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July 19, 2019

By Hand Delivery
Ms. Lora W. Johnson, CMC, LMMC
Clerk of Council
Council of the City of New Orleans
Room 1E09, City Hall
1300 Perdido Street
New Orleans, LA 70112

Re: **In Re: 2018 Triennial Integrated Resource Plan of Entergy New Orleans, Inc.**
Docket No. UD-17-03

Dear Ms. Johnson:

Entergy New Orleans, LLC ("ENO" or the "Company") respectfully submits the Public Version of its 2018 Integrated Resource Plan with Appendices attached thereto in the above referenced Docket. Please file an original and two copies into the record in the above referenced matter, and return a date-stamped copy to our courier.

In connection with ENO's filing, contain information considered by ENO to be proprietary and confidential. Public disclosure of certain of this information may expose ENO and its customers to an unreasonable risk of harm. Therefore, in light of the commercially sensitive nature of such information, these exhibits bear the designation "Highly Sensitive Protected Materials" or words of similar import. The confidential information and documents included with the Application may be reviewed by appropriate representatives of the Council and its Advisors pursuant to the provisions of the Official Protective Order adopted in Council Resolution R-07-432 relative to the disclosure of Highly Sensitive Protected Materials. As such, these confidential materials shall be exempt from public disclosure, subject to the provisions of Council Resolution R-07-432.

RECEIVED
JUL 19 2019
BY:

Should you have any questions regarding the above, I may be reached at (504) 576-2984. Thank you for your assistance with this matter.

Sincerely,

Harry M. Barton

HMB/bkd
Enclosures
cc: Official Service List (Public Version *via email)*

2018 Integrated Resource Plan

Entergy New Orleans, LLC

July 2019

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1. Executive Summary

Productive Collaboration

The process leading up to this 2018 Integrated Resource Plan ("IRP") report has undoubtedly been the most collaborative to date. Working under the new IRP Rules developed through the Council for the City of New Orleans's ("Council's") 2017 rulemaking,[1] the parties have engaged in a series of constructive discussions at four technical meetings over the last 18 months about the inputs and analysis required to develop the IRP.[2] The result is a report that meets the goal expressed in the preamble to the new Rules: "It is the Council's desire that a comprehensive IRP conducted in accordance with these IRP Rules provide **a full picture** of **all reasonably available resource options** in light of current and expected market conditions and technology trends, and generate an informed understanding of the **economic, reliability, and risk evaluation** of utility resource planning as well as associated **social and environmental impacts** [emphasis added]." The following summaries provide additional context on these key elements:

- A full picture—This IRP provides a broad view of options for meeting customers' electrical needs across the 20-year planning period from 2019-38 in light of current and expected market conditions and technology trends. The analysis was built on three different planning Scenarios that varied a number of key assumptions about future market conditions outside New Orleans and five different planning Strategies that assessed policy and planning objectives within the city. The parameters of these Scenarios and Strategies were discussed and agreed upon by all parties during the stakeholder process outlined in the new IRP Rules. An important variable among the five Strategies involved the assumed potential savings from and costs of Demand Side Management ("DSM") programs over the 20-year period. These assumptions came from two DSM Potential Studies—the study prepared by Optimal Energy and the one prepared by Navigant Consulting. The parties agreed on assignments of DSM input cases from one study or the other to each of the five Strategies for use in the analysis. A discussion of the Scenarios and Strategies can be found in Section 5.1 and Section 5.2.[3]

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[1] *See,* Council Docket No. UD-17-01.

[2] Technical Meeting #1 was held on January 22, 2018, Technical Meeting #2 on September 14, 2018, Technical Meeting #3 on November 28, 2018, and Technical Meeting #4 on May 1, 2019.

[3] While the inputs and Council policies to be considered in this 2018 IRP analysis were finalized prior to the initiation of the Council's Renewable Portfolio Standard ("RPS") Rulemaking in Docket UD-19-01, the Company recognizes that future IRP proceedings will clearly be affected by any policies resulting from that rulemaking. To that end, ENO has filed two

- All reasonably available resource options—Each Strategy was analyzed in the context of each Scenario to identify an optimized Portfolio of resources to serve customers' needs under that combination of assumptions. Given the combination of three Scenarios times five Strategies, this resulted in an initial set of 15 Optimized Portfolios. The parties reviewed this initial set and agreed on a representative subset of five Portfolios to carry through the remainder of the detailed total relevant supply cost analysis. These Portfolios include different combinations of renewables, battery storage, combustion turbines, and DSM programs depending on their particular assumptions. A discussion of the down-selected set of five Portfolios can be found in Section 5.5.

