Benchmarking of Demand Response Potentials – Final Report:

Adaptation of *FERC's NADR Model to Xcel Energy's Public Service Company of Colorado Territory*

Prepared for Xcel Energy

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1. Executive Summary

KEMA developed estimates of demand response (DR) potential for the Xcel Energy Public Service Company of Colorado (PSCo) service territory through 2021 using the Federal Energy Regulatory Commission's (FERC) National Assessment of Demand Response[1] (NADR) model with specific inputs for PSCo's service territory. For the analysis, KEMA benchmarked three alternative DR program scenarios against DR savings as forecast by PSCo from its current program efforts. The alternative scenarios, consistent with the FERC analysis, were developed by using the NADR model with specific inputs for PSCo's service territory for customer characteristics and loads combined with NADR-model assumptions regarding customer response to the various DR initiatives. The values for the PSCo system peak without DR were derived by adding PSCo's known and projected DR savings to the appropriate system peak. Where possible, the inputs for the model were developed using information provided by Xcel Energy staff and from recent KEMA research for PSCo.

This report includes the following components:

1. An overview of the model and input definitions;
2. A listing of the inputs used to assess the potential in PSCo's territory; and
3. A summary of the results generated by the model under four different scenarios.

The model estimates impacts for four customer segments (residential and small, medium, and large nonresidential) and five DR program mechanisms (direct load control, interruptible rates, dynamic pricing with enabling technologies, dynamic pricing without enabling technologies, and other DR programs such as demand bidding and other aggregator offerings). It develops these estimates for four scenarios, business as usual (BAU), expanded business as usual (EBAU), achievable participation (AP), and full participation (FP) which are defined in the body of this report (see Section 3 – Model Overview).

Table 1 and Figure 1 below present a summary of the model outputs. The BAU scenario shows similar levels of DR potential for the direct load control and the interruptible rates delivery mechanisms. The EBAU scenario shows an expansion of potential for "Other" DR programs that mainly address the large commercial and industrial (C&I) customer segment. This "Other"

[1] *A National Assessment of Demand Response Potential*, Staff Report, Federal Energy Regulatory Commission, prepared by The Brattle Group, Freeman, Sullivan & Co., and Global Energy Partners, LLC, June 2009.

category is influenced by regions that have Independent System Operator/Regional Transmission Organization (ISO/RTO) programs, which increases the standard upon which the EBAU scenario is based.

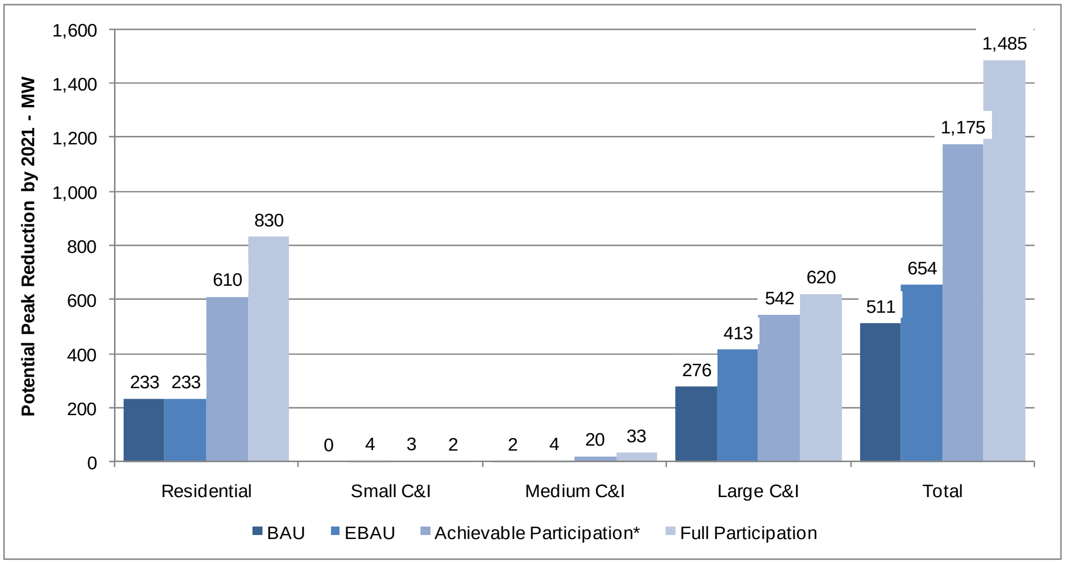
The AP and FP scenarios show increases over the BAU and EBAU scenarios that are mainly through the dynamic pricing mechanisms. These pricing potentials are modeled to be incremental to the direct load control and interruptible tariff potentials, as the latter two programs are assumed, in the FERC study, to continue through all scenarios as unchanged potential. However, we have some concern that potentials for the pricing mechanisms may overstate the incremental potential in the AP and FP scenarios. These pricing mechanisms target similar end uses as the direct load control and interruptible tariffs mechanisms (mainly HVAC for the direct load control and multiple end uses for large C&I interruptible tariffs), and these latter two mechanisms are already achieving high levels of participation and savings. We also note the assumption that direct load control and interruptible tariff potentials may change, contrary to the assumptions in the NADR analysis for the AP and FP scenarios. This may shift some of these potentials to dynamic pricing programs if pursued by PSCo. Potentials from Other DR programs decreases in the AP and FP scenarios as customers are assumed to move out of these programs into the pricing programs. The main sources of savings across all scenarios are the residential and large C&I segments.

Table 1 – Summary of Cumulative Demand Response Potential by Mechanism (2021), MW

DR Mechanism (MW)	BAU	EBAU	Achievable* Participation	Full Participation
Pricing with Technology	0	0	292	726
Pricing without Technology	0	1	284	245
Automated/Direct Load Control	233	238	235	233
Interruptible/Curtailable Tariffs	231	231	234	234
Other DR Programs	47	183	129	47
Total	511	654	1,175	1,485

Estimates developed using FERC NADR model, modified to reflect the PSCo service territory customers and loads and the PSCO business as usual program impacts. * Achievable Participation is the name given to a specific scenario in the FERC NADR study; these potentials are only achievable under the specific assumptions that define this scenario.

Figure 1 – Summary of Cumulative Demand Response Potential by Sector (2021)



* Achievable Participation is the name given to a specific scenario in the FERC NADR study; these potentials are only achievable under the specific assumptions that define this scenario.

There are significant barriers to achieving the DR potentials developed in this study, including but not limited to:

- Constraints on the number of AMI installations which are required for critical peak pricing, with the understanding that there are many other factors with more significant costs and benefits that influence the decision to install AMI, beyond DR; AMI is currently not widely deployed in PSCo, and installing an AMI system presents significant barriers in terms of total costs, timing of deployment and cost recovery;
- Regulatory barriers that include reluctance to adopt dramatically different pricing structures and reluctance to fund investments in AMI installations or in customer-side enabling technologies;
- Technology barriers such as the limitations on cost-effective enabling technologies; and,
- Customer barriers including: lack of awareness regarding DR, risk aversion to new technologies and pricing strategies, and perceived lack of ability to respond to DR events.

This analysis for PSCo developed a theoretical estimate of the peak savings that might be achieved if all the assumptions, forecast inputs, and model design logic prove accurate over time. KEMA strongly recommends that the reviewers of this analysis keep the following caveats firmly in mind:

1. This analysis does not address the need for demand response programs in PSCo's service territory. This can only be determined by a comprehensive review of forecasts regarding future load and economic conditions, demand response resources, existing and projected generation, transmission, and distribution capacities, and other attributes outside the scope of this study.
2. This analysis does not incorporate a full assessment of the costs and benefits of any course of action or scenario. The cost-effectiveness of direct load control technologies and enabling technologies for pricing programs was determined based on NADR model inputs for the state of Colorado and a high-level cost-effectiveness analysis [2]. Once the technologies were determined to be cost-effective, the NADR analysis just focused on the demand savings available from DR programs and did not quantify overall benefits and costs associated with those savings.
3. The analysis does not take into account directly-measured PSCo-customer acceptance of programs and enabling technologies, but rather uses the acceptance level and price elasticity assumptions developed for the NADR model.
4. The model does not account for the demand response savings acquired by energy efficiency measures and programs that are not incorporated in the baseline conditions.

