ASSESSMENT OF DR OPTIONS FOR BPA

Submitted to

Load Management Group
Bonneville Power Administration (BPA)

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1 INTRODUCTION

The purpose of this interim report is to provide to BPA a detailed assessment of relevant demand response (DR) options. This information can be used to guide the development of a DR strategy and lead to the design and implementation of DR programs.

First, a word about definitions. *DR options* are specific measures that could be pursued by BPA to reduce peak load during critical times. A residential direct load control program is an example of a DR option as is a dynamic pricing rate design.

A *DR program* is a portfolio of DR options that are jointly pursued through a concentrated marketing and operations effort. A DR program would have a focused goal, such as facilitating DR in the residential sector. It could, for example, be composed of a direct load control option, a dynamic pricing rate, and a customer education initiative to show customers how they might take advantage of these options.

Finally, a *DR strategy* could be composed of one or several DR programs. The strategy would define BPA's overall vision and approach to providing DR services. Examples could include an emergency-based strategy with day-of dispatch of the programs or a price-driven economic dispatch strategy with a mix of day-ahead and day-of programs. The strategies could also have varying degrees of aggressiveness. In a more aggressive strategy, BPA might pursue default customer enrollment in DR programs. In a less aggressive strategy, BPA could promote the programs as voluntary.

In an earlier project task, we worked with BPA staff to define several capacity-constrained scenarios that could affect the operation and planning of the BPA system in the future. These reflect current experiences and most likely conditions for the future. The choice and assessment of DR options needs to take into consideration how these options could be applied to address these scenarios.

This report provides an overview of the full array of existing DR options and their characteristics. It creates detailed profiles of the options that are likely to satisfy some or all of the capacity-constrained scenarios. It presents both a qualitative and a quantitative assessment of DR options. The information is based on a detailed profiling of existing DR options and experiences around the country, as well as an understanding of how these options relate to BPA's system and conditions. Drawing on this information, we identify and select the DR options most relevant for meeting BPA's capacity requirements.

Quantitative assessment of the DR options includes a detailed analysis of load reduction impacts associated with each option and the levelized costs for attaining the load reductions. However, as mentioned earlier, this report precedes development of DR program strategies. Therefore, cost assessments presented here are preliminary. Actual costs related to DR options need to consider how these options are being packaged into DR program strategies. A more realistic assessment of costs is only possible during the next stage: DR strategy formulation. The information in this report provides the foundation for developing these future assessments.

2 OVERVIEW OF KEY CHARACTERISTICS OF DR OPTIONS & CHOICE OF RELEVANT DR OPTIONS

This section presents a taxonomy of DR options and the dimensions along which these DR options can be characterized. This is helpful for understanding and selecting the options that are relevant for BPA's system and conditions. Based on this, we also discuss why some options are considered relevant for BPA while others are not. Section 3 presents a brief profile of individual DR options that are considered relevant for BPA.

2.1 Characteristics of DR Options

The key dimensions along which DR options can be characterized are:

1. Signal to the end-use customer: incentive-based or price-based
2. Trigger for the DR event: reliability vs. price
3. Program implementation: wholesale vs. retail
4. Response requirement: mandatory vs. voluntary
5. Dispatchability: dispatchable vs. non-dispatchable
6. Notification: day-ahead vs. day-of notification
7. Control: utility-controlled vs. customer-controlled
8. Type of incentive payment: fixed vs. market-based

DR options span a spectrum of value to the utility and convenience to customers, based on the option characteristics. Generally, DR option characteristics that are of higher value to the utility tend to be less convenient to the end-use customer (see Figure 2.1).

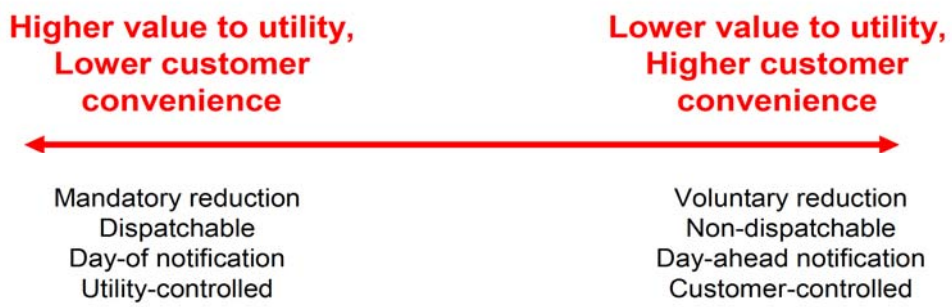

Figure 2.1 Utility Value/Customer Convenience Spectrum for DR Options

A brief discussion on the characteristics is provided below.

1. Signal to the End-use Customer. Department of Energy (DOE) has created a distinction between incentive-based and price-based options depending on the nature of the signal to the customer.

Incentive-based options pay customers to reduce load during events called by the program sponsor. These events can be triggered by an emergency on the grid or by high electricity prices. Incentive-based options include:

- Direct load control (DLC)
- Interruptible/curtailable rates
- Emergency DR option
- Capacity market DR
- Ancillary services

Price-based options incorporate time varying rates that reflect the cost of providing electricity during different time periods. These rates encourage customers to change consumption patterns and provide opportunities for electricity bill savings. Price-based options include:

- Critical peak pricing (CPP)
- Peak time rebate (PTR)
- Real time pricing (RTP)

Time-of-use rates are sometimes also considered price-based DR options but have been excluded from our analysis. For an explanation, see the discussion of the "dispatchability" criterion below.

2. Trigger for the DR event. DR events can be either reliability-triggered or price-triggered. Reliability-triggered options are called in response to emergency conditions on the grid (e.g., outages). These options typically provide short notification time due to unpredictable nature of emergencies. On the other hand, price-triggered options are called in anticipation of high market prices.

A single DR option can be both price-triggered and reliability-triggered and have a dual character. Usually, incentive-based programs are called at times when the system operator or utility determines that the need for peak load reduction is critical. This can occur either when electricity prices are high or when demand is near the reserve margin and there is an increased risk of grid failure (such as blackouts). This distinction does not define any particular program, but is something that can vary within a program category. For example, in California the IOUs implement programs that are triggered by both price and system emergencies. Most other ISOs and utilities in the U.S. do the same.

3. Program Implementation: Wholesale vs. retail. DR can be implemented at the wholesale level or the retail level. Wholesale-market DR options are administered by ISOs/RTOs. Some wholesale markets accept demand reductions as comparable to supply-side bids. Among the options being discussed in this report, emergency DR, capacity market, and ancillary services options are administered at the wholesale level.

Retail-level DR options are administered by retail utilities to their end-use customers. Some wholesale options, such as 'demand bidding', can also manifest themselves as retail options.

4. Response Requirement- Mandatory vs. Voluntary. DR options with mandatory participation requirements carry a stiff penalty fee for non-compliance. Typically, participation in a capacity-market option is mandatory as the load commitment from the end-use customer represents a firm resource level for the utility or program provider.

Voluntary options provide participants an incentive to reduce demand but do not penalize for non-compliance. Participation in dynamic pricing options is usually voluntary (although due to new policy in California dynamic pricing could soon be the default rate in that state). Among incentive-based options, participation in an emergency DR option, as well DLC, is voluntary.

Separately, participation in DR options can be mandatory, voluntary, or "default" with the option to opt-out. While the response requirement for a particular DR option can be mandatory, participation in the DR option may be voluntary. For example, enrollment in capacity market DR option is voluntary, but once enrolled, all participants are required to reduce their load.

5. Dispatchability: Dispatchable vs. Non-dispatchable. Dispatchability of DR options refers to the ability to provide a DR-inducing signal within a limited timeframe. Some argue that dispatchability is a requirement of a DR option. All DR options being considered in this analysis are 'dispatchable'.

Time-of-use (TOU) rates are sometimes considered a demand-response option. TOU rates are non-dispatchable and produce a consistent reduction in peak demand. They are excluded from our current analysis.

6. Notification: Day-Ahead vs. Day-Of. The amount of response time that is provided to the participant is another characteristic of DR options. Day-ahead DR options are those which require that the customer be notified a day in advance of the critical event. Day-of could mean 6 hours of notification, 1 hour, 15-30 minutes of notice, or even an instantaneous demand reduction. Day-of options become more feasible if end-use customers are equipped with enabling technology, which allows automatic response to DR signals. Day-of dispatch requires more customer education and management of expectations. Also, participant incentives increase as notification time becomes shorter.

Dynamic pricing can be offered as day-of when customers are equipped with enabling technologies. Among reliability-based options, direct load control (DLC) is a day-of option.

7. Control: Utility-controlled vs. Customer-controlled. DR options can also be distinguished on the basis of whether the load reduction is being controlled by the utility or by the customer. DR options such as DLC, provide the utility with physical control of the end-use customer's air conditioning, hot water heater, or other appliances. However, in most DR options, the customer physically controls the demand reduction. This often allows for greater flexibility in which end uses or processes are ramped down.

8. Type of Incentive Payment: Fixed vs. Market-based. There are variations in the type of incentive payment that is offered to participants in a DR option. Some options have a fixed level of incentive payment that is not directly tied to electricity market fluctuations in price. For example, DLC participants are usually offered a fixed monthly incentive per kW of load reduction. However, most of the wholesale-level DR options provide incentives that are based on the market price for energy, capacity, or both.

2.2 DR Options for BPA

In a meeting with BPA staff on August 6, 2008, we reviewed the full list of DR options. In that meeting, we narrowed down the list somewhat to include only those options relevant to BPA. The incentive-based options considered relevant for BPA include:

1. Direct load control (DLC)
2. Emergency DR option
3. Capacity market option
4. Ancillary services

The interruptible/curtailable rate option and demand bidding/buyback options are not considered relevant for BPA. The capacity market option is the wholesale market analog of interruptible/curtailable rates. They are structurally similar in that both offer a fixed capacity payment to participants for agreeing to reduce loads at times of emergency, in addition to providing direct incentives based on performance during a DR event. The capacity market option is administered by wholesale market operators such as ISO/RTO, while interruptible/curtailable has traditionally been administered by retail level utilities to their end-use customers. Based on BPA's characteristics and conditions, we consider that the 'capacity market' option is the one relevant for BPA.

