 3.9 percent and 4.4 percent of the forecast 40,000 megawatt peak load forecast for 2030, respectively). With dispatchable standby generation, the totals are 2,550 megawatts in the winter and 2,750 megawatts in the summer, or 6.4 percent and 6.9 percent of forecast peak load, respectively.

The assumptions are summarized in Table H-1. Two points are worth making about these assumptions: First, they include demand response that has already been achieved, amounting to more than 160 megawatts by 2009. Second, they include announced plans to acquire demand response by regional utilities amounting to more than 350 megawatts.

While the Council regards these assumptions as reasonable for the region as a whole, each utility service area has its own characteristics that determine the demand response available in that area. Further, while the allocation of the total potential to individual components is reasonable, more experience could well support changes in the allocation.

For example, ALCOA has offered to provide reserves as part of its proposed contract with Bonneville that could provide from about 15 megawatts to over 300 megawatts of demand response, depending on how much aluminum production capacity is operating and the level of

[24] For more information about the working of the portfolio model, see Chapter 9.

compensation. A complete potline (in the case of the ALCOA Ferndale plant, about 160 megawatts) can be reduced by about 10 percent for an extended time (i.e. about 16 megawatts for a number of hours) or shut down entirely for at least an hour without the risk of the alumina "freezing" in the pots. If two or more potlines are operating, they can alternate shutting down for an hour, so that load can be reduced by about 160 megawatts on a continuous basis without freezing pots. The alternating potlines would not have to be at the same plant – the result could be achieved by negotiating the cooperation of other smelter owners (e.g. Columbia Falls Aluminum) and other electricity suppliers to aluminum smelters (e.g. Chelan County Public Utility District).

Cold storage facilities for food are estimated to use about 140 average megawatts of energy in the region and could be interrupted briefly without compromising the quality and safety of food. These facilities have participated in demand response programs in other regions, with reductions in load of 50 percent at peak load hours. The large thermal mass of food products stored in these facilities allows them to cut load for hours with minimal change in food temperatures. The same quality could also allow a form of energy storage by pre-cooling the product slightly below nominal temperatures if the power system has a temporary (i.e. a few minutes or hours) surplus of energy.

As the region gains more experience with as-yet-unexamined resources such as these, the Council will revise its assumptions on potential for demand response.

Table H-1: Demand Response Assumptions

Program	MW	Fixed Cost	Variable Cost or hours/year Limit	Season available
Air Conditioning (Direct Control)	200	$60/kW-year	100 hours/year	Summer
Irrigation	200	$60/kW-year	100 hours/year	Summer
Space heat/Water Heat (Direct Control)	200	$100/kW-year	50 hours/year	Winter
Aggregators (Commercial)	450	$70/kW-year	$150/MWh 80 hours/year	Summer + Winter
Interruptible Contracts	450	$80/kW-year	40 hours/year	Summer + Winter
Demand Buyback	400	$10/kW-year	$150/MWh	All year
Dispatchable Standby Generation	1,000	$20-$40/kW-year	$175-300/MWh	All year

The resource programs examined were:

Direct load control for air conditioning. Direct control of air conditioners, by cycling or thermostat adjustment, is one of the most common DR programs across the country, and is most attractive in areas where electricity load peaks in the summer. The Pacific Northwest as a whole is still winter-peaking, but new forecasts show the region's summer peak load growing faster than winter peak load. PacifiCorp's Rocky Mountain Power division and Idaho Power already face summer-peaking load. The two utilities have acquired and exercised more than 100 peak megawatts of demand response from direct control of air conditioning. Most of those 100 megawatts are outside the Council's planning region, in Utah. Air conditioning is increasing in the region as a whole, as is the importance of the summer peak load in the region. The assumption for the portfolio model analysis is that there will be 200 megawatts of this resource in the region by 2030. Based on PacifiCorp's experience, the resource is assumed to cost $60 per kilowatt a year and to be limited to 100 hours per summer.

1. **Irrigation.** PacifiCorp and Idaho Power are currently reducing irrigation load by nearly 100 megawatts by scheduling controls. Both utilities are in the process of modifying their programs to give them more control of the resource, increasing the load reduction available when the utilities need it. There is significant irrigation load elsewhere in the region as well. The assumption for the portfolio model analysis is that 200 megawatts of irrigation DR will be available by 2030. Based on PacifiCorp's experience, this resource is assumed to cost $60 per kilowatt a year, limited to 100 hours per summer. Since the adoption of these assumptions for the draft plan, the Council has learned that the planned acquisition of demand response from irrigation by Idaho Power alone would exceed 200 megawatts.

2. **Direct load control of space heat and water heat.** While there has been some experience with direct control of water heating in the region, experience with direct control of space heating is limited. The assumption for the portfolio model analysis is 200 megawatts, at $100 per kilowatt a year for a maximum of 50 hours per winter. These assumptions are informed by the Global Energy and Brattle Group study for Bonneville. The megawatt assumption is about half the study's estimate for residential and commercial direct control programs when the study's most optimistic result is extended from Bonneville's customers to the whole region.

3. **Aggregators.** Increasingly, aggregators facilitate demand response by acting as middlemen between utilities or system operators on the one hand and the ultimate users of electricity on the other. These aggregators are known by a variety of titles such as "demand response service providers" for the independent system operators in New York and New England and "curtailment service providers" for the PJM regional transmission organization. Aggregators could recruit demand response from loads already described here, in which case aggregators would not add to the total of available demand response. But in the Council's analysis, aggregators are assumed to achieve additional demand response by recruiting commercial and small industrial load that is not otherwise captured in the assumptions. This resource is assumed to be 450 megawatts. The assumed fixed costs of $70 a kilowatt per year and variable costs of $150 per megawatt hour are based on conversations with aggregators. The resource is assumed available for a maximum of 80 hours during the winter or summer.

4. **Interruptible contracts.** Interruptible contracts offer rate discounts to customers who agree to have their electrical service interrupted under defined circumstances. This is an old mechanism for reducing load in emergencies, although in some cases they became de facto discounts with no expectation that the utility would ever actually interrupt service. These contracts are usually arranged with industrial customers, and PacifiCorp has about 300 megawatts of interruptible load under such contracts. The assumption for the portfolio analysis is that 450 megawatts will be available by 2030 at a fixed cost of $80 a kilowatt per year, limited to 40 hours any time during the year. The costs of existing interruptible contracts are considered proprietary, so the Council's cost assumption is based on conversations with aggregators.