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[2] A simple Total Resource Cost (TRC) Test was used to compare the lifetime benefits of the control technologies to the associated costs on a per customer basis. The analysis was not performed at the program level, and therefore the effects of incentives and participation rates are not included in the analysis. For dynamic pricing, it is assumed that AMI is already installed, and AMI costs are not included in the cost-effectiveness determination.

The NADR cost-effectiveness analysis looked at a 10-year time horizon. An avoided capacity cost of $75 per kW (based on the cost of a gas-fired combustion turbine generator) was used to develop benefits. This cost was escalated at a 3% inflation rate and discounted to present value using a 5% discount rate. Equipment costs, as noted in the following table, were utilized with an additional 15% adder to account for program costs. These costs were developed in the NADR study and are based on vendor estimates and utility program cost data for programs with similar demand response options. This study does not assess how these enabling technology and load control costs compare to PSCo costs.

Customer Type	Dynamic Pricing		Direct Load Control	
	Equipment	Unit Cost	Equipment	Unit Cost
Residential	PCT	$200	Switch	$200
Small C&I	PCT	$350	Switch	$350
Medium C&I	PCT	$1,050	Auto-DR	$1,050
Large C&I	Auto-DR	$13,500	N/A	N/A

PCT: programmable Communicating Thermostats
Auto-DR: automated demand response technologies for large customers

With the adoption of emerging technologies, and ongoing utility and regulatory support of energy efficiency programs, it is likely that the load susceptible to peak reduction through demand response mechanisms is less than the model projects. For this reason, the results of the model runs are likely to overstate the savings that may be achieved from demand response mechanisms.

5. The model estimates are based on national benchmarked data and are not based on economic analysis using PSCo's rates, industrial structure or costs to customers. These are significant factors that would need to be addressed when moving beyond this study to estimate economic or market potential.
6. Regulatory mechanisms are not in place to address the likely revenue losses associated with expanded demand response programs.

The primary uses of this benchmarking study include:

- Understanding the amount of DR potential that might be available, in addition to forecasted business-as-usual impacts, under varying program assumptions (some of which require a significant investment in AMI);
- Understanding how current PSCo DR programs compare against high participation programs in the U.S. by comparing business-as-usual potentials against the estimates of the expanded business-as-usual scenario, which assumes participation rates equal to the 75th percentile of ranked participation rates of existing programs in the country; and
- Understanding which program mechanisms and customer segments provide the most significant sources of DR potential, if DR program expansion is ever required to meet system needs.

2. Introduction

KEMA developed an estimate of demand response (DR) potential for the Xcel Energy Public Service Company of Colorado (PSCo) service territory through 2021 using the Federal Energy Regulatory Commission's (FERC) National Assessment of Demand Response (NADR) model with specific inputs for PSCo's service territory. For this analysis KEMA compared demand response savings as forecast by PSCo from its current program efforts to three reference scenarios and to peak load absent DR through 2021. The reference scenarios were developed by using the Federal Energy Regulatory Commission's (FERC) National Assessment of Demand Response (NADR) model with specific inputs for PSCo's service territory. The values for the system peak without DR were derived by adding PSCo's known and projected DR savings to the appropriate system peak. Where possible, the inputs for the model were developed using information provided by Xcel Energy staff and from recent KEMA research for PSCo.

This report includes the following components:

1. An overview of the model and input definitions;
2. A listing of the inputs used to assess the potential in PSCo's territory; and
3. A summary of the results generated by the model under four different scenarios.

3. Model Overview

FERC's NADR model is an Excel spreadsheet tool with default state-specific data that enables users to estimate and better understand demand response (DR) resources and potential under various scenarios. Model inputs can also be adjusted for aggregation at the utility or municipal level by the user.

While the model as distributed by FERC is populated with state-specific data, utility-specific data can be used for service territory scenario analysis. This section describes the customer classes, DR programs, and scenarios incorporated in the model.

Table 2 below identifies customer segments as defined in the NADR model.

Table 2 – Customer Segment Definition*

Customer Segment	Description
Residential	All residential customers
Small C&I	Commercial and Industrial customers with summer peak demand < 20 kW
Medium C&I	Commercial and Industrial customers with summer peak demand between 20 kW and 200 kW
Large C&I	Commercial and Industrial customers with summer peak demand > 200 kW

*Xcel Energy does not readily segment its commercial and industrial customers according to the NADR model definitions, so assumptions were made and analysis conducted in order to categorize Xcel Energy's customer information for inclusion in the NADR model.

The NADR model assesses savings from four basic types of DR programs:

1. Dynamic pricing with and without enabling technology[3];
2. Direct Load Control (DLC);
3. Interruptible tariffs; and,

[3] "Enabling technology" refers to devices that are capable of reducing consumption during peak demand or higher cost time periods. Examples of these devices include programmable communicating thermostats for air conditioning applications, typically used for residential applications, and automated demand response systems that respond to a signal to coordinate load reductions in multiple end-uses at commercial facilities.

4. Other DR programs likely administered by independent system operators (ISO) and regional transmission organizations (RTO (e.g., capacity/ demand bidding).

The NADR model estimates demand savings under four different participation scenarios, defined[4] as follows:

1. Business-as-usual (BAU): BAU assumes current programs and tariffs are held constant;
2. Expanded BAU (EBAU): EBAU assumes that: 1) the currently available mix of demand response programs is implemented in the study area with "best practices" participation levels[5]; 2) partial deployment of advanced metering infrastructure; and 3) the availability of dynamic pricing to customers, with a small number of customers (5 percent) choosing dynamic pricing. Note, areas with participation rates higher than the 75th percentile are assumed to remain at existing levels, rather than revert to the 75th percentile.
3. Achievable Participation (AP): AP assumes advanced metering infrastructure (AMI) is universally deployed, and dynamic pricing is the opt-out default tariff; and,
4. Full Participation (FP): FP assumes that dynamic pricing and the acceptance of enabling technology is mandatory. This scenario quantifies the maximum cost-effective DR potential, absent any regulatory and market barriers.

The BAU scenario has been calibrated to PSCo's known and forecast program accomplishments and system peaks. The other three scenarios are generated by the model based on PSCo specific inputs (e.g. customer populations and system load forecasts) and inputs derived incorporated in the NADR model by its creators, such as price elasticities. Each of these three scenarios is a theoretical and speculative estimate of the demand response savings that might be acquired under a very constrained, and artificial, set of conditions. As such, the scenarios are best used as reference points, not as goals.

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[4] Note that the scenario names are the same names utilized in the *National Assessment of Demand Response Potential* report.

[5] For purposes of this Assessment, "best practices" refers only to high rates of participation in demand response programs, not to a specific demand response goal or the endorsement of a particular program design or implementation. The best practice participation rate is equal to the 75th percentile of ranked participation rates of existing programs of the same type and customer class. (ibid., page xi) In order to develop participation rates, program customer counts by program type and customer class were collected by state and divided by total state customer counts (by customer class). The 75th percentile participation was determined for each program type and customer class by looking at the participation rate for the 13th highest state (which defines the 75th percentile).

