

Final Report

Demand Response Proxy Supply Curves

Prepared for:
PacifiCorp

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I. Introduction

This report summarizes the results of an assessment of technical, market, and achievable potentials for demand response (DR) resources for PacifiCorp's system overall and its two control areas: West (California, Oregon, Washington), and East (Idaho, Utah, Wyoming). The results of this assessment form the basis for producing proxy supply curves for Class I and Class III demand-side management (DSM) resources, which will be incorporated into PacifiCorp's 2006 integrated resource plan (IRP).

The project's key objectives included: meeting PacifiCorp's IRP regulatory requirements; addressing public comments regarding comparable treatment of DR resources, with respect to power production options in PacifiCorp's resource portfolio evaluation; and assisting the company in further refining DR opportunities. Specifically, the project is intended to address an Oregon Public Utility Commission (OPUC) 2004 IRP requirement to evaluate Class I and Class III DSM resources, using a supply curve approach for portfolio modeling in PacifiCorp's 2006 IRP. In 2007, PacifiCorp plans to complete a more detailed assessment of DSM potentials, providing state-specific results. Therefore, this project is to be considered preliminary, and to serve as a "proxy" for the DR portion of that study.

The resulting supply curves show the price/quantity relationship for various categories of DR strategies and options within Class I and Class III DSM resources, as defined by PacifiCorp. As part of this project, to facilitate the economic screening of alternative DR options, research was also conducted regarding current utility practices in valuation of DR resources, with an emphasis on identifying key value drivers used in this evaluation.

This report is organized in five parts. The remainder of this chapter provides a general overview of DR resources, as well as the specific program concepts used in this study. Section II describes the results of research on DR value factors and valuation methods. Section III reports the results of the DR potential assessment. Section IV describes the general approach and methodology for estimating resource potentials. Detailed data and assumptions used to derive resource potentials for each specific DR resource are described in Section V.

Demand-Response Resources

Demand-response resources are comprised of flexible, price-responsive customer loads that may be curtailed in whole or in part during system peak load periods, when wholesale market prices exceed the utility's marginal power supply cost, or in the event of a system emergency. Acquisition of DR resources may be based on either reliability considerations or economic/market objectives. Demand response objectives may be met through a broad range of price-based (e.g., time-varying rates and curtailable rates) or incentive-based (e.g., direct load control) strategies. For the purpose of this project, DR is defined based on PacifiCorp's characterization in terms of two distinct classes of firm and non-firm resource options:

Class I (Firm) DSM Resources

This class of DR strategies allows either direct or scheduled interruption of electrical equipment and appliances such as water heaters, space heaters, central air-conditioners, commercial energy management systems, and irrigation pumps. Programmatic options in this class of resources fall into the four following categories:

- Fully dispatchable programs, 10 minute or less response, up to 87 hours annually (e.g., direct curtailment of residential air conditioning, water heating, space heating)
- Fully dispatchable programs, over 10 minute response, up to 87 hours annually (e.g., commercial energy management system coordination)
- Scheduled firm up to 170 hours annually (e.g., irrigation load curtailment)
- Scheduled firm at 360 or more hours annually (e.g., thermal energy storage)

Pre-determined incentive payments are typically the main instrument for compensating participants in this class of programs.

Class III (Non-Firm) DSM Resources

Demand response resources in this class differ from those in Class I in that their dispatch is outside the utility's control and, therefore, less reliable or "firm." Resources in this class include curtailable rate programs, time-varying prices (time-of use, real-time pricing, critical peak pricing), and demand buyback or demand bidding programs. Incentives are provided to participants either as a special tariff (curtailable rates, time-varying prices) or per-event payments (demand buyback).

Although residential seasonal programs such as Customer Energy Challenge are considered Class III resources, they are not included in this analysis. Arguably, such programs serve better as contingency resources during periods when energy prices are projected to be high and expected to stay high for an extended period of time, rather than as capacity relief resources.

Program Concepts

Before developing resource potential estimates, it is important to consider how each resource is likely to be structured as a demand response product or program. Using the definitions of Class I and Class III resources above, program concepts were developed as a framework for estimating market potential. For the purpose of this assessment, five specific program concepts were formulated, as described below.

Fully Dispatchable

Often referred to as direct load control (DLC), these fully-dispatchable programs are designed to reduce the demand during peak periods by turning off equipment or limiting the "cycle" time (i.e., frequency and duration of periods when the equipment is in operation) during system peak. The offerings for the residential sector are seasonally divided, while the potential with large

commercial and industrial customers typically focus on summer cooling loads only. Three program concepts in this category of resources were included in the analysis:

- **Winter.** Direct load control of water and space heating during winter are the program options considered in this class. This program would be dispatched during the morning and evening peak hours. The largest potential for such a program will be in the West control area because of the higher saturation of electric space heating. Incentives are generally paid on a monthly basis. Although there are no large scale DLC programs in the Northwest, Portland General Electric (PGE) and Puget Sound Energy (PSE) have both studied implementation through pilot programs. Nationally, there are many utilities with space and/or water heating controls, including Duke Power, Wisconsin Power and Light, Great River Energy, and Alliant Energy.
- **Summer.** The main DR product in this group is direct load control of air-conditioning units¹, which are typically dispatched during the hottest summer days, and are common place due to the relatively high summer loads in warm climates. PacifiCorp currently pays monthly incentives to residential and small commercial participants in Utah’s Cool Keeper AC Load Control program. There is approximately 130 MW of connected load for this program. Using a 50% cycling dispatch strategy, approximately half can be expected during an event. In addition to those utilities listed above, Nevada Power, Florida Power and Light, Alliant Energy, and the major investor-owned-utilities in California run air conditioner direct load control programs (e.g., Sacramento Municipal Utility District and San Diego Gas and Electric).
- **Large Commercial & Industrial.** Direct control of large commercial and industrial (C&I) customers requires coordination with the existing energy management systems (EMS). The focus of this program is adjustment of the heating, ventilation, and air conditioning (HVAC) equipment during the top summer hours. Incentives are generally paid on a per-kW or per-ton (of cooling equipment) basis. Some utilities running comparable programs include Florida Light & Power, Hawaiian Electric, and Southern California Edison.

Scheduled Firm

Program strategies that provide consistent reductions during pre-specified hours target customers with usage patterns and technology that allow scheduled shifting of consumption from peak to off-peak periods.

- **Irrigation Pumping.** Irrigation load control is a candidate for summer DR due to the relatively low load factor (approximately 30%) of pumping equipment and the coincidence of these loads with system summer peak. Through PacifiCorp’s irrigation load control program, customers subscribe in advance for specific days and hours when their irrigation systems will be turned off. Load curtailment is executed automatically based on a pre-determined schedule through a timer device. Although a total of 100 MW

¹ Although it may be possible to add control of electric hot water heating to this summer program, this study does not address this option due to the declining saturations of electric hot water heating and the relatively low peak coincident demand during summer.

is contracted with this program, only half is available due to the alternating schedules of program participants. In the Northwest, Bonneville Power Administration (BPA) has run a pilot irrigation program (on a dispatch, rather than scheduled, basis) and Idaho Power has a program similar to that of PacifiCorp.

- **Thermal Energy Storage.** For small commercial and industrial customers, it is possible to have thermal energy storage (TES) cooling systems that produce ice during off-peak periods, which is then used during the on-peak period to cool the building. The system is programmed to use ice-cooling during pre-specified times (typically six hours per day, from April to October) and participants are given incentives on a per-kW or per-ton-of-cooling basis.

Curtable Rates

Curtable rate options have been offered by many utilities in the United States for many years. These programs are designed to ease system peak by requiring that customers shed load (in part or whole) by a set amount or to a set level (e.g., by turning off equipment and/or by on-site generation) when requested by the utility. Participants are either provided with a fixed rate discount or variable incentives, depending on load reduction; penalties are often levied for participants who do not respond to curtailment events. Large commercial and industrial customers are the target market for those programs that address PacifiCorp's summer system peak. Many utilities provide a broad range of program options, including Duke Power, Georgia Power, Dominion Virginia Power, Pacific Gas and Electric, ConEd, Southern California Edison, MidAmerican, and Wisconsin Power and Light.

Critical Peak Pricing

Critical Peak Pricing (CPP) rates only take effect a limited number of times during the year. In times of emergency or high market prices, the utility can invoke a critical peak event, where customers are notified and rates become much higher than normal, encouraging customers to shed or shift load. Typically, the CPP rate is bundled with a time-of-use rate schedule, whereby customers are given a lower off-peak rate as an incentive to participate in the program. Customers in all customer classes (residential, commercial, and industrial) may choose to participate in a CPP program, although there are certain segments in the commercial sector that are less able to react to critical peak pricing signals. Currently, there are no CPP programs being offered by Northwest utilities. Peak pricing is, however, being offered through experimental pilots or full-scale programs by several organizations in the United States, notably Southern Company (Georgia Power), Gulf Power, Niagara Mohawk, California utilities (SCE, PG&E, SDG&E), PJM Interconnection, and New York ISO (NYISO). Adoption of CPP has not been as widespread in the Western states as they have in the East. In the Pacific Northwest, this may be partly explained by the generally milder climate and the fact that, due mainly to large hydroelectric resources, energy, rather than capacity, tends to be the constraining factor.

Demand Buyback/Demand Bidding

Demand buyback and/or bidding (DBB) products are designed to encourage customers to curtail loads during system emergencies or high price periods. Unlike curtailment programs, customers have the option to curtail power requirements on an event-by-event basis. Incentives are paid to participants for the energy reduced during each event, based primarily on the difference between market prices and the utility rates. All major investor-owned utilities in the Northwest and Bonneville Power Administration have offered variants of this option, beginning in 2001. PacifiCorp's current program, Energy Exchange, was used extensively during 2001 and resulted in maximum reduction of slightly over 40 MW in that period. Demand reductions from PacifiCorp's current program are approximately 1 MW. Demand buyback products are common in the United States and are being offered by many major utilities. The use of DBB offerings as a means of mitigating price volatility in power markets is especially common among independent system operators including CAISO, NYISO, PJM, and ISO-NE. However, DBB options are not currently being exercised regularly due to relatively low power prices.

II. Valuation of Demand Response Resources

Overview

In the Northwest and elsewhere in the country, valuation of DR programs has been the subject of much debate among utility industry experts. Although there is broad agreement on the existence and relevance of a wide range of benefits arising from DR, there is little agreement on how and to what extent these benefits can be attributed to specific DR programs and what metrics might be used to quantify them. In response to this, in 2005 the Northwest Power and Conservation Council sponsored a series of workshops to identify and enumerate value attributes of DR resources and to develop a consistent methodology for their valuation. The Demand Response Research Center in California recently commissioned two parallel studies to investigate alternative frameworks for valuation and cost-effectiveness analysis of DR products.

As part of this study, we conducted a thorough search of DR literature, evaluation reports, and utility filings, followed by informal interviews with several industry experts to investigate current practices for evaluating DR resources. The results of this analysis are intended to inform PacifiCorp's process for screening DR resource options and how they might be incorporated in its integrated resource plan. We begin this section with a review of potential benefits and value factors ascribed to DR, discuss the current practices and the basis for valuation of these benefits, and then consider alternative approaches for incorporating DR options in the integrated resource planning process.

Benefits of Demand Response

There are many different views on the types and the relative importance of value factors associated with DR. Industry experts agree on at least three general categories of benefits from DR: economic, system reliability, and environmental (Hirst 2001).

Economic Benefits. There is a host of economic benefits to the utility, the consumers, and the power system as a whole that are presumed to arise from DR. Some of these benefits are more tangible and more readily quantifiable than others. Cost avoidance and cost reduction are the main economic drivers for DR. Demand response allows utilities to avoid or defer incurring costs for generation, transmission, and distribution, including capacity costs, line losses, and congestion charges. Economic benefits may also accrue directly to participants in the form of incentives, rate discounts, and greater ability to adjust their loads to prices, thereby gaining greater control over their energy use and managing their energy costs (Braithwait, 2003). DR has also been credited with several harder to quantify economic benefits, such as creating a hedge against market exposure (price objectives), helping create a more elastic demand curve by sending appropriate price signals (elasticity objectives), and reducing the overall market price by alleviating pressure on reserves (market efficiency objectives) (Ruff, 2002).

System Reliability Benefits. Demand response reliability considerations are those meant to ensure reliability in power supply and delivery during system emergencies by providing the ability to shed load under emergency conditions. Customer demand management can enhance

reliability of the electric supply and delivery systems by providing the utility with the means to better balance loads with supply during system emergencies and/or high-use periods. In this context, DR can help improve the adequacy and security of the power supply and delivery (T&D) systems by augmenting the utility's ancillary services, such as supplemental reserve (Hirst, 2002).

Potential Environmental Benefits. Demand response resources promote the efficient use of resources in general. Depending on the generation fuel mix of the sponsoring utility, this can help reduce externalities in power generation and reduce emissions. Increasingly, utilities have begun to consider the potential effects of future carbon taxes in their DR product design.

Although this is by no means an exhaustive list of all potential benefits discussed in DR literature, it represents the most common set of benefits recognized by industry experts. Additional benefits such as risk management, market power mitigation, customer service, and third-party benefits (for example to aggregators and service providers) have also been cited as potential benefits of DR. These benefits, however, generally tend to be less pronounced and difficult to quantify (Peak Load Management Alliance, 2002). Approaches and current practices for evaluating DR resources and quantifying each of the above benefit categories are discussed below.

Resource Valuation Methods

Current practices in valuation of DR resources largely rely on an extension of the “Standard Practice Manual” (SPM) originally developed in California for evaluating energy-efficiency programs (California Public Utilities Commission, 2001). Of the four tests set forth in the latest version of the SPM, published in 2001, the total resource cost test (TRC), usually accompanied by the participant test, is the most common method used to screen DR resources by utilities (California Public Utilities Commission, 2003).² A clear instance of the application of SPM to the evaluation of DR resources is found in the California Public Utilities Commission's direction that the SPM be used as an option in evaluating DR, “since it allows an assessment of demand reductions from multiple viewpoints: society, customer, utility, and ratepayer.”

A review of current practices in valuation of DR benefits indicates that not all benefits discussed above are taken into account by utilities or system operators, mainly due to the fact they tend to be hard to quantify. Potential benefits of DR, common basis for their valuation, and the range of suggested values are summarized in Table 1. Current valuation methods and practices are discussed in greater detail below.

² The other tests are the Ratepayer Impact Measure (RIM) Test, Participant Tests, and the Program Administrator (or Utility) Test.