- Economic, reliability, and risk evaluation—The total relevant supply cost analysis, which represents the cost to serve customers' resource needs reliably under the assumptions of that Portfolio through the planning horizon, used cross-testing to identify a 20-year revenue requirement for each of the five Portfolios in all three Scenarios. In order to work within schedule and resource constraints, the parties agreed to a framework under which stochastic analysis was conducted on four of the five Portfolios to evaluate their sensitivity to changes in two main input assumptions—natural gas price and CO_2 price. Information on the total relevant supply cost and risk analysis can be found in Section 5.5 and Section 5.6.

- Social and environmental impacts—The new IRP Rules required the development of a scorecard to assist the Council in assessing the IRP based on several aspects of the Resource Portfolios, including social and environmental impacts, some of which are only able to be evaluated on a subjective basis. Given the difficulties inherent in trying to compare Portfolios developed under different assumptions across subjective and objective characteristics, the parties agreed on a framework for this initial scorecard, found in Section 5.7.

Practical Considerations

There are two important points to bear in mind while reviewing this IRP report. First, the analysis conducted here shows that Entergy New Orleans, LLC ("ENO" or the "Company") will not have a capacity need for new resources until 2033 (the year Union 1 is assumed to deactivate) based on current assumptions. With the removal of the requirement that a preferred Portfolio be identified, the value of the IRP as a general planning and strategic study has been emphasized. Thus, there are two main uses for this IRP—as the long-term planning tool contemplated in the preamble to the Rules that can inform the Council and ENO about a wide range of possibilities for serving customer needs in the future, and as a near-term source to inform the implementation of Energy Smart DSM programs in the city over the next few years.

The second main point is that the use of DSM input cases from two different potential studies greatly

rounds of comments presenting various analyses of the relative benefit to customers of a Clean Energy Standard that recognizes the value of existing nuclear generation, electrification efforts, demand-side management, and flexible means of compliance as compared to a Renewable Portfolio Standard that mandates compliance through prescribed amounts, types, and locations of particular renewable technologies.

increased both the complexity of the analysis and the difficulty in comparing Portfolios and total relevant supply costs. The use of two DSM potential studies, as contemplated by the new IRP Rules, presented a novel issue for consideration among the parties and highlighted associated challenges in conducting the IRP analysis. This may, in fact, be the first time that two different potential studies have been used in the same IRP analysis in any jurisdiction. Given the requirements of the Rules and the discussions among the parties that led to the identification of the subset of five Portfolios, the Resource Portfolios include a mix of DSM cases —three Portfolios using three different Navigant cases (Base, 2%, and High) and two using the Optimal Program Achievable case. Despite starting from the same set of data provided by ENO, historical Energy Smart results, and current implementation information, Navigant and Optimal drew very different conclusions about the achievable DSM potential and the costs to implement programs to capture it. The net effect for the IRP is that the two Portfolios using Optimal cases show generally lower total relevant supply costs due mainly to the large amounts of kWh and kW savings assumed over the 20-year period that Optimal believes can be achieved at a, perhaps unrealistically, low cost. It is important to note that the total costs of Portfolios incorporating DSM inputs from the two different studies cannot be directly compared. However, the costs of any Portfolio can be considered for the Scenario in which it was initially optimized, compared to the other Scenarios in which it was cross-tested, and to a similar degree compared to other Portfolios created using DSM inputs from the same potential study.

One key takeaway from the Portfolio data is that over the 20-year planning period, the spread between the lowest and highest total relevant supply costs is relatively small. Looking at the total costs for the five selected Portfolios in the Scenarios where they were initially optimized, the difference from the lowest (Portfolio 5 with the Optimal Program Achievable case) to the highest (Portfolio 2 with the Navigant 2% case) is about 18%. In other words, the comparative value of this IRP report comes from considering the different inputs, assumptions, and risk sensitivities of each Portfolio as a guide for the future, not from focusing on the costs of one Portfolio versus another, particularly given the use of different DSM inputs and the fact that actual costs in the future will be driven by resource certifications and DSM implementations that rely on then-current, actual market costs.