We note that the NADR model results should be qualified. As stated on page 18 of the 2009 NADR report:

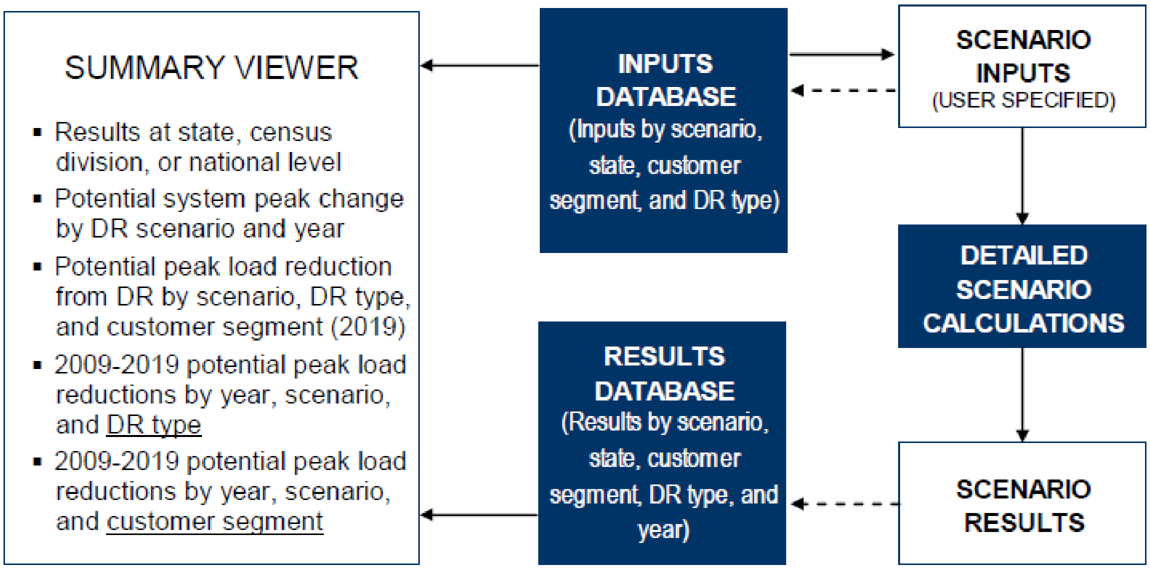
> "It is important to note that the results of the four scenarios are in fact estimates of potential, rather than projections of what is likely to occur. The numbers reported in this study should be interpreted as the amount of demand response that could potentially be achieved under a variety of assumptions about the types of programs pursued, market acceptance of the programs, and the overall cost-effectiveness of the programs. This report does not advocate what programs/measures should be adopted/implemented by regulators; it only sets forth estimates should certain things occur.
>
> As such, the estimates of potential in this report should not be interpreted as targets, goals, or requirements for individual states or utilities. However, by quantifying potential opportunities that exist in each state, these estimates can serve as a reference for understanding the various pathways for pursuing increased levels of demand response.
>
> As with any model-based analysis in economics, the estimates in this Assessment are subject to a number of uncertainties, most of them arising from limitations in the data that are used to estimate the model parameters. Demand response studies performed with accurate utility data have had error ranges of up to ten percent of the estimated response per participating customer. In this analysis, the use of largely publicly-available, secondary data sources makes it likely that the error range for any particular estimate in each of the scenarios studied is larger, perhaps as high as twenty percent."

3.1 How the NADR Model Works

The model architecture is shown in the figure below and is provided in the model guide.[6] Each box in the figure below is equal to one worksheet in the Excel workbook (model).

[6] Source: The Brattle Group, Freeman, Sullivan & Co. and Global Energy Partners, LLC. *National Demand Response Potential Model Guide*, online 06/09.

Figure 2 – Model Architecture



To develop DR potential estimates, users adjust scenario inputs through an interface that appears in the Scenario Inputs sheet of the model. Once fields are updated the user then clicks on a "button" or macro assigned graphic to run the model. After the model is run, results can be found in the Scenario Results sheet and are summarized in the Summary Viewer. The Summary Viewer is considered the end product of the model (incorporating more permanent state (or utility) data entered/ adjusted in the Inputs Database sheet and more temporary scenario inputs entered/ adjusted in the Scenario Inputs sheet).

The final inputs and results are stored in the Inputs Database sheet and Results Database sheet, respectively. A database format enables users to conduct analysis in database and statistical analysis software. For example, a comparison of inputs or outputs can be made in Excel by creating a pivot table and chart from either database.

3.2 Summary of Inputs

The NADR model imports default data which can be changed on a temporary or a more permanent basis. These inputs are identified below and appear as defined in the model guide.[7]

[7] Ibid.

3.2.1 Temporary Changes

Temporary changes refer to parameter changes that define the type of scenario to be run by the model and are useful for sensitivity or comparative analyses once the model is populated.

Parameters include:

1) State (or utility territory)
2) Type of Potential (scenarios):
    - Business As Usual (BAU)
    - Expanded BAU
    - Achievable Participation (AP), and
    - Full Participation (FP)
3) New Peak to Old Peak Price Ratio for all four customer types listed in Table 2.
4) Year the data is from.

3.2.2 Permanent Changes

For the purposes of this model, permanent changes are changes to the underlying data entered by the user, e.g. the PSCo-specific data added to the model for this analysis. These changes appear are reflected on the scenario worksheets (BAU, EBAU, AP, and FP) and stored in the Inputs Database worksheet. To assure closest calibration of the model to PSCo actual conditions, KEMA and Xcel Energy staff used 2011 data and set the beginning of the analysis horizon at 2011 as well. This approach allows the comparison of the model outputs to PSCo actual accomplishments and does not require scaling or forecasting.

3.2.3 Definition of Inputs

Customer Population Inputs

Starting Customer Population – Number of accounts in each customer segment.

Annual Growth Rate – Annual growth rate in the number of accounts.

Annual Consumption Growth (Per Customer) – Growth in annual consumption per customer; this input is different than the growth in consumption for the customer segment as a whole in that it excludes growth associated with increases in the number of accounts.

Annual Critical Peak Load Growth (Per Customer) – Annual growth in critical peak load per customer; this input is different than the peak load growth for the customer segment as a whole in that it excludes growth associated with increases in the number of accounts.

Yearly System Peak and AMI Deployment Inputs

System Peak Forecast (MW) – This is the forecast summer system peak for each year.

Advanced Metering Infrastructure (AMI) Deployment – AMI deployment for each year for each customer segment. This is the share of accounts, by customer segment and year, expected to have meters capable of supporting dynamic pricing.

Average Participant Critical Day Load and Load Reductions Inputs

Critical Peak Avg. Hourly Load (kW) – This is an estimate of the average demand, by customer segment, for the 2-6pm period during the 15 highest system load days as described in Appendix D of FERC's National Assessment of Demand Response Potential.[8]

Customers on Dynamic Pricing without Enabling Technology (Percent Reduction) – This is the percent load reduction from customers on dynamic pricing *without* enabling technology.

Customers on Dynamic Pricing with Enabling Technology (Percent Reduction) – This is the percent load reduction from customers on dynamic pricing *with* enabling technology. Residential customers without air conditioning are not eligible for the default enabling technology.

Automated or Direct Load Control DR (kW Reduction) – This is the load reduction per participant in this type of program (kW/participant). If the available information is on a per device basis, multiply by the average number of AC units for the customer segment.

Interruptible Tariffs (Percent Reduction) – This is the load reduction per participant (kW/participant).

Other DR (Percent Reduction) – This is the expected percent load reduction per participant (kW/participant).

[8] FERC, prepared by The Brattle Group, Freeman, Sullivan & Co. and Global Energy Partners, LLC. *A National Assessment of Demand Response Potential*, online 2009.

Program Participation Inputs

Dynamic Pricing:

Max Percent Enrolled or Notified – Maximum percent of customers who enroll in dynamic pricing. The participation rate varies based on whether opt-in, as in the Achievable potential scenario, or op-out is assumed.

Rates Become Effective at (Percent AMI Penetration) – Determines whether a specific AMI deployment threshold needs to be met prior to offering dynamic pricing to customers.

Customers with Load Suitable for Enabling Technology (Percent) – For Residential, Small C&I and Medium C&I, this is central air conditioning (CAC) saturation. For Large C&I this is the share of customers with system configurations and load suitable for automated demand response systems.