Table 1. Potential Benefits of Demand Response

Benefit Category	Value Factors	Basis for Valuation	Range of Values
Market-wide	<ul style="list-style-type: none"> Overall economic efficiency (better alignment of supply and demand) Reduction in average price of electricity in the spot market Reduced costs of electricity in bilateral transactions Reduced hedging costs, e.g., reduced cost of financial options Reduced market power Private entity (e.g. aggregator) benefits 	Not Quantified	Not Applicable
Utility System	<ul style="list-style-type: none"> Avoided capacity costs (generation) Avoided energy costs Avoided T&D losses Deferred grid system expansion 	Benchmarking (peaker unit) Benchmarking (market prices) Adders Marginal (local) T&D costs	\$50-\$85 Variable 6%-10% Variable
Customer	<ul style="list-style-type: none"> Incentives Reduced power bill (participants) Greater choice and flexibility 	Value of payment Rates, demand charges Cash-flow, Option model	Variable Variable Variable
Reliability Benefits	<ul style="list-style-type: none"> Increase in overall system reliability Value of insurance against low-probability/high-consequence events Option value (added flexibility to address future events) Portfolio benefits (increase in resource diversity) 	Change in LOLP Value of un-served energy (customer outage costs) Not Quantified Not Quantified	Not Available \$3-\$5 per kWh Not Applicable Not Applicable
Environmental Benefits	<ul style="list-style-type: none"> Avoided emissions Avoided future carbon taxes 	Environmental “adder” Not Quantified	8%-12% Not Applicable

Valuation of Economic Benefits

With the exception of participant tests, the application of the SPM tests rely on the concept of cost avoidance as the key mechanism for taking into account the economic value of DR. The TRC test, which is often used as the primary criterion for screening of DR resources, takes into account a variety of avoided costs associated with generation, transmission, distribution, and line losses. The avoided capacity and, to a lesser extent, energy costs are the principal economic benefits included in the test. Determination of avoided capacity and energy costs are most commonly based on a benchmarking method. In the case of avoided capacity costs, the approach relies on using average per-unit life cycle cost of a peaker resource (usually a combined- or simple-cycle gas turbine) as a benchmark for screening of DR options. Market price curves are the most commonly-used proxy for determination of avoided energy costs.

Avoided capacity costs tend to vary across utilities and the program to which they are applied. Regardless of how they are calculated, capacity costs used by most utilities surveyed fall in the range of \$50 to \$85 per kW-year. In a recent ruling, the California Public Utilities Commission

authorized an avoided cost of \$52 per kW as compared to the previously established avoided cost of \$85 per kW, based on the average life-cycle cost of a peaker plant method for screening and valuation of DR resources (CPUC, PG&E Application 05-06-028, 2005).

Avoided energy costs represent additional benefits from DR programs. Since most DR programs lead to a shift (rather than a reduction) in energy use, the energy benefits are typically measured in terms of on-peak/off-peak price differential. Other DR programs, such as DLC may result in reductions in energy use, since some portion of the foregone energy use may not be offset by additional consumption during the off-peak period. The latter benefits are especially important in evaluating DR programs from the participants' point of view, since they tend to directly affect bills. Avoided energy costs have been used to measure the benefits in a number of evaluations of DR programs in the Northwest.³ Avoided energy costs are also the sole basis for determination of payments in demand buyback and demand bidding programs. Indeed, incentives in all demand buyback programs are structured on the basis of market energy prices, rather than avoided capacity costs.

Benefits to the grid system generally fall into two categories: 1) avoided line loss; and 2) value of opportunities to defer system expansion. In the Northwest, both PacifiCorp and PGE have explicitly incorporated avoided T&D losses in their past evaluations of time-of-use and direct load control programs, and Bonneville Power Administration has explicitly included deferral of investments transmission system expansion in its system planning and valuation of DR programs.

Direct benefits to customers represent additional benefits likely to result from DR. These benefits generally appear in the form of incentive payments from the utility or lower bills resulting from reductions in demand charges, shift of demand to lower-priced, off-peak periods and potential energy savings. As discussed above, in the case of DR programs involving a shift in consumption, these benefits tend to be small. In many DR programs, such as time-of-use rates and load control/curtailment programs, portions of the foregone energy use during DR events (high rate or curtailment period) may not be compensated by higher use during off-peak period, thus resulting in net reductions in the customer's energy consumption.

Other potential benefits to customers, such as greater choice and "option value," are generally more difficult to quantify. Attempts at quantification of these benefits generally rely on either a discounted cash-flow analysis or an "option model" (see Sezgen 2005).

Valuation of System Reliability Benefits

The planning and screening of utility-sponsored DR programs typically have not included reliability benefits. But reliability has been the primary metric for valuation of DR programs offered by independent system operators (ISOs). Most of the seven established ISOs have been actively engaged in offering DR options. Since the primary goal of an ISO is to maintain system reliability, it stands to reason that valuation of their programs would be based on reliability

³ These include evaluations of irrigation load curtailment and pilot time-of-use programs offered by PacifiCorp, evaluations of residential time-of-use and direct load control programs by PGE, and Bonneville Power Administration's evaluation of remote irrigation load control.

benefits rather than avoided generation capacity. Indeed, evaluations of ISO-sponsored programs completed to date have focused almost exclusively on reliability benefits based on avoided congestion, valued in terms of the location-specific marginal transmission costs (LMC).

The general approach used in valuation of ISO-sponsored DR is based on two factors: 1) the difference between market power price and the DR program costs; and 2) the expected marginal value of increased reliability realized through assumed reductions in loss-of-load probability (LOLP) and its impact on the expected value of un-served energy (EVUE) as a function of the value of lost load (VOLL), that is:

$$EVUE = \text{Value of Lost Load (VOLL)} * \Delta \text{LOLP} * \text{Load at Risk}$$

The underlying concept in the evaluation approach is that the value of curtailable load (therefore the value of the DR programs that generate it) is a function of the “expectation” of future loss of load. This suggests that the actual value of DR programs stems primarily from their societal value as a hedge against low-probability, high-cost events and the associated outage costs to customers.

The NYISO and ISO-NE have both used this approach in evaluation of their DR products (RLW Analytics, 2005). Calculation of changes in LOLP and the value at risk are generally established on an event-by-event basis and tend to be highly variable. In its evaluations, the NYISO, for example, typically has assumed a VOLL of \$5.00/kWh (NYISO, 2004); and the PJM Interconnection recently proposed a VOLL of \$20/kWh. However, as data on several real-time pricing programs suggest, the VOLL tends to fall in the range between \$3/kWh and \$5/kWh (Barbose 2004, Violette 2006). Available estimates of VOLL are calculated from the customer’s or societal perspectives and are generally expressed in terms of energy, rather than capacity. Presumably, given the actual, program-specific hours of curtailment, it may be possible to convert these estimates to an equivalent capacity value.

Valuation of Environmental Benefits

Demand response has the potential to produce tangible environmental benefits by avoiding emissions from the operation of peak units as well as potential conservation effects (load shed versus load shift) during peak periods. Such environmental impacts, however, depend entirely on the emissions profile of the utility’s generation resource mix. It is also possible that reduced emissions during peak periods might be offset by increased emissions during off-peak periods, as well as from additional emissions from on-site, back-up generation at commercial and industrial facilities. Due partly to these complexities, potential environmental benefits are not currently being considered in valuation of utility-sponsored DR programs.

Treatment of DR Options in Integrated Utility Resource Planning

Classification of DR Options

Values arising from DR options, and the manner in which they are incorporated in the integrated planning process may vary by the type of DR product and the entity that sponsors them. There have been several attempts at classification of DR programs. The most common approach to

classification of DR involves characterizing them according to the degree of the utility’s dispatch control. From this perspective, DR resources are generally categorized according to a “firm” versus “non-firm” dichotomy. Another approach, adopted in the recent report by the U.S. Department of Energy, classifies DR programs in terms of the basis on which participants are compensated and proposes two categories: tariff-based and incentive-based (DOE, 2006). A third approach, suggested in a recent study sponsored by the Rocky Mountain Institute (Rocky Mountain Institute, 2006), classifies DR resources along two dimensions: 1) the criteria that trigger a curtailment request by the utility (economic versus reliability); and 2) the method by which utilities motivate customers to participate in DR (load response versus price response).

These approaches, however, generally do not provide guidance as to how DR benefits and costs might be allocated or how various resources might be modeled in an integrated resource plan. Arguably, from a utility’s perspective, the most important benefits of DR are economic (reducing the overall supply cost) and reliability (offering an optional resource in case of system emergencies).

An alternative, and perhaps more appropriate, classification of DR would be in terms of the degree of variability in curtailment period and prices paid by the sponsoring utility.⁴ Under this scheme, DR resources are classified in terms of two dimensions: curtailment period and incentive payment. As shown in Figure 1, both period of curtailment and the level of incentives paid by the utility to motivate curtailment may be either fixed or variable. (See Neenan, 2006.)

Figure 1. Classification of Demand Response Programs

		Incentive Payment	
		Fixed	Variable
Curtailment Period	Fixed	<ul style="list-style-type: none"> •Time-of-Use Tariff •Direct Load Control •Scheduled Curtailment •Curtailment Contract 	<ul style="list-style-type: none"> •Critical Peak Pricing
	Variable	<ul style="list-style-type: none"> •Real-Time Pricing 	<ul style="list-style-type: none"> •Demand Buyback •Demand Bidding

⁴ Time-of-use rates and critical peak pricing are examples of programs where both pricing period and price levels are fixed. Demand buy-back and demand bidding demand response strategies are examples of programs where both price periods and levels of payment are variable.

Time-of use, load control, scheduled curtailment, and curtailment contracts are examples of resources where both incentive payments and curtailment periods are fixed in advance. Although this group of programs offers more *predictable* prices and, to a lesser extent, amounts of reduction, they also pose a degree of price risk in that program prices are set in advance through the use of price forecasts rather than based on actual prices at the time of load reduction. Demand buyback and demand bidding, on the other hand, are resources where both curtailment period and incentive payments are variable.

Incorporating DR into the IRP Process

Much the same as energy efficiency resources, DR products may be incorporated into the IRP in two ways. The first approach, often referred to as “decrementing,” begins with pre-screening of DR resources for general cost-effectiveness based on an external benchmark (generally avoided capacity costs), decrementing the load forecast by the amount of DR resources that pass the screening, and solving for the true avoided cost as derived from the value of decremented load to the resource portfolio. The second approach entails simultaneous modeling of generation and DR resources in the context of an optimization or system expansion planning model and selecting the optimal, least cost, mix of resources. In our view, the latter approach is preferred in that it treats DR resources on a level playing field with supply options and forces the model to select from the most attractive, least-cost mix of resources regardless of their classification as supply or demand-side.

The main shortcoming of these approaches to valuation and integration of DR resources is that they generally focus on economic (cost-reduction) benefits of DR and ignore the reliability benefits. Moreover, the economic benefits of DR often are measured in terms of energy, rather than capacity, values. For most DR resources, the benefits ought to be evaluated primarily in terms of an alternative, “optional” capacity resource and secondary energy benefits (in terms of both reduced consumption and/or peak-off-peak energy costs differential). Regardless of the method used, it is important that the full range of economic values (including avoided capacity, energy, and T&D benefits, as well as reliability benefits) be fully considered in the screening and planning processes. Although the greatest value of DR options is likely to be on the generation side, additional benefits such as avoided T&D losses and reliability benefits may be incorporated in the valuation as utility-specific “adders.”

An additional shortcoming of these approaches is that they ignore the role of risk and uncertainty associated with various resource options. Clearly, there are technical (e.g. equipment failure) and market (e.g. program and event participation rates) uncertainties inherent in any demand-response option. These risks need to be explicitly taken into account in screening of DR resources. It is equally important in the context of IRP that the treatment of DR risks be symmetrical; that is, the screening process ought to also take into account upside risks of DR. Since DR resources are valued on the basis of expected future loads and power prices, future fluctuations in loads and avoided costs are likely to have a direct effect on the value of DR options.⁵

⁵ Portfolio management principles and techniques are being used in a limited way by some utilities to analyze uncertainties in the IRP process. This is particularly the case in designing standard renewable portfolios in several

In the context of IRP, joint consideration of economic (capacity and energy) and reliability benefits does, however, pose additional complexity. Since integrated resource planning processes are generally based on long-run resource needs, the value of DR hinges on its ability to displace some portion of the utility's peak demand. As pointed out in the Department of Energy's recent report, once DR resources are included in the utility's capacity resource mix, they become part of the planned capacity and are no longer available for dispatch during system emergencies (DOE, 2006). It is important, therefore, to distinguish between DR resources that serve the economic objectives and might be incorporated in the resource plan and those that are more appropriately set aside for reliability purposes. Certain DR resources, such as demand bidding or demand buyback, may be set aside as reliability options to be called upon during system emergencies.

Potential adverse customer impacts are additional considerations in DR planning. Clearly, once DR resources are incorporated in the planned capacity, the utility can maximize the value of DR resources by exercising these options to the maximum extent possible. However, the more frequently these options are exercised, the higher the likelihood of more severe disruptive impacts of the customers' operations. This will affect the customers' decision to participate in the DR program and thus reduce the market potential for DR.

jurisdictions. For a discussion of uncertainty in IRP and the portfolio management approach see Awerbuch (1993 and 2005). Also see Bolinger (2005) for a survey of current utility practices in portfolio design.

III. Demand Response Resource Potentials

The approach to estimation of resource potentials in this study distinguishes between three definitions of demand-response potential that are widely used in utility resource planning: technical, market, and achievable potentials. Technical potential assumes that all demand-response resource opportunities may be captured regardless of their costs or market barriers, notwithstanding obvious exceptions such as load control in mission-sensitive operations. Market potential, on the other hand, represents that portion of technical potential that is likely to be available over the planning horizon, given resource constraints and prevailing market barriers. Finally, achievable potential recognizes that not all of the market potential can be implemented due to the overlap (or interaction) among DR options targeted for the same sectors and/or end uses.

To the extent possible, we have sought in this study to obtain the most recent and reliable data on market prospects for various DR options, relying upon available resources from other utilities offering similar products. However, information and assumptions based on current demand response experiences and costs, no matter how accurate, are subject to future uncertainty. Therefore, the results of this study are to be viewed as preliminary and indicative rather than conclusive.

The general methodology and analytic techniques used in this study conform to standard practices and methods used in the utility industry. Given the scope and timeframe of this study, it was necessary to utilize a consistent and relatively simple methodology to effectively address PacifiCorp's immediate IRP needs. The methodology and inputs assumptions are fully described in Sections IV and V of this report.

Technical Potential

In the context of demand response, technical potential assumes that all applicable end-use loads, in all customer sectors, are at least partially available for curtailment, except those customer segments (e.g., hospitals) and end uses (e.g., restaurant cooking loads) that do not lend themselves to curtailment,⁶ and for those programs (e.g., direct load control) that utilize cycling strategies.

Table 2 provides for each customer class (industrial, commercial, irrigation and residential) the technical potential in MW at the system level. (Separate results for the East and West control areas are provided in Appendices 1 and 2.) From a strictly technical perspective, critical peak pricing is expected to have the largest potential due to its broad-based eligibility, followed by curtailable rates and demand buyback. In the absence of market constraints, these figures should

⁶ Although hospitals generally rely on some on-site generation capability, which may be called upon by the utility as a dispatchable resource, such resources are not being considered in this study. Arguably these units are likely to be needed by the host facility during the same period as the utility and are therefore unlikely to be made available for dispatch.

be viewed largely as estimates of “technical feasibility” only and a measure of the total load that is technically available for demand response.