5. **Demand buyback.** Utilities with demand buyback programs offer to pay customers for reducing load for hours-long periods on a day-ahead basis. Early in the 2000-2001 energy crisis, Portland General Electric conducted a program that had significant participation. Other utilities were developing similar programs, but the idea of buying back power for several hours a day was overtaken by high prices in all hours, and deals were made that bought back power for months rather than hours (mostly from Direct Service Industries). Since 2001, the most active buyback program has been PacifiCorp's program. Buyback programs still exist elsewhere in principle, but have not been maintained in a ready-to-use state. While this option could be replaced by expanded aggregator programs, the assumption for the Council's portfolio model analysis is that demand buyback programs with customers who deal directly with utilities (not through aggregators) could amount to 400 megawatts by 2030, at fixed costs of $10 a kilowatt per year and variable costs of $150 per megawatt hour available all year. These cost assumptions are based on the experience of Portland General Electric with its Demand Exchange program in 2000-2001.

Dispatchable standby generation. This resource is composed of emergency generators in office buildings, hospitals, and other facilities that need electric power even when the grid is down. The generators can also be used by utilities to provide contingent reserves, an ancillary service. Ancillary services are not simulated in the portfolio model, but dispatchable standby generation is nevertheless a form of demand response that has significant potential and cannot be overlooked. Portland General Electric has pursued this resource aggressively, taking over the maintenance and testing of the generators in exchange for the right to dispatch them as reserves when needed. PGE has 53 megawatts of dispatchable standby generation available in early 2009, and plans to have 125 megawatts by 2012. This potential will grow over time as more facilities with emergency generation are built and existing facilities are brought into the program. The Council assumes that at least 300 megawatts would be available in PGE's service territory by 2030, and that the rest of the region will have at least twice as much, for a total of about 1,000 megawatts by 2030. Based on Portland General Electric's program, cost assumptions are $20-$40 per kilowatt per year fixed cost and $175-$300 per megawatt-hour variable cost, available all year.

The dispatchable standby generation component was not modeled by the regional portfolio model, since it is expected to be used for contingency reserves, which cannot be represented in the model. The other programs were simulated in the portfolio model, with schedules based on those in Table H-2. The air conditioning and irrigation programs were treated as one program, since their costs and dispatch constraints were identical. That program, the space and water heating program, the aggregator's component, and the interruptible contracts component were modeled similarly. For each of these components, the portfolio model could try:

1. No demand response at all,
2. Demand response on the 2009-2019 schedule in Table H-2 followed by no additional demand response,
3. No demand response for 2009-2019 followed by demand response in 2019-2029 following the 2009-2019 schedule in Table H-2,
4. Demand response for 2009-2029 on the schedule in Table H-2.

Previous analysis with the portfolio model has shown the demand buyback program to consistently reduce costs and risks. It was modeled on the schedule shown in Table H-2.

Table H-2: Schedule of Demand Response Programs in the Regional Portfolio Model

	Megawatts										
Program	**2009**	**2011**	**2013**	**2015**	**2017**	**2019**	**2021**	**2023**	**2025**	**2027**	**2029**
AC and Irrigation	100	200	230	260	290	320	350	380	400	400	400
Space and Water Heat		10	20	30	40	50	70	90	120	160	200
Aggregators		20	60	100	150	200	250	300	350	400	450
Interruptible Contracts		50	100	150	200	250	300	350	400	450	450
Demand Buyback	70	100	130	160	190	220	250	290	340	370	400

Pricing Structures

The Council is not making assumptions now about the amount of demand response that might be available from pricing structures. There is no doubt that time-sensitive prices can reduce load at appropriate times, but the region does not yet appear to be ready for general adoption of these pricing structures. While hourly meters are becoming more common, most residential customers don't yet have them, which makes time-of-day pricing, critical peak pricing, peak time rebates, and real time prices unavailable to those customers for the time being. Many in the region are concerned that some customers will experience big bill increases with different pricing structures. There is also the potential for double counting between demand response programs and any pricing strucuture initiatives.

The Pacific Northwest Demand Response Project, co-sponsored by the Council and the Regulatory Assistance Project is taking up the subject of pricing structures as a means of achieving demand response in the spring of 2009. In addition, Idaho Power and Portland General Electric are launching pilot projects for time-sensitive electricity prices, which can be expected to provide valuable experience not only for those utilities but the region as a whole.

Providing Ancillary Services with Demand Response

Demand response has usually been regarded as an alternative to generation at peak load (or at least near peak load), which occur a few hours per year. Because demand response for this purpose is only needed a few hours a year, customers need to reduce their usage for only a few hours a year. The load whose reduction provides such demand response need not be year-round load, as long as the load is present during hours when system load is at or near peaks (the most familiar example is air conditioning load for summer-peaking systems).

But demand response can do more than help meet peak load. It can help provide ancillary services such as "contingency reserves" and "regulation and load following." Historically ancillary services have not been considered a problem in the Pacific Northwest, but as loads have grown, and especially as wind generation has increased, power system planners and operators have become more concerned about ancillary services (see Chapter 12 of this plan). Not all demand response can provide such services, since they have different requirements than meeting peak load.

Ancillary services are not simulated in the Council's Regional Portfolio Model, so the potential value of demand response in this area will not be captured in the model's analysis. Nevertheless, the potential cannot be ignored, and the subject should be pursued as one of the demand response action items.

Contingency Reserves

In some respects providing contingency reserves with demand response is similar to meeting peak loads with demand response. In both cases load reductions of a few hours per year are likely to meet the system need.[25]

But in other respects providing contingency reserves requires somewhat different demand response than meeting peak loads. To provide contingency reserves during non-peak load hours, demand response will require reductions in end use loads that are present in those hours. For example, residential space heating cannot provide reserves in the summer; residential air conditioning cannot provide reserves in the winter; but commercial lighting and residential water heating can provide contingency reserves throughout the year.

Regulation and Load Following

Providing regulation and load following with demand response presents new requirements, compared to serving peak loads. Regulation is provided by generators that automatically respond to relatively small but quite rapid (in seconds) variations in power system loads and generation. Load following is provided by larger and slower adjustment in generator output in response to differences between the amount of prescheduled generation and the amount of load that actually occurs. Regulation and load following are needed in virtually every hour of the year, and require that generation be able to both increase and decrease.

Many customers who would be willing to provide demand response for meeting peak loads will not be available for regulation or load following. Providing regulation or load following with demand response would involve decreasing or increasing loads in virtually every hour.[26] Customers who are willing and able to decrease <u>and</u> increase use when the power system needs it will be harder to recruit than those who are willing and able only to decrease loads. Even if customers are asked only to decrease loads, many of them who could participate in, for example, a 100 hour per year demand response program that helps meet peak loads, will not be able participate in a load following program that requires thousands of actions per year.

While demand response that can provide regulation or load following will be a subset of all possible demand response, there may well be a useful amount. What kinds of loads make good candidates for this kind of demand response?

One example would be pumping for municipal water systems. Such systems don't pump continuously -- they fill reservoirs from which water is provided to customers as needed. The

[25] Contingency reserves are only called to operate when unexpected problems make the regularly scheduled resource unavailable, which occurs infrequently. Further, utilities are required to restore reserves within 105 minutes, so that the reserves' hours of operation per occurrence are limited. The result is that actual calls on contingency reserves are likely to be a few hours per year.