Price-based options considered relevant for BPA include-

1. Critical peak pricing (CPP)
2. Peak time rebate (PTR)

Note that real-time pricing (RTP) is not considered relevant for BPA as administration of RTP requires hourly market price signals to be sent to the end-use customer. The absence of a wholesale hourly electricity market in the Pacific Northwest poses difficulties for implementing RTP. Also, based on discussions with BPA staff, utilities under BPA's jurisdiction are unlikely to offer RTP as a retail rate to their end-use customers in the near future. Therefore, we do not consider RTP as a relevant DR option in our analysis.

Tables 2.1 and 2.2 summarize the characteristics of relevant incentive-based and price-based DR options. Section 3 of the report discusses these options in more details.

Table 2.1 Summary of key features for relevant reliability-based DR options

Features	DLC	Emergency DR	Capacity Market DR	Ancillary Services
Trigger	Emergency/ high prices	Emergency/ high prices	Emergency/ high prices	Need for operating reserves
Implementation	Retail	Wholesale	Wholesale	Wholesale
Response requirement	Voluntary	Voluntary	Universal	Universal
Whether dispatchable	Yes	Yes	Yes	Yes
Control	Utility-controlled	Customer-controlled	Customer-controlled	Customer-controlled
Participant incentive	Fixed	Market-based	Fixed plus market-based	Fixed plus market-based

Table 2.2 Summary of key features for relevant price-based DR options

Features	Critical Peak Pricing (CPP)	Peak Time Rebate (PTR)
Trigger	Emergency/ high prices	Emergency/ high prices
Implementation	Retail	Retail
Response requirement	Voluntary	Voluntary
Whether dispatchable	Yes	Yes
Control	Customer-controlled	Customer-controlled
Participant incentive	Market-based	Market-based

3 PROFILES OF RELEVANT DR OPTIONS

This section presents profiles of relevant reliability-based and pricing-based DR options, while drawing on the information presented in the earlier section related to characteristics of DR options.

3.1 Profiles of Reliability-based Options

Table 3.1 below represents a summary of the profiles of relevant reliability-based options, followed by a brief description of each of the options.

Table 3.1 Profiles of relevant reliability-based DR options

Items	DLC	Emergency DR	Capacity Market DR	Ancillary Services
Targeted customer segment	Residential & Small Commercial (<200 kW of load)	Medium and Large Commercial & Industrial (C&I) (>200 kW of load)	Medium and Large Commercial & Industrial (C&I) (>200 kW of load)	Large C&I (greater than 1,000 kW of load)
Controlled end-uses	CAC, water heating, space heating	Any	Any	Any
Min. load for participation	No specification	Usually 100 kW; aggregation allowed	Usually 100-200 kW; aggregation allowed	200 kW and greater
Participant incentives	Fixed monthly incentive	Real-time market based energy payment, with a min. floor price	Fixed monthly capacity payment, plus real-time market based energy payment	Market-based energy plus capacity payment
Notification time	Instantaneous	Typically 2 hours	30 min-2 hours	30 minutes or less
Technology requirements	Remote switch/ Smart thermostat (PCT)	Interval meter	Interval meters plus communications	Advanced real-time telemetry

Direct Load Control (DLC)

Under direct load control (DLC), a utility or system operator remotely shuts down or cycles a customer's electrical equipment on short notice to address system or local reliability contingencies. In exchange, the customer receives an incentive payment or bill credit. Operation of DLC typically occurs during times of high peak demand. However, it can also be operated when economic to avoid high on-peak electricity purchases.

The traditional DLC option is implemented as follows. During a DR event, DLC participants have their appliances turned off for the full duration of an event or for various fractions of an hour (e.g., a common duty cycle is 15 minutes off during an hour). A one-way remote switch is connected to the condensing unit of an air conditioner or to the immersion element in a water heater. The operation of the switch is controlled through radio signals (for older systems) or through digital paging (for newer systems). Most switches also contain multiple relays so that air conditioners and water heaters can be controlled by the same switch with independent control strategies for each relay.

More recent DLC programs involve installation of programmable communicating thermostats for customers. Smart thermostats allow remote adjustment of temperature settings, so the utility can remotely adjust the temperature upward to reduce demand. After an event, the temperature setting is readjusted to the pre-event, customer-selected level.

Although actual reductions vary by size of the appliance, customer usage patterns and climate, the demand reductions for each central air conditioner is about 1 kW and for water heaters about 0.6 kW[1]. Typically, DLC programs limit the number of times or hours that the customer's appliance can be turned off per year or season. DLC participants usually receive a fixed monthly incentive payment. The payment amount may depend on the load commitment level.

This option primarily targets residential customers. However, a third of all DLC programs offered around the country also target small commercial customers.

Emergency Demand Response Option

The emergency demand response option provides incentives to customers for reducing load during reliability triggered events. These events may also be called in response to high wholesale electricity prices. End-use customer participation in this option is most often voluntary. Upon notification, customers can choose not to curtail and in turn not receive any payment. Usually on-site generators are allowed to participate and supply power during curtailment periods.

This option is typically offered by wholesale-market providers such as ISOs and RTOs. However, electric utilities too can offer this as an option to their retail-level end-use customers. Typically, the response time for loads to curtail is two hours. A minimum resource size is specified for participation in this option, which is usually at a level of 100 kW. However, smaller loads can be aggregated to meet the minimum specified size requirement.

The participant incentive is in the form of energy payment only, depending on actual curtailment levels during DR events. Participants do not receive any capacity payment. The energy payment is based on either a specified floor price or the market price of energy, whichever is greater. For example, in the New York ISO's Emergency Demand Response Program (EDRP), participants are paid the greater of $500/MWh or the prevailing location-based marginal price (LBMP) for curtailments. Participants are usually guaranteed payment for a minimum certain number of hours, irrespective of the actual event duration. Since participation in this option is voluntary, there is no penalty for non-curtailment.

This option is typically targeted toward medium and large Commercial and Industrial (C&I) end-use customers. Customers need to have interval meter installed for measurement, verification, and settlement.

Capacity Market Option

A capacity market DR option is typically offered by wholesale market providers such as ISOs and RTOs. This is the wholesale market analog of interruptible/curtailable tariffs, traditionally offered by utilites to retail customers. Participants in this option commit to provide pre-specified load reductions when system contingencies arise. In return, they receive a fixed incentive payment in the form of capacity credits and are paid to be on call even though actual load curtailments may not occur. Enrolled loads represent a firm resource and can be counted toward Installed Capacity (ICAP) requirements. Since loads represent a firm resource, curtailment is mandatory and there are penalties for non-curtailment. Similar to the emergency DR option, on-site generators are allowed to supply power during DR events. The signal for DR events could either be system emergency or high wholesale market prices.

Unlike the emergency DR option, there is a fixed monthly capacity payment for firm load commitment in addition to the payment for energy reduction at real-time market prices with a minimum floor price. Payment to participants is usually guaranteed for a minimum of two to four hours. Typically, for this option, response time ranges between 30 minutes to two hours. Like the emergency DR option, there is a minimum size require for participation, usually in the range of 100-200 kW. Aggregation of smaller loads for meeting the minimum size qualification is allowed.

The target segment for this option is the medium and large C&I end-users, the same as for the emergency option. Participants need to have an interval meter in place, along with internet-based communication capability.

[1] *Assessment of Demand Response and Advanced Metering*. Staff Report. Docket No. AD-06-2-000; August 2006.

Ancillary Services

In the ancillary services DR option, end-use customers are allowed to bid load curtailments in ISO/RTO markets as operating reserves. Accepted bids are paid the market price for committing to be on standby. In order to participate in ancillary-service markets, end-use customers must be able to adjust load quickly during a DR event. The response requirement depends on the nature of the event and the type of reserve being supplied. Loads typically have a very short response time, usually specified in minutes, rather than in hours. These short timeframes and program requirements limit the type of resources that can participate. End-use loads that qualify for participation as an ancillary services option could include large industrial processes that can be curtailed safely and quickly without harm to equipment. Examples of loads are air products or electric arc steel furnaces, large water pumping load, or remote automatic control of appliances such as air conditioners.

End-use customers participating in this option receive a capacity payment for committing loads to be on standby. The capacity payment is based on the market clearing price for capacity (MCPC). If load curtailments are needed, and they are called by the ISO/RTO, participants are paid the spot-market energy price. There is typically a higher minimum size for reductions and customers are required to install advanced real-time telemetry because of the stringent program requirements.

3.2 Profiles of Price-based Options

Table 3.2 below resents a summary of the profiles of relevant price-based options, followed by a brief description of each of the options.

Table 3.2 Profiles of relevant price-based DR options

Items	Critical Peak Pricing (CPP)	Peak Time Rebate (PTR)
Targeted customer segment	Medium and large C&I (>200 kW of load)	Residential & Small Commercial (<200 kW of load)
Min. load for participation	Not specified	Not specified
Notification time	Day-ahead or day-of (hour-ahead)	Day-ahead or day-of (hour-ahead)
Technology requirements	Advanced Metering Infrastructure (AMI); Enabling technology: Auto-DR	Advanced Metering Infrastructure (AMI); Enabling technology: Auto-DR

Note: Enabling technologies are not a requirement for offering CPP and PTR rates, but greatly enhance the end-use customer's ability to respond to the rates, particularly on a day-of basis.

Critical Peak Pricing (CPP)

A critical peak pricing option is an overlay on either time-of-use or flat pricing that uses a predefined critical-peak price that approaches real-time prices at times of extreme system peak. During these times, the rate is much higher than a normal peak price (e.g., 3x and 5x times the partial peak and on-peak rates). CPP days are dispatched on relatively short notice as needed, for a limited number of days during the year. Usually their timing is unknown ahead of being called. Figure 3.1 is an illustration of a CPP rate.