Table 2. Technical Potential (MW), System

Sector	Fully Dispatchable			Scheduled Firm - Irrigation	Thermal Energy Storage	Curtable Rates	Critical Peak Pricing	Demand Buyback
	Winter	Summer	Large C&I					
Industrial	---	---	194	---	---	510	531	500
Commercial	---	55	50	-	93	133	232	130
Irrigation	---	---	-	381	---	---	---	---
Residential	374	351	-	---	---	---	618	---
Total	374	406	244	381	93	642	1,380	630
<i>% of System Peak</i>	<i>4%</i>	<i>5%</i>	<i>3%</i>	<i>5%</i>	<i>1%</i>	<i>8%</i>	<i>16%</i>	<i>7%</i>

To provide an illustration of the methods used to estimate technical potentials, the fully dispatchable winter program will be used. First, eligibility for this program is limited to residential customers due to low saturation of electric space and water heating in other customer classes. Next, PacifiCorp energy sales and system and end-use load shapes indicate that the total residential space and water heating loads during the top 87 hours of the winter average approximately 580 MW and 250 MW, respectively. Although DLC programs can fully interrupt this load when installed, it is assumed that a 50% cycling strategy is used, and only 90% of this is technically available to account for the fact that not all systems can be retrofitted with DLC equipment. Therefore, the system-level technical potential, as shown in Table 3, is 374 MW.

Market Potential

Market potential is the subset of technical potential that may reasonably be accessible by program strategies, accounting for market barriers and customers’ ability and willingness to participate in demand response programs. For the majority of demand response options, market potentials are estimated by adjusting technical potential by two factors: expected rates of “program” and “event” participation. For all programs options, estimates for both program and event participation are derived based on the experiences of PacifiCorp and other utilities offering similar programs. In the case of curtable rates and demand buyback, market potentials are estimated based on observed price elasticity of load response. See Figure 2 for a comparison of technical and market potentials for various program options.

As shown in Table 3, curtable rates have the highest market potential (144 MW), followed by summer DLC and irrigation.

Figure 2: Technical and Market Potential (MW), System

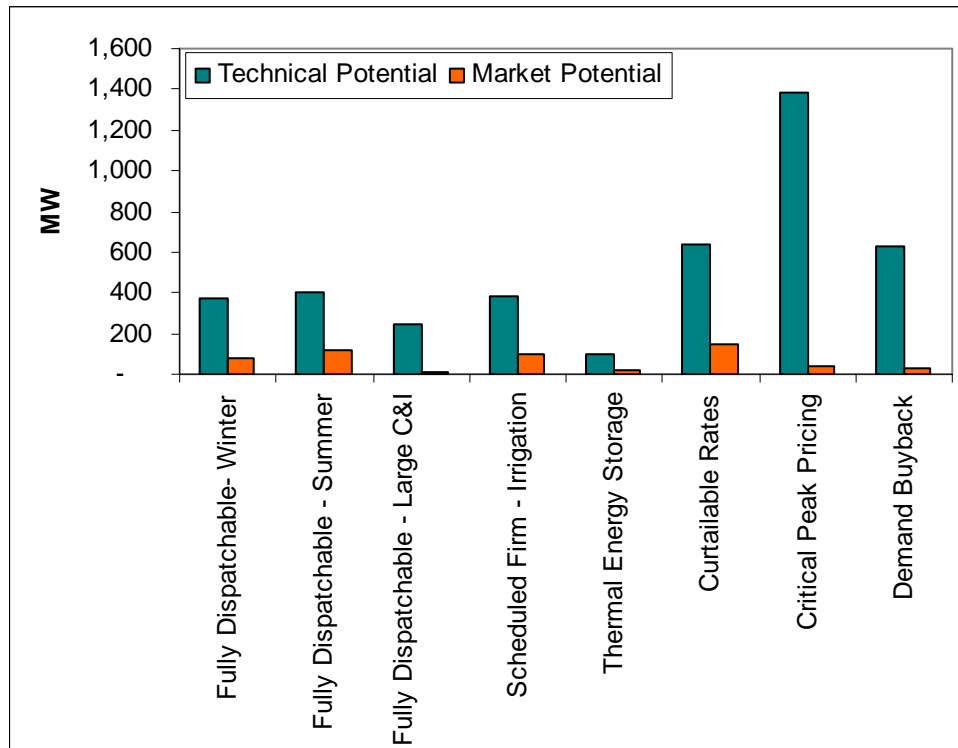


Table 3. Market Potential (MW), System

Sector	Fully Dispatchable			Scheduled Firm - Irrigation	Thermal Energy Storage	Curtailable Rates	Critical Peak Pricing	Demand Buyback
	Winter	Summer	Large C&I					
Industrial	---	---	5	---	---	115	14	22
Commercial	---	3	1	---	19	30	6	6
Irrigation	---	---	---	95	---	---	---	---
Residential	75	118	---	---	---	---	17	---
Total	75	120	7	95	19	144	37	28
<i>% of System Peak</i>	<i>0.9%</i>	<i>1.4%</i>	<i>0.1%</i>	<i>1.1%</i>	<i>0.2%</i>	<i>1.7%</i>	<i>0.4%</i>	<i>0.3%</i>

For a fully dispatchable winter program, an expected load participation rate of 20% (based on experience of similar programs) and event participation rate of 100% are assumed. This assumption is based on the fact that, absent customers' ability to override curtailment and no equipment failure, load interruption would occur once the load is dispatched by the utility.⁷

⁷ Reliability of direct load control systems is primarily a function of the type of equipment and communication systems used to affect control such as radio frequency, telephone networks, wide-area networks, or power line carrier systems. Historical experience with systems has shown that the assumption of a zero failure rate may be unjustified.

Based on these assumptions, this program could reasonably be expected to provide approximately 75 MW of load reduction for the PacifiCorp system.

Using price elasticity of load participation and a measure of commercial and industrial customers' willingness to participate in demand buyback, market potential for this option is estimated at 28 MW. As discussed in Section IV of this report, the elasticity estimates were calculated based on data available on 2000-'01 demand buyback program experience of Northwest utilities. Data available on PacifiCorp's 2000-'01 Energy Exchange program indicate approximately 40 MW of reduction at an average cost of approximately \$100 per MWh. The estimated 28 MW of future market potential may prove overly optimistic due to the dramatically different market conditions prevailing today. Reductions similar to those achieved in 2000-'01 could be difficult or impossible to repeat if electricity prices and customer concerns over energy market conditions continue to be low. Indeed, based on PacifiCorp's program records, operation of the Energy Exchange program during the past three years has resulted in a maximum reduction of no more than 1 MW.

Achievable Potentials

In analyzing levels of achievable potential it is important to take into account two factors: resource interactions and load reduction being achieved given existing programs. Achievable potentials, therefore, represent unique impacts of various DR program options net of the impacts of existing programs. Estimates of market potentials presented above provide "stand alone" estimates of potential. In calculating achievable potential, it is also important to take into account the interaction among DR programs that target the same customer sector and/or end uses within the same sector. Generally, interaction may be accounted for by first ranking competing programs by levelized cost and then allocating the market potentials based on an "availability" factor⁸.

For the purpose of this study, we have assumed that DBB and scheduled firm irrigation are fully available; therefore they have been assigned an availability factor of 100%. Since curtailable rates and dispatchable large C&I compete for the same target market as DBB, only a portion of their market potential will be available. In the residential and small commercial sector, the summer DLC program is fully available; however, thermal energy storage would only be partially available as it competes with the commercial sector DLC program option.

As shown in Table 4, the DR options considered in this analysis may be expected to provide 373 MW of capacity for the PacifiCorp system. In 2005, the PacifiCorp system peaked at 8,940 MW with 570 MW and 1,540 MW of load occurring during the top one percent and ten percent of the load duration curve. The estimated achievable potentials for DR provide the opportunity to offset 66% of the top one percent and 25% of the top ten percent of the system peak load.

⁸ Technically, this is the percentage of the market potential that remains after accounting for resource interactions. For example, a 25% availability factor would be multiplied by the market potential to arrive at the achievable potential on a program-by-program basis.

Summer DLC (120 MW), irrigation (95 MW), and curtailable rate (72 MW) are expected to provide the highest levels of achievable potential. Yet, approximately 114 MW of the identified potential is already under contract through PacifiCorp’s Cool Keeper (65 MW), irrigation load curtailment (48 MW), and Energy Exchange (1 MW), resulting in a remaining achievable potential of 259 MW. Therefore, in addition to achievable potential, Table 4 also provides potential net of current programs.

Table 4. Achievable Potential (MW) – System

	Fully Dispatchable			Irrigation	Thermal Energy Storage	Curtailable Rates	Critical Peak Pricing	Demand Buyback	Total
	Winter	Summer	Large C&I						
Achievable Potential	37	120	3	95	9	72	7	28	373
Current Program MW	---	65	---	48	---	---	---	1	114
Potential Net of Current Programs	37	55	3	47	9	72	7	27	259

Proxy Resource Supply Curves

Supply curves are constructed to show the relationship between the cumulative quantities of DR resources and their costs. Development of supply curves first requires the estimation of per-unit costs. Demand response strategies vary significantly with respect to both type and cost levels. Applicable resource acquisition costs for DR generally fall into two categories: 1) fixed direct expenses such as infrastructure, administration, maintenance and data acquisition; and 2) variable costs. In the category of fixed cost, this study distinguishes between initial development and on-going program administration and operation costs. Variable costs also fall into two categories: costs that vary by the number of participants (e.g., hardware costs) and those that vary by kW reduction (primarily incentives).

Although a large number of national programs were researched for this project, the reporting of costs, particularly development and ongoing administrative costs, were found to be either unavailable or difficult to measure. For the purposes of this study, to the extent possible, we have relied primarily on administrative costs associated with PacifiCorp’s other, similar programs, or have adopted rough estimates available from other utilities. See Section IV for specific cost assumptions for various DR options.

In developing proxy supply curves, all program costs were first allocated annually over the expected program life cycle (10 to 15 years) discounted by PacifiCorp’s real cost of capital at 5.1% to estimate the per-kW levelized⁹ costs for each resource. Resources were then ranked based on their levelized costs along the supply curve. Figure 3 displays per-unit costs for the various DR options.

⁹ Levelized costs represent the annual contract cost, per kW/year, for each DR option. This approach provides means for treating all DR on a consistent basis with supply alternatives in the IRP framework.

Figure 3: Levelized Resource Costs (\$/kW/year)

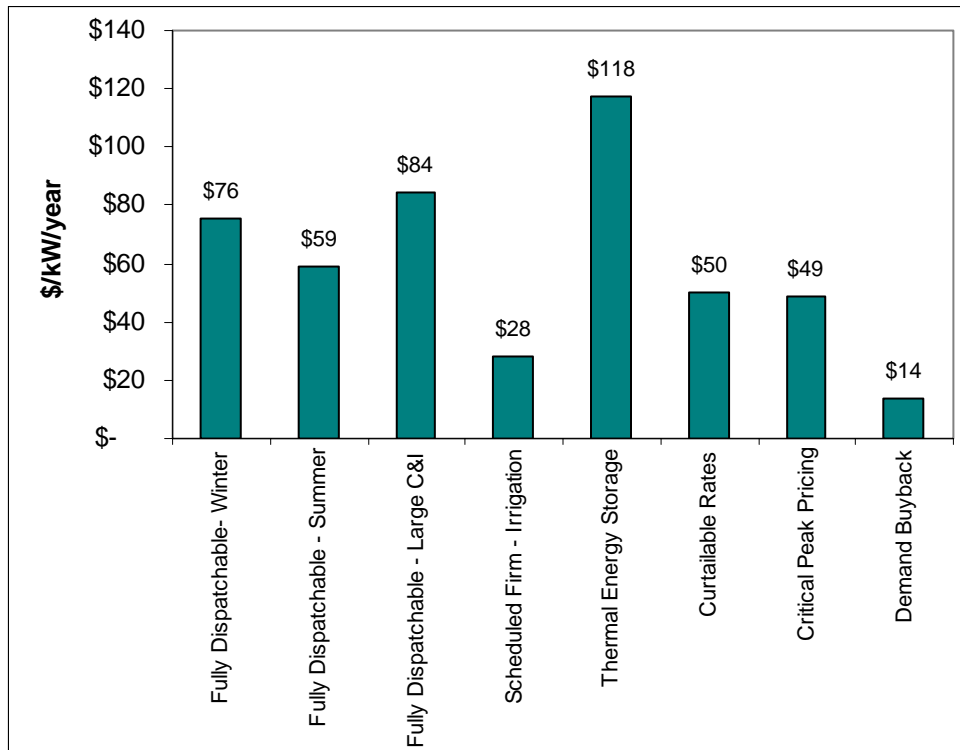


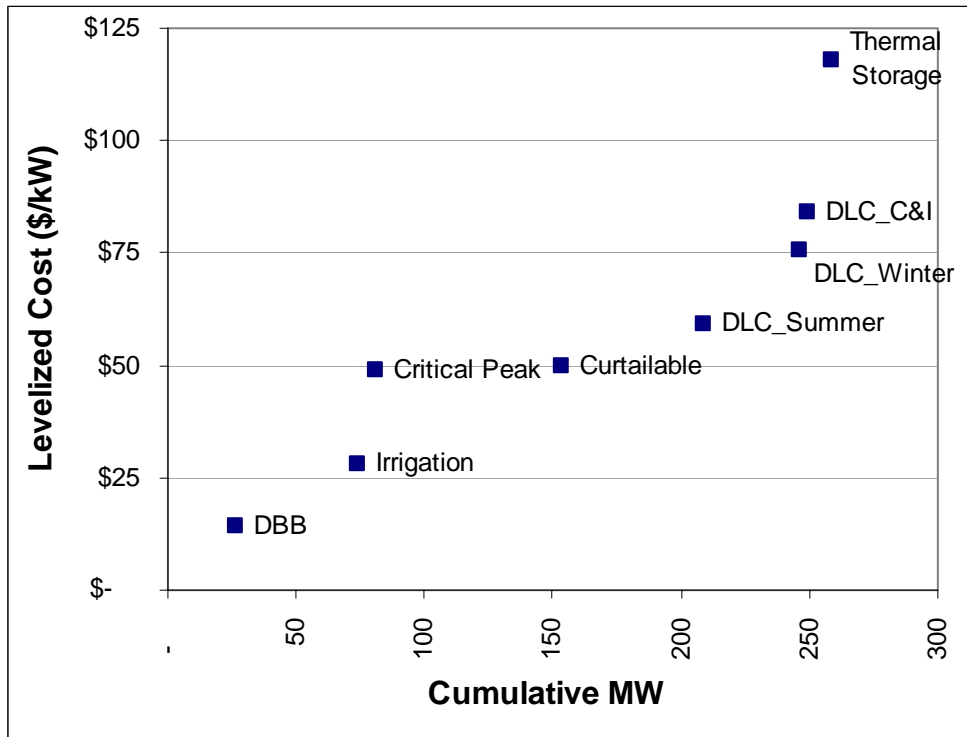
Figure 3 indicates that, with the exception of the irrigation program, per-unit costs tend to increase with the level of firmness of the load: the more reliable the load reduction, the more costly the program. Demand buyback, at \$14/kW/year, is expected to be the least expensive option. This program, although relatively inexpensive, provides possibly the least reliable load reduction among the eight program options.

Firm irrigation is the next lowest-cost resource at \$28/kW/year. Because reductions by this program are pre-determined and scheduled, it is an effective program for achieving firm seasonal load reductions. However, its value as a reliability option is limited because 100% capacity reductions are already incorporated into the utility’s planned resource capacity, and hence cannot be “called” to provide load relief during system emergencies. Critical peak pricing (\$49/kW/year) provides the ability to notify customers of curtailment events; national experience indicates the potential for reductions can be significant, but customer acceptance and response have generally been lower than expected. Curtailable rate programs (\$50/kW/year) may provide additional dependability due to contract requirements on customers and may serve as an effective option for reliability purposes. Owing mainly to hardware costs and incentives required of fully dispatchable resources, per-unit costs for the three direct load control programs exceed \$59/kW/year. Finally, thermal energy storage is expected to be the most costly option with a per-unit cost of \$118/kW/year.