[26] It may be possible to achieve an equivalent effect by a combination of loads that can make reductions when necessary together with generation that can make reductions when necessary. One such combination could be DR and wind machines.

schedule of pumping can be quite flexible, as long as the reservoir level remains somewhere between specified minimum and maximum levels. For such a load, the water utility could specify the total amount of pumping for the next 24 hours based on its customers' expected usage, and allow the power system to vary the pumping over the period to help meet variation in the power system's loads (and variation of wind generation), as long as the total daily pumping requirement is satisfied. Presently, accomplishing this degree of coordination between the power system and its customers is probably not practical, but with the Smart Grid's promise of cheaper metering and communication and more automated control, it could become so.

Another example is the charging load for plug-in hybrid cars (PHEVs). Many parties have suggested this possibility, and the general outline of these cars' potential interaction with the power system is common to most proposals -- the PHEVs' individual batteries together act as a large storage battery for the power system whenever they are connected to the grid, at home, at work or elsewhere. This aggregate battery accepts electricity when the cost of electricity is low (e.g. at night) and gives electricity back to the system when the cost is high (e.g. hot afternoons or during cold snaps). The Smart Grid could coordinate[27] this exchange.

Domestic water heating is yet another example of a load that could be managed to provide regulation or load following to the power system. In this case we have enough information to make a rough estimate of how much flexible reserve could be available. Current estimates of the region's total number of electric water heaters run in the 3.4 million range. If each of these heaters has heating elements of 4,500 watts, the total connected load is about 15,300 megawatts. Of course water heaters are not all on at the same time, but load shape estimates suggest that the total water heating load on the system ranges from about 400 megawatts to about 5,300 megawatts, depending on the season, day and hour.

In normal operation water heaters' heating elements come on almost immediately when hot water is taken from the tank, to heat the replacement (cold) water coming into the tank. But if the elements don't come on immediately, the water in the tank is stratified, hot at the top and cold at the bottom. Opening a hot water faucet continues to get hot water from the top of the tank until the original charge of hot water in the tank is gone. This means that heating the replacement water can be delayed (reducing loads) for some time without depriving water users of hot water. Based on the load shape estimates cited above, the maximum available reduction ranges from about 400 to about 5,300 megawatts, depending on when it is needed.

But to provide regulation or load following, reductions aren't sufficient -- loads need also to be increased when the power system needs it. An example of such a condition is 4:00 AM during the spring runoff, when demand for electricity is low, river flows cannot be reduced, not much non-hydro generation is operating, and winds are increasing. System operators have too much energy and few good options – they can cut hydro generation by increasing spill, which loses revenue and can hurt fish, or they can require wind machine operators to feather their rotors, losing both market revenue and production tax credits.

Water heating can help absorb this temporary surplus of energy and make productive use of it. Water heating loads can be increased up to the maximum connected load, but the duration of the

[27] A common assumption is that this coordination includes a requirement that the charge in the PHEV's battery at the end of the day is sufficient to get home. Even if requirement is not met, however, PHEV's have the ability to charge their own batteries, so they are not stranded.

increase will be limited by the rise in water temperature above its normal setting that we allow. If, for example, we allow the temperature to rise from 120 degrees Fahrenheit to 135 degrees Fahrenheit, 3.4 million 50 gallon water heaters can accept 6,198 megawatt hours of energy, store it (at the cost of roughly 24 megawatt-hours per hour higher standby losses) and return it to the system in the form of a reduction in hot water heating requirement in a later hour.[28]

There are other loads that have some sort of reservoir of "product," a reservoir whose contents can vary within an acceptable range. The "product" might be crushed rock, compressed and cooled air (in the process of air separation), stored ice (for commercial building air conditioning), pulped wood for paper making, or the like. This reservoir of "product" could allow the electricity customer to tolerate variation in his rate of electricity use to provide ancillary services to the power system, assuming that the customer receives adequate compensation.

There is an industrial plant in Texas that provides 10 megawatts of regulation to the Electricity Reliability Council of Texas (ERCOT) the independent system operator of the Texas interconnected power system. ERCOT's rules keep plant information confidential, but it is understood that the plant's process is electrochemical, and that its unique situation makes unlikely that many other plants could provide regulation to the power system.

[28] This rise could result from an increase in load of 6,198 megawatts for an hour, or an increase in load of 3,099 megawatts for two hours, etc. See Appendix K for a fuller description of providing reserves, load following and energy storage using water heaters.

Appendix H1: Demand Response

Guidelines for Cost-effectiveness Valuation Framework for Demand Response Resources in the Pacific Northwest - Pacific Northwest Demand Response Project

Background

In May 2007, the Pacific Northwest Demand Response Project (PNDRP) agreed to form several Working Groups to explore demand response (DR) issues in more detail (Cost-effectiveness, Pricing, and Integrating DR into Distribution System Planning and Investment). In July 2007, the Cost-Effectiveness Working Group met for a one-day workshop in Portland Oregon, which included presentations by a number of utilities on valuation approaches used for DR resources. In January 2008, draft guidelines for a DR Cost-effectiveness valuation framework were presented and discussed at a Working Group workshop.[29] In September 2008, the draft final guidelines were presented and discussed at a Working Group workshop; participants provided comments and suggestions. At that meeting, there was consensus among participants on the guidelines and that the final guidelines document should be provided to the Northwest Power and Conservation Council to be included as an Appendix in the Sixth Pacific Northwest Power and Conservation Plan. This document offers proposed guidelines for a cost-effectiveness valuation framework for Demand Response Resources that could be considered as a screening tool by state commissions and utilities in the Pacific Northwest.

Purpose

The primary purposes of a cost-effectiveness valuation framework for DR resources are to:

- Propose workable methods for state commissions, utilities and others to consider for valuing the benefits and costs of different types of DR resources in long-term resource planning;
- Provide methods that can be used in *ex ante* screening of DR programs for cost-effectiveness and to evaluate the treatment of a portfolio of DR resources/program options in an integrated utility resource plan;
- Document value of demand response for the purpose of rate setting.

Demand Response Resources

- Demand Response resources (DRR) are comprised of flexible, price-responsive customer loads that may be curtailed or shifted in the event of system emergencies and system operational needs or when wholesale market prices are high.
- It is useful to characterize Demand Response resources in terms of their “firmness” as a resource option from the perspective of the utility.
- Firm DSM Resources (Class 1)

[29] The Draft Guidelines were developed based on discussions among participants in the PNDRP Cost-effectiveness Working Group and our review of DR valuation studies and cost-effectiveness proceedings currently underway in other jurisdictions (see References).

  - This class of DR resources allows either interruptions of electrical equipment or appliances that are directly controlled by the utility or are scheduled ahead of time. These resources can include such programmatic options as fully dispatchable programs (e.g. direct load control of air conditioning, water heating, space heating, commercial energy management system coordination) and scheduled firm load reductions (e.g. irrigation load curtailment, thermal energy storage).[30]
- "Non-firm" DSM resources (Class 3)
  - DR resources in this group are typically outside of the utility's direct control and include curtailable rate tariffs, time-varying prices (e.g., real-time pricing, critical peak pricing), demand buyback, or demand bidding programs.