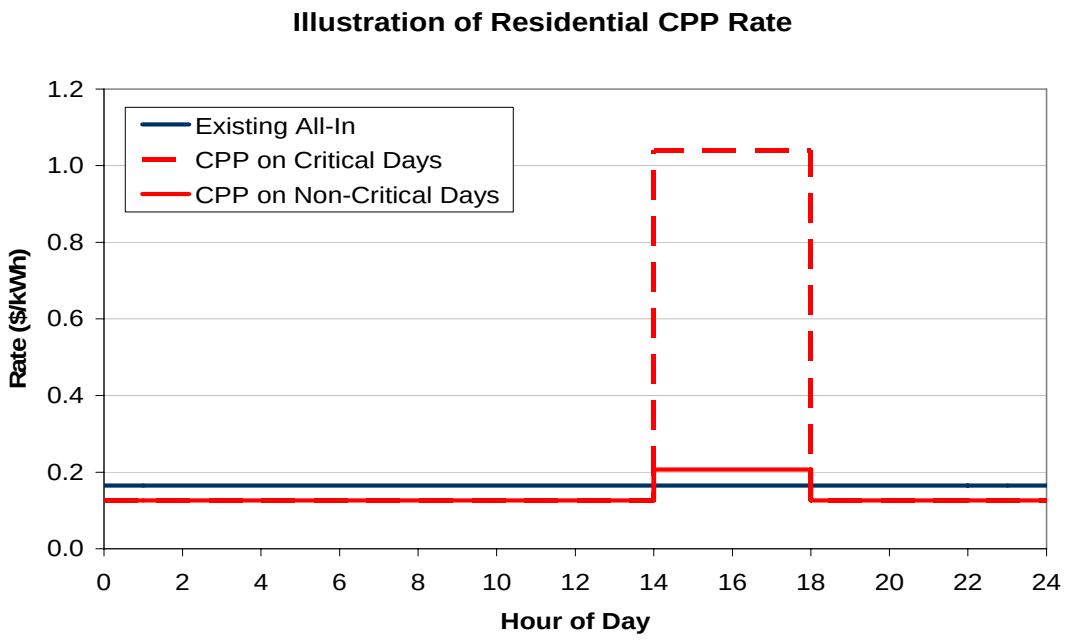

Figure 3.1 Illustration of a CPP rate

CPP events can be called during times of system contingencies or when faced with high prices in procuring wholesale power. Typically, this rate is offered to C&I end-use customers by an electric utility or Load Entity (LSE). However, residential customers too can be offered this rate. CPP rate participants pay a lower off-peak price on all days than they would pay otherwise on their applicable tariff.

Participants can be notified of CPP events either a day in advance or on the day of the event. For participation in this option, end-users need to have Advanced Metering Infrastructure (AMI) installed. A web-based notification system informs participants about an impending event. Enabling technologies such as automated demand response (Auto-DR), with customer-programmed automated response options, allow automatic responses to critical peak prices.

Peak Time Rebate (PTR)

Peak time rebate (PTR) is sometimes described as an inverted CPP rate. This option provides rebates to participants to reduce electricity use during days when electricity demand is the highest (critical peak days). PTR could also be considered a mass-market equivalent of the emergency DR option. Figure 3.2 illustrates PTR.

The dispatch for PTR is the same as that for CPP. Participants are paid a rebate for reducing electricity usage during critical peak days, usually called in response to system contingencies or high electricity market prices. The PTR is an overlay on end-use customers existing rates. If customers fail to curtail during the event, there is no penalty; the customer simply does not receive the rebate.

This option is offered at the retail level by electric utility or Load Serving Entity (LSE) to end-use customers. Usually, the targeted sectors include residential and small commercial end-users. Like CPP, participants can be notified of critical peak days either a day in advance or on the day of the event.

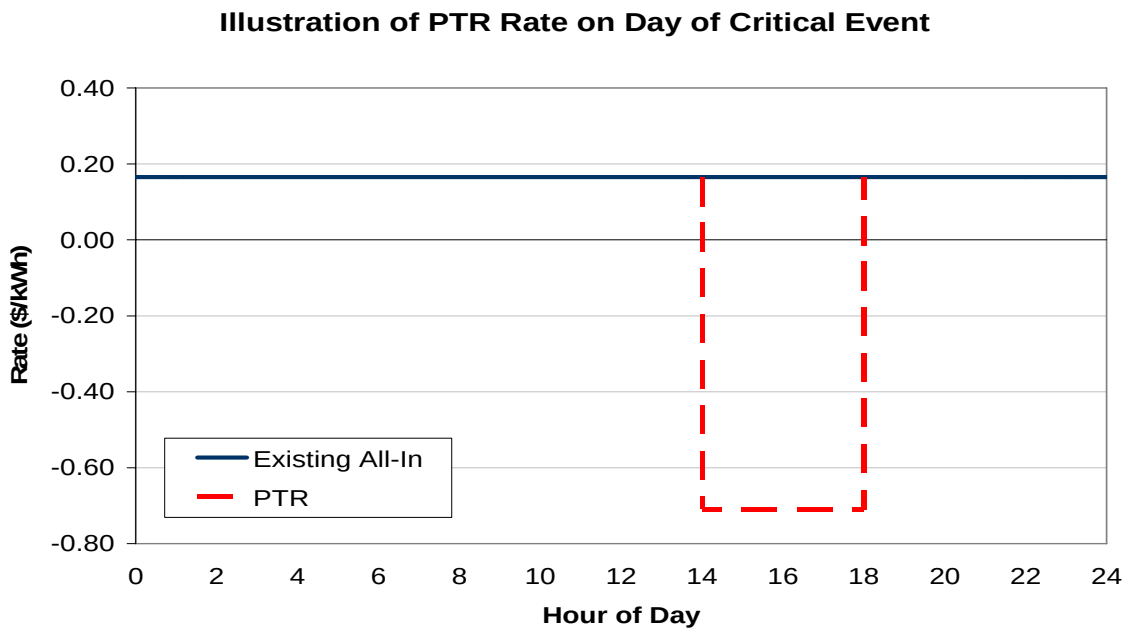

Figure 3.2 Illustration of Peak Time Rebate (PTR)

4 MAPPING DR OPTIONS TO BPA'S CAPACITY-CONSTRAINED SCENARIOS

BPA has developed five capacity-constrained scenarios based on conditions faced by BPA's system over the past few years. These scenarios represent conditions under which DR options are likely to be called to address capacity constraints being faced. The five scenarios are:

1. Summer heat wave
2. Winter cold spell
3. Increased reliance on wind generation
4. Unexpected large unit outage
5. Difficulty managing the system

Table 4.1 defines and summarizes the scenarios along a few key characteristics. An understanding of the capacity constrained scenarios is necessary for a critical assessment of the DR options and for mapping the DR options into the five scenarios.

Table 4.1 BPA's five capacity-constrained scenarios

	Scenario 1: Summer Heat Wave	Scenario 2: Winter Cold Spell	Scenario 3: Increased Reliance on Wind Generation	Scenario 4: Large Unit Outage	Scenario 5: Difficulty Managing System
Season	Summer	Winter	Any	Any	Shoulder
Continuous event days	Three days	Three days	Year-round	Two days	One day
Timing	Afternoon (2 pm - 9 pm)	Morning (6 am - 9 am), Evening (5 pm - 9 pm)	Intermittent	All day	All day
Frequency	Once per day, 3 events per summer	Twice per day, 0 or 1 events per winter	Many deviations from expected output per day	Constant throughout day	Constant throughout day
Foresight	2 to 5 days	1 to 2 days	Less than 1 hour	Less than 1 hour	1 day
Trigger	Reliability/Price	Reliability/Price	Reliability	Reliability/Price	Reliability/Price
Relevant region	Pacific Northwest	Pacific Northwest	Pacific Northwest	BPA control area	BPA control area
Size of peak impact	1,000 to 2,000 MW	1,000 to 2,000 MW	1,000 to 4,000 MW	1,100 MW	1,000 MW

One of the key determinants for mapping DR options to these scenarios is the notification and response time associated with the different DR options. If the response time associated with a particular DR option is longer than the foresight for a particular scenario, that particular DR option cannot be called on to address that scenario. Say a DR option has a required response time of one hour or more. That option cannot be called on to address a situation which has a foresight of less than an hour (Scenarios 3 and 4 in Table 4.1).

Table 4.2 summarizes the response times associated with the relevant DR options being considered in this assessment. DR options are broadly categorized into three groups based on the response time:

- Day-ahead notification or response time
- Hour-ahead notification or response time
- 30 minutes or less response time

All reliability-based options, other than DLC and ancillary services, can respond to DR events with a day-ahead or an hour-ahead notification time. Load reduction associated with DLC takes place instantaneously and there is no notification time. End-use loads that qualify for participation in the ancillary service option require capability to respond to an event notification that is going to occur within 30 minutes of the notification. Pricing-based options - CPP and PTR - usually require notification a day in advance of the DR event occurrence. Enabling technology such as Auto-DR can facilitate end-use load response within a much shorter timeframe.

Therefore, pricing options coupled with enabling technology can respond to DR events with an hour notification.

Table 4.2 Range of response times for DR options

Long ← **Required response time of DR options** → Short

Day Ahead	Hour Ahead	30 Mins or Less
Direct Load Control	Direct Load Control	Direct Load Control
Ancillary Services	Ancillary Services	Ancillary Services
Emergency DR	Emergency DR	
Capacity Market	Capacity Market	
CPP	CPP (w/technology)	
PTR	PTR (w/technology)	
RTP	RTP (w/technology)	

Other criteria for mapping DR options to capacity-constrained scenarios are the season of occurrence and the frequency with which events are likely to occur. For example, summer DLC will be available for addressing any scenario, other than Scenario 2. Design of DR options needs to take into consideration the number of times an option can be called in a year and the average duration of such occurrence. This needs to be mapped to the 'frequency' and 'timing' of the capacity-constrained scenarios.

Based on these considerations, Table 4.3 shows the relevant DR options mapped to BPA's capacity-constrained scenarios.