The proxy supply curve for the eight resource options investigated in this study was constructed based on estimated achievable resource potential net of current programs and per-unit cost of each resource option. Figure 4 displays graphical presentation of the supply curve, which

represents the quantity of resources (cumulative MW) that can be achieved at or below the cost at any point. Cumulative MW is created by summing the achievable potential net of current programs along the horizontal axis sequentially, in the order of their levelized costs. For example, the irrigation program has 47 MW available, and its cost is second lowest. Therefore, its quantity is added to the 27 MW of DBB, showing that in total, 74 MW of resources are available at prices equal to or less than \$28/kW.

Figure 4. Cumulative Supply Curve, System



Resource Potential Scenarios

High and Low

For the purpose of IRP modeling, achievable potentials were estimated under three scenarios: base case, high, and low, corresponding with PacifiCorp’s projected on-peak market prices of \$40/MWh (low), \$60 (base) and \$100 (high). To account for the relationship between market prices (and incentives) and program potential, high scenarios generally assume aggressive marketing efforts and higher incentive levels and, therefore, higher program participation. The low scenario reflects a less aggressive marketing effort and relatively weak program participation. (See Sections IV and V for assumptions underlying the two scenarios.)

The high and low scenarios for the DBB and curtailment contract options were constructed based on load response elasticity estimates. As reported in the 2006 Department of Energy’s Report to Congress, commercial and industrial customers have typically exhibited an inelastic response to

prices (elasticity = 0.1) in load curtailment. This figure was used as a basis for the high and low program participation scenarios for the fully dispatchable large commercial and industrial and curtailable rates options. For the DBB program, a price elasticity of 1.45, estimated based on the 2000-2001 regional data on demand buyback programs, was used to develop the high and low scenarios. (See Section IV for a discussion of methodology and data.)

The results for the three scenarios are shown in Table 5. Generally, as the potential increases, so does the per-unit costs, due to higher incentives and marketing costs. Yet, in a few cases, such as critical peak pricing and fully-dispatchable commercial and industrial programs, per-unit costs are expected to fall from the low to the base case due to economies of scale; lower marginal per-unit costs result from the fact that fixed program costs are spread over a larger number of units.

Table 5. High, Base, and Low Costs and Quantities System

	Fully Dispatchable			Scheduled Firm - Irrigation	Thermal Energy Storage	Curtailable Rates	Critical Peak Pricing	Demand Buyback
	Winter	Summer	Large C&I					
Low								
Achievable Potential MW	19	80	1	76	7	30	1	9
Resource Costs (\$/kW/yr)	\$58	\$53	\$167	\$29	\$115	\$39	\$91	\$13
Base								
Achievable Potential MW	37	120	3	95	9	72	7	28
Resource Costs (\$/kW/yr)	\$76	\$59	\$84	\$28	\$118	\$50	\$49	\$14
High								
Achievable Potential MW	56	141	9	114	12	88	14	65
Resource Costs (\$/kW/yr)	\$84	\$72	\$102	\$37	\$119	\$86	\$45	\$18

Treatment of Metering Costs

The DR scenarios presented above include metering costs, where applicable (please see Section V for detailed assumptions). In the future, these costs may not be necessary if advanced metering technology is implemented in PacifiCorp’s territory. Therefore, this additional scenario excludes metering costs from the base estimates of per unit cost. Figure 5 below displays the new figures and Table 6 provides a comparison of the base (with metering) scenario and the alternative (without metering). The exclusion of meter costs makes little difference (less than \$1/kW/year) in all programs, except critical peak pricing where the reduction equals \$7 /kW/year.

Figure 5. Per Unit Resource Costs – Excluding Metering Costs

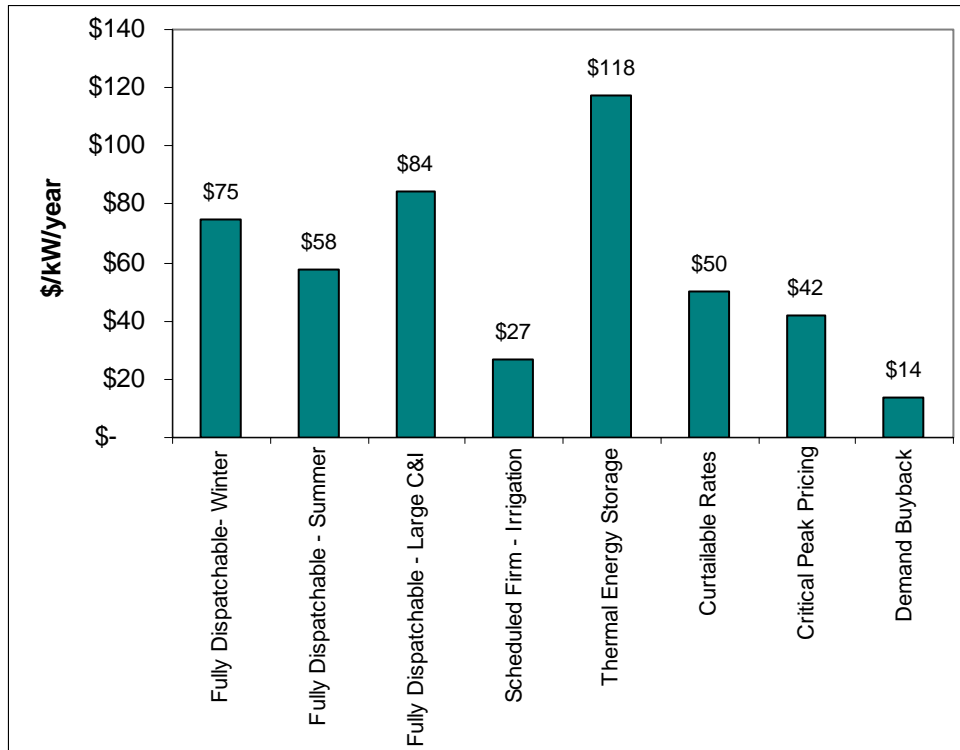


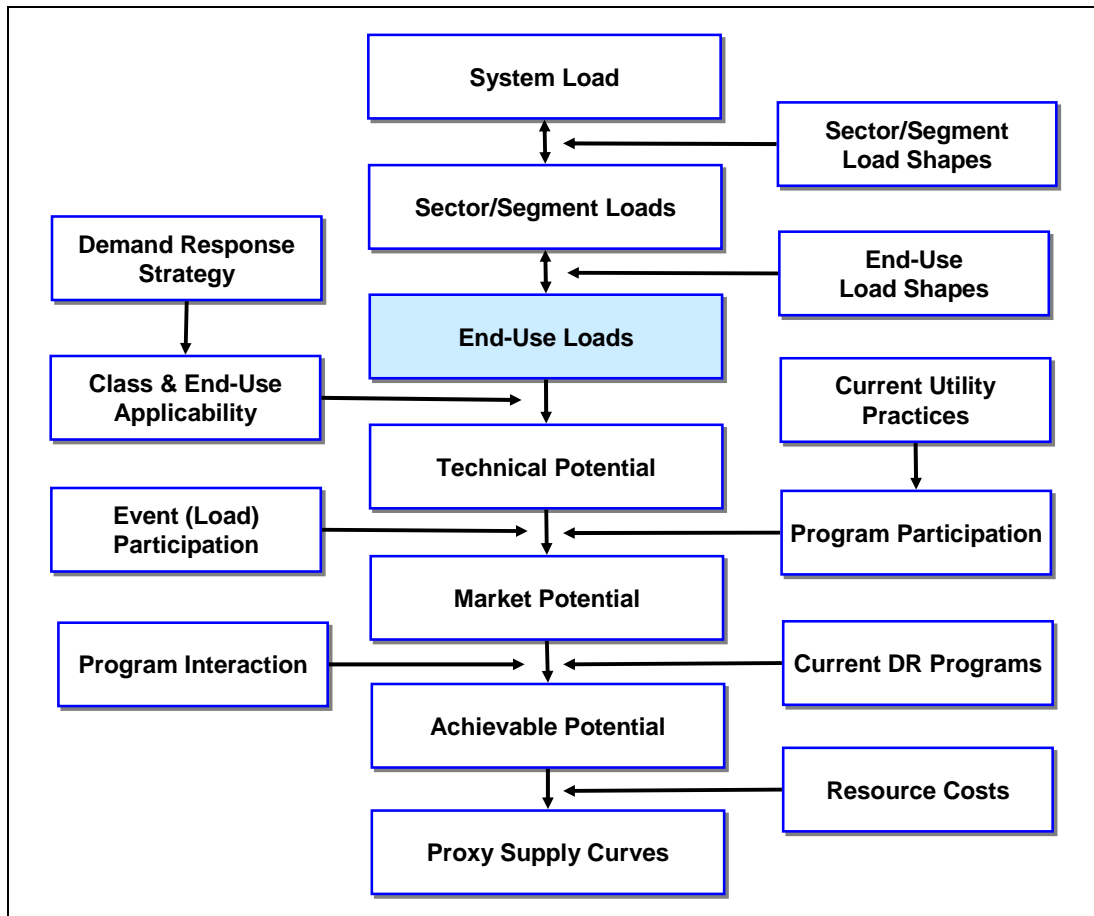
Table 6. Comparison of Costs with and without Metering Costs

	Fully Dispatchable			Scheduled Firm - Irrigation	Thermal Energy Storage	Curtailable Rates	Critical Peak Pricing	Demand Buyback
	Winter	Summer	Large C&I					
With Meter Costs (\$/kW/year)	\$76	\$59	\$84	\$28	\$118	\$50	\$49	\$14
Without Meter Costs (\$/kW/year)	\$75	\$58	\$84	\$27	\$118	\$50	\$42	\$14

IV. Methodology and Data

The development of proxy supply curves requires both reasonable approximations of available quantities and reliable estimates of procurement costs for each DR resource. With respect to quantities, the overall approach in this project (see Figure 6) distinguishes between three definitions of DR resource potential that are widely used in utility resource planning: *technical*, *market*, and *achievable*. Load shapes for the PacifiCorp system, East/West regions, customer segments, and end use load shapes combine with sales data to produce hourly load profiles. For each DR strategy, technical potential is estimated by applying end use and sector applicability, while market potential additionally incorporates program and event participation. Achievable potential estimates also consider interactions among programs and current DR offerings at PacifiCorp. Finally, proxy supply curves show the relationship between achievable potential and the expected per-unit cost of each strategy.

Figure 6. Schematic Overview of Methodology



Data Requirements and Sources

Development of DR supply curves requires the compilation of a large and complex database on load data, end-use and appliance saturations, demand response impacts, and costs, gathered from multiple sources. To the greatest extent possible, this study relies on data available from PacifiCorp on loads, sales, end-use load profiles, and estimates of administrative costs. Secondary data sources were utilized for estimates of DR program impacts. Specific data elements and their respective sources are listed in Table 7.

Table 7. Data Elements and Sources

Data Element	Source – Various Years
Total Sales by Customer Class	PacifiCorp, 2005, Table A
Commercial Segmentation	PacifiCorp, 2005, Commercial Survey (by participants)
Hourly System and Regional Load Profiles	PacifiCorp, 2005
End-Use Shares and Load Shapes	EIA, Commercial Buildings Energy Consumption Survey (CBECS) EIA, Residential Energy Consumption Survey (RECS) Northwest Power Planning Council PacifiCorp PGE Quantec Load Shape Library
Existing PacifiCorp Demand Response Programs	PacifiCorp studies, various years
Demand Response Impact Estimates	PacifiCorp, California Energy Commission, Peak Load Management Alliance (PLMA), Edison Electric Institute (EEI), Lawrence Berkeley National Laboratories (LBNL), Various RTO and Utility Reports, Department of Energy
Demand Response Program Costs	PacifiCorp, Other Utilities, Regional Transmission Organizations

Methodology for Estimating Technical Potential

Within the context of demand response, technical potential assumes that all applicable end-use loads, in all customer sectors, are at least partially available for curtailment, excepting those customer segments (e.g., hospitals) and end-uses (e.g., restaurant cooking loads) that clearly do not lend themselves to curtailment.

Demand response options are not equally applicable to or effective in all segments of the electricity consumer market, and their impacts tend to be end-use specific. In recognition of this fact, this methodology employs a “bottom-up” approach, which involves first breaking down system loads for each of PacifiCorp’s two control areas into sectors, market segments within each sector, and applicable end uses within each market segment. Demand response potentials are estimated at the end-use level and then aggregated to sector and system levels. This approach is implemented in four steps as follows.

- 1. Define customer sectors, market segments, and applicable end-uses.** The first step in the process involves defining appropriate sectors and market segments within each sector. Given the available data, this study includes four customer classes (residential, commercial, industrial, and irrigation), the eleven commercial segments defined in

Commercial Building Energy Consumption Survey (Education, Food Stores, Hospitals, Hotels/Motels, Other Health, Offices, Public Assembly, Restaurants, Retail, Warehouses, and Miscellaneous), and total industrial loads.

2. **Create sector and segment load profiles.** Using available local hourly load profiles, service area sales are used to generate sector- and segment-specific load shapes. Figure 7 displays the load duration curves for East, West and System overall, and Figure 8 shows the typical daily system load profiles. Figure 9 exhibits sector load shapes; the “System” shown is the actual load and “Total Sector” is the sum of load by sector. The difference between these lines are due to loads that are not amenable to demand response, such as traffic and street lighting, and loads not directly attributable to end use load profiles.