Offered Technology (Percent of Eligible) – Percent of eligible customers where the enabling technology is cost-effective. This affects the share of customers that are offered enabling technology (at no cost to the customer) in conjunction with dynamic pricing.

Accept Technology (Percent) – Used for Achievable – This affects the share of customers that are expected to accept enabling technology if offered to them at no cost. Default estimates are based on enabling technology acceptance observed in pricing pilots.

Automated or Direct Load Control DR (Air conditioning related):

Current Market Penetration (Percent of Eligible Customers) – Current participation rate by customer segment where eligibility is defined as possessing load suitable for enabling technology..

Max Market Penetration (Percent of Eligible Customers) – Program saturation potential among eligible customers by customer segment.

Years Required to Achieve Max Penetration – This determines how quickly the program moves from current participation to max penetration.

Interruptible Tariffs:

Current Penetration (Percent of Customers in Segment) – The current share of customers in the segment that are participating in interruptible tariffs programs.

Current Penetration (Percent of MW in Segment) – The load of current participants as a percent of the total segment load.

Max Penetration (Percent of Customers in Segment) – The participation defined as the maximum share of customers in the segment that would participate.

Max Penetration (Percent of MW in Segment) – The maximum participation defined as the participant load as a percent of the total segment load.

<u>Other DR Programs:</u>

Current Penetration (Percent of Customers in Segment) – The current share in the segment that are participating in other programs.

Current Penetration (Percent of MW in Segment) – The current participants as a percent of the total segment load.

Max Penetration (Percent of Customers in Segment) – Estimate of the participation potential defined as the maximum share of customers in the segment that would participate.

Max Penetration (Percent of MW in Segment) – Estimate of the maximum participation defined as the share of load as a percent of the total load segment load.

4. Public Service Company of Colorado Inputs

This section documents the model input adjustments that were made so that the DR potential estimates better reflect PSCo's service territory and not just default state values. Issues (if any) are also identified in this section.

4.1 Customer Population Inputs

The numbers in the below table were used for each scenario run and were derived using PSCo provided data.

Table 3 – Customer Population Inputs

		Commercial & Industrial		
CUSTOMER POPULATION INPUTS	Residential	Small	Medium	Large
Starting Customer Population	1,165,788	148,682	3,848	1,594
Population Growth Rate	1.45%	1.47%	1.47%	1.47%
Annual Consumption Growth (per customer)	-0.36%	-0.78%	-0.78%	-0.78%
Annual Critical Peak Load Growth (per customer)	-0.31%	-1.08%	-1.08%	-1.08%

4.2 Yearly System Peak and AMI Deployments Inputs

System peak values for 2011 through 2021 were developed through an iterative process based on PSCo's October 2011 load forecasts. The table below shows both the actual, or BAU peaks and the calculated peaks in the absence of any demand response savings.

Table 4 – System Peak with and without Base DR

SYSTEM PEAKS (MW)		
YEAR	No DR	Actual (BAU)
2011	6,215	5,805
2012	6,297	5,855
2013	6,357	5,893
2014	6,407	5,929
2015	6,471	5,979
2016	6,533	6,027
2017	6,566	6,059
2018	6,592	6,084
2019	6,611	6,102
2020	6,633	6,123
2021	6,650	6,139

Actual peak demand forecast based on PSCo October 2011 forecast release.

Model inputs for the AMI metering penetration were calculated for the BAU scenario based on PSCo data. For the other scenarios, we utilized the NADR model defaults, but delayed these default penetrations by two years to provide a somewhat more realistic AMI deployment schedule for the PSCo service territory. AMI penetrations are shown in the following tables by scenario for each sector.

Table 5 – AMI Penetration Inputs - Residential

YEAR	SECTOR - RESIDENTIAL			
	BAU	EBAU	AP	FP
2011	0%	0%	0%	0%
2012	0%	0%	0%	0%
2013	0%	0%	0%	0%
2014	0%	0%	0%	0%
2015	0%	0%	0%	0%
2016	0%	7%	13%	13%
2017	0%	13%	27%	27%
2018	0%	21%	44%	44%
2019	7%	28%	63%	63%
2020	13%	36%	81%	81%
2021	21%	43%	100%	100%

Table 6 – AMI Penetration Inputs – Small C&I

YEAR	SECTOR - SMALL C&I			
	BAU	EBAU	AP	FP
2011	0%	0%	0%	0%
2012	0%	0%	0%	0%
2013	0%	0%	0%	0%
2014	0%	0%	0%	0%
2015	0%	0%	0%	0%
2016	7%	7%	13%	13%
2017	13%	13%	27%	27%
2018	21%	21%	44%	44%
2019	28%	28%	63%	63%
2020	36%	36%	81%	81%
2021	43%	43%	100%	100%

Table 7 – AMI Penetration Inputs – Medium C&I

YEAR	SECTOR - MEDIUM C&I			
	BAU	EBAU	AP	FP
2011	0%	0%	0%	0%
2012	0%	0%	0%	0%
2013	0%	0%	0%	0%
2014	0%	0%	0%	0%
2015	0%	0%	0%	0%
2016	7%	7%	13%	13%
2017	13%	13%	27%	27%
2018	21%	21%	44%	44%
2019	28%	28%	63%	63%
2020	36%	36%	81%	81%
2021	43%	43%	100%	100%

Table 8 – AMI Penetration Inputs – Large C&I

YEAR	SECTOR - LARGE C&I			
	BAU	EBAU	AP	FP
2011	0%	0%	0%	0%
2012	0%	0%	0%	0%
2013	0%	0%	0%	0%
2014	0%	0%	0%	0%
2015	0%	0%	0%	0%
2016	7%	7%	13%	13%
2017	13%	13%	27%	27%
2018	21%	21%	44%	44%
2019	28%	28%	63%	63%
2020	36%	36%	81%	81%
2021	43%	43%	100%	100%

4.3 Average Participant Critical Day Load and Load Reduction Inputs

The critical peak average hourly load (kW) for C&I customers was calculated using billing data provided by PSCo (1.93 kW for S C&I, 49.73 for M C&I, and 1,997.15 for L C&I). BAU, Expanded BAU, Achievable Participation and Full Participation data inputs for average participant critical day load and load reduction can be seen in the tables below.

Table 9 – Average Critical Peaks and Load Reductions

AVERAGE PARTICIPANT CRITICAL DAY LOAD AND LOAD REDUCTIONS	Residential w/o Central AC	Residential w/ Central AC	Commercial & Industrial		
			Small	Medium	Large
Critical peak avg. hourly load (kW)	1.04	2.10	1.93	49.73	1,997.15
Customers on dynamic pricing without enabling tech (% reduction)					
BAU	10.6%	24.1%	0.7%	8.7%	7.5%
EBAU	10.6%	24.1%	0.7%	8.7%	7.5%
Achievable Participation	10.6%	24.1%	0.7%	8.7%	7.5%
Full Participation	10.6%	24.1%	0.7%	8.7%	7.5%
Customers on dynamic pricing with enabling tech (% reduction)					
BAU	DNA	42.2%	14.9%	13.9%	13.9%
EBAU	DNA	42.2%	14.9%	13.9%	13.9%
Achievable Participation	DNA	42.2%	14.9%	13.9%	13.9%
Full Participation	DNA	42.2%	14.9%	13.9%	13.9%
Automated or Direct Load Control DR (kW reduction)					
BAU	DNA	1.07	0.00	0.00	0.00
EBAU	DNA	0.55	2.33	7.00	35.02
Achievable Participation	DNA	0.55	2.33	7.00	35.02
Full Participation	DNA	0.55	2.33	7.00	35.02
Interruptible Tariffs - (% reduction)					
BAU	0.0%	0.0%	0.0%	0.0%	0.03%
EBAU	0.0%	0.0%	0.0%	0.0%	22.5%
Achievable Participation	0.0%	0.0%	0.0%	69.9%	22.5%
Full Participation	0.0%	0.0%	0.0%	69.9%	22.5%
Other DR (% reduction)					
BAU	0.0%	0.0%	0.0%	3.1%	0.4%
EBAU	0.0%	0.0%	0.0%	0.0%	22.5%
Achievable Participation	0.0%	0.0%	0.0%	39.4%	39.4%
Full Participation	0.0%	0.0%	0.0%	39.4%	39.4%

Notes: DNA = Does not apply.