Table 4.3 Mapping relevant options to BPA's capacity-constrained scenarios

Relevant DR Options	Scenario 1: Summer Heat Wave	Scenario 2: Winter Cold Spell	Scenario 3: Increased Reliance on Wind Generation	Scenario 4: Large Unit Outage	Scenario 5: Difficulty Managing System
DLC	√	√	√	√	√
Emergency DR	√	√			√
Capacity Market DR	√	√			√
Ancillary Services			√	√	
CPP	√	√			√
PTR	√	√			√

5 OVERVIEW OF BPA'S MARKET CHARACTERISTICS

This section describes the BPA market. It begins with segmentation by contract type and continues with a discussion of peak-demand characteristics.

5.1 Market Segmentation by Contract Type

BPA has contracts for the supply of power with approximately 150 utility customers. The customers include a mix of cooperatives, municipalities, utilities, federal agencies, and large industrial customers. The customers can be segmented by BPA contract type, which in turn, defines the target market for the DR option. "Slice" and "Block" contracts are the target markets for implementation of wholesale level DR options such as emergency DR, capacity market DR and ancillary services. The "load-following" (non-Slice and Block) contracts, which include public utilities and small municipals that offer retail services to other customers, are the target markets for retail-level DR options which include direct load control (DLC), critical peak pricing (CPP), and peak time rebate (PTR). The Slice and Block contracts are also a potential target market for these retail level options.

BPA's utility customers provide service to approximately 2.5 million end users. Table 5.1 provides a summary of the 2.5 million end users that make-up the customer base of BPA's contracts. The table was compiled using 2006 sales data reported in EIA Form 861. (This table does not include government agencies or the large industrial customers.) The residential sector accounts for 87% of the end-use customers across all utilities. The commercial sector accounts for 12% of the total end-use customers, while the remaining 1% is comprised of the industrial sector.

Table 5.1 Number of Customers by Contract Type

	Number of Customers			
Contract Type	**Res**	**Comm**	**Ind**	**Total**
Full	594,102	89,897	9,427	693,426
Partial	179,236	32,075	524	211,835
PF Block	355,385	36,056	8,298	399,739
Slice	1,010,374	125,053	8,651	1,144,078
Total	**2,139,097**	**283,081**	**26,900**	**2,449,078**
% of Total	**87%**	**12%**	**1%**	**100%**

"Slice" contracts represent the largest share of the contracts at 47%. "Full" contracts represent the next largest portion at 28%. The "PF Block" contracts are the next highest at 16% share. Together, Slice and Block (S&B) customers have a 63% share in the total market. The remaining 37% comes from load-following (LF) utilities.

Out of the total 87% of residential end-users in BPA's service territory, close to 30% of the end-users belong to the LF utilities while the remaining 57% come from S&B utilities. Similarly, for C&I end-users, S&B utilities have a higher share as compared to LF ones.

5.2 Overview of Summer-peak and Winter-peak Demand in BPA's service territory

Table 5.2 presents a summary of the 2006 peak demand by contract type as reported in EIA Form 861 and the estimated sectoral break-down of peak based on shares from LCAP data. Based on LCAP data, residential sector's share of peak demand is 35% in the summer and 51% in the winter. The commercial sector accounts for 39% of the summer peak and 34% of the winter peak. The industrial sector accounts for 26% of the summer peak and 16% of the winter peak.

Table 5.2 Peak Demand by Contract Type

	Summer Peak (MW)				Winter Peak (MW)			
Contract Type	**Res**	**Comm**	**Ind**	**Total**	**Res**	**Comm**	**Ind**	**Total**
Full	937	1,049	687	2,673	1,573	1,038	488	3,098
Partial	455	509	333	1,297	844	557	262	1,662
PF Block	703	788	516	2,007	1,239	817	384	2,440
Slice	1,574	1,763	1,154	4,491	2,814	1,857	872	5,544
Total	**3,669**	**4,109**	**2,689**	**10,467**	**6,469**	**4,270**	**2,005**	**12,744**
% of Total	**35%**	**39%**	**26%**	**100%**	**51%**	**34%**	**16%**	**100%**

Figure 5.1 displays the share of the summer and winter peak demand for the residential, commercial, and industrial sectors by the contract groupings for the target markets.

- Residential customers for load-following contracts account for 13% of the summer peak and 19% of the winter peak. Commercial customers account for 15% of the summer peak and 13% of the winter peak.
- Commercial and industrial customers for Slice and Block contracts account for approximately 40% of the summer peak and 30% of the winter peak.

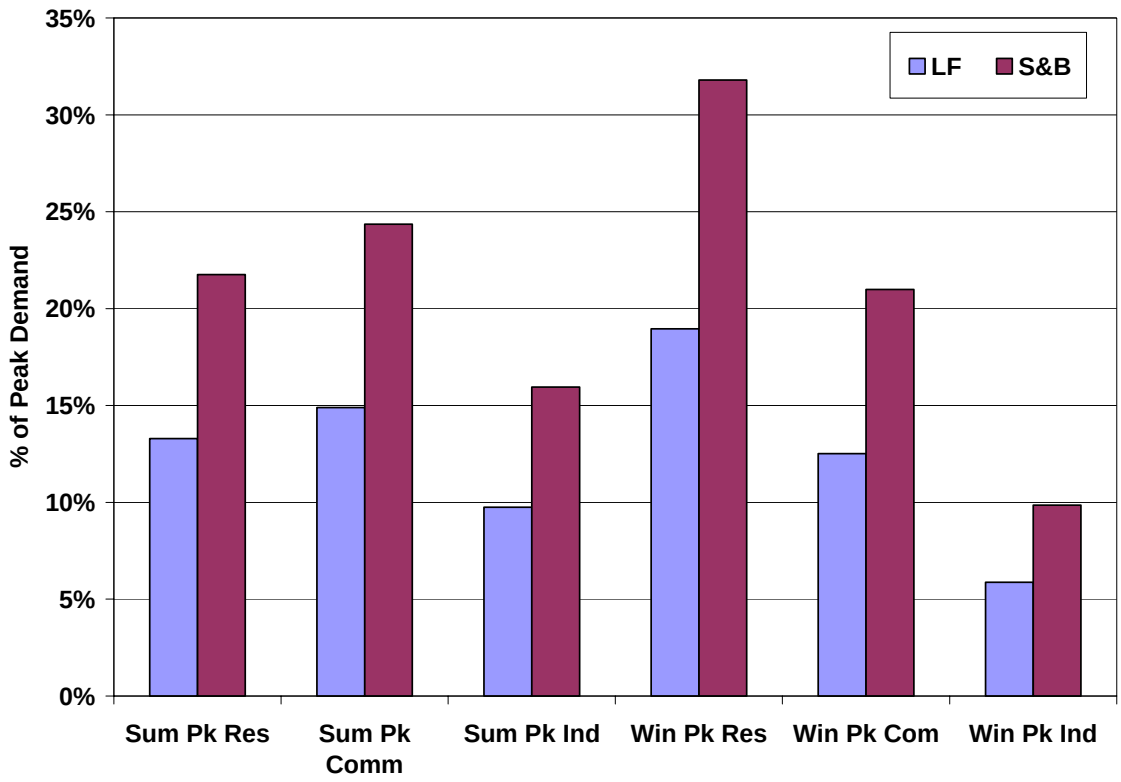

Figure 5.1 Peak Demand Share by Sector by Target Market Contract Group

5.3 Sectoral and End-use Shares of Peak Demand

Table 5.3 presents the contribution of the end uses to the summer and winter peak demand by sector. Figure 5.2 displays the share of the end uses to the peak in the residential sector. Figure 5.3 presents the share by end uses in the commercial and industrial sectors.

Table 5.3 End-Use Share of Peak Load

Sector	% Share of Peak	
	Summer Peak	Winter Peak
Residential		
Central AC	8%	0%
Space Heat	0%	29%
Water Heating	7%	7%
Lighting	2%	2%
Other	18%	13%
Total	**35%**	**51%**
Commercial		
Cooling	10%	0%
Lighting	13%	8%
Heating	0%	14%
Ventilation	5%	3%
Other	11%	8%
Total	**39%**	**34%**
Industrial		
Cooling	7%	4%
Lighting	4%	2%
Motors	6%	4%
Process Cooling	2%	1%
Process Heating	5%	3%
Other	3%	2%
Total	**26%**	**16%**

- In the residential sector, central air conditioning and water heating contribute 15% to the total summer peak demand. Space heating and water heating contribute 36% to the total winter peak demand.
- In the commercial sector, cooling and lighting account for 23% of the total summer peak demand. Lighting and heating account for 22% of the total winter peak demand.
- In the industrial sector, cooling, motors, and process heating contribute 18% to the total summer peak demand and 11% to the total winter peak demand.