Figure 7: PacifiCorp Load Duration Curve, 2005

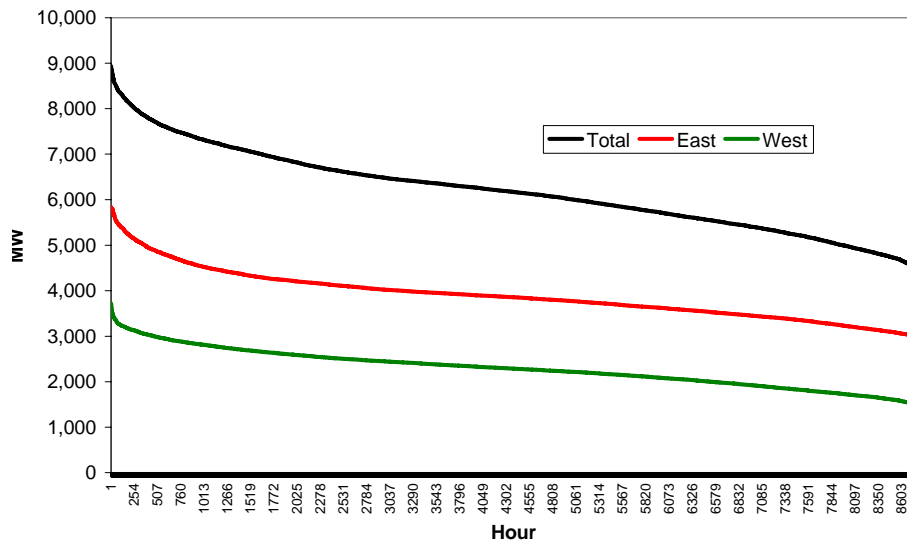


Figure 8: Typical Daily (Week-Day) Seasonal Load Profiles by System and Control Area

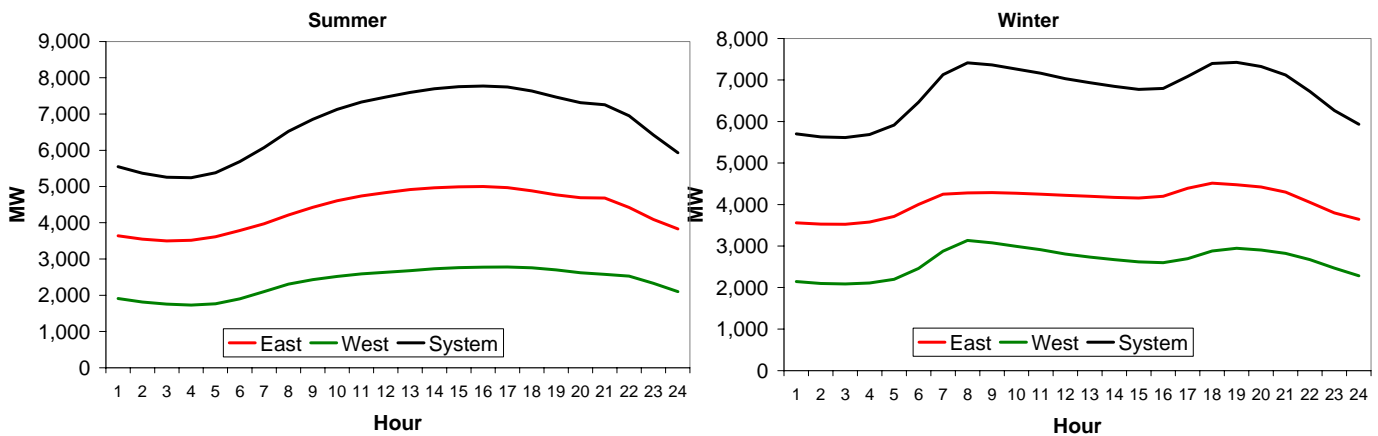
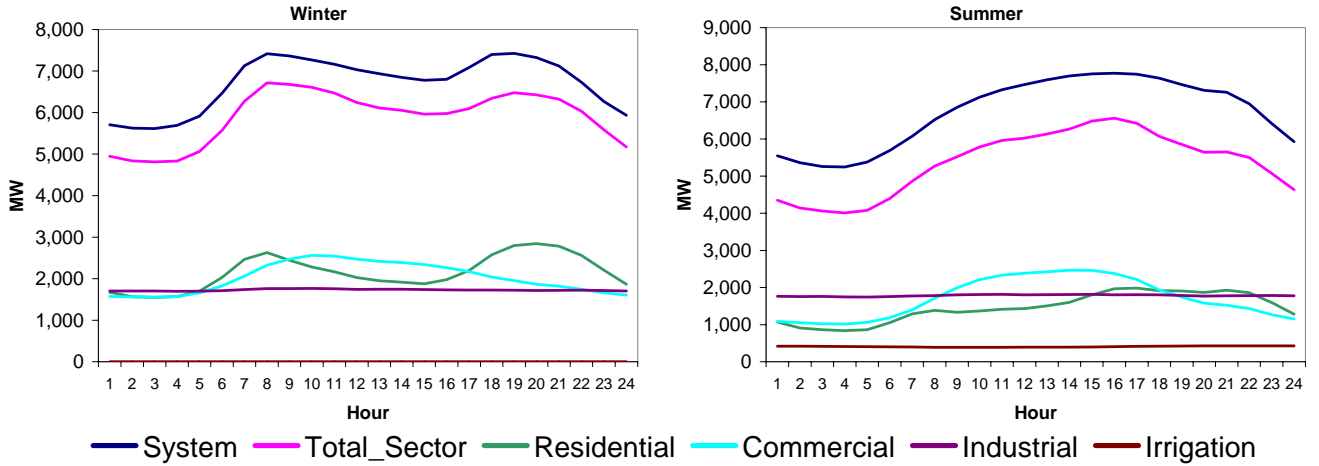


Figure 9: Typical Daily (Week-Day) System Load Profiles by Sector



3. *Develop sector- and segment-specific typical peak day load profiles for each end use.* “Typical” daily profiles are developed for each end-use within various market segments. Contributions to system peak for each end-use are estimated based on end-use shares available from PacifiCorp or regional estimates, available through EIA energy use surveys. Figure 10 and Figure 11 display the end-use contributions, summarized across sectors, to system load.

Figure 10: End-Use Contributions to System Load- Summer

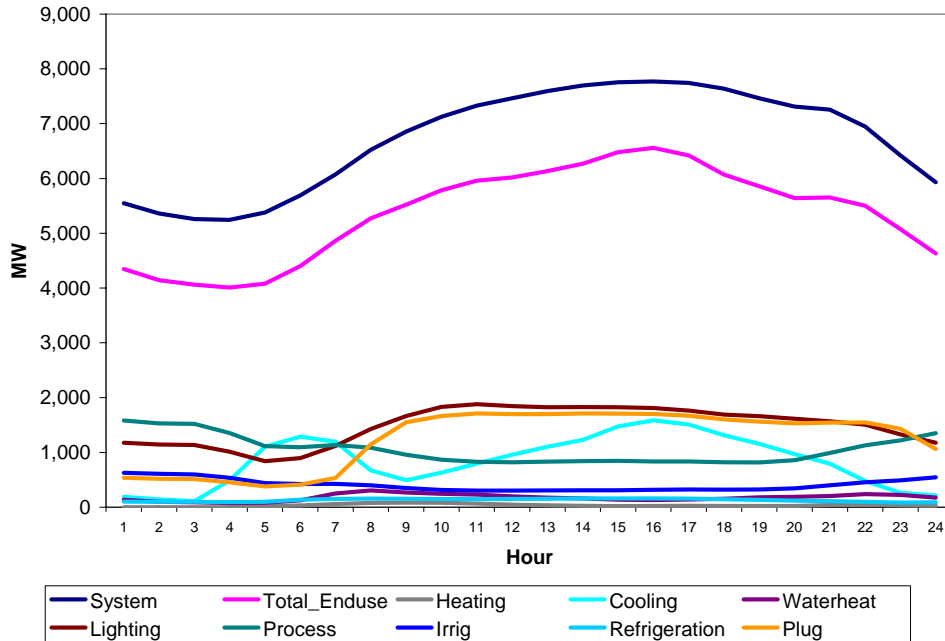
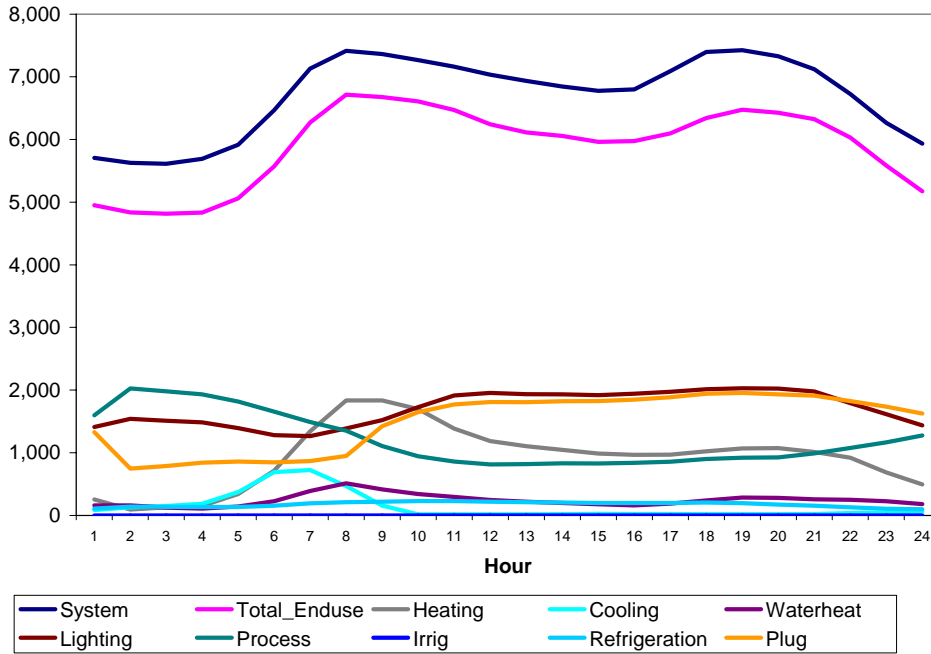


Figure 11: End-Use Contributions to System Load- Winter



4. **Estimate technical potential.** Technical potential for each demand response strategy is assumed to be a function of customer eligibility in each class and the expected impact of the strategy on the targeted end-uses. Analytically, technical potential (TP) for demand-response strategy s is calculated as the sum of impacts at the end-use level (e), generated in customer sector (c), by the strategy (s), that is:

$$TP_s = \sum TP_{sce}$$

and

$$TP_{sce} = LE_{cs} \times LI_{se}$$

where,

- LE_{cs} (load eligibility) represents the percent of customer class loads that are eligible for strategy s
- LI_{se} (load impact) is percent reduction in end-use load e resulting from strategy s

Load eligibility (LE_{cs}) thresholds are established by calculating the percent of load by customer class and market segment that meet load criteria for each strategy. Table 8 outlines the portion of load that is eligible for program strategies. (Section V provides detailed program-specific assumptions.)

Estimates of maximum load impacts, resulting from various demand response strategies (LI_{se}), are derived from the commercial and industrial Enhanced Automation Study sponsored by the California Energy Commission, studies by Lawrence Berkeley National Laboratories

(e.g., Goldman, 2004), and the experiences of PacifiCorp and other utilities with similar DR programs. Table 9 outlines these inputs; detailed assumptions are found in the following section.

Table 8: Eligibility by Sector and Program

Program Name/Sector	Fully Dispatchable			Scheduled Firm - Irrigation	Thermal Energy Storage	Curtailable Rates	Critical Peak Pricing	Demand Buyback
	Winter	Summer	Large C&I					
Residential	100%	100%	---	---	---	-	100%	-
Education	---	---	19%	---	---	50%	100%	50%
Food Stores	---	---	27%	---	---	70%	100%	70%
Hospitals	---	---	---	---	---	-	-	-
Hotels/Motels	---	20%	5%	---	20%	12%	100%	12%
Other Health	---	7%	23%	---	7%	60%	-	60%
Miscellaneous	---	---	---	---	---	-	-	-
Offices	---	10%	19%	---	10%	50%	100%	50%
Assembly	---	10%	8%	---	10%	20%	-	20%
Restaurants	---	50%	---	---	50%	-	-	-
Retail	---	12%	---	---	12%	-	-	-
Warehouses	---	13%	15%	---	13%	40%	-	40%
Industrial	---	---	30%	---	---	80%	100%	80%
Irrigation	---	---	19%	100%	---	50%	-	-
Eligibility Criteria	Residential	Residential and Small Commercial (<30 kW)	Large C&I - >250 kW with EMS	Irrigation only	Small Commercial	Large C&I - >250 kW	No Load Threshold	Large C&I - >250 kW

Table 9: Technical Load Impacts

Program Name/Sector	Fully Dispatchable				Scheduled Firm - Irrigation	Thermal Energy Storage	Curtailable Rates	Critical Peak Pricing	Demand Buyback
	Winter		Summer	Large C&I					
End Use	Space Htg	Hot Water	Cooling	Total	Process	Cooling	Total	Total	Total
Residential	90%	90%	90%	---	---	---	---	25%	---
Education	---	---	---	22%	---	---	22%	25%	22%
Food Stores	---	---	---	20%	---	---	20%	25%	20%
Hospitals	---	---	---	---	---	---	---	---	---
Hotels/Motels	---	---	90%	20%	---	90%	20%	25%	20%
Other Health	---	---	90%	8%	---	90%	8%	---	8%
Miscellaneous	---	---	---	---	---	---	---	---	---
Offices	---	---	90%	32%	---	90%	32%	25%	32%
Assembly	---	---	90%	20%	---	90%	20%	---	20%
Restaurants	---	---	90%	---	---	90%	---	---	---
Retail	---	---	90%	---	---	90%	---	---	---
Warehouses	---	---	90%	30%	---	90%	30%	---	30%
Industrial	---	---	---	30%	---	---	30%	25%	30%
Irrigation	---	---	---	30%	90%	---	30%	---	30%

Methodology for Estimating Market Potential

Market potential is the subset of technical potential that may reasonably be implemented, taking into account the customers’ ability and willingness to participate in load reduction programs, subject to their unique business priorities, operating requirements, and economic (price) considerations. Market levels of potential are derived by adjusting technical potentials by two factors: expected rates of *program* and *event* participation. Market potential (MP) is calculated as the product of technical potential, sector program participation rates (PP_c), and expected event participation (EP_c) rates:

$$MP_s = TP_{sc} \times PP_c \times EP_c$$

Rates of program and event participation are estimated based on the recent experiences of PacifiCorp and other utilities, as well as those of Regional Transmission Organizations (RTOs) that have offered similar programs. Table 10 outlines the estimates of program and event participation; referenced assumptions are found Section V.

Table 10: Program and Event Participation Inputs

	Fully Dispatchable			Scheduled Firm - Irrigation	Thermal Energy Storage	Curtailable Rates	Critical Peak Pricing	Demand Buyback
	Winter	Summer	Large C&I					
Program Participation	10%	20%*	3%	50%	20%	25%	3%	35%
Event Participation	100%	100%	90%	50%	100%	90%	90%	13%

* Represents residential sector; commercial sector is assumed to be 5%

Utility customers’ willingness to participate in DR programs (or “market potential”) is itself a function of price and non-price factors. Non-price factors generally depend on specific operational constraints that may impede participation in DR. These are generally difficult to quantify and may only be determined through rigorous market studies.

Price-induced effects, particularly for market-based DR strategies, can, however, be estimated explicitly by calculating price elasticity of load response, based on empirical data, using the following general formulation of price elasticity:

$$\text{Log}N(MW) = \alpha + \beta \text{LOG}(P),$$

where MW is the quantity of demand reduction commitment during each curtailment event and P represents the offer prices (incentives) from the utility.

Since the equation is specified in logarithmic form, β is a direct measure of elasticity, indicating percent change in load commitment that may be expected to result from a one percent change in incentives.

To estimate the parameters of the above model, data were collected on the 2000-2001 experience of four major utilities in the Northwest (PacifiCorp, PSE, PGE, and Avista) on their demand buyback programs. The estimated parameters of the model are shown below.

$$\text{LogN}(MW) = -0.5 + 1.45 (3.0) \text{LogN}(P)$$

The calibration of the demand model resulted in a price coefficient of 1.45 with a t-statistic of 3.0, indicating that the estimated coefficient is statistically significant at the 95% level of significance or better. The estimated parameter for the price variable shows that for every one percent change in price, load response is expected to change by 1.45%, indicating a moderately elastic response. The statistical parameters of the estimated model are shown in Table 11, below.