Guidelines and Principles

1) Treat DR resources on par with alternative supply-side resources and include them in the utilities' integrated resource plans and transmission system plans.

2) Distinguish among DR programs with respect to their design purpose, dispatchability, response time, and relative certainty regarding load response (e.g., firmness).

3) In assessing cost-effectiveness of DR resources, it is important to account explicitly for all potential benefits, including avoided/deferred generation capacity costs, avoided energy costs, avoided T&D losses, deferred/avoided T&D grid system expansion, environmental benefits, system reliability benefits, and benefits to participating customers.

4) Incorporate the temporal and locational benefits of DR programs systematically (e.g. estimate avoided costs at hourly level, treat transmission congestion zones separately). Most of the benefits of DR resources are related to avoiding relatively low probability future events (e.g. unusually high peak demand or energy prices) in relatively few hours, whose occurrence could have significant economic consequences.

5) All DR program incentive and administration costs, costs of enabling technology, and participant costs should also be included. For DR programs in which customers have to voluntarily enroll, it can be assumed that total costs incurred by participants are less than or equal to the benefits, otherwise they would be unlikely to sign up and participate.[31]

6) DSM programs are often screened using a set of benefit-cost tests that compare and assess the benefits and costs from different perspectives (i.e., society, utility, participants,

[31] For participants, benefits include bill reductions and any financial incentives paid, tax credits (if available) and non-energy benefits; costs include capital and O&M costs associated with installation of DR enabling technologies, the value of service lost (e.g. reduced productivity and/or comfort), and transaction costs. As a practical matter, this means that for a voluntary DR program, utilities can assume that the benefit/cost values for the Participant Test are greater than one.

and non-participants).[32] These tests are not intended to be used individually or in isolation; results from the various tests should be compared and trade-offs between tests considered.[33] These benefit-cost tests may need to be modified and adapted in some areas to account for the distinctive characteristics and features of DR resources.

7) Utilities should consider conducting sensitivity analysis on key benefit and cost variables that have significant uncertainties which can have a major impact on program cost-effectiveness (see an Excel workbook with illustrations of the proposed cost-effectiveness screening method at: http://www.nwcouncil.org/energy/powerplan/6/final/AppendixH2.xls).

8) Initiate and conduct DR pilot programs to assess market readiness, barriers to customer participation and to obtain information on customer performance that can be used to characterize the timing and duration of load impacts for long-term resource planning. Pilot programs need to include exercises of "non-firm" DR resources with a view to identifying a fraction of the resource that could be treated as firm for planning purposes.

Benefits of DR Resources

1) Avoided Generation Capacity Costs
   a. "Firm" DR resources, when directly incorporated into a utility's resource and reliability planning processes, can avoid the need for a relatively high heat rate generating capacity. The market value of that type of generating capacity will typically be based on a new natural gas-fired combustion turbine (CT).
   b. There is not a consensus on methods to determine the market value of new generating capacity avoided by a DR resource. Some parties in the Pacific Northwest have raised concerns about the appropriate way to value capacity when the region is long on power.[34] Moreover, market prices for new capacity are not widely available.
   c. In the interim, using a benchmarking method that estimates the costs of a new gas-fired CT as a proxy to derive the market value of avoided generation capacity is a reasonable approach for screening DR programs.[35] *These costs have typically been estimated to range between $50-85 per kW-year in the past, but recent increases in costs have resulted in estimates of over $100 per kW-year.*

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[32] See *California Standard Practice Manual Economic Analysis of Demand Side Programs and Projects, October 2001* as one example. http://www.energy.ca.gov/greenbuilding/documents/background/07-J_CPUC_STANDARD_PRACTICE_MANUAL.PDF

[33] PUCs and utilities may consider using the Total Resource Cost (TRC) or Societal Test as the primary test in screening DR programs.

[34] Similarly, in California, the investor-owned utilities have proposed to offset the present value of the total fixed costs of that new CT by the present value of the gross margins that the new CT capacity is expected to earn from selling energy when wholesale electricity market prices exceed variable costs. Other parties in California (e.g. industrial customers) disagree with the method proposed by the California utilities.

[35] In estimating CT costs, utilities should annualize total investment using a real economic carrying charge rate that takes into account return, income taxes, and depreciation, with O&M, ad valorem and payroll taxes, insurance, costs associated with obtaining firm gas transmission, and capital costs incurred to comply with existing environmental regulations including acquisition of offsets for criteria pollutants.

d. Estimates of hourly market prices for new generation capacity can be derived by allocating the estimated annual market price of generation capacity ($/kW-yr) among the hours in each year, in proportion to the relative need for generation capacity in each hour. Utilities, regulators, and other stakeholders should agree on method(s) to allocate avoided generation capacity costs to specific time periods that is appropriate for the Pacific Northwest power system.[36]
e. Avoided T&D losses and Reserve margin -- The resulting estimates of generation capacity costs avoided by DR program should be adjusted upward to reflect the T&D line losses avoided by that DR resource capacity and the capacity planning reserve margin avoided by that DR program.[37]
f. The capacity benefits of a DR resource should also be adjusted for differences that reflect operational program constraints (e.g., limits on the months, days, and/or hours in which DR program events can be called; limits on maximum duration of program events, limits on number of consecutive days on which program events can be called) compared to the capacity value of a new CT (including limits on the use of a CT).

2) Avoided Energy Costs
   a. DR resources typically result in load shifting from peak to off-peak periods or load curtailments in which customers forego consumption for relatively short time periods. Thus, DR resources also enable utilities to avoid energy costs.
   b. Because utilities can always buy or sell electricity in the wholesale energy market, the expected wholesale market electricity price in each future time period is the relevant opportunity cost for estimating the value of electricity that will be avoided by a DR resource.
   c. Avoided energy costs should be adjusted upward to reflect distribution system line losses that DR load reductions would avoid in event hours.
   d. Avoided energy costs can be particularly important in evaluating DR programs from the participants' perspective as they tend to directly affect customer bills.
   e. DR program events are most likely to be called in hours when prices are higher than expected; using expected hourly prices will tend to under-estimate actual electricity market prices in the hours in which an event-based DR program is called and will reduce loads.
   f. Avoided energy costs may be estimated using several options: (1) wholesale energy prices averaged over the highest priced hours of a price forecast, and (2) stochastic methods (e.g., Monte Carlo simulations) that analyze the correlation between electricity prices and times that DR events are expected to occur and explicitly address the uncertainty in future loads, prices, hydro conditions in the Pacific Northwest regional utility system.

3) Deferred Investments in Transmission and/or Distribution System Capacity
   a. The transmission and distribution system is comprised of three key elements: interties, local network transmission, and local distribution systems.