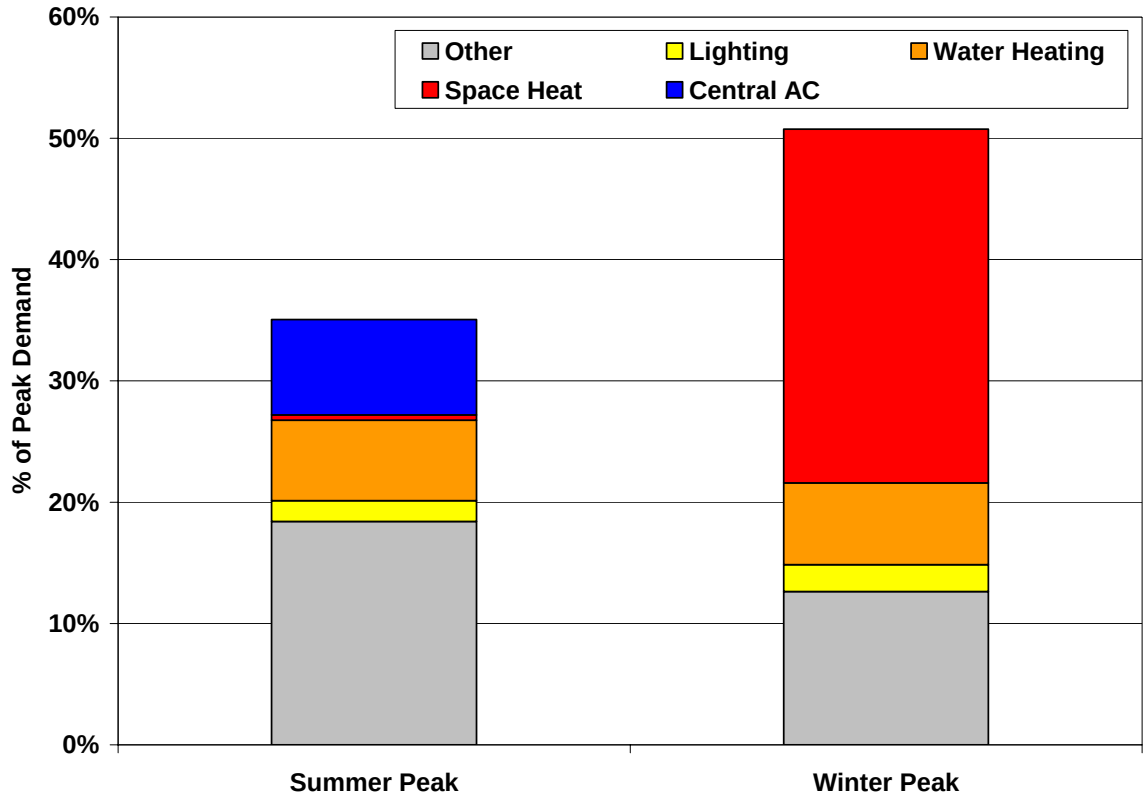

Figure 5.2 Residential End-Use Shares of Peak Demand

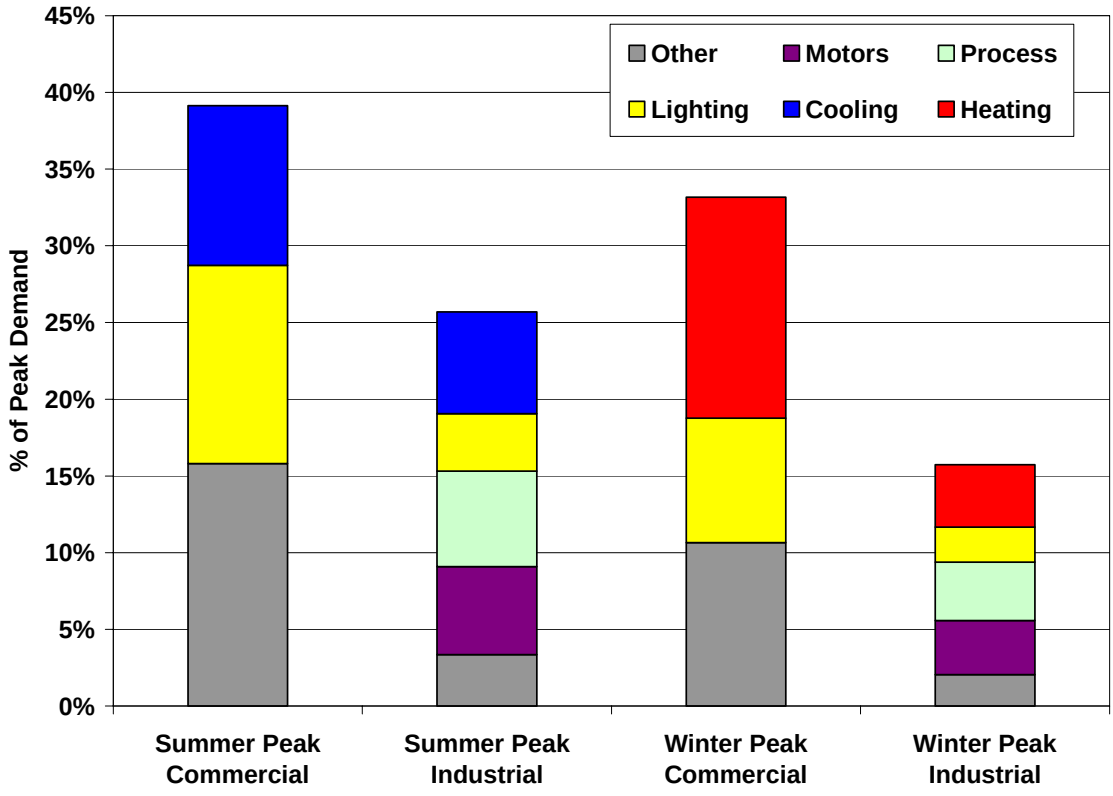

Figure 5.3 Commercial and Industrial End-Use Shares of Peak Demand

6 METHODOLOGY FOR ESTIMATION OF IMPACTS AND COSTS

This section discusses the methodology for estimation of load reduction impacts and costs associated with achieving these impacts for each of the DR options being considered in our analysis as relevant for BPA. A detailed summary of all input assumptions are presented in Appendix A to the report.

6.1 Methodology for Estimating Load-reduction Impacts

This section describes the methodology for estimating load-reduction impacts for the different DR options (discussed in earlier sections). Table 6.1 shows the eligible end-use sectors for each of the DR options considered in this analysis.

Among the reliability-based options, the direct load control (DLC) option is administered at the retail level and targeted towards residential and small commercial (<200 kW) end-users. DLC is not applicable to medium and large C&I end-users to control individual loads using a traditional switch or a PCT. Among the other reliability-based options, emergency DR and capacity market DR are targeted towards medium and large commercial and industrial (C&I) end-users (>200 kW of load). These options do not apply to residential and small commercial end-use customers, as they usually have a minimum load threshold level for participation (say, 100 kW) and require interval meter installation at end-user site. Only the large C&I customers (>1,000 kW of load) are considered eligible for the ancillary services option. This is based on existing experience on load participation in Ancillary Services option being currently implemented, in which large industrials primarily participate. Except for DLC, all other reliability-based options are administered at the wholesale level.

The pricing options are all administered at the retail level by BPA's utility customers. Among the three pricing options discussed in the earlier section, critical peak pricing (CPP) and peak time rebate (PTR) are the only ones being considered in this analysis. We have chosen CPP as a representative dynamic rate for the medium and large C&I sector for the purposes of this projection. But CPP could also be offered to residential and small C&I end-users. Similarly, we have chosen PTR as a representative dynamic rate for the residential and small commercial sectors for the purposes of this projection. But in reality the end-use customers in residential and small commercial sectors could be offered CPP as well.

As discussed earlier in Section 2, real-time pricing (RTP) is not considered relevant for BPA as administration of RTP requires hourly market price signals to be sent to the end-use customer. The absence of a wholesale hourly electricity market in the Pacific Northwest poses difficulties for implementing RTP. Also, based on discussions with BPA staff, utilities under BPA's jurisdiction are unlikely to offer RTP as a retail rate to their end-use customers in the near future. Therefore, we do not consider RTP as a relevant DR option in our analysis. BPA may wish to revisit this decision in the future.

Table 6.1 End-user Segmentation for DR Options

End-Use Sectors	DLC	Emergency DR	Capacity Market DR	Ancillary Services	Critical Peak Pricing (CPP)	Peak Time Rebate (PTR)
Residential	√					√
Small C&I (<200 kW)	√					√
Medium C&I (200-1000 kW)		√	√		√	
Large C&I (>1000 kW)		√	√	√	√	

Table 6.2 shows segmentation of DR options by utility contract type. We consider that the retail level options- which include DLC, CPP, and PTR, can be individually administered by both 'Load Following' and 'Slice and Block' utilities to their end-use customers. On the other hand, the wholesale level DR options- which include

emergency DR, capacity market DR, and ancillary services are administered by BPA. Slice and Block utilities may participate in these options through aggregation of their individual end-user loads. Also, large Commercial and Industrial (C&I) end-users of Load following utilities can participate in wholesale level DR options administered by BPA through direct contracts.

Table 6.2 Utility Segmentation for DR Options

	DLC	Emergency DR	Capacity Market DR	Ancillary Services	Critical Peak Pricing (CPP)	Peak Time Rebate (PTR)
Program Administration Level	**Retail**	**Wholesale**	**Wholesale**	**Wholesale**	**Retail**	**Retail**
Load following utilities (Full & Partial Contract types)	√	√	√	√	√	√
Slice & Block Utilities	√	√	√	√	√	√

Utility participation assumptions

Before estimating impacts and costs associated with individual DR options, we assume two levels of utility participation rates for both 'Slice & Block' and 'Load Following' utilities- a 'High Participation Rate' scenario and a 'Low Participation Rate' scenario. The 'High Participation Rate' scenario assumes that the aggregate peak contribution from participating utilities is 90% of the total winter peak contribution from that particular category. On the other hand, the 'Low Participation Rate' scenario assumes that the aggregate peak contribution from participating utilities is 60% of the total winter peak contribution from that particular category. Overall impacts are estimated for each of the two utility participation scenarios for individual DR options.

Approach for Estimating DLC Impacts

The following steps outline the approach used for estimating impacts associated with DLC for residential and small commercial end-use customers. For DLC, we estimate impacts for both load-following utilities as well as Slice and Block utilities, since both these groups are likely to offer DLC at the retail level to their end-use customers. The time period considered in our analysis is from 2012 to 2020[2]. Table A in the Appendix shows the detailed input assumption values used for estimation of impacts.

1. **Selection of eligible market segment.** The first step is to estimate the total number of residential and small commercial end-users eligible for participation in DLC based on market data from BPA's service territory. For DLC, the total number of eligible customers is further segmented by utility contract type into load-following and Slice and Block utilities. We assume an average annual growth rate of 1.3% for the eligible population. For residential customers, only single-family homes are considered eligible for participation in DLC.
2. **Estimation of end-use equipment saturation**. Based on available data for BPA's service territory, we estimate the saturations for end-use equipment targeted for control under DLC. In our current analysis, the targeted end-uses are :
    a. Central space cooling
    b. Central electric space heating
    c. Electric water heating

    The end-use saturations for each of these end uses are then applied to the eligible population to arrive at the total number of end-use customers with central space cooling, central electric space heating, and

[2] Most of the utilities in BPA's service territory are likely to revise retail rates in 2012, and are likely to place a higher priority on load management options. BPA indicated that they are likely to have full-scale DR programs in 2012 and that they will run pilots between 2012 and 2011

electric water heating. Based on market data, we assume different levels of saturation for existing and new construction for the residential sector.