Table 11. Estimation Results of the Elasticity Model

Variable	Estimated Parameter	t-Statistic
Intercept (α)	-0.5	
LogN (Price)	1.45	3.0
Number of Observations: 13		

R² = 0.65

The elasticity estimate obtained from the data is higher than expected. There have not, however, been any other studies of response elasticity for demand buyback or demand bidding programs. Additionally, slight changes in the specification of the above quantity/price relationship, introduced by using alternative data frequency levels, such as daily or monthly, are likely to alter the parameter estimates. For example, daily, event-by-event data, available from Puget Sound Energy for 2000-2001, resulted in a significantly lower elasticity of 0.45. Unfortunately, event-by-event data were not available for all four utilities. Such data, we expect, would likely have produced a more robust and reliable estimate of price elasticity for demand buyback programs.

Development of Cost Estimates

Demand response strategies vary significantly with respect to both type and level of costs. Applicable resource acquisition costs for DR generally fall into two categories: 1) fixed direct expenses such as infrastructure, administration, and data acquisition; and 2) variable costs (i.e., incentive payments to participants). For this project, cost estimates are based on the experiences of PacifiCorp and other utilities, as well as RTOs offering various DR programs.

Fixed Costs. Fixed costs vary significantly across various DR resource acquisition programs and depend, to a large extent, on program design. For example, implementation of some market-based programs, such as demand buyback, may require up-front investments in communication and data acquisition infrastructures, while tariff-based programs may be implemented at a relatively low cost to the utility.

Variable Costs. Estimation and treatment of variable costs, particularly in the case of market-based programs poses a much greater challenge in determining the price component of the supply curve as, clearly, these will have a direct effect on the quantity of resources that are available. As described above, elasticity estimates were used to account for these impacts.

Table 12 outlines the development (up-front investment) and annual costs for the three categories of cost inputs: per-kW/year, per-customer, and program administration. Incentive payments for large commercial and industrial customers are often paid on a per-kW basis. On a per-customer basis, development costs typically include control hardware, installation, and marketing costs; annual costs include maintenance and incentives. Program costs were assumed to be relatively consistent across all programs - \$300,000 to begin a new program, \$150,000 to expand existing programs¹⁰; \$100,000 in ongoing administrative cost.¹¹

Table 12: Cost Inputs

Cost Type/ Frequency	Fully Dispatchable			Scheduled Firm - Irrigation	Thermal Energy Storage	Curtable Rates	Critical Peak Pricing	Demand Buyback
	Winter	Summer	Large C&I					
per kW-year								
Development	---	---	---	---	---	---	---	---
Annual	---	---	\$48	\$10	\$105	\$48	---	\$10
per Customer-year (including meter costs)								
Development	\$320	\$320	\$1,200	\$700	---	\$1,200	\$500	\$700
Annual	\$112	\$55	---	\$1,000	---	---	\$50	---
Program								
Development	\$300,000	\$150,000	\$300,000	\$150,000	\$300,000	\$300,000	\$300,000	\$150,000
Annual	\$100,000	\$100,000	\$100,000	\$600,000	\$100,000	\$100,000	\$100,000	\$100,000

These costs are allocated to each year of the planning horizon, based on:

$$Costs_{sy} = \$Pgm_{dy1} + \$Pgm_a + (\$kW_a \times kW_y) + (\$Customer_d \times Part_{y-y0}) + (\$Customer_a \times Part_y)$$

Where,

¹⁰ PacifiCorp Energy Exchange (2001) spent over \$200,000 in initial costs. TOU (2001) had initial costs of \$341,000, including load research.

¹¹ Energy Exchange (2005) spends \$72,000 annually in external vendor costs (not including PacifiCorp administrative costs), Idaho Irrigation Pilot (2005) spent \$55,000 in program management, TOU had ongoing costs of \$155,000 (2002) and \$110,000 (2003).

- $Costs_{sy}$ are the costs for a program strategy s in year y ,
- $\$Pgm_{dy1}$ are the program development costs in year 1 only
- $\$Pgm_a$ are the annual program costs
- $\$kW_a$ are the annual costs on a per kW basis (Table 12)
- kW_y is the amount of kW potential in year y . This study uses a three-year ramping, such that one-third of the achievable potential, shown in Table 4, is added in each of the first three program years. The quantity in subsequent years increases at the same rate as sales.
- $\$Customer_d$ are per-customer development costs
- $Part_{y-y0}$ is the number of new participants in the program in year y
- $\$Customer_a$ is the annual cost per customer
- $Part_y$ is the number of total participants in the program, as a function of PartkW, which is the kW impact per customer, as shown in Table 13 (program-level assumptions found in Section V).

$$Part_y = \frac{kW_y}{Part_{kW}}$$

Table 13: Load Impact per Customer (kW)

Program Name/Sector	Fully Dispatchable			Scheduled Firm - Irrigation	Thermal Energy Storage	Curtable Rates	Critical Peak Pricing	Demand Buyback
	Winter	Summer	Large C&I					
Residential	2.0	1.5	---	---	---	---	2	---
Education	---	---	124	---	---	124	21	124
Food Stores	---	---	134	---	---	134	22	134
Hospitals	---	---	---	---	---	---	-	---
Hotels/Motels	---	2.0	104	---	---	104	10	104
Other Health	---	2.0	82	---	---	82	---	82
Miscellaneous	---	---	---	---	---	---	---	---
Offices	---	2.0	221	---	---	221	7	221
Assembly	---	2.0	230	---	---	230	---	230
Restaurants	---	2.0	---	---	---	---	---	---
Retail	---	2.0	---	---	---	---	---	---
Warehouses	---	2.0	173	---	---	173	---	173
Industrial	---	---	531	---	---	531	53	531
Irrigation	---	---	---	90	---	---	---	---

Resource Interaction Estimates

The final step in supply curve development is to estimate the amount of market potential that is available for each program in the portfolio. Table 14 outlines the percent of market potential that is considered available, given the ranking of programs by levelized cost with consideration given to reliability. For example, 100% of demand buyback and scheduled firm irrigation is considered achievable. Although critical peak pricing is ranked next in levelized cost, it is another non-firm resource, so it becomes tertiary to curtailable rates. Curtailable rates and dispatchable large C&I compete for the same target market as DBB, therefore only 50% of their market potential will be available. The summer DLC program is the least expensive residential and small commercial control program. Therefore 100% of this program is available. Since the TES also targets the cooling loads (cool storage) as a secondary option, half of the TES potentials are assumed to be available.

Table 14: Interaction (Percent of Market Potential Available)

Program Name/Sector	Fully Dispatchable			Scheduled Firm - Irrigation	Thermal Energy Storage	Curtailable Rates	Critical Peak Pricing	Demand Buyback
	Winter	Summer	Large C&I					
Residential	50%	100%	---	---	---	---	20%	---
Education	---	---	50%	---	---	50%	20%	100%
Food Stores	---	---	50%	---	---	50%	20%	100%
Hospitals	---	---	---	---	---	---	---	---
Hotels/Motels	---	100%	50%	---	50%	50%	20%	100%
Other Health	---	100%	50%	---	50%	50%	---	100%
Miscellaneous	---	---	---	---	---	---	---	---
Offices	---	100%	50%	---	50%	50%	20%	100%
Assembly	---	100%	50%	---	50%	50%	---	100%
Restaurants	---	100%	---	---	50%	---	---	---
Retail	---	100%	---	---	50%	---	---	---
Warehouses	---	100%	50%	---	50%	50%	---	100%
Industrial	---	---	50%	---	---	50%	20%	100%
Irrigation	---	---	50%	100%	---	50%	---	---

V. Detailed Program Assumptions

Table 15. Fully Dispatchable – Winter

Programs Researched	Portland General Electric Space and Water Heating Direct Load Control Program; Pennsylvania, New Jersey, Maryland ISO water heating; Florida Power & Light Residential On Call program; Puget Sound Energy Home Comfort Control Thermostat; Hawaiian Electric Residential Hot Water; Wisconsin Public Services DLC
Load Basis	Average of top 87 winter hours
Basis for Cost Calculations	Development: Customer - \$300 for control equipment and labor, \$200 for meter and installation labor (PGE – Quantec 2003) but installed for only 10% of participants, \$300,000 for program development; Annual: \$30 in maintenance, \$9 (1.5/month for 6 months) in communications, \$72 (\$12/month for 6 months - both water heating and space) in incentives, and \$100,000 annual program administration.
High/Low Cost Notes	High assumes incentives are increased (\$15/month - \$90), low is half incentive (\$6/mth - \$36). Annual program administrative costs are increased by \$50,000 in high case and reduced by \$50,000 in low case.
Technical Potential	Less than complete technical ability to cycle different technologies (90%) and 50% cycling strategy; therefore 45%
Eligible Load (%)	Residential space heating and water heating
Program Participation (%)	High is based on 20% participation of FPL On Call program, base (10%) closer to Duke program of 13% (Duke – Quantec 2005), and low (5%) represents low program participation (DOE - 2006)
Event Participation (%)	100%
Current Program (kW)	NA
Per-Customer Impacts (kW)	2kW estimate per participant based (PSE, Quantec 2003) - includes cycling strategy
Hours Per Month	3 hours in January; 84 hours in December (based on the distribution of the PacifiCorp 2005 system profile)

Table 16. Fully Dispatchable – Summer

Programs Researched	Florida Power & Light Residential On Call & Business On Call; SCE Large Business Summer Discount Plan; Wisconsin Public Services; Duke Residential AC Program, PacifiCorp and MidAmerican
Load Basis	Average of top 87 summer hours
Basis for Cost Calculations	Development: Customer - \$300 for control equipment and labor, \$200 for meter and installation labor (PGE – Quantec 2003) but installed for only 10% of participants, \$300,000 for program development; Annual: \$30 in maintenance, \$4.5 (1.5/month for 3 months) in communications, incentives - \$20 (3 months at \$7/month - PSE pays \$6, Duke \$8, PAC \$7), and \$100,000 annual program administration
High/Low Cost Notes	High assumes incentives are doubled (\$40), low is half incentive (\$10). Annual program administrative costs are increased by \$50,000 in high case and reduced by \$50,000 in low case.
Technical Potential	Less than complete technical ability to cycle different technologies (90%) and 50% cycling strategy; therefore 45%
Eligible Load (%)	Cooling load for residential and portion of commercial load that is less than 30 kW (PacifiCorp - Quantec 2003)
Program Participation (%)	Assumes 20% residential and 5% small commercial (FP&L - 13% small C&I participation, 19% residential, PAC Utah Cool Keeper 27% residential and ~0% commercial), high assumes that 5% more program participation is possible, low assumes 5% less
Event Participation (%)	100%
Current Program (kW)	65 MW of load reduction in Utah Cool Keeper Program on Dispatch mode
Per-Customer Impacts (kW)	Impact: Cooling - 1.5 kW for residential, 2.0 kW for small com, DOE 2006, Quantec 2003
Hours Per Month	June 8, July 54; August 32 – adjusts 2005 System load to account for experience in program dispatch by Cool Keeper

Table 17. Fully Dispatchable – Large C&I

Programs Researched	Florida Light & Power C&I On Call; Hawaiian Electric Large Commercial; Wisconsin Public Services DLC; Southern California Edison Large Business Summer Discount Plan
Load Basis	Average of top 87 summer hours
Basis for Cost Calculations	Development: Per customer of \$500 for targeted marketing and \$700 for meter (Duke – Quantec 2005); \$300,000 for program development, \$100,000 annual program administration. Per kW costs assume \$8/month for 3 months (double the incentive as curtailable rates but for fewer months)
High/Low Cost Notes	High incentive is \$14/month and low is \$6/month (again, double curtailable rates incentive; see curtailable rates for references) Annual program administrative costs are increased by \$50,000 in high case and reduced by \$50,000 in low case.
Technical Potential	Total curtailable load based on Goldman (2004)- National Trends, by sector. If not mentioned, unclassified was used.
Eligible Load (%)	Using portion of cooling load that is greater than 250 kW as eligible (PacifiCorp - Quantec 2003) and assuming only 38% with EMS systems (CBSA 05)
Program Participation (%)	Participation - Florida Power And Light C&I On Call has less than 1% of all customers. Because our figures already account for those not eligible, we have assumed 3% base, 8% high, and 1% low.
Event Participation (%)	90%
Current Program (kW)	NA
Per-Customer Impacts (kW)	Per customer impacts are calculated as product of average load for customers >250 kW and the technical potential above
Hours Per Month	June 8, July 54; August 32 - adjusts 2005 System load to account for experience in program dispatch by Cool Keeper, assuming that system decisions to curtail residential customers would be similar for C&I customers

Table 18. Scheduled Firm – Irrigation

Programs Researched	BPA Irrigation, Idaho Power, PacifiCorp
Load Basis	Average of entire summer on-peak period
Basis for Cost Calculations	Development: \$700 installed cost of advanced metering technologies; Idaho IRR: Annual: \$10 per kW (\$8.5 in 2005), \$300,000 for program development, \$100,000 annual program administration. Also includes \$500K of additional expenditures committed in 2005 for ongoing programs by PacifiCorp.
High/Low Cost Notes	High cost doubles incentive; low assumes the same, Annual program administrative costs are increased by \$50,000 in high case and reduced by \$50,000 in low case.
Technical Potential	Less than complete technical ability to schedule reductions on all load (e.g., lift stations)
Eligible Load (%)	Irrigation sector
Program Participation (%)	Program participation of 50% (2005 Idaho IRR - 100 MW signed up of 200 MW load) is assumed to be base. High and low has relatively tight band +/-5%.
Event Participation (%)	50% event participation assumes participants sign up only for 2 out of 4 days (similar to PacifiCorp Idaho program)
Current Program (kW)	48 MW from Idaho program
Per-Customer Impacts (kW)	Idaho reduction of 100 kW per customer reduced to 90 to account for smaller irrigators in other regions
Interaction	100% taken due to relatively inexpensive cost and lack of competition with other programs.
Variable Cost \$/MWh	NA
Hours Per Month	June – August 96 hours per month, September 48 hours per month (4 days per week, 6 hours per day)

Table 19. Thermal Energy Storage

Programs Researched	Based on RFP response to PacifiCorp, summarized for Quantec in "TES Overview"
Load Basis	Average of entire summer on-peak period
Basis for Cost Calculations	Costs from "TES Overview" sent to Quantec on June 2, 2006 using per-kW costs by external vendor, \$300,000 for program development, \$100,000 annual program administration
High/Low Cost Notes	Incentives remain constant, Annual program administrative costs are increased by \$50,000 in high case and reduced by \$50,000 in low case.
Technical Potential	Less than complete technical ability to use this technology (90%) on cooling load
Eligible Load (%)	Using portion of commercial cooling load that is less than 30 kW as eligible (PacifiCorp - Quantec 2003)
Program Participation (%)	20% program participation, with +/- 5% for high and low participation
Event Participation (%)	100%
Current Program (kW)	NA
Per-Customer Impacts (kW)	NA
Hours Per Month	240 – April, 186 – May, 180 – June, 186 – July, 186 – August, 180 – September, 279 October