[36] In California, the utilities have proposed allocating the annual market value of new CT capacity to individual hours in proportion to the loss of load expectation (LOLE) in each hour.
[37] T&D losses will typically be higher during peak periods compared to average values for T&D losses.

b. DR programs that provide highly predictable load reductions on short notice may allow utilities to defer and/or reduce transmission and/or distribution (T&D) capacity investments in specifically defined congested locations on the grid. This may lead to a reduction in a utility's projected T&D capital budget and thus avoid some T&D costs.[38]
c. Utilities should consider one of two options in estimating avoided T&D costs: (1) develop a default avoided T&D cost which may be applied to DR programs that meet pre-established criteria regarding locational value and certainty of load reductions or (2) estimate avoided or deferred T&D capacity investments on a case specific basis.[39]
d. The default avoided T&D costs can be calculated by using marginal costs associated with local transmission and distribution substation equipment, which is principally related to transformer capacity.[40]

4) Environmental Benefits (and Costs)
   a. DR resources have the potential to produce environmental benefits by avoiding emissions from peaking generation units as well as some potential conservation effects (i.e. through load curtailments, foregoing usage).
   b. Assessing the environmental impacts of DR resources depends primarily on the emissions profile of the utility's generation resource mix as well as participating customer's DR strategy (e.g., load curtailment vs load shifting vs onsite generation).
   c. For DR resources that result in load curtailments, a reasonable proxy for estimating the volume of greenhouse gas (GHG) emissions avoided by a DR resource is to base it on the operating and emission rate characteristics of a new CT.

5) Reliability Benefits
   a. DR resources can provide value in responding to system contingencies that compromise electric system operator's ability to sustain system level reliability and increase the likelihood and extent of forced outages.
   b. In the context of long-term resource planning, joint consideration of economic (avoided capacity and energy) benefits and reliability benefits is challenging. In an IRP plan, the value of DR hinges primarily on its ability to displace some portion of the utility's peak demand. Once DR resources are included in the utility's projected capacity resource mix, they become part of planned capacity and are no longer available for dispatch during system emergencies.

[38] The extent to which DR programs may defer or avoid specific T&D capital investments depends on: 1) the characteristics of the individual utility system, 2) the specific T&D investment proposed, 3) the characteristics of the customer load to be served by the proposed T&D investment, 4) the attributes of the proposed DR program, and 5) the level of uncertainty associated with the projected load impacts of the DR program.
[39] The specified criteria for DR programs are designed to limit application of avoided T&D costs to DR programs that: (1) are located in areas where load growth would result in need for additional delivery infrastructure, (2) are capable of addressing local delivery capacity needs, (3) have sufficient certainty of providing long-term reduction that the risk to utility of incurring after-the-fact distribution system replacement costs is modest, and (4) can be relied upon for local T&D equipment loading relief.
[40] Marginal T&D costs often include local T&D lines, towers and power poles, underground conduit and structures which are added as service is extended into new geographic areas; these costs are generally not related to peak demands in a specific area and are typically not avoided by a DR program.

c. Customers participating in emergency or other "non-firm" DR programs are not counted on as system resources for planning purposes; they represent an additional resource for reliability assurance; distinct from "firm" DR programs that are counted among planned reserves.[41]

d. In assessing the value of these emergency-type DR programs, a reasonable proxy for monetizing the value of load curtailments is the product of the value of lost load (VOLL) with typical values between $3-5/kWh and the expected un-served energy (EUE).[42]

6) "Hard to quantify" benefits

a. Some potential benefits of demand response are inherently difficult to quantify. Examples of "hard to quantify benefits" include: the long-term educational value of customers being exposed to and having a choice of how to respond to time-varying wholesale market prices or customer satisfaction in helping to avert system emergency. These non-quantifiable benefits are likely to be small but state PUCs may also want to consider them in assessing dynamic pricing (if appropriate).

DR Resource Costs

7) Program Administration Costs

a. Utilities will incur initial and ongoing costs in operating DR programs. Incremental program costs attributable to DR resources can include program management, marketing, customer education, on-site hardware, customer event notification system upgrades, and payments to third party curtailment service providers that implement aspects of a DR program.

8) Customer costs

a. Customer costs are defined as those costs incurred by the customer to participate in a DR program and can include investments in enabling technology to participate, developing a load response strategy, comfort/inconvenience costs, rescheduling costs for facility workers, or reduced product production.

b. For a voluntary DR program, it is reasonable to assume that participant costs are less than or equal to the incentives offered by the program; otherwise most customers would not voluntarily chose to participate.[43] The exceptions are those customers who believe participation is the right thing to do, regardless of their personal costs

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[41] Emergency DR programs provide incremental reliability benefits at times of unexpected shortfalls in reserves. When all available resources have been deployed and reserve margins still cannot be maintained, curtailments under an emergency DR program reduce the likelihood and extent of forced outages.

[42] Expected unserved energy (EUE) is a measure of the magnitude of a reserve shortfall which takes into account the change in the likelihood of curtailment (i.e. loss of load probability) and the amount of load at risk.

[43] One possible exception are those customers that are motivated by civic responsibility and believe that participation in a DR program and responding to a electric power system emergency are the "right thing" to do, regardless of their personal costs.

9) Incentive payments to participating customers
    a. Incentive payments are paid to customers participating in DR programs to encourage them to enroll initially and continue in the program. Incentives also compensate customers for any reduction in the value of service that they would normally receive (e.g. higher household temperatures during an A/C cycling event or increased costs when a business shuts down some of its equipment when an emergency event is called).
    b. For voluntary DR programs, in evaluating cost-effectiveness, it is reasonable to assume that total customer costs incurred by participants will be equal to the present value of incentives expected to be paid.[44]

10) Characterizing DR Resource Costs
    a. It is reasonable to ramp up enrollment in DR programs over a multi-year period (e.g. 3-4 years) and to match the time horizon of DR costs and benefits (e.g. use expected life of DR enabling technology in assessing benefits).
    b. In modeling DR program options, it is useful to categorize costs into fixed expenses (program development, ongoing administration, communication and data acquisition infrastructure) and variable costs (e.g. incentive payments to customers, participant acquisition costs, other program costs that vary with number of participants or the number of times that DR program events are called).).

11) Relationship between DR screening and portfolio analysis
    a. A long-term resource plan that includes a portfolio analysis and accounts for the uncertainties in future loads, prices, and resources, is the preferred approach to fully value the benefits of DR resources
    b. In screening DR resources and program concepts, it is also useful to establish cost-effectiveness thresholds that allow regulators and utilities to estimate whether a DR program is worthwhile to pursue.

References on DR Cost-effectiveness and Valuation

U.S. Department of Energy (2006). "Benefits of DR in Electricity Markets and Recommendations for Achieving them: A Report to U.S. Congress Pursuant to Section 1252 of the Energy Policy Act of 2005," February 2006.

Quantec 2006. "Demand Response Proxy Supply Curves," prepared for Pacificorp, September 8, 2006.