The difference between the two potential studies raises another, more immediate issue regarding their suitability as foundations for actual DSM program implementation plans. As will be discussed further in this report, ENO has significant doubts about the possibility of developing a viable implementation plan based solely on Optimal's study given several factors, including but not limited to: (i) its assumption that administrative costs could be held to less than 25% when experience with Energy Smart and programs in other jurisdictions comparable to New Orleans[4] has shown that implementation costs are generally higher

[4] The Optimal study notes, at page 74, that data concerning administrative costs of program measures was "sourced from recent program performance in New England, the MidAtlantic states, and Minnesota." The study also notes that data from these sampled jurisdictions shows that the "average administrative costs for the various program types range from 25 percent to 37 percent." Optimal provided no explanation as to why its study avoided including data from Southeastern utilities, or

than what Optimal's study assumes, (ii) its overall assumptions about the cost of programs necessary to achieve the high level of savings projected in the study, and (iii) its assumptions around measure-level savings that in some cases appear overly aggressive for New Orleans based on actual experience and results with Energy Smart, as confirmed through independent Evaluation, Measurement, and Verification ("EM&V"). That said, the inclusion of two DSM Potential Studies in the IRP process has allowed for varied and diverse perspectives to inform views on demand-side resources and ENO intends to develop its Implementation Plan drawing on both studies.

Additional Focus Areas

The new Rules require that ENO discuss its progress towards developing the capability to optimize the value of distributed energy resources on the distribution grid. Several ongoing efforts are key to developing this capability, including the implementation of Automated Metering Infrastructure ("AMI") and its associated software systems, the execution of Grid Modernization projects, the implementation of the LoadSEER application, which, when coupled with AMI, its associated software, and resulting data, can enable bottom-up capacity analysis at the feeder level, and the utilization of additional functionality in existing software applications. Section 3.9 of this report includes more detail on these important efforts.

Section 3.6 and Section 3.7 provides an overview of ENO's transmission planning activities as a market participant in Midcontinent Independent System Operator, Inc. ("MISO") and the relationship of those activities to resource planning, as required by Section 6 of the new IRP Rules.

While the new IRP Rules no longer mandate identification of a preferred Portfolio, there are numerous ongoing and planned activities that are important to supporting Council goals and Company initiatives in the short term. Some of these include filing the Implementation Plan for the next few years of Energy Smart programs in the city, continuing to support the Council's Smart Cities initiative, and completing the AMI and Grid Modernization work necessary to support critical goals and policies in the future. The Action Plan for pursuing these efforts is found in Section 6.2.

In conclusion, ENO greatly appreciates the collaborative efforts of the Council, its Advisors, Intervenors, and the public that resulted in this 2018 IRP report. As the first effort under the Council's new IRP Rules, the result is an instructive view of resource options under a range of possible future Scenarios that should be useful in ongoing discussions about meeting the electricity needs of ENO's customers.

why Optimal used cost inputs at the absolute lowest level supported by its sample set. Optimal also admitted in discovery that it made no adjustments to account for changes to economies of scale attributable to the fact that its selected samples were from jurisdictions with state-wide programs, whereas Energy Smart is only available to customers in New Orleans.

Section 2

2. Planning Objectives and Principles

Under the Council's new IRP Rules, the planning process seeks to identify Portfolios of supply- and demand-side resources that could reliably meet customer power needs across a range of possible future Scenarios at the lowest reasonable supply cost, while considering risk. This work is particularly relevant given the ongoing evolution of the electric utility industry, and ENO's continued focus on meeting its customers' needs and expectations.

2.1 Planning Objectives

While the utility environment may be changing, ENO strives to achieve a balance between providing customers sustainably-sourced, reliable power, at the lowest reasonable supply cost, while considering risk. The ENO IRP was developed consistent with these objectives and in accordance with the following objectives articulated in Section 3 of the Council's IRP Rules:

1. Optimize the integration of supply-side resources and demand-side resources, while taking into account transmission and distribution, to provide New Orleans ratepayers with reliable electricity at the lowest practicable cost given an acceptable level of risk;
2. Maintain the Utility's financial integrity;
3. Anticipate and mitigate risks associated with fuel and market prices, environmental compliance costs, and other economic factors;
4. Support the resiliency and sustainability of the Utility's systems in New Orleans;
5. Comply with local, state and federal regulatory requirements and known policies (including such policies identified in the Initiating Resolution) established by the Council;
6. Evaluate the appropriateness of incorporating advances in technology, including, but not limited to, renewable energy, storage, and distributed energy resources ("DERs"), among others;
7. Achieve a range of acceptable risk in the trade-off between cost and risk; and
8. Maintain transparency and engagement with stakeholders throughout the IRP process by conducting technical conferences and providing for stakeholder feedback regarding the Planning Scenarios, Planning Strategies, input parameters, and assumptions.