3. **Participation rate estimation**. The time period for estimating impacts is from 2012 to 2020. Participation rate is assumed to be 0.5% in 2012 and progressively increases to 20% in 2020.
4. **Control technology assumptions**. We assume that half of the total participants are controlled using a traditional load control switch, while the other half are controlled using a programmable communicating thermostat (PCT).
5. **Estimation of overall impacts**. For estimation of the load reduction impacts associated with the different end-uses, we use standard industry approximations for load reduction. For example, the industry standard for load reduction from central space cooling is 1 kW per unit. The load reduction per unit is multiplied by the number of units to derive the overall impacts for DLC.
6. **De-rating of estimated impacts**. Experience from utility DLC programs show that a certain percentage of participants being controlled manually override or drop-out of participation during an event. There are cases where the control equipment malfunctions. Also, if DR events are called on consecutive days, the response rate becomes progressively lower. Taking all of these factors into account, the estimated impacts are scaled down by a factor, based on industry experience.

Approach for Estimating Impacts for Emergency DR, Capacity Market DR, and Ancillary Services

The following steps outline the approach we used for estimating impacts associated with the remaining reliability-based options, other than DLC. As illustrated in Table 6.1, the targeted end-use segments for these options are the commercial and industrial end-use customers. Also, the impact estimation is relevant only for BPA's Slice and Block utility customers, since these options are likely to be administered at the wholesale level by BPA (see Table 6.2). The time period considered in our analysis is from 2012 to 2020. Table A in the Appendix shows the detailed input assumption values used for estimation of impacts.

1. **Selection of eligible market segment.** Based on market data from BPA's service territory for each of the reliability-based options, we estimate the number of eligible commercial and industrial end users in the specific C&I sub-segment (see Table 6.1). We assume an average annual growth rate of 1.3% for the eligible population.
2. **Estimation of achievable participation rate**. The next step is to arrive at the total number of participants by applying an appropriate participation rate. The participation rate varies across the options. Based on industry experience, the capacity market option is assumed to have a higher participation rate than the emergency DR option. Since the former option offers a fixed monthly capacity payment for load reduction commitment in addition to payments for energy reduction during events, participation levels are likely to be higher. Implementation of DR in the ancillary services market requires a high degree of technological sophistication and very high reliability levels for load curtailment. Therefore only certain types of loads are able to fulfill the stringent eligibility requirements under this option. Consequently, participation rates are assumed to be much lower than either capacity market or emergency DR options.
3. **Peak demand projection for targeted end-use customer segment**. We start with projections of BPA summer and winter peak demand for 2012 to 2020. The peak load projections are gathered from BPA's official filings with FERC. Then, we break-up the overall system peak projection into sectoral peaks based on sectoral share in peak demand. The sectoral share in BPA's system peak demand (by residential, commercial and industrial end-users), is calculated based on LCAP data. This share is then used to estimate residential, commercial, and industrial peak demands over 2012 to 2020. In order to arrive at the peak load estimate from a specific sub-sector that is being targeted with a DR option (say, large commercial), we use the sub-sectoral share in the total sectoral load, based on load distribution data.
4. **Demand savings reduction estimate.** The demand reduction estimate for each of the options is estimated based on a top-down approach. The LCAP data provides an estimate of the end-use shares in peak for a specific sector, say commercial. For each of these end-uses (say cooling), we estimate a certain percentage of load reduction based on industry estimates. For these reliability-based options, we assume a separate set of demand reduction estimates with and without enabling technology. Enabling technology implies incorporation of advanced control and communications technologies that enable automatic response to DR signals without any kind of human intervention. The estimated load reductions from these Auto-DR customers are likely to be significantly higher than reductions from customers whose loads are not programmed to respond automatically to DR event signals.

5. **Estimation of overall impacts**. The demand reduction estimates for the targeted end-use customer segments are then applied to the peak demand projections to arrive at the overall impact associated with a specific DR option, with and without enabling technology.

Approach for Estimating Impacts for Pricing-based Options: CPP and PTR

As Table 6.2 illustrates, the pricing-based DR options are offered by both load-following and Slice and Block utilities to their end-use customers at the retail level. While CPP is offered to medium and large C&I end-use customers, PTR is offered to residential and small commercial end-use customers. The methodology for estimating impacts for these two pricing-based options is very similar to that used for the reliability-based options outlined in the previous section (similar to Steps 1-5 for for emergency DR, capacity market DR, and ancillary services). The only difference is the assumption related to the target market segments for these pricing-based options, which is described below. Table A in the Appendix shows the detailed input assumption values used for estimation of impacts.

Selection of targeted end-use customer segment. We assume that only end-use customers with Advanced Metering Infrastructure (AMI) are eligible to participate in pricing-based options. The AMI penetration among all customer classes is estimated to grow from 10% in 2012 to 100% in 2020, by which time a full deployment of AMI seems likely. We assume that the 'load-following' utilities offer the pricing-based options as an opt-in rate. The achievable participation rate for these two options is assumed to be 20% of customers with AMI, which is supported by research conducted by Momentum Market Intelligence during the time of the California Statewide Pricing Pilot.

6.2 Estimation of Levelized Costs

For estimating the levelized costs associated with achieving the load reduction impacts for each of the DR options, we consider various categories of costs associated with offering of the various DR options to utility end-use customers. The following cost items are considered in our analysis:

- Development of a DR option- This is a one-time initial cost associated with developing a DR option.
- Customer recruitment costs
- Equipment capital and installation costs
- Annual program administration costs
- Annual operation and maintenance (O&M) costs
- Additional costs associated with Auto-DR enablement, where applicable.
- Incentives offered to participants

A caveat here is that the cost assumptions presented in this report are preliminary and do not consider bundling or packaging of different combinations of options into programs and strategies. Therefore, a more realistic estimation of costs is possible only after program strategies have been designed. However, the current cost estimates provide a base for further modifications in later stages under program strategy development. These estimates also provide some ideas on relative ranking of options, based on costs.

Table A in the Appendix shows the detailed input assumption values used for estimation of costs for the different DR options considered in our analysis. These values are based on a review of DR program experiences. All costs are assumed to escalate annually at a rate of 3%. The discount rate for calculating the levelized costs is assumed to be 4%.

The cost estimates presented in this report are used to construct a preliminary supply curve that shows the hierarchy of DR options based on costs against their impacts, which is subject to modifications during development of DR program strategies. In an earlier section of the report we discuss how the relevant DR options can be mapped to the capacity constrained scenarios developed for BPA (see Table 4-3). Consequently, it is possible to construct a supply curve for each of the capacity-constrained scenarios that depicts the cost-based ranking of options against their load impacts. Since the cost estimates are subject to revision at the time program strategies are being considered, we do not present scenario-specific supply curves in this report.

7 RESULTS: IMPACTS AND COSTS FOR DR OPTIONS

Based on the methodology discussed above, we estimate load reduction impacts associated with the different DR options over the selected timeframe for the analysis (2012-2020). Also, the levelized costs associated with achieving the load reduction impacts are presented. We present rank-ordered levelized costs for the options along with associated impacts. As discussed earlier, supply curves are not presented in this report as consideration of supply curves is relevant only at the time DR program strategies are being formulated. Detailed results related to each DR option are presented in Appendix B.

7.1 Load Reduction Impacts from DR Options

This section presents detailed load reduction impacts associated with individual DR options. It shows aggregate load impacts from 'Load Following' and 'Slice and Block' utilities. Load impacts according to the utility customer type are presented in the Appendix. This section presents summer and winter peak reduction results for the two utility participation scenarios, discussed earlier in Section 6. It also shows variations in impacts associated with enabling technology assumptions, as to what load reductions are being achieved 'with' and 'without' enabling technology. The impacts calculations assume the 'most likely' estimate of end-use customer participation rate.

7.1.1 Residential Direct Load Control Impacts

Load reduction impacts associated with Residential Direct Load Control (DLC) progressively increases over time (see Table 7.1). Overall, summer load reductions are higher as compared to winter load reductions as 'Central Air Cooling' saturation rate is higher among eligible population as compared to 'Central Space Heating' saturation.

In 2012, impacts without enabling technology (using a traditional switch) range from a low of 1.1 MW peak reduction in winter, assuming low utility participation rate, to 1.8 MW peak reduction in summer, assuming a high utility participation rate scenario and with enabling technology (using a 'Smart Thermostat'). With progressive increase in end-use participation, impacts in 2016 and 2020 are substantially higher. In 2020, residential DLC impacts range from 44 MW (winter peak reduction without enabling technology, under a low utility participation scenario) to almost 80 MW of summer peak reduction (with enabling technology, under a high utility participation rate scenario). 80 MW of summer peak reduction from residential DLC in 2020 translates to a 0.7% reduction in BPA system summer peak. Load reductions using a 'Smart Thermostat' are estimated to be 11% higher as compared to impact projections using a traditional switch. Projected load reductions under a 'high utility participation rate' scenario are almost 35% higher as compared to those projected under a 'low utility participation rate' scenario.

Table 7.1 Residential Direct Load Control Impacts Summary

Season	Enabling Technology	Utility Participation Rate	Peak Reduction in 2012 (MW)	Peak Reduction in 2016 (MW)	Peak Reduction in 2020 (MW)
Winter	With	High (90%)	1.6	33.4	66.3
		Low (60%)	1.2	24.9	49.3
	Without	High (90%)	1.4	30.0	59.5
		Low (60%)	1.1	22.3	44.3
Summer	With	High (90%)	1.8	39.4	80.6
		Low (60%)	1.4	29.3	60.0
	Without	High (90%)	1.6	35.3	72.4
		Low (60%)	1.2	26.3	53.8

Our analysis shows that almost 70-75% of the reduction is derived from 'Slice' and 'Block' utility customers, while the remaining 25-30% comes from 'Load Following' utilities. Detailed utility customer wise load reduction impact results are presented in the Appendix.