Table 20. Curtailable Rates

Programs Researched	Duke Interruptible Power Service; Georgia Power (Southern) Demand Plus Energy Credit; Duke Curtailable Service Pilot; Dominion Virginia Power Curtailable Service; MidAmerican; ConEd Interruptible/Curtailment Service, Southern California Edison C&I Base Interruptible Program, Wisconsin
Load Basis	Average of top 87 summer hours
Basis for Cost Calculations	Development: Per Customer of \$500 for marketing and \$700 for meter (Duke - Quantec, 05); \$300,000 for new program development, \$100,000 annual program administration, Base incentive of \$48 (\$4/kWMonth) (Pacific Gas and Electric pays \$3-\$7/kWMonth, Southern California Edison pays \$7/kWMonth, Wisconsin Power and Light pays \$3.3/kWMonth, MidAmerican pays \$3.3, Duke Power pays \$3.5/kW-Month).
High/Low Cost Notes	Base incentive of \$48 (\$4/kWMonth) is increased by 50% in high case. Low assumes same incentive as base (\$42). Annual program administrative costs are increased by \$50,000 in high case and reduced by \$50,000 in low case.
Technical Potential	Total curtailable load based on Goldman (2004)- National Trends, by sector. If not mentioned, unclassified was used.
Eligible Load (%)	Using portion of load that is greater than 250 kW as eligible (PacifiCorp - Quantec 2003)
Program Participation (%)	National participation ranges from slightly greater than 0% (ISO NE) of customers to 30%, (NYISO 29%, Duke 14%). Base assumes 25% (due to load eligibility already accounted for), 5% more for high case and 12.5% less for low case.
Event Participation (%)	Event Participation reflects compliance rate (Duke - 90% + compliance, CEC – 90% + compliance Goldman (2002))
Current Program (kW)	NA
Per-Customer Impacts (kW)	Per customer impacts are calculated as product of average load for customers >250 kW and the technical potential above
Hours Per Month	July 69; August 18 (based on the distribution of the PacifiCorp 2005 system profile)

Table 21. Critical Peak Pricing

Programs Researched	Gulf Power GoodCents Select; Pacific Gas and Electric Critical Peak Pricing; Southern California Edison Critical Peak Pricing; San Diego Gas and Electric Critical Peak Pricing
Load Basis	Average of top 87 summer hours
Basis for Cost Calculations	Development: Customer: \$500 for advanced metering technologies; Program - \$300,000 for new program development; Annual: Customer - \$20 for meter reading, extra mailing, and messaging (PSE – Quantec (2004)), \$30 to account for the rate and energy benefits to the customer (Quantec PacifiCorp TOU (2005)) \$100,000 annual program administration
High/Low Cost Notes	Annual program administrative costs are increased by \$50,000 in high case and reduced by \$50,000 in low case.
Technical Potential	Range of impacts from high 41% (Gulf Power super peak) to 18% (Piette, 2006), therefore assume low-mid-point of 25%, (other relevant references – McAulife (2004) DOE 2006)
Eligible Load (%)	Eligibility- all customers assumed to be eligible except those deemed unable to respond (based on sectors reported in Quantum (2004))
Program Participation (%)	Current programs in nation have very low participation (reviewed seven programs McAulife (2004) and Gulf Power with maximum of 3% - PG&E commercial program) - base is 3%, low is 0.5% and high is 5.5%
Event Participation (%)	Event participation assumed to be less than all - i.e., 90%
Current Program (kW)	NA
Per-Customer Impacts (kW)	Per customer impacts are calculated as product of average load for customers >250 kW and the technical potential above
Hours Per Month	July 69; August 18 (based on the distribution of the PacifiCorp 2005 system profile)

Table 22. Demand Buyback

Programs Researched	Pacific Gas and Electric Demand Buyback (Commercial and Industrial); Southern California Edison Demand Buyback (Commercial and Industrial); San Diego Gas and Electric Demand Buyback; New York ISO Day Ahead Demand Response, PacifiCorp
Load Basis	Average of top 175 summer hours
Basis for Cost Calculations	Development: \$700 for advanced meter; Program development cost of \$150,000 for expansion; \$100,000 annually for program administration. Incentive of \$10/kW is consistent with 2005 PacifiCorp Integrated Resource Plan base prices of \$60/MWh
High/Low Cost Notes	High and low incentive levels are consistent with 2005 PacifiCorp Integrated Resource Plan base prices of \$40/MWh (low) and \$100/MWh (high). Annual program administrative costs are increased by \$50,000 in high case and reduced by \$50,000 in low case.
Technical Potential	Total curtailable load based on Goldman (2004)- National Trends, by sector. If not mentioned, unclassified was used.
Eligible Load (%)	Using portion of load that is greater than 250 kW as eligible (PacifiCorp - Quantec 2003)
Program Participation (%)	Range of program participation is from 0-6% (various California utilities – Quantum (2004)) to 17-25% (PJM/NYISO – Goldman (2004)). This study uses 35% to account for the eligibility correction for those >250 kW. High is 30%, low is 5%
Event Participation (%)	Event participation calculated from 2001 Northwest demand bidding experience
Current Program (kW)	1 MW of participation (165 MWh over 15 events, 10 hours per event)
Per-Customer Impacts (kW)	Per-customer impacts are calculated as product of average load for customers >250 kW and the technical potential above
Hours Per Month	July 129; August 46 (based on the distribution of the PacifiCorp 2005 system profile)

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Appendix A: East Region Results

Table 23: Technical Potential (MW), East

Sector	Fully Dispatchable			Scheduled Firm - Irrigation	Thermal Energy Storage	Curtable Rates	Critical Peak Pricing	Demand Buyback
	Winter	Summer	Large C&I					
Industrial	---	---	143	---	---	377	392	368
Commercial	---	35	30	---	59	79	134	76
Irrigation	---	---	---	254	---	---	---	---
Residential	163	318	---	---	---	---	342	---
Total	163	353	173	254	59	455	868	444
% of East Peak	3%	7%	3%	5%	1%	9%	17%	9%

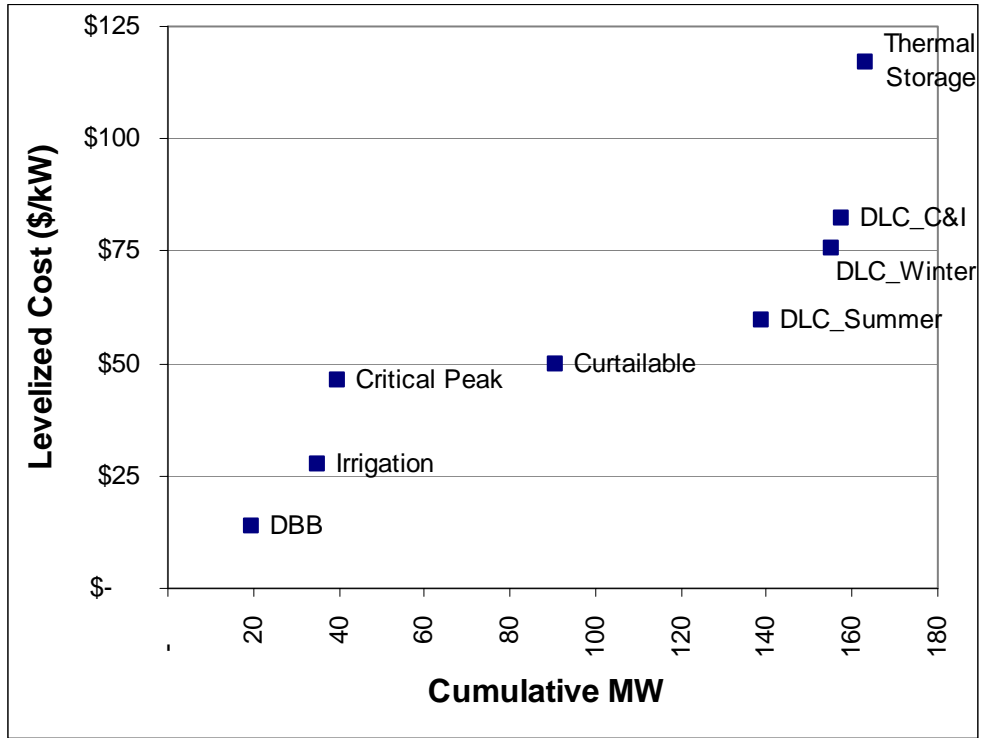
Table 24: Market Potential (MW), East

Sector	Fully Dispatchable			Scheduled Firm - Irrigation	Thermal Energy Storage	Curtable Rates	Critical Peak Pricing	Demand Buyback
	Winter	Summer	Large C&I					
Industrial	---	---	4	---	---	85	11	16
Commercial	---	2	1	---	12	18	4	3
Irrigation	---	---	---	63	---	---	---	---
Residential	33	111	---	---	---	---	9	---
Total	33	113	5	63	12	102	23	19
% of East Peak	0.7%	2.3%	0.1%	1.3%	0.2%	2.0%	0.5%	0.4%

Table 25. Achievable Potential (MW) and Costs, East

	Fully Dispatchable			Scheduled Firm - Irrigation	Thermal Energy Storage	Curtable Rates	Critical Peak Pricing	Demand Buyback	Total
	Winter	Summer	Large C&I						
Resource Costs (\$/kW/yr)	\$76	\$59	\$82	\$28	\$117	\$50	\$46	\$14	---
Achievable Potential	16	113	2	63	6	51	5	19	276
Potential Net of Current Programs	16	48	2	15	6	51	5	19	163

Figure 12: Cumulative Supply Curve, East



Appendix B: West Region Results

Table 26. Technical Potential, West

Sector	Fully Dispatchable			Scheduled Firm - Irrigation	Thermal Energy Storage	Curtailable Rates	Critical Peak Pricing	Demand Buyback
	Winter	Summer	Large C&I					
Industrial	---	---	50	---	---	133	138	132
Commercial	---	20	21	---	35	54	98	54
Irrigation	---	---	---	128	---	---	---	---
Residential	210	33	---	---	---	---	275	---
Total	210	54	71	128	35	187	512	185
% of West Peak	7%	2%	2%	4%	1%	6%	16%	6%

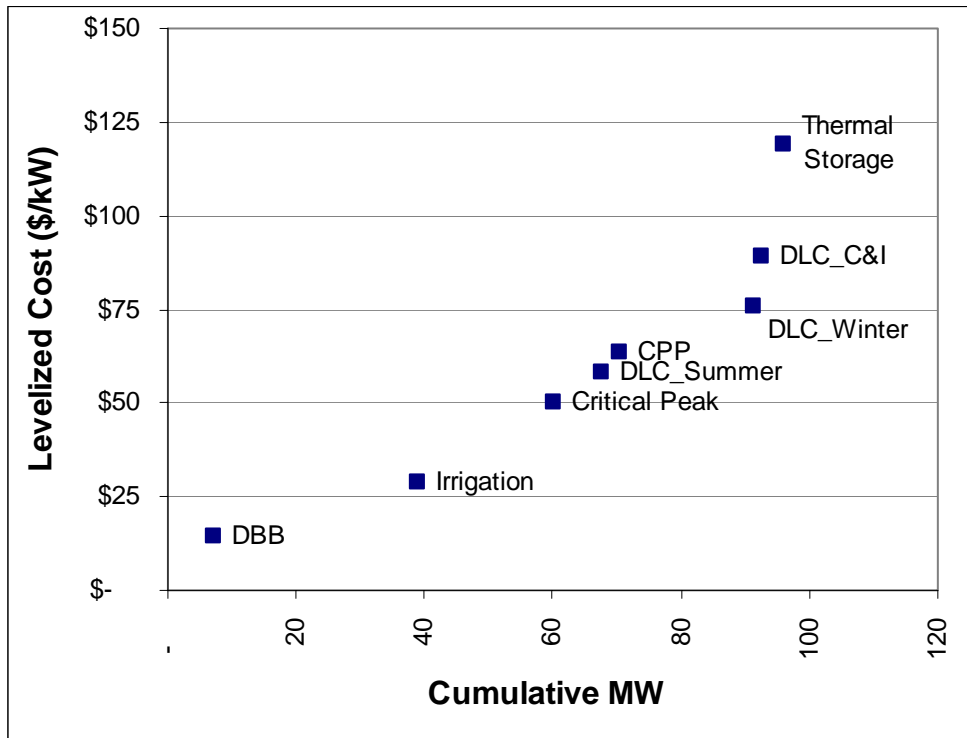
Table 27. Market Potential, West

Sector	Fully Dispatchable			Scheduled Firm - Irrigation	Thermal Energy Storage	Curtailable Rates	Critical Peak Pricing	Demand Buyback
	Winter	Summer	Large C&I					
Industrial	---	---	1	---	---	30	4	6
Commercial	---	1	1	---	7	12	3	2
Irrigation	---	---	---	32	---	---	---	---
Residential	42	7	---	---	---	---	7	---
Total	42	8	2	32	7	42	14	8
% of West Peak	1.3%	0.2%	0.1%	1.0%	0.2%	1.3%	0.4%	0.3%

Table 28. Achievable Potential (MW) and Costs, West

	Fully Dispatchable			Scheduled Firm - Irrigation	Thermal Energy Storage	Curtailable Rates	Critical Peak Pricing	Demand Buyback	Total
	Winter	Summer	Large C&I						
Resource Costs (\$/kW/yr)	\$76	\$58	\$89	\$29	\$119	\$50	\$63	\$15	---
Achievable Potential	21	8	1	32	3	21	3	8	97
Potential Net of Current Programs	21	8	1	32	3	21	3	7	96

Figure 13: Supply Curve, West



Appendix C: Data Provided to IRP

Figure 14: East Region, Reference Case

Program Name	Fully Dispatchable- Winter	Fully Dispatchable- Summer	Fully Dispatchable- Large C&I	Scheduled Firm Irrigation	Thermal Energy Storage	Curtable Rates	Critical Peak Pricing	Demand Buyback
Variable Costs (\$/MWh)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	Market Prices
Demand Reduction Period (Hours)	2	2	4	6	6	4	4	10
Start Year	2,009	2,009	2,009	2,009	2,009	2,009	2,009	2,009
Base								
Total Achievable Potential --Maximum (MW)	16	113	2	63	6	51	5	19
Currently Under Contract	-	65	-	48	-	-	-	-
Resource Costs (\$/kW/yr)	\$ 76	\$ 59	\$ 82	\$ 28	\$ 117	\$ 50	\$ 46	\$ 14
Low								
Total Achievable Potential --Maximum (MW)	8	78	0	51	4	22	1	6
Currently Under Contract	-	65	-	48	-	-	-	-
Resource Costs (\$/kW/yr)	\$ 58	\$ 53	\$ 159	\$ 29	\$ 115	\$ 38	\$ 95	\$ 13
High								
Total Achievable Potential --Maximum (MW)	25	131	7	76	7	63	9	46
Currently Under Contract	-	65	-	48	-	-	-	-
Resource Costs (\$/kW/yr)	\$ 84	\$ 73	\$ 101	\$ 37	\$ 118	\$ 86	\$ 42	\$ 18
Hours Available by Month								
January	3	-	-	-	-	-	-	-
February	-	-	-	-	-	-	-	-
March	-	-	-	-	-	-	-	-
April	-	-	-	-	240	-	-	-
May	-	-	-	-	186	-	-	-
June	-	8	8	96	180	-	-	-
July	-	46	46	96	186	69	69	129
August	-	33	33	96	186	18	18	46
September	-	-	-	48	180	-	-	-
October	-	-	-	-	279	-	-	-
November	-	-	-	-	-	-	-	-
December	84	-	-	-	-	-	-	-