CPUC (2007). "Order Instituting Rulemaking Regarding Policies and Protocols for Demand Response Load Impact Estimates, Cost-effectiveness Methodologies, Megawatt Goals and Alignment with California System Operator Market Design Protocols," OIR 07-01-041, Jan 25, 2007.

[44] It is reasonable to treat incentive payments in voluntary DR programs as compensation for any loss of service or out of pocket costs that participating customers expect to incur under the assumption that the customer would not participate if the incentive wasn't sufficient to offset these costs.

CPUC Energy Division (2008). *Draft Demand Response Cost-effectiveness Protocols.* April 4, 2008.

Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (2007). *Revised Straw Proposals For Demand Response Load Impact Estimation and Cost Effectiveness Evaluation*, September 10, 2007 (http://docs.cpuc.ca.gov/efile/REPORT/72728.pdf)

Joint Comments of California Large Energy Consumers Association, Comverge, Inc., Division of Ratepayer Advocates, EnergyConnect, Inc., EnerNoc, Ice Energy, Pacific Gas and Electric Company, San Diego Gas & Electric Company, Southern California Edison Company and The Utility Reform Network (2007). *Recommending a Demand Response Cost Effectiveness Evaluation Framework*, September 19, 2007 (http://docs.cpuc.ca.gov/efile/CM/75556.pdf).

Appendix H1-A

Examples of Cost Effectiveness Screening Methodology

We have constructed two prototypical demand response programs - a direct load control water heater program and a smart thermostat air conditioning program – in a spreadsheet-based tool to illustrate how the Cost Effectiveness screening methodology may be applied to specific demand response programs.[45] . The spreadsheet tool includes “typical” first-year values and compound annual growth rates for key model inputs on costs and load impacts; LBNL established “typical” values for key inputs based on our analysis of reference values (i.e., minimum, average, median, and maximum values) observed in pilot and full-scale DR program evaluations from the Pacific Northwest and a review of the DR program planning and evaluation literature. Users of the spreadsheet tool have the capability to change model inputs based on their assessment of appropriate model input values for DR programs under consideration and can use the Reference Values as a guide to the range of values observed in the Pacific Northwest.

Direct Load Control – Water Heater

This program targets single-family residential customers with standard-sized electric water heaters. A control switch is installed in each participant’s home near the water heater circuit breaker, which is then controlled via a one-way pager signal to trip the relay on and off according to the received message. Curtailments are initiated during peak hours of winter weekdays (i.e., mornings and/or afternoons) and are not expected to exceed sixty hours each year (i.e., fifteen events at four hours/event). A sample of participants will also have interval meters installed to help program administrators document and verify the achieved level of demand savings during program events. We assume an average event performance rate of 95% for this DLC program (i.e., 5% of the customer switches fail to respond).

Figure A-1 summarizes information on market penetration, aggregate load impacts, economic and reliability benefits, and costs of the DLC Water Heater program. The utility expects to ramp up the DR program over a seven-year period with the goal of achieving 30,000 participants. With per unit savings expected to be 1.0 kW during events, the program is anticipated to reduce the residential class peak demand by 1.6% when it reaches steady-state in year 7 (i.e., 2014). After 2014, the utility plans to add new participants to maintain aggregate peak demand savings. This will require the utility to enroll new participants to offset projected growth in peak demand (2.2% per year) and replace customers that move or drop out of the program. The utility expects that ~7% of the customers per year will be lost due to changes in electric service (5%) or removal from the program (2%). In terms of energy savings, it is anticipated that the water heater DLC program will have a small impact on energy usage during peak periods when events are called (60 kWh/unit-year), which is completely made up in the four-hour period following a curtailment.

The utility has budgeted $100,000 up-front to develop the program in year 1. The utility projects that customer acquisition costs are ~$25/customer for marketing and back-office costs, that cost and installation of the switch is $175/customer, and that load impact verification costs are $5/customer (e.g. cost and installation of a logger for a sample of customers). The utility will also offer customers an incentive for participating in events ($6.66/month bill credit for three months = $20/customer-year). The use of the one-way paging system is expected to cost the

[45] See spreadsheet entitled “DR_Cost_Effectiveness_Methodology_Model_Public~112508.xls”

utility $7/customer-year, while the utility believes it will incur $10/customer-year to inspect a sample of switches and loggers as well as perform any necessary service calls for these items of equipment. The cost to run the program every year is estimated to be $60,000/year. These costs are anticipated to grow by 2% per year after 2008.

Benefits from the program are derived from the avoided cost of energy, capacity and transmission and distribution, as well as environmental savings. No reliability benefits are calculated because this resource is considered “firm”, and thus is directly integrated into the planning process. The utility projects that in 2008 the value of avoided cost of peak and off-peak energy is 7.5 ¢/kWh and 4.5 ¢/kWh respectively, which is projected to increase at 2% per year. Environmental benefits are estimated to be $0.008/kW-year, increasing 2% annually. The first year avoided cost of capacity is set at $80/kW-year, and is expected to increase by 3% a year thereafter. T&D savings can be broken out into two pieces: line loss savings and reduced investment in plant. The utility has a secondary voltage level loss factor of 6%, thus any associated reduction in sales and peak demand means 106% of that electricity need not be generated and maintained for reserves, respectively. The utility has deemed that the average T&D cost savings associated with the program are $3/kW-year, which grows at an annual rate of 3%. Avoided capacity benefits account for ~95% of total benefits of the water heater DLC program. Because the DLC program is treated as a “firm” resource and is credited with avoiding and/or deferring a supply-side resource, we do not include additional reliability benefits.

Using these inputs and assuming the DLC water heater program is maintained for twenty years, the utility anticipates total program costs, on a present value basis using a discount rate of 8.8%, to be $19.63MM and program benefits to be $25.12MM. This water heater DLC program produces $5.49MM in net benefits with a TRC benefit-cost ratio of 1.28.

Our screening analysis tool can be utilized by utility planners and regulatory staff to conduct sensitivity analysis on key input values that might affect program cost-effectiveness. Input values that have the most significant impact on cost-effectiveness are the avoided cost of capacity and T&D (initial year value and assumed escalation rate). Lower program costs would also improve cost-effectiveness with assumed values for technology and back-office costs and program incentives having the most significant impact.