Figure 7.1 shows the end-use shares in estimated load reductions from DLC. Cooling accounts for 77% of total DLC load reduction, while the remaining 23% comes from water heating.

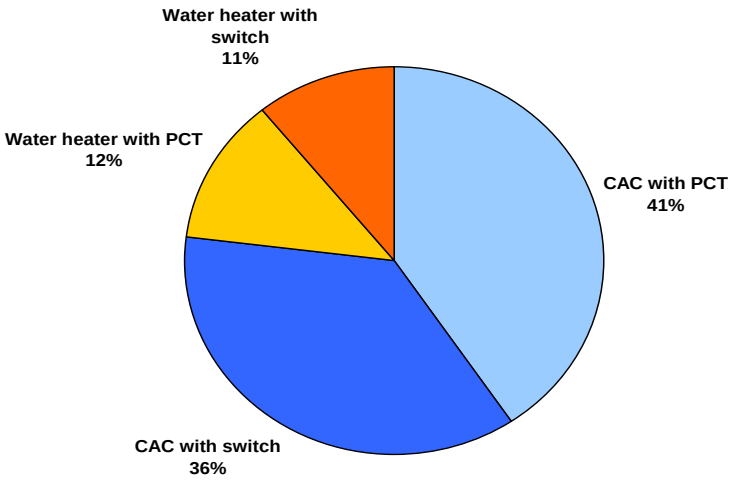

Figure 7.1 End-use shares in residential DLC summer peak reduction

In our analysis we assumed that 50% of the targeted eligible residential population is controlled using a traditional switch, while the remaining 50% of the population is controlled using a programmable communicating thermostat (PCT). However, the effective participation rate (taking into consideration the override rate and other factors affecting participation) for PCT is higher than that for a switch. Consequently, load reductions from end-use customers with a PCT control are higher than those with a traditional switch.

Figure 7.2 shows the end-use shares in estimated load reductions from DLC. More than half of the reductions in winter are estimated to come from water heating, with the remaining from central space heating. Central electric space heating saturation is lower than that for central space cooling, hence winter peak load reduction impacts from DLC are lower as compared to summer peak load reduction impacts.

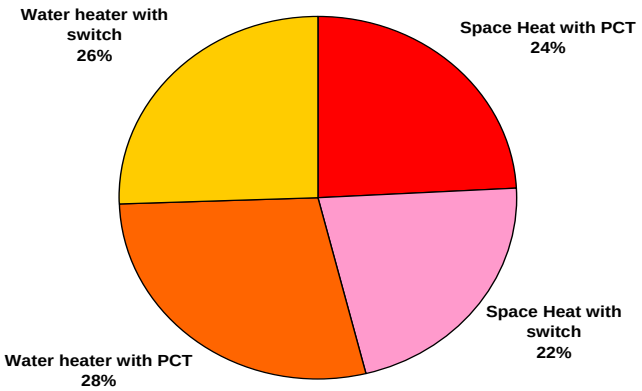

Figure 7.5 End-use Shares of Residential DLC Winter Peak Reduction in 2015

7.1.2 Small Commercial Direct Load Control Impacts

Compared to residential DLC impacts, small commercial DLC impacts are lower due to smaller size of the eligible market segment (see Table 7.2). Here too, summer load reductions are higher as compared to winter load reductions as 'Central Air Cooling' saturation rate is higher among eligible population as compared to 'Central Space Heating' saturation.

In 2012, impacts without enabling technology (using a traditional switch) range from a low of 0.1 MW peak reduction in winter, assuming low utility participation rate, to 0.3 MW peak reduction in summer, assuming a high utility participation rate scenario and with enabling technology (using a 'Smart Thermostat'). In 2020, small commercial DLC impacts range from a low of 6 MW (winter peak reduction without enabling technology, under a low utility participation scenario) to almost 13 MW of summer peak reduction (with enabling technology, under a high utility participation rate scenario). The highest level of load reduction achieved with this option in 2020 is projected to be only 0.1% of BPA summer peak. As with residential DLC, load reductions using a 'Smart Thermostat' are estimated to be 11% higher as compared to impact projections using a traditional switch. Projected load reductions under a 'high utility participation rate' scenario are almost 50% higher as compared to those projected under a 'low utility participation rate' scenario.

Our analysis shows that almost 65-70% of the reduction is derived from 'Slice' and 'Block' utility customers, while the remaining 30-35% comes from 'Load Following' utilities. Detailed utility customer wise load reduction impact results are presented in the Appendix.

Table 7.2 Small Commercial Direct Load Control Impacts Summary

Season	Enabling Technology	Utility Participation Rate	Peak Reduction in 2012 (MW)	Peak Reduction in 2016 (MW)	Peak Reduction in 2020 (MW)
Winter	With	High (90%)	0.2	4.9	10.1
		Low (60%)	0.2	3.3	6.7
	Without	High (90%)	0.2	4.4	9.1
		Low (60%)	0.1	2.9	6.0
Summer	With	High (90%)	0.3	6.3	13.0
		Low (60%)	0.2	4.2	8.6
	Without	High (90%)	0.3	5.7	11.7
		Low (60%)	0.2	3.8	7.7

7.1.3 Emergency DR Option Impacts

Load reduction impacts from Emergency DR are initially higher as compared to those from Residential DLC (see Table 7.3). But with time, these impacts are lower as compared to those from Residential DLC, but higher as compared to impacts from Small Commercial DLC.

At the start year (2012), impacts without enabling technology range from a low of 1.5 MW peak reduction in winter, assuming low utility participation rate, to 3.6 MW peak reduction in summer, assuming a high utility participation rate scenario and with enabling technology, using Auto-DR. Impacts from Emergency DR are projected to increase by more than tenfold in 2020. In 2020, impact levels range from 16 MW (winter peak reduction under a low utility participation rate scenario, and without enabling technology) to 36 MW (summer peak reduction under a high utility participation rate scenario, and with enabling technology). Summer peak reduction from Emergency DR in 2020 is estimated to be a maximum of 0.3% of BPA summer peak projection for that year.

Enabling technology, such as Auto-DR, results in substantial increase in the impact level. Impact levels are almost 37% higher with enabling technology as compared to corresponding impact levels without enabling technology. Under a 'high utility participation rate' scenario, summer peak load reductions are estimated to be almost 50% higher as compared to load reductions under a 'low utility participation rate' scenario, while corresponding increase in winter peak load reductions is by 45%.

Our analysis also shows that 67% of the total load reduction from Emergency DR is derived from 'Slice' and 'Block' utility customers, while the 33% comes from 'Load Following' utilities. Detailed utility customer wise load reduction impact results are presented in the Appendix.

Table 7.3 Emergency DR Option Impacts Summary

Season	Enabling Technology	Utility Participation Rate	Peak Reduction in 2012 (MW)	Peak Reduction in 2016 (MW)	Peak Reduction in 2020 (MW)
Winter	With	High (90%)	3.0	17.0	32.1
		Low (60%)	2.1	11.8	22.2
	Without	High (90%)	2.2	12.4	23.4
		Low (60%)	1.5	8.6	16.2
Summer	With	High (90%)	3.6	19.8	36.4
		Low (60%)	2.4	13.2	24.3
	Without	High (90%)	2.7	14.6	26.8
		Low (60%)	1.8	9.7	17.8

7.1.4 Capacity Market DR Option Impacts

Load reduction levels associated with Capacity Market DR option are higher as compared to that from Emergency DR (see Table 7.4). In 2012, impact levels range from a low of 2.7 MW (winter peak reduction under a low utility participation rate scenario, and without enabling technology) to 6.6 MW (summer peak reduction under a high utility participation rate scenario, and with enabling technology). Impact levels are substantially higher in later years with progressive rise in end-use customer participation. In 2020, impact levels range from 23 MW (winter peak reduction under a low utility participation rate scenario, and without enabling technology) to 53 MW (summer peak reduction under a high utility participation rate scenario, and with enabling technology). Summer peak reduction from Capacity Market DR in 2020 is estimated to be a maximum of 0.45% of BPA summer peak projection for that year.

Enabling technology, such as Auto-DR, results in substantial increase in the impact level. Impact levels are almost 40% higher with enabling technology as compared to corresponding impact levels without enabling technology. The variation in impact level with utility participation is the same as that obtained for Emergency DR option. Under a 'high utility participation rate' scenario, summer peak load reductions are estimated to be almost 50% higher as compared to load reductions under a 'low utility participation rate' scenario, while corresponding increase in winter peak load reductions is by 45% with increase in utility participation.

Table 7.4 Capacity Market DR Option Impacts Summary

Season	Enabling Technology	Utility Participation Rate	Peak Reduction in 2012 (MW)	Peak Reduction in 2016 (MW)	Peak Reduction in 2020 (MW)
Winter	With	High (90%)	5.4	25.3	46.7
		Low (60%)	3.7	17.5	32.3
	Without	High (90%)	3.9	18.2	33.5
		Low (60%)	2.7	12.6	23.2
Summer	With	High (90%)	6.6	29.5	53.1
		Low (60%)	4.4	19.7	35.4
	Without	High (90%)	4.8	21.4	38.4
		Low (60%)	3.2	14.2	25.6

Similar to the results for Emergency DR option, our analysis shows that a third of the total load reduction from Capacity Market DR is derived from 'Load Following' utility customers, while the remaining 67% comes from 'Slice and Block' utilities. Detailed utility customer wise load reduction impact results are presented in the Appendix.

7.1.5 Ancillary Services Option Impacts

Load reduction impact levels associated with the Ancillary Services Option are a lot lower as compared to that projected from other options (see Table 7.5). Also, enabling technology such as Auto-DR is an essential pre-

requisite for end-use load participation in the Ancillary Services Market. Therefore, we consider only one scenario with enabling technology as loads do not qualify for participation without enabling technology.