4.4 Program Participation Inputs

The tables below show the program participation inputs for each of the demand response mechanisms by scenario (BAU, Expanded BAU, Achievable Potential and Full Potential). As mentioned above, where possible, data from PSCo provided documents was used.

Table 10 – Dynamic Pricing Inputs

Program Participation Input - Dynamic Pricing	Residential	Commercial & Industrial		
		Small	Medium	Large
Max Percent Enrolled or Notified				
BAU	0.0%	0.0%	0.0%	0.0%
EBAU	5.0%	5.0%	5.0%	5.0%
Achievable Participation	75.0%	75.0%	60.0%	60.0%
Full Participation	100.0%	100.0%	100.0%	100.0%
Rates become effective at (% AMI penetration)				
BAU	0.0%	0.0%	0.0%	0.0%
EBAU	0.0%	0.0%	0.0%	0.0%
Achievable Participation	0.0%	0.0%	0.0%	0.0%
Full Participation	0.0%	0.0%	0.0%	0.0%
Customers with load suitable for enabling technology (%)				
BAU	43.0%	75.0%	75.0%	40.0%
EBAU	43.0%	75.0%	75.0%	40.0%
Achievable Participation	43.0%	75.0%	75.0%	40.0%
Full Participation	43.0%	75.0%	75.0%	40.0%
Offered technology (% of eligible)				
BAU	0.0%	0.0%	0.0%	0.0%
EBAU	0.0%	0.0%	0.0%	0.0%
Achievable Participation	95.0%	0.0%	95.0%	95.0%
Full Participation	100.0%	0.0%	100.0%	100.0%
Accept technology (%) - used for achievable				
BAU	60.0%	60.0%	60.0%	60.0%
EBAU	60.0%	60.0%	60.0%	60.0%
Achievable Participation	60.0%	60.0%	60.0%	60.0%
Full Participation	100.0%	100.0%	100.0%	100.0%

Table 11 – Automated or Direct Load Control Inputs

Program Participation Input - Automated or DLC	Residential	Commercial & Industrial		
		Small	Medium	Large
Current Market Penetration (% of eligible customers)				
BAU	30.0%	0.0%	0.0%	0.0%
EBAU	9.2%	0.0%	0.0%	0.0%
Achievable Participation	9.2%	0.0%	0.0%	0.0%
Full Participation	9.2%	0.0%	0.0%	0.0%
Max Market Penetration (% of eligible customers)				
BAU	42.0%	0.0%	0.0%	0.0%
EBAU	25.0%	1.2%	7.2%	0.0%
Achievable Participation	25.0%	1.2%	7.2%	0.0%
Full Participation	25.0%	1.2%	7.2%	0.0%
Years required to achieve max penetration				
BAU	5	5	5	5
EBAU	5	5	5	5
Achievable Participation	5	5	5	5
Full Participation	5	5	5	5

Table 12 – Interruptible Tariffs Inputs

Program Participation Input - Interruptible Tarriffs	Residential	Commercial & Industrial		
		Small	Medium	Large
Current Penetration (% of customers in segment)				
BAU	0.0%	0.0%	0.0%	12.6%
EBAU	0.0%	0.0%	0.0%	2.5%
Achievable Participation	0.0%	0.0%	0.0%	2.5%
Full Participation	0.0%	0.0%	0.0%	2.5%
Current Penetration (% of MW in segment)				
BAU	0.0%	0.0%	0.0%	6.6%
EBAU	0.0%	0.0%	0.0%	26.5%
Achievable Participation	0.0%	0.0%	0.0%	26.5%
Full Participation	0.0%	0.0%	0.0%	26.5%
Max Penetration (% of customers in segment)				
BAU	0.0%	0.0%	0.0%	13.3%
EBAU	0.0%	0.0%	0.3%	6.9%
Achievable Participation	0.0%	0.0%	0.3%	6.9%
Full Participation	0.0%	0.0%	0.3%	6.9%
Max Penetration (% of MW in segment)				
BAU	0.0%	0.0%	0.0%	6.9%
EBAU	0.0%	0.0%	1.7%	26.5%
Achievable Participation	0.0%	0.0%	1.7%	26.5%
Full Participation	0.0%	0.0%	1.7%	26.5%
Years required to achieve max penetration				
BAU	5	5	5	5
EBAU	5	5	5	5
Achievable Participation	5	5	5	5
Full Participation	5	5	5	5

Table 13 – Other DR Program Inputs

Program Participation Input - Other DR Programs	Residential	Commercial & Industrial		
		Small	Medium	Large
Current Penetration (% of customers in segment)				
BAU	0.0%	0.0%	0.1%	2.6%
EBAU	0.0%	0.0%	0.0%	1.0%
Achievable Participation	0.0%	0.0%	0.0%	1.0%
Full Participation	0.0%	0.0%	0.0%	1.0%
Current Penetration (% of MW in segment)				
BAU	0.0%	0.0%	1.1%	1.4%
EBAU	0.0%	0.0%	0.0%	23.5%
Achievable Participation	0.0%	0.0%	0.0%	23.5%
Full Participation	0.0%	0.0%	0.0%	23.5%
Max Penetration (% of customers in segment)				
BAU	0.0%	0.0%	0.1%	2.6%
EBAU	0.0%	0.0%	0.1%	18.9%
Achievable Participation	0.0%	0.0%	0.1%	18.9%
Full Participation	0.0%	0.0%	0.1%	18.9%
Max Penetration (% of MW in segment)				
BAU	0.0%	0.0%	1.1%	1.4%
EBAU	0.0%	0.0%	0.0%	23.5%
Achievable Participation	0.0%	0.0%	0.0%	23.5%
Full Participation	0.0%	0.0%	0.0%	23.5%
Years required to achieve max penetration				
BAU	5	5	5	5
EBAU	5	5	5	5
Achievable Participation	5	5	5	5
Full Participation	5	5	5	5

5. Public Service Company of Colorado Outputs

5.1 Reduction Overview

The NADR model was run with the data inputs described in the previous sections for the years 2011 through 2021. The Table 14 below shows a summary of demand reduction by scenario in both megawatts and percentage of peak demand reduced. Figure 3 graphically displays the impact of the savings on peak demand over time.