Figure 15: West Region, Reference Case

Program Name	Fully Dispatchable- Winter	Fully Dispatchable - Summer	Fully Dispatchable - Large C&I	Scheduled Firm - Irrigation	Thermal Energy Storage	Curtable Rates	Critical Peak Pricing	Demand Buyback
Variable Costs (\$/MWh)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	Market Prices
Demand Reduction Period (Hours)	2	2	4	6	6	4	4	10
Start Year	2,009	2,009	2,009	2,009	2,009	2,009	2,009	2,009
Base								
Total Achievable Potential --Maximum (MW)	21	8	1	32	3	21	3	8
Currently Under Contract	-	-	-	-	-	-	-	1
Resource Costs (\$/kW/yr)	\$ 76	\$ 58	\$ 89	\$ 29	\$ 119	\$ 50	\$ 63	\$ 15
Low								
Total Achievable Potential --Maximum (MW)	11	2	0	26	3	9	0	3
Currently Under Contract	-	-	-	-	-	-	-	1
Resource Costs (\$/kW/yr)	\$ 58	\$ 61	\$ 185	\$ 30	\$ 116	\$ 39	\$ 144	\$ 14
High								
Total Achievable Potential --Maximum (MW)	32	10	3	38	4	26	5	19
Currently Under Contract	-	-	-	-	-	-	-	1
Resource Costs (\$/kW/yr)	\$ 84	\$ 70	\$ 104	\$ 37	\$ 121	\$ 87	\$ 56	\$ 19
Hours Available by Month								
January	3	-	-	-	-	-	-	-
February	-	-	-	-	-	-	-	-
March	-	-	-	-	-	-	-	-
April	-	-	-	-	240	-	-	-
May	-	-	-	-	186	-	-	-
June	-	8	8	96	180	-	-	-
July	-	46	46	96	186	69	69	129
August	-	33	33	96	186	18	18	46
September	-	-	-	48	180	-	-	-
October	-	-	-	-	279	-	-	-
November	-	-	-	-	-	-	-	-
December	84	-	-	-	-	-	-	-

Figure 16: System, Reference Case

Program Name	Fully Dispatchable- Winter	Fully Dispatchable - Summer	Fully Dispatchable - Large C&I	Scheduled Firm - Irrigation	Thermal Energy Storage	Curtable Rates	Critical Peak Pricing	Demand Buyback
Variable Costs (\$/MWh)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	Market Prices
Demand Reduction Period (Hours)	2	2	4	6	6	4	4	10
Start Year	2,009	2,009	2,009	2,009	2,009	2,009	2,009	2,009
Base								
Total Achievable Potential --Maximum (MW)	37	120	3	95	9	72	7	28
Currently Under Contract	-	65	-	48	-	-	-	1
Resource Costs (\$/kW/yr)	\$ 76	\$ 59	\$ 84	\$ 28	\$ 118	\$ 50	\$ 49	\$ 14
Low								
Total Achievable Potential --Maximum (MW)	19	80	1	76	7	30	1	9
Currently Under Contract	-	65	-	48	-	-	-	1
Resource Costs (\$/kW/yr)	\$ 58	\$ 53	\$ 167	\$ 29	\$ 115	\$ 39	\$ 91	\$ 13
High								
Total Achievable Potential --Maximum (MW)	56	141	9	114	12	88	14	65
Currently Under Contract	-	65	-	48	-	-	-	1
Resource Costs (\$/kW/yr)	\$ 84	\$ 72	\$ 102	\$ 37	\$ 119	\$ 86	\$ 45	\$ 19
Hours Available by Month								
January	3	-	-	-	-	-	-	-
February	-	-	-	-	-	-	-	-
March	-	-	-	-	-	-	-	-
April	-	-	-	-	240	-	-	-
May	-	-	-	-	186	-	-	-
June	-	8	8	96	180	-	-	-
July	-	46	46	96	186	69	69	129
August	-	33	33	96	186	18	18	46
September	-	-	-	48	180	-	-	-
October	-	-	-	-	279	-	-	-
November	-	-	-	-	-	-	-	-
December	84	-	-	-	-	-	-	-

Figure 17: East Region, No DBB

Program Name	Fully Dispatchable- Winter	Fully Dispatchable - Summer	Fully Dispatchable - Large C&I	Scheduled Firm - Irrigation	Thermal Energy Storage	Curtable Rates	Critical Peak Pricing
Variable Costs (\$/MWh)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Demand Reduction Period (Hours)	2	2	4	6	6	4	4
Start Year	2,009	2,009	2,009	2,009	2,009	2,009	2,009
Base							
Total Achievable Potential --Maximum (MW)	16	113	2	63	6	102	5
Currently Under Contract	-	65	-	48	-	-	-
Resource Costs (\$/kW/yr)	\$ 76	\$ 59	\$ 82	\$ 28	\$ 117	\$ 49	\$ 46
Low							
Total Achievable Potential --Maximum (MW)	8	78	0	51	4	43	1
Currently Under Contract	-	65	-	48	-	-	-
Resource Costs (\$/kW/yr)	\$ 58	\$ 53	\$ 159	\$ 29	\$ 115	\$ 37	\$ 95
High							
Total Achievable Potential --Maximum (MW)	25	131	7	76	7	125	9
Currently Under Contract	-	65	-	48	-	-	-
Resource Costs (\$/kW/yr)	\$ 84	\$ 73	\$ 101	\$ 37	\$ 118	\$ 85	\$ 42
Hours Available by Month							
January	3	-	-	-	-	-	-
February	-	-	-	-	-	-	-
March	-	-	-	-	-	-	-
April	-	-	-	-	240	-	-
May	-	-	-	-	186	-	-
June	-	8	8	96	180	-	-
July	-	46	46	96	186	69	69
August	-	33	33	96	186	18	18
September	-	-	-	48	180	-	-
October	-	-	-	-	279	-	-
November	-	-	-	-	-	-	-
December	84	-	-	-	-	-	-

Figure 18: West Region, No DBB

Program Name	Fully Dispatchable- Winter	Fully Dispatchable - Summer	Fully Dispatchable - Large C&I	Scheduled Firm - Irrigation	Thermal Energy Storage	Curtable Rates	Critical Peak Pricing
Variable Costs (\$/MWh)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Demand Reduction Period (Hours)	2	2	4	6	6	4	4
Start Year	2,009	2,009	2,009	2,009	2,009	2,009	2,009
Base							
Total Achievable Potential --Maximum (MW)	21	8	1	32	3	42	3
Currently Under Contract	-	-	-	-	-	-	-
Resource Costs (\$/kW/yr)	\$ 76	\$ 58	\$ 89	\$ 29	\$ 119	\$ 49	\$ 63
Low							
Total Achievable Potential --Maximum (MW)	11	2	0	26	3	18	0
Currently Under Contract	-	-	-	-	-	-	-
Resource Costs (\$/kW/yr)	\$ 58	\$ 61	\$ 185	\$ 30	\$ 116	\$ 38	\$ 144
High							
Total Achievable Potential --Maximum (MW)	32	10	3	38	4	51	5
Currently Under Contract	-	-	-	-	-	-	-
Resource Costs (\$/kW/yr)	\$ 84	\$ 70	\$ 104	\$ 37	\$ 121	\$ 86	\$ 56
Hours Available by Month							
January	3	-	-	-	-	-	-
February	-	-	-	-	-	-	-
March	-	-	-	-	-	-	-
April	-	-	-	-	240	-	-
May	-	-	-	-	186	-	-
June	-	8	8	96	180	-	-
July	-	46	46	96	186	69	69
August	-	33	33	96	186	18	18
September	-	-	-	48	180	-	-
October	-	-	-	-	279	-	-
November	-	-	-	-	-	-	-
December	84	-	-	-	-	-	-

Figure 19: System, No DBB

Program Name	Fully Dispatchable- Winter	Fully Dispatchable- Summer	Fully Dispatchable- Large C&I	Scheduled Firm Irrigation	Thermal Energy Storage	Curtable Rates	Critical Peak Pricing
Variable Costs (\$/MWh)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Demand Reduction Period (Hours)	2	2	4	6	6	4	4
Start Year	2,009	2,009	2,009	2,009	2,009	2,009	2,009
Base							
Total Achievable Potential --Maximum (MW)	37	120	3	95	9	144	7
Currently Under Contract	-	65	-	48	-	-	-
Resource Costs (\$/kW/yr)	\$ 76	\$ 59	\$ 84	\$ 28	\$ 118	\$ 49	\$ 49
Low							
Total Achievable Potential --Maximum (MW)	19	80	1	76	7	61	1
Currently Under Contract	-	65	-	48	-	-	-
Resource Costs (\$/kW/yr)	\$ 58	\$ 53	\$ 167	\$ 29	\$ 115	\$ 37	\$ 91
High							
Total Achievable Potential --Maximum (MW)	56	141	9	114	12	177	14
Currently Under Contract	-	65	-	48	-	-	-
Resource Costs (\$/kW/yr)	\$ 84	\$ 72	\$ 102	\$ 37	\$ 119	\$ 85	\$ 45
Hours Available by Month							
January	3	-	-	-	-	-	-
February	-	-	-	-	-	-	-
March	-	-	-	-	-	-	-
April	-	-	-	-	240	-	-
May	-	-	-	-	186	-	-
June	-	8	8	96	180	-	-
July	-	46	46	96	186	69	69
August	-	33	33	96	186	18	18
September	-	-	-	48	180	-	-
October	-	-	-	-	279	-	-
November	-	-	-	-	-	-	-
December	84	-	-	-	-	-	-

Figure 20: East Region, No Metering

Program Name	Fully Dispatchable- Winter	Fully Dispatchable - Summer	Fully Dispatchable - Large C&I	Scheduled Firm - Irrigation	Thermal Energy Storage	Curtailable Rates	Critical Peak Pricing	Demand Buyback
Variable Costs (\$/MWh)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	Market Prices
Demand Reduction Period (Hours)	2	2	4	6	6	4	4	10
Start Year	2,009	2,009	2,009	2,009	2,009	2,009	2,009	2,009
Base								
Total Achievable Potential --Maximum (MW)	16	113	2	63	6	51	5	19
Currently Under Contract	-	65	-	48	-	-	-	-
Resource Costs (\$/kW/yr)	\$ 75	\$ 58	\$ 82	\$ 27	\$ 117	\$ 50	\$ 40	\$ 14
Low								
Total Achievable Potential --Maximum (MW)	8	78	0	51	4	22	1	6
Currently Under Contract	-	65	-	48	-	-	-	-
Resource Costs (\$/kW/yr)	\$ 57	\$ 52	\$ 159	\$ 28	\$ 115	\$ 38	\$ 89	\$ 13
High								
Total Achievable Potential --Maximum (MW)	25	131	7	76	7	63	9	46
Currently Under Contract	-	65	-	48	-	-	-	-
Resource Costs (\$/kW/yr)	\$ 83	\$ 71	\$ 101	\$ 36	\$ 118	\$ 86	\$ 36	\$ 18
Hours Available by Month								
January	3	-	-	-	-	-	-	-
February	-	-	-	-	-	-	-	-
March	-	-	-	-	-	-	-	-
April	-	-	-	-	240	-	-	-
May	-	-	-	-	186	-	-	-
June	-	8	8	96	180	-	-	-
July	-	46	46	96	186	69	69	129
August	-	33	33	96	186	18	18	46
September	-	-	-	48	180	-	-	-
October	-	-	-	-	279	-	-	-
November	-	-	-	-	-	-	-	-
December	84	-	-	-	-	-	-	-

Figure 21: West Region, No Metering

Program Name	Fully Dispatchable- Winter	Fully Dispatchable - Summer	Fully Dispatchable - Large C&I	Scheduled Firm - Irrigation	Thermal Energy Storage	Curtable Rates	Critical Peak Pricing	Demand Buyback
Variable Costs (\$/MWh)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	Market Prices
Demand Reduction Period (Hours)	2	2	4	6	6	4	4	10
Start Year	2,009	2,009	2,009	2,009	2,009	2,009	2,009	2,009
Base								
Total Achievable Potential --Maximum (MW)	21	8	1	32	3	21	3	8
Currently Under Contract	-	-	-	-	-	-	-	1
Resource Costs (\$/kW/yr)	\$ 75	\$ 57	\$ 89	\$ 28	\$ 119	\$ 50	\$ 56	\$ 14
Low								
Total Achievable Potential --Maximum (MW)	11	2	0	26	3	9	0	3
Currently Under Contract	-	-	-	-	-	-	-	1
Resource Costs (\$/kW/yr)	\$ 57	\$ 60	\$ 185	\$ 29	\$ 116	\$ 39	\$ 136	\$ 14
High								
Total Achievable Potential --Maximum (MW)	32	10	3	38	4	26	5	19
Currently Under Contract	-	-	-	-	-	-	-	1
Resource Costs (\$/kW/yr)	\$ 83	\$ 69	\$ 104	\$ 37	\$ 121	\$ 86	\$ 48	\$ 19
Hours Available by Month								
January	3	-	-	-	-	-	-	-
February	-	-	-	-	-	-	-	-
March	-	-	-	-	-	-	-	-
April	-	-	-	-	240	-	-	-
May	-	-	-	-	186	-	-	-
June	-	8	8	96	180	-	-	-
July	-	46	46	96	186	69	69	129
August	-	33	33	96	186	18	18	46
September	-	-	-	48	180	-	-	-
October	-	-	-	-	279	-	-	-
November	-	-	-	-	-	-	-	-
December	84	-	-	-	-	-	-	-

Figure 22: System, No Metering

Program Name	Fully Dispatchable- Winter	Fully Dispatchable - Summer	Fully Dispatchable - Large C&I	Scheduled Firm - Irrigation	Thermal Energy Storage	Curtable Rates	Critical Peak Pricing	Demand Buyback
Variable Costs (\$/MWh)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	Market Prices
Demand Reduction Period (Hours)	2	2	4	6	6	4	4	10
Start Year	2,009	2,009	2,009	2,009	2,009	2,009	2,009	2,009
Base								
Total Achievable Potential --Maximum (MW)	37	120	3	95	9	72	7	28
Currently Under Contract	-	65	-	48	-	-	-	1
Resource Costs (\$/kW/yr)	\$ 75	\$ 58	\$ 84	\$ 27	\$ 118	\$ 50	\$ 42	\$ 14
Low								
Total Achievable Potential --Maximum (MW)	19	80	1	76	7	30	1	9
Currently Under Contract	-	65	-	48	-	-	-	1
Resource Costs (\$/kW/yr)	\$ 57	\$ 52	\$ 167	\$ 29	\$ 115	\$ 38	\$ 84	\$ 13
High								
Total Achievable Potential --Maximum (MW)	56	141	9	114	12	88	14	65
Currently Under Contract	-	65	-	48	-	-	-	1
Resource Costs (\$/kW/yr)	\$ 83	\$ 71	\$ 102	\$ 36	\$ 119	\$ 86	\$ 38	\$ 18
Hours Available by Month								
January	3	-	-	-	-	-	-	-
February	-	-	-	-	-	-	-	-
March	-	-	-	-	-	-	-	-
April	-	-	-	-	240	-	-	-
May	-	-	-	-	186	-	-	-
June	-	8	8	96	180	-	-	-
July	-	46	46	96	186	69	69	129
August	-	33	33	96	186	18	18	46
September	-	-	-	48	180	-	-	-
October	-	-	-	-	279	-	-	-
November	-	-	-	-	-	-	-	-
December	84	-	-	-	-	-	-	-