Figure A-1 – Direct Load Control Water Heater Demand Response Program: Benefit-Cost Estimates

Year Index	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Year	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Utility System Characteristics																				
Forecasted Retail Sales (GWh)	23,000	23,460	23,929	24,408	24,896	25,394	25,902	26,420	26,948	27,487	28,037	28,598	29,170	29,753	30,348	30,955	31,574	32,206	32,850	33,507
Forecasted Peak Demand (MW)	4,000	4,088	4,178	4,270	4,364	4,460	4,558	4,658	4,761	4,865	4,972	5,082	5,194	5,308	5,425	5,544	5,666	5,791	5,918	6,048
Residential Retail Sales (GWh)	8,740	8,915	9,093	9,275	9,460	9,650	9,843	10,040	10,240	10,445	10,654	10,867	11,084	11,306	11,532	11,763	11,998	12,238	12,483	12,733
Residential Peak Demand (MW)	1,520	1,553	1,588	1,623	1,658	1,695	1,732	1,770	1,809	1,849	1,890	1,931	1,974	2,017	2,061	2,107	2,153	2,200	2,249	2,298
DR Program Characteristics																				
Number of New Participants (Units)	4,286	4,586	4,886	5,186	5,486	5,786	6,086	2,760	2,821	2,883	2,946	3,011	3,077	3,145	3,214	3,285	3,357	3,431	3,506	3,584
Number of Returning Participants (Units)	0	3,986	7,971	11,957	15,943	19,929	23,914	27,900	28,514	29,141	29,782	30,437	31,107	31,791	32,491	33,206	33,936	34,683	35,446	36,226
Number of Total Participants (Units)	4,286	8,571	12,857	17,143	21,429	25,714	30,000	30,660	31,335	32,024	32,728	33,448	34,184	34,936	35,705	36,490	37,293	38,114	38,952	39,809
Peak Period Energy Reduction (MWh)	244	489	733	977	1221	1466	1710	1748	1786	1825	1866	1907	1949	1991	2035	2080	2126	2172	2220	2269
Off-Peak Period Energy Increase (MWh)	244	489	733	977	1221	1466	1710	1748	1786	1825	1866	1907	1949	1991	2035	2080	2126	2172	2220	2269
Proportion of Class Retail Sales (%)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Capacity Reduction (MW)	4.07	8.14	12.21	16.29	20.36	24.43	28.50	29.13	29.77	30.42	31.09	31.78	32.48	33.19	33.92	34.67	35.43	36.21	37.00	37.82
Proportion of Class Peak Demand (%)	0.3%	0.5%	0.8%	1.0%	1.2%	1.4%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%
Benefits																				
Avoided Energy Cost Savings ($MM)	$0.01	$0.02	$0.02	$0.03	$0.04	$0.05	$0.06	$0.06	$0.07	$0.07	$0.07	$0.08	$0.08	$0.08	$0.09	$0.09	$0.09	$0.10	$0.10	$0.11
Avoided Capacity Cost Savings ($MM)	$0.35	$0.71	$1.10	$1.51	$1.94	$2.40	$2.89	$3.04	$3.20	$3.37	$3.54	$3.73	$3.93	$4.13	$4.35	$4.58	$4.82	$5.07	$5.34	$5.62
Avoided T&D System Cost Savings ($MM)	$0.01	$0.03	$0.04	$0.05	$0.07	$0.08	$0.10	$0.11	$0.11	$0.12	$0.13	$0.13	$0.14	$0.15	$0.15	$0.16	$0.17	$0.18	$0.19	$0.20
Environmental Benefits ($MM)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Reliability Benefits ($MM)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total ($MM)	***$0.37***	***$0.75***	***$1.16***	***$1.60***	***$2.05***	***$2.54***	***$3.05***	***$3.21***	***$3.38***	***$3.55***	***$3.74***	***$3.94***	***$4.14***	***$4.36***	***$4.59***	***$4.83***	***$5.08***	***$5.35***	***$5.63***	***$5.93***
Benefits - Present Value ($MM)	**$25.12**																			
Costs																				
Program Development Costs ($MM)	$0.10	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Customer Acquisition Costs ($MM)	$0.88	$0.96	$1.04	$1.13	$1.22	$1.31	$1.40	$0.65	$0.68	$0.71	$0.74	$0.77	$0.80	$0.83	$0.87	$0.91	$0.94	$0.98	$1.03	$1.07
Annual Program Administration Costs ($MM)	$0.06	$0.06	$0.06	$0.06	$0.06	$0.07	$0.07	$0.07	$0.07	$0.07	$0.07	$0.07	$0.08	$0.08	$0.08	$0.08	$0.08	$0.08	$0.09	$0.09
Annual Program Variable costs ($MM)	$0.16	$0.32	$0.49	$0.67	$0.86	$1.05	$1.25	$1.30	$1.36	$1.42	$1.48	$1.54	$1.60	$1.67	$1.74	$1.82	$1.89	$1.97	$2.06	$2.15
Total ($MM)	***$1.20***	***$1.34***	***$1.60***	***$1.86***	***$2.14***	***$2.43***	***$2.72***	***$2.02***	***$2.11***	***$2.19***	***$2.29***	***$2.38***	***$2.48***	***$2.58***	***$2.69***	***$2.80***	***$2.92***	***$3.04***	***$3.17***	***$3.30***
Costs - Present Value ($MM)	**$19.63**																			
Net Benefits ($MM)	***5.49***																			
Benefit Cost Ratio	***1.28***																			

Smart Thermostat – Air Conditioning Program

This smart thermostat program targets single-family residential customers with central air conditioning system. A smart thermostat is installed in each participant's home, replacing the existing thermostat, which is then controlled via a one-way pager signal to manage the set-point and cycling of the furnace. Curtailments are initiated during peak hours of summer (June - August) weekday afternoons and are not expected to exceed one-hundred twenty hours each year (i.e., thirty events of four hours/event). Due to the cycling strategy undertaken coupled with a customer's ability to override the set-point signal, it is assumed that about 65% of the households participate during events. A sample of participants will also have interval meters installed to help program administrators document and verify the achieved level of demand savings during program events.

Figure A-2 summarizes projected market penetration, aggregate load impacts, economic and reliability benefits, and costs for the smart thermostat air conditioning program. The utility expects to ramp up the smart thermostat program over a seven-year period, with the goal of achieving 30,000 participants. With per unit savings expected to be 1.1 kW during events, the program is anticipated to reduce the residential class peak demand by 1.2% when it reaches a steady-state in year 7 (i.e., 2014). After 2014, the utility plans to add new participants to maintain aggregate peak demand savings. This will require the utility to enroll new participants to offset projected growth in peak demand (2.2% per year) and replace customers that move or drop out of the program. The utility expects that ~7% of the customers per year will be lost due to changes in electric service (5%) or removal from the program (2%)). The utility estimates that increasing set-points and cycling the air conditioner will have a measurable impact on energy consumption during events (132 kWh/unit-year). The utility also assumes that customers will take back about 50% of these energy savings during the four hour period following a curtailment.

The utility has budgeted $150,000 up-front to develop the program in year 1. The utility projects that customer acquisition costs are $30/customer for marketing and back-office costs, that cost and installation of the smart thermostat is $175/customer, and that load impact verification costs are $5/customer. Costs for the smart thermostat are assumed to decrease by 1.5% per year, due to technology improvements and greater market volumes. The utility will offer customers an incentive for participating in events ($7/month bill credit for three months = $21/customer-year). The use of the paging system is expected to cost $5/customer-year, while the utility believes it will incur $15/customer-year to inspect a sample of smart thermostats and interval meters as well as perform any necessary service calls for these items of equipment. The cost to run the program every year is estimated to be $65,000/year. These costs are anticipated to grow by 2% per year after 2008.