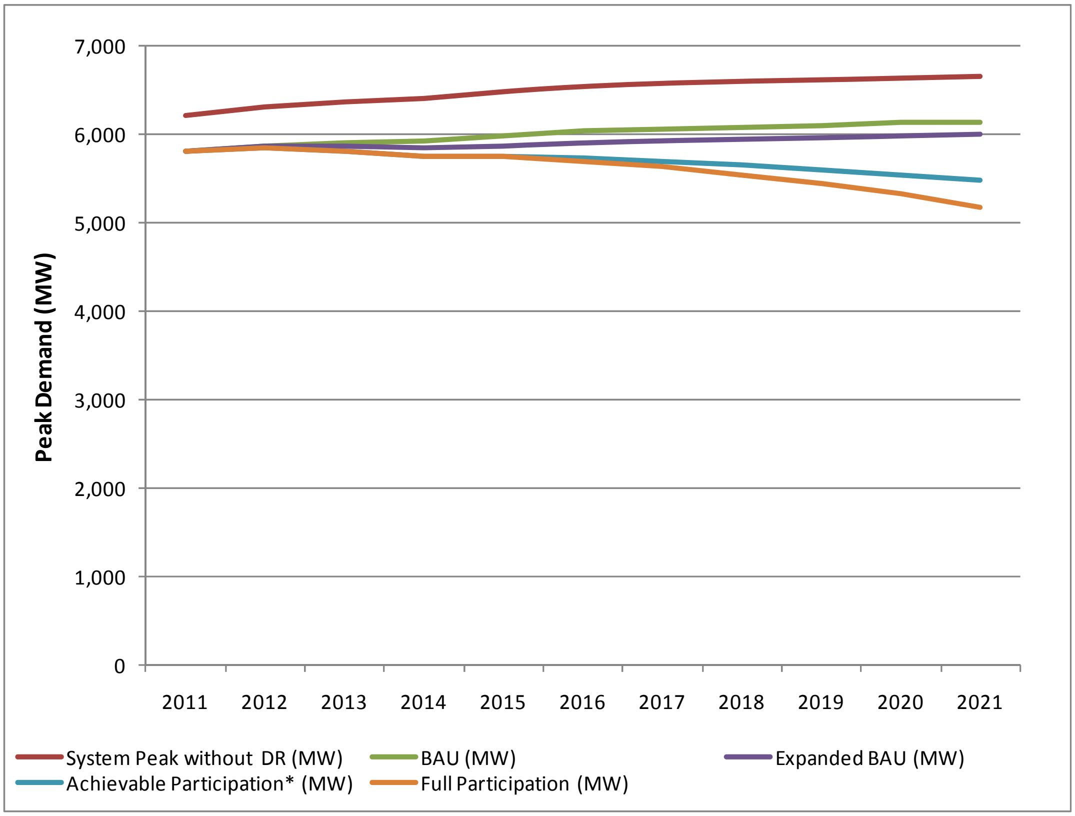
Under the BAU scenario, the model predicts a reduction of 7.7% in peak demand by the year 2021. The Expanded BAU scenario predicts that peak demand savings will be 9.8% when participation in PSCo's service territory is modeled at 75th percentile penetration rates. Under the Achievable Participation and Full Participation scenarios the model predicts peak demand reduction of 17.7% and 22.3% for the year 2021, respectively.

Table 14 – Summary Results by Year and Scenario - MW

Year	System Peak without DR (MW)	BAU (MW)	% Reduction	Expanded BAU (MW)	% Reduction	Achievable Participation* (MW)	% Reduction	Full Participation (MW)	% Reduction
2011	6,215	5,805	6.6%	5,805	6.6%	5,805	6.6%	5,805	6.6%
2012	6,297	5,855	7.0%	5,854	7.0%	5,841	7.3%	5,841	7.3%
2013	6,357	5,893	7.3%	5,857	7.9%	5,797	8.8%	5,797	8.8%
2014	6,407	5,929	7.5%	5,843	8.8%	5,746	10.3%	5,746	10.3%
2015	6,471	5,979	7.6%	5,863	9.4%	5,743	11.3%	5,743	11.3%
2016	6,533	6,027	7.7%	5,899	9.7%	5,723	12.4%	5,690	12.9%
2017	6,566	6,059	7.7%	5,927	9.7%	5,700	13.2%	5,633	14.2%
2018	6,592	6,084	7.7%	5,949	9.7%	5,656	14.2%	5,544	15.9%
2019	6,611	6,102	7.7%	5,965	9.8%	5,597	15.3%	5,436	17.8%
2020	6,633	6,123	7.7%	5,983	9.8%	5,540	16.5%	5,327	19.7%
2021	6,650	6,139	7.7%	5,996	9.8%	5,475	17.7%	5,165	22.3%

BAU peak demand forecast based on PSCo October 2011 forecast release. * Achievable Participation is the name given to a specific scenario in the FERC NADR study; these potentials are only achievable under the specific assumptions that define this scenario.

Figure 3 – Summary Results Graph – MW



BAU peak demand forecast based on PSCo October 2011 forecast release. * Achievable Participation is the name given to a specific scenario in the FERC NADR study; these potentials are only achievable under the specific assumptions that define this scenario.

5.2 Reduction by Mechanism

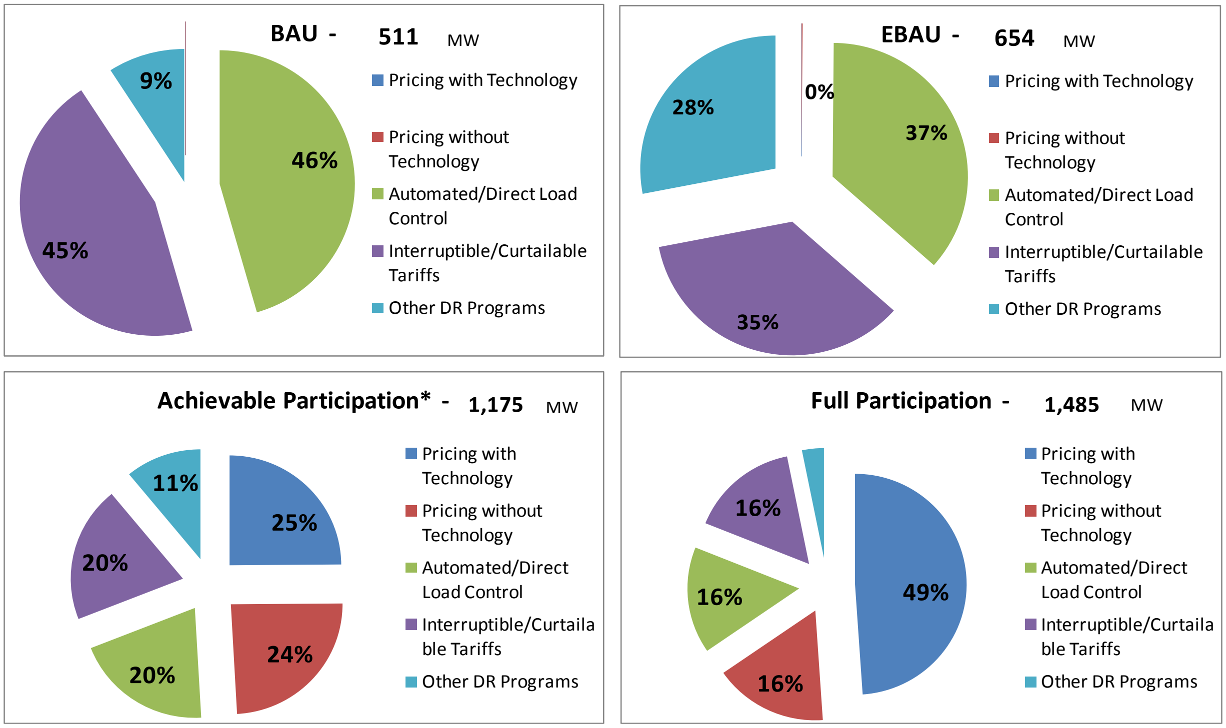
As shown in Table 15 and Figure 4, the direct load control and interruptible tariffs mechanisms provide a steady source of potentials in all scenarios throughout the study period. "Other" DR potential remains constant in the BAU scenario, increases steadily in the EBAU scenario, and first increases and then declines in the AP and FP scenarios as potential savings are assumed to move toward the pricing mechanisms in the latter years. Potentials for critical peak pricing for both the AP and FP scenarios increase steadily beginning in 2016 as AMI deployment is assumed to begin penetrating the service territory. The pricing scenarios account for about half of the DR potentials in the AP scenario, growing to about 65 percent of the potentials in the FP scenario. Under the FP scenario, pricing with enabling technologies is shown to account for about half of all potentials, under the assumptions that AMI is fully deployed, enabling technologies are universally accepted, and price elasticities utilized in the NADR model are reflective of future customer response.