2.2 Planning Principles

In designing Portfolios to achieve the planning objectives listed above, the planning process is guided by the following principles:

- ***Capacity*** - Provide adequate capacity to meet customer needs measured by non-coincident peak load plus a long-term planning reserve margin, accounting for impacts from DSM programs.
- ***Base Load Production Cost*** - Provide resources to economically meet base load requirements at reasonably stable prices.
- ***Load Following Production Cost*** - Provide economically dispatchable resources capable of responding to the varying needs of customers as driven by such factors as hourly demands, weather, and the integration of renewable generation.
- ***Modern Portfolio*** - Leverage modern, efficient supply alternatives
- ***Price Stability*** - Mitigate exposure to price volatility associated with uncertainties in fuel and purchased power costs.
- ***Supply Diversity*** - Mitigate exposure to risks that that may occur through concentration of Portfolio attributes such as technology, location, large capital commitments, or supply channels.
- ***In-Region Resources*** - Avoid overreliance on remote resources; provide adequate amounts and types of in-region resources to meet area needs reliably at a reasonable cost.

3. ENO Generation, Transmission, and Distribution

Generation

3.1 Current Fleet

As shown in Figure 1, below, which accounts for approved and planned resource additions, ENO has been successful in transforming its portfolio with reliable, efficient gas-fired generation, renewables generation, and load modifying resources to meet its supply needs.

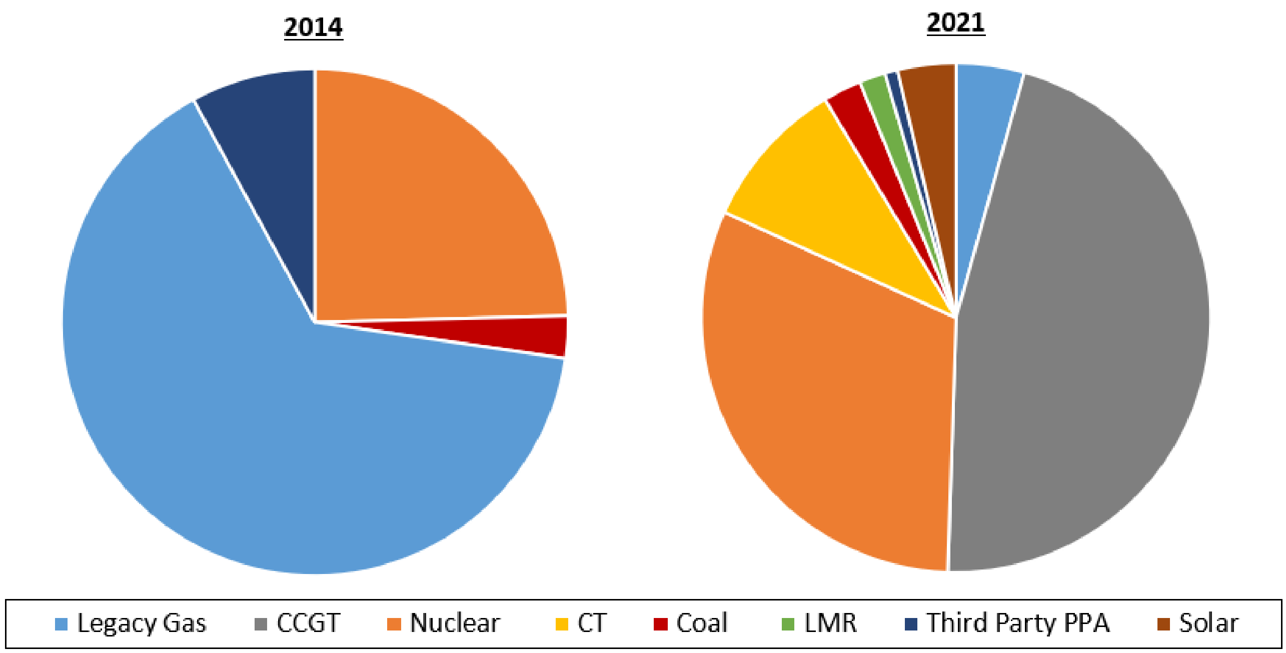

Figure 1: ENO's Evolving Portfolio

ENO currently controls about 1.2 GW of generating capacity either through direct ownership or contracts with affiliate Entergy Operating Companies and other counterparties. Table 1 below shows ENO's supply resources by fuel type measured in installed capacity with percentages of the overall Portfolio, taking into account existing units and planned additions.