Benefits from the program are derived from the avoided cost of energy, capacity and transmission and distribution, as well as environmental savings (see discussion of water heater DR program). The avoided capacity costs account for ~90% of the total benefits.

Using these inputs and assuming the smart thermostat air conditioning program is maintained for twenty years, the utility anticipates total program costs, on a present value basis using a discount rate of 8.8%, to be $19.28MM and program benefits to be $19.91MM. The TRC Benefit Cost ratio for this program would be slightly above 1.0 and is only marginally cost-effective.

Our screening analysis tool can be utilized by utility planners and regulatory staff to conduct sensitivity analysis on key input values that might affect program cost-effectiveness. Input values that have the most significant impact on cost-effectiveness are the avoided cost of capacity (initial year value and assumed escalation rate) and the assumed proportion of customers that participate and respond to events and don't override (e.g. we assume 65% participate). Lower program costs would also improve cost-effectiveness with assumed values for technology and back-office costs and program incentives having the most significant impact.

Figure A-2 – Smart Thermostat Air Conditioning Demand Response Program: Benefit-Cost Estimate

Year Index	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Year	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Utility System Characteristics																				
Forecasted Retail Sales (GWh)	23,000	23,460	23,929	24,408	24,896	25,394	25,902	26,420	26,948	27,487	28,037	28,598	29,170	29,753	30,348	30,955	31,574	32,206	32,850	33,507
Forecasted Peak Demand (MW)	4,000	4,088	4,178	4,270	4,364	4,460	4,558	4,658	4,761	4,865	4,972	5,082	5,194	5,308	5,425	5,544	5,666	5,791	5,918	6,048
Residential Retail Sales (GWh)	8,740	8,915	9,093	9,275	9,460	9,650	9,843	10,040	10,240	10,445	10,654	10,867	11,084	11,306	11,532	11,763	11,998	12,238	12,483	12,733
Residential Peak Demand (MW)	1,520	1,553	1,588	1,623	1,658	1,695	1,732	1,770	1,809	1,849	1,890	1,931	1,974	2,017	2,061	2,107	2,153	2,200	2,249	2,298
DR Program Characteristics																				
Number of New Participants (Units)	4,286	4,586	4,886	5,186	5,486	5,786	6,086	2,760	2,821	2,883	2,946	3,011	3,077	3,145	3,214	3,285	3,357	3,431	3,506	3,584
Number of Returning Participants (Units)	0	3,986	7,971	11,957	15,943	19,929	23,914	27,900	28,514	29,141	29,782	30,437	31,107	31,791	32,491	33,206	33,936	34,683	35,446	36,226
Number of Total Participants (Units)	4,286	8,571	12,857	17,143	21,429	25,714	30,000	30,660	31,335	32,024	32,728	33,448	34,184	34,936	35,705	36,490	37,293	38,114	38,952	39,809
Peak Period Energy Reduction (MWh)	368	735	1103	1471	1839	2206	2574	2631	2689	2748	2808	2870	2933	2998	3063	3131	3200	3270	3342	3416
Off-Peak Period Energy Increase (MWh)	184	368	552	735	919	1103	1287	1315	1344	1374	1404	1435	1467	1499	1532	1565	1600	1635	1671	1708
Proportion of Class Retail Sales (%)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Capacity Reduction (MW)	3.06	6.13	9.19	12.26	15.32	18.39	21.45	21.92	22.40	22.90	23.40	23.92	24.44	24.98	25.53	26.09	26.66	27.25	27.85	28.46
Proportion of Class Peak Demand (%)	0.2%	0.4%	0.6%	0.8%	0.9%	1.1%	1.2%	1.2%	1.2%	1.2%	1.2%	1.2%	1.2%	1.2%	1.2%	1.2%	1.2%	1.2%	1.2%	1.2%
Benefits																				
Avoided Energy Cost Savings ($MM)	$0.02	$0.04	$0.06	$0.09	$0.11	$0.14	$0.16	$0.17	$0.18	$0.18	$0.19	$0.20	$0.21	$0.22	$0.22	$0.23	$0.24	$0.25	$0.27	$0.28
Avoided Capacity Cost Savings ($MM)	$0.26	$0.54	$0.83	$1.14	$1.46	$1.81	$2.17	$2.29	$2.41	$2.53	$2.67	$2.81	$2.96	$3.11	$3.27	$3.45	$3.63	$3.82	$4.02	$4.23
Avoided T&D System Cost Savings ($MM)	$0.01	$0.02	$0.03	$0.04	$0.05	$0.06	$0.08	$0.08	$0.09	$0.09	$0.09	$0.10	$0.10	$0.11	$0.12	$0.12	$0.13	$0.14	$0.14	$0.15
Environmental Benefits ($MM)	$0.00	$0.00	$0.00	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02
Reliability Benefits ($MM)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total ($MM)	***$0.29***	***$0.60***	***$0.92***	***$1.27***	***$1.63***	***$2.02***	***$2.42***	***$2.55***	***$2.68***	***$2.82***	***$2.96***	***$3.12***	***$3.28***	***$3.45***	***$3.63***	***$3.82***	***$4.02***	***$4.23***	***$4.45***	***$4.68***
Benefits - Present Value ($MM)	**$19.91**																			
Costs																				
Program Development Costs ($MM)	$0.15	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Customer Acquisition Costs ($MM)	$0.90	$0.95	$1.00	$1.04	$1.08	$1.13	$1.17	$0.52	$0.52	$0.53	$0.53	$0.54	$0.54	$0.54	$0.55	$0.55	$0.55	$0.56	$0.56	$0.56
Annual Program Administration Costs ($MM)	$0.07	$0.07	$0.07	$0.07	$0.07	$0.07	$0.07	$0.07	$0.08	$0.08	$0.08	$0.08	$0.08	$0.08	$0.09	$0.09	$0.09	$0.09	$0.09	$0.09
Annual Program Variable costs ($MM)	$0.18	$0.36	$0.55	$0.75	$0.95	$1.16	$1.39	$1.44	$1.51	$1.57	$1.64	$1.71	$1.78	$1.85	$1.93	$2.01	$2.10	$2.19	$2.28	$2.38
Total ($MM)	***$1.29***	***$1.37***	***$1.61***	***$1.86***	***$2.11***	***$2.36***	***$2.63***	***$2.04***	***$2.11***	***$2.18***	***$2.25***	***$2.32***	***$2.40***	***$2.48***	***$2.56***	***$2.65***	***$2.74***	***$2.84***	***$2.93***	***$3.04***
Costs - Present Value ($MM)	**$19.28**																			
Net Benefits ($MM)	***0.63***																			
Benefit Cost Ratio	***1.03***																			