Table 15 – Reductions by Mechanism by Year (MW)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
BAU											
Pricing With Enabling Technology	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pricing Without Enabling Technology	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Automated or Direct Control DR	156.0	175.0	194.0	207.0	220.0	233.0	233.0	233.0	233.0	233.0	233.0
Interruptible Tariffs	208.6	221.1	223.2	224.2	225.2	226.3	227.3	228.4	229.4	230.4	231.5
Other DR	45.8	46.9	46.9	46.9	46.9	46.9	46.9	46.9	46.9	46.9	46.9
TOTAL	410.4	443.0	464.0	478.1	492.1	506.2	507.2	508.2	509.3	510.3	511.3
Expanded BAU											
Pricing With Enabling Technology	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pricing Without Enabling Technology	0.0	0.0	0.0	0.0	0.0	0.1	0.2	0.4	0.5	0.6	0.8
Automated or Direct Control DR	156.0	175.4	195.5	210.3	224.5	237.9	238.1	238.1	238.2	238.3	238.4
Interruptible Tariffs	208.6	221.1	223.2	224.2	225.2	226.3	227.3	228.4	229.4	230.4	231.5
Other DR	45.8	46.9	81.5	129.9	158.8	169.5	173.3	175.9	178.3	180.8	183.3
TOTAL	410.5	443.3	500.2	564.4	608.5	633.8	638.9	642.7	646.4	650.2	654.0
Achievable Participation*											
Pricing With Enabling Technology	0.0	0.0	0.0	0.0	0.0	36.3	73.7	122.9	177.7	234.2	292.3
Pricing Without Enabling Technology	0.0	0.0	0.0	0.0	0.0	35.4	71.7	119.6	173.0	227.9	284.4
Automated or Direct Control DR	156.0	175.4	195.5	210.3	224.5	237.5	237.1	236.6	235.9	235.3	234.6
Interruptible Tariffs	208.7	221.3	223.9	225.9	227.5	228.8	229.9	230.9	232.0	233.1	234.2
Other DR	45.8	60.1	140.9	225.5	276.0	271.5	253.7	226.2	194.9	162.6	129.3
TOTAL	410.5	456.7	560.3	661.7	728.1	809.4	866.1	936.1	1,013.5	1,093.0	1,174.7
Full Participation Potential											
Pricing With Enabling Technology	0.0	0.0	0.0	0.0	0.0	90.3	183.2	305.3	441.7	582.0	726.3
Pricing Without Enabling Technology	0.0	0.0	0.0	0.0	0.0	30.4	61.7	102.8	148.8	196.0	244.7
Automated or Direct Control DR	156.0	175.4	195.5	210.3	224.5	237.3	236.7	235.9	234.9	234.0	233.0
Interruptible Tariffs	208.7	221.3	223.9	225.9	227.5	228.8	229.9	230.9	232.0	233.1	234.2
Other DR	45.8	60.1	140.9	225.5	276.0	255.8	221.7	172.8	117.6	60.7	46.9
TOTAL	410.5	456.7	560.3	661.7	728.1	842.6	933.1	1,047.8	1,175.0	1,305.8	1,485.0

Large savings potential for pricing mechanisms in the Achievable and Full Participation scenarios are dependent on extensive AMI deployment and price elasticities contained in the NADR model. * Achievable Participation is the name given to a specific scenario in the FERC NADR study; these potentials are only achievable under the specific assumptions that define this scenario.

Figure 4 – Cumulative Reduction by Mechanism - 2021



* Achievable Participation is the name given to a specific scenario in the FERC NADR study; these potentials are only achievable under the specific assumptions that define this scenario.

5.3 Reduction by Customer Segment

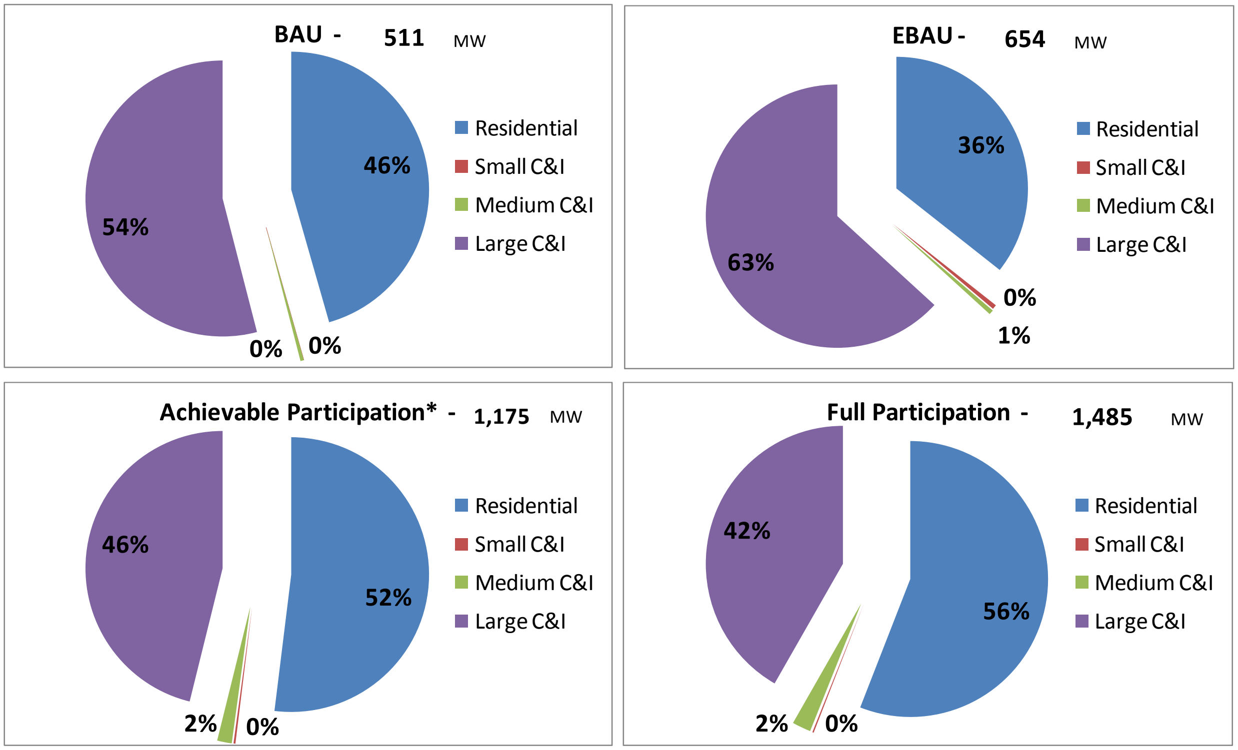
As Table 16 and Figure 6 show, the residential and large C&I customer segments account for the majority of savings. The residential share declines between the BAU and EBAU scenarios, under the assumption that "Other" programs targeted at the large C&I segment come into play. DR potentials increase significantly for both the residential and large C&I segments in the AP and FP scenarios, and the share between residential and large C&I remains fairly constant for both scenarios.