Table 7.5 Ancillary Services Option Impacts Summary

Season	Enabling Technology	Utility Participation Rate	Peak Reduction in 2012 (MW)	Peak Reduction in 2016 (MW)	Peak Reduction in 2020 (MW)
Winter	With	High (90%)	0.4	1.5	2.7
		Low (60%)	0.3	1.1	1.9
Summer	With	High (90%)	0.5	1.8	3.1
		Low (60%)	0.3	1.2	2.1

Peak reduction in 2012 ranges from 0.3 MW to 0.5 MW in 2012. In 2020, impact levels are higher, ranging between 2-3 MW. Almost 70% of the total load reduction from this option is derived from Slice and Block utilities, while the remaining 30% comes from Load Following utilities.

7.1.6 Critical Peak Pricing (CPP) Impacts

Table 7.6 shows load reduction levels associated with Critical Peak Pricing (CPP) option. Load reduction associated with CPP is close to that achieved from the Capacity Market DR option. This is understandably so, as both options target the same market segment (medium and large C&I end-users).

In 2012, impact levels range from a low of 2.6 MW (winter peak reduction under a low utility participation rate scenario, and without enabling technology) to 6.4 MW (summer peak reduction under a high utility participation rate scenario, and with enabling technology). CPP impact levels are higher as compared to impacts from Capacity Market option in later years. In 2020, impact levels range from 28 MW (winter peak reduction under a low utility participation rate scenario, and without enabling technology) to 65 MW (summer peak reduction under a high utility participation rate scenario, and with enabling technology). Summer peak reduction from CPP in 2020 is estimated to be a maximum of 0.55% of BPA summer peak projection for that year.

Table 7.6 Critical Peak Pricing (CPP) Impacts Summary

Season	Enabling Technology	Utility Participation Rate	Peak Reduction in 2012 (MW)	Peak Reduction in 2016 (MW)	Peak Reduction in 2020 (MW)
Winter	With	High (90%)	5.2	29.6	55.8
		Low (60%)	3.6	20.5	38.6
	Without	High (90%)	3.7	21.4	40.3
		Low (60%)	2.6	14.8	27.9
Summer	With	High (90%)	6.4	35.3	65.0
		Low (60%)	4.3	23.5	43.3
	Without	High (90%)	4.7	25.7	47.2
		Low (60%)	3.1	17.1	31.5

Enabling technology, such as Auto-DR, results in substantial increase in the impact level. Impact levels are almost 38% higher with enabling technology as compared to corresponding impact levels without enabling technology. Under a 'high utility participation rate' scenario, summer peak load reductions are estimated to be almost 50% higher as compared to load reductions under a 'low utility participation rate' scenario, while corresponding increase in winter peak load reductions is by 45% with increase in utility participation.

Our analysis shows that around 30-33% of the total load reduction from CPP is derived from 'Load Following' utility customers, while the remaining 67-70% comes from 'Slice and Block' utilities. Detailed utility customer wise load reduction impact results are presented in the Appendix.

7.1.7 Peak Time Rebate (PTR) Impacts

Among all DR options being considered, PTR achieves the highest level of load reduction impacts (see Table 7.7). Impact levels are substantially higher as compared to that from other DR options.

In 2012, impact levels range from a low of 7.6 MW (summer peak reduction under a low utility participation rate scenario, and without enabling technology) to 24 MW (winter peak reduction under a high utility participation rate scenario, and with enabling technology). Winter peak reduction impacts are higher as compared to summer peak reductions as the residential sector has a higher share in winter peak load as compared to it's share in the summer peak load. In 2020, impact levels range from 77 MW (summer peak reduction under a low utility participation rate scenario, and without enabling technology) to 260 MW (winter peak reduction under a high utility participation rate scenario, and with enabling technology). Winter peak reduction from PTR in 2020 is estimated to reach a high of 1.8% of BPA winter peak projection for that year. Load reduction from PTR only in 2020 is close to the aggregate load reduction impact from all other DR options combined in that particular year.

Table 7.7 Peak Time Rebate (PTR) Impacts Summary

Season	Enabling Technology	Utility Participation Rate	Peak Reduction in 2012 (MW)	Peak Reduction in 2016 (MW)	Peak Reduction in 2020 (MW)
Winter	With	High (90%)	24.2	138.5	261.1
		Low (60%)	16.7	95.7	180.4
	Without	High (90%)	16.7	95.6	180.1
		Low (60%)	11.5	66.0	124.5
Summer	With	High (90%)	16.6	91.4	168.1
		Low (60%)	11.1	60.9	112.0
	Without	High (90%)	11.5	63.0	115.9
		Low (60%)	7.6	42.0	77.2

As with other DR options, enabling technology increases impact levels by almost 45%. Two-thirds of the entire load reduction from PTR is estimated to come from 'Slice and Block' utility customers, while the remaining one-third is estimated to come from 'Load Following' utilities.

7.1.8 Comparison of Load Reduction Impacts Across DR Options

Table 7.8 shows the load reduction impacts from reliability-based DR options in 2016. Across the different options, the largest reduction impact is from Direct Load Control (DLC), followed by Capacity Market DR. Table 7.9 shows the impacts from the two price-based options in 2016. Peak Time Rebate (PTR) has the highest impact among all options in 2016. Impacts from Critical Peak Pricing (CPP) are slightly higher than those from the Capacity Market Option.

Table 7.8 Impacts for Reliability-based DR Options in 2016

Season	Enabling Technology	Utility Participation Rate	Res- DLC	Small Comm. DLC	Emergency DR	Capacity Market DR	Ancillary Services
Winter	With	High (90%)	33.4	4.9	17.0	25.3	1.54
		Low (60%)	24.9	3.3	11.8	17.5	1.07
	Without	High (90%)	30.0	4.4	12.4	18.2	NA
		Low (60%)	22.3	2.9	8.6	12.6	NA
Summer	With	High (90%)	39.4	6.3	19.8	29.5	1.8
		Low (60%)	29.3	4.2	13.2	19.7	1.2
	Without	High (90%)	35.3	5.7	14.6	21.4	NA
		Low (60%)	26.3	3.8	9.7	14.2	NA

Table 7.9 Impacts for Price-based DR Options in 2016

Season	Enabling Technology	Utility Participation Rate	Critical Peak Pricing (CPP)	Peak Time Rebate (PTR)
Winter	With	High (90%)	29.6	138.5
		Low (60%)	20.5	95.7
	Without	High (90%)	21.4	95.6
		Low (60%)	14.8	66.0
Summer	With	High (90%)	35.3	91.4
		Low (60%)	23.5	60.9
	Without	High (90%)	25.7	63.0
		Low (60%)	17.1	42.0

7.2 Estimation of Levelized Costs for DR Options

Table 7.10 shows the levelized costs for the different reliability-based DR options in 2016, while table 7.11 shows levelized costs for the two price-bsed options. Among reliability-based options, Ancillary Services has the highest cost followed by Capacity Market DR. Capacity Market Option with enabling technology has almost 30% higher costs as compared to the option without any enabling technology.

The ranking of Emergency DR and the DLC options varies according to the scenario being considered. Without enabling technology, 'Emergency DR' Option costs are lower as compared to that for DLC. With enabling technology, levelized costs are 50-60% higher for Emergency DR as compared to costs without enabling technology. These costs are higher as compared to DLC costs. DLC costs are lower with enabling technology as compared to costs without enabling technology. This is because increase in total impacts outweighs increase in total costs associated with enabling technology, such as 'Smart Thermostats' for DLC as compared to using a traditional switch. Therefore, effectively levelized costs are slightly lowered by using a Programmable Communicating Thermostat (PCT).

Table 7.10 Levelized Costs for Reliability-based DR Options in 2016

Season	Enabling Technology	Utility Participation Rate	Res- DLC	Small Comm. DLC	Emergency DR	Capacity Market DR	Ancillary Services
Winter	With	High (90%)	104.7	103.1	154.9	199.7	476.7
		Low (60%)	106.4	120.3	150.1	193.0	552.9
	Without	High (90%)	107.3	109.1	95.9	151.4	NA
		Low (60%)	109.1	128.2	100.6	152.2	NA
Summer	With	High (90%)	105.6	98.4	133.2	171.3	406.5
		Low (60%)	107.1	111.7	133.9	171.8	489.2
	Without	High (90%)	109.6	105.2	81.7	129.0	NA
		Low (60%)	111.2	120.0	88.9	134.5	NA

All reliability-based options, other than residential DLC, have lower costs for summer peak reduction as compared to winter peak reduction costs. This is because impacts are higher for summer peak reduction, and hence costs are lower.

Taking into consideration levelized costs associated with price-based options as well, PTR emerges as the least-cost, highest impact option for winter peak reduction. PTR costs are significantly lower for winter peak reduction as compared to that for other options. For CPP, costs with enabling technology are estimated to be more than 50-60% higher as compared to costs without enabling technology. In the case of PTR, costs with enabling technology are estimated to be higher by around 8-16% as compared to costs without enabling technology.

Table 7.11 Levelized Costs for Price-based DR Options in 2016

Season	Enabling Technology	Utility Participation Rate	Critical Peak Pricing (CPP)	Peak Time Rebate (PTR)
Winter	With	High (90%)	173.2	93.1
		Low (60%)	161.5	74.9
	Without	High (90%)	108.6	86.2
		Low (60%)	105.6	64.2
Summer	With	High (90%)	145.1	141.1
		Low (60%)	140.4	117.8
	Without	High (90%)	90.5	130.7
		Low (60%)	91.2	101.1

The three DR options targeted toward medium and large C&I end-use customers are Emergency DR, Capacity Market DR, and Critical Peak Pricing (CPP). Among these three options being offered to the same market segment, Emergency DR is the least cost option followed by CPP. Capacity Market option has the highest cost among these three. DLC and PTR are being considered for residential and small commercial end-use customers. Among these two options targeting the same market segment, PTR has lower costs associated with winter peak reduction. Summer peak reduction costs are lower for DLC as compared to those from PTR.