Table 16 – Reduction by Customer Segment by Year (MW)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
BAU											
Residential	156.0	175.0	194.0	207.0	220.0	233.0	233.0	233.0	233.0	233.0	233.0
Small C&I (20 kW or less)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Medium C&I (20 to 200 kW)	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1
Large C&I (200 kW and up)	252.3	265.8	267.9	268.9	270.0	271.0	272.1	273.1	274.1	275.2	276.2
TOTAL	410.4	443.0	464.0	478.1	492.1	506.2	507.2	508.2	509.3	510.3	511.3
Expanded BAU											
Residential	156.0	175.0	194.0	207.0	220.0	233.0	233.0	233.0	233.0	233.0	233.0
Small C&I (20 kW or less)	0.0	0.3	1.1	2.3	3.1	3.4	3.5	3.5	3.6	3.6	3.7
Medium C&I (20 to 200 kW)	2.1	2.3	2.6	3.2	3.5	3.7	3.7	3.7	3.8	3.8	3.8
Large C&I (200 kW and up)	252.3	265.8	302.5	352.0	381.9	393.8	398.7	402.4	406.1	409.8	413.5
TOTAL	410.5	443.3	500.2	564.4	608.5	633.8	638.9	642.7	646.4	650.2	654.0
Achievable Participation*											
Residential	156.0	175.0	194.0	207.0	220.0	279.9	328.2	391.6	462.4	535.3	610.2
Small C&I (20 kW or less)	0.0	0.3	1.1	2.3	3.1	3.3	3.2	3.1	2.9	2.7	2.6
Medium C&I (20 to 200 kW)	2.2	2.4	3.4	4.8	5.8	7.8	9.7	12.0	14.6	17.3	20.0
Large C&I (200 kW and up)	252.3	279.0	361.9	447.6	499.2	518.4	525.1	529.5	533.6	537.8	542.0
TOTAL	410.5	456.7	560.3	661.7	728.1	809.4	866.1	936.1	1,013.5	1,093.0	1,174.7
Full Participation Potential											
Residential	156.0	175.0	194.0	207.0	220.0	307.3	383.7	484.2	596.4	711.8	830.5
Small C&I (20 kW or less)	0.0	0.3	1.1	2.3	3.1	3.2	3.1	2.9	2.7	2.4	2.2
Medium C&I (20 to 200 kW)	2.2	2.4	3.4	4.8	5.8	9.4	12.9	17.3	22.3	27.4	32.7
Large C&I (200 kW and up)	252.3	279.0	361.9	447.6	499.2	522.6	533.5	543.3	553.6	564.2	619.6
TOTAL	410.5	456.7	560.3	661.7	728.1	842.6	933.1	1,047.8	1,175.0	1,305.8	1,485.0

* Achievable Participation is the name given to a specific scenario in the FERC NADR study; these potentials are only achievable under the specific assumptions that define this scenario.

Figure 5 – Cumulative Reduction by Customer Segment - 2021



* Achievable Participation is the name given to a specific scenario in the FERC NADR study; these potentials are only achievable under the specific assumptions that define this scenario.

5.4 Cumulative Reductions by Segment and Mechanism

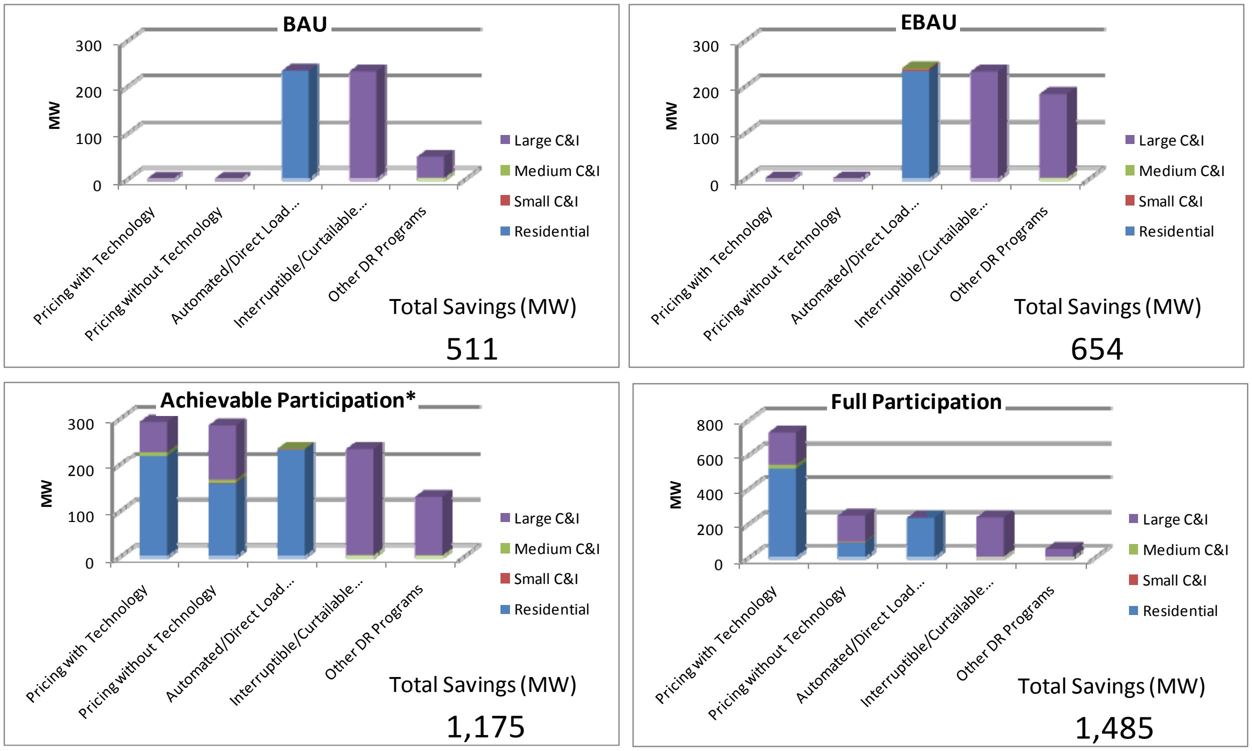
Table 17 below presents the consolidated results by scenario, mechanism, and segment over the analysis period. Figure 6 shows a graphical depiction of the same data.

Table 17 – Cumulative Reductions by Scenario, Mechanism and Sector (2021), MW

Scenario/Mechanism	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Automated/Direct Load Control	233	3.5%	0	0.0%	0	0.0%	0	0.0%	233	3.5%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	231	3.5%	231	3.5%
Other DR Programs	0	0.0%	0	0.0%	2	0.0%	45	0.7%	47	0.7%
Total	**233**	**3.5%**	**0**	**0.0%**	**2**	**0.0%**	**276**	**4.2%**	**511**	**7.7%**
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	1	0.0%	1	0.0%
Automated/Direct Load Control	233	3.5%	4	0.1%	2	0.0%	0	0.0%	238	3.6%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	231	3.5%	231	3.5%
Other DR Programs	0	0.0%	0	0.0%	2	0.0%	181	2.7%	183	2.8%
Total	**233**	**3.5%**	**4**	**0.1%**	**4**	**0.1%**	**413**	**6.2%**	**654**	**9.8%**
Achievable Participation*										
Pricing with Technology	219	3.3%	0	0.0%	8	0.1%	65	1.0%	292	4.4%
Pricing without Technology	158	2.4%	2	0.0%	7	0.1%	118	1.8%	284	4.3%
Automated/Direct Load Control	233	3.5%	1	0.0%	1	0.0%	0	0.0%	235	3.5%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	3	0.0%	231	3.5%	234	3.5%
Other DR Programs	0	0.0%	0	0.0%	2	0.0%	127	1.9%	129	1.9%
Total	**610**	**9.2%**	**3**	**0.0%**	**20**	**0.3%**	**542**	**8.1%**	**1,175**	**17.7%**
Full Participation										
Pricing with Technology	513	7.7%	0	0.0%	23	0.3%	190	2.9%	726	10.9%
Pricing without Technology	84	1.3%	2	0.0%	5	0.1%	153	2.3%	245	3.7%
Automated/Direct Load Control	233	3.5%	0	0.0%	0	0.0%	0	0.0%	233	3.5%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	3	0.0%	231	3.5%	234	3.5%
Other DR Programs	0	0.0%	0	0.0%	2	0.0%	45	0.7%	47	0.7%
Total	**830**	**12.5%**	**2**	**0.0%**	**33**	**0.5%**	**620**	**9.3%**	**1,485**	**22.3%**

Large savings potential for pricing mechanisms in the Achievable and Full Participation scenarios are dependent on extensive AMI deployment and price elasticities contained in the NADR model. * Achievable Participation is the name given to a specific scenario in the FERC NADR study; these potentials are only achievable under the specific assumptions that define this scenario.

Figure 6 – Cumulative Results by Mechanism and Segment – 2021



* Achievable Participation is the name given to a specific scenario in the FERC NADR study; these potentials are only achievable under the specific assumptions that define this scenario.