Table 1: ENO's 2021 Resource Portfolio – Fuel Mix

ENO's Resource Portfolio: Fuel Type	MW	%
Coal	33	2%
Nuclear	422	30%
CCGT	623	45%
CT/ RICE	129	9%
Legacy Gas	58	4%
Solar	100	7%
Load Modifying Resources	22	2%
Third Party PPAs	11	1%
Total	**1,399**	**100%**

ENO's Portfolio by unit is shown in the table below.

Table 2: ENO's 2021 Resource Portfolio by Unit

Plant	Unit	MW	Fuel	Typical Operating Role	Operation Date
ANO	1	23	Nuclear	Base Load/ Load Following	1974
ANO	2	27	Nuclear	Base Load/ Load Following	1980
Acadia		7	Natural Gas	Base Load/ Load Following	2002
Grand Gulf ENMP		216	Nuclear	Base Load/ Load Following	1985
Grand Gulf ELMP		3	Nuclear	Base Load/ Load Following	1985
Grand Gulf EAMP		32	Nuclear	Base Load/ Load Following	1985
Independence	1	7	Coal	Base Load/ Load Following	1983
Little Gypsy	2	8	Natural Gas	Seasonal Load Following	1966
Little Gypsy	3	10	Natural Gas	Seasonal Load Following	1969
Ninemile	4	13	Natural Gas	Seasonal Load Following	1971
Ninemile	5	14	Natural Gas	Seasonal Load Following	1973
Ninemile	6	118	Natural Gas	Base Load/ Load Following	2015
Perryville	1	2	Natural Gas	Base Load/ Load Following	2002
Perryville	2	1	Natural Gas	Peaking	2001
Riverbend 30		99	Nuclear	Base Load/ Load Following	1986

Waterford	1	7	Natural Gas	Seasonal Load Following	1975
Waterford	2	7	Natural Gas	Seasonal Load Following	1975
Waterford	3	22	Nuclear	Base Load/ Load Following	1985
Waterford	4	1	Natural Gas	Peaking	2009
White Bluff	1	12	Coal	Base Load/ Load Following	1980
White Bluff	2	13	Coal	Base Load/ Load Following	1981
Sterlington 7A		1	Natural Gas	Peaking/ Reserves	1974
Union PB	1	496	Natural Gas	Base Load/ Load Following	2016
LMR (Load Modifying Resource)		22	N/A	Peaking/ Reserves	-
Third Party PPAs		11	N/A	N/A	-
New Orleans Power Station	1	128	Natural Gas	Peaking/ Reserves	2020
ENO Rooftop Solar Project	1	5	Solar	Peaking/ Reserves	2019
ENO Renewables RFP 2	1	50	Solar	Peaking/ Reserves	2021
ENO Renewables RFP 3	1	20	Solar	Peaking/ Reserves	2021
ENO Renewables RFP 4	1	20	Solar	Peaking/ Reserves	2021
ENOI Solar	1	5	Solar	Peaking/ Reserves	2021
Total	**-**	**1,399**			

3.2 Existing Fleet Deactivation Assumptions

The IRP includes deactivation assumptions for existing generation in order to plan for and evaluate the best options for replacing that capacity over the planning horizon. Based on current planning assumptions, during the planning period, the total net reduction in ENO's generating capacity from the anticipated unit deactivations is expected to be approximately 650 MWs. Generally, current planning assumptions reflect generic deactivation assumptions for the generation fleet: 60 years for coal and legacy gas resources, and 30 years for combustion turbine ("CT") technology (CTs and combined cycle gas turbines ("CCGTs")). As resources age and assumed deactivation dates near, as equipment failures occur, or as operating performance diminishes, cross-functional teams are assembled within the Company to evaluate whether to keep a particular unit in service for an additional length of time at an acceptable level of cost and reliability. These deactivation assumptions do not constitute a definitive deactivation schedule but are based upon the best available information and are used as planning tools to help prompt cross-functional reviews and recommendations.[5] It is not unusual for these assumptions to change over time, given the dynamic use and

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[5] In Council Resolution No. R-17-332, adopting the new IRP Rules, the Council found that the IRP should not be used to evaluate resource deactivation decisions. *See* R-17-332 at pg. 26. ("[T]he Council agrees that requiring the type of analysis

operating characteristics of generating resources. ENO's unit deactivation assumptions for the 2018 IRP are outlined below.[6]

3.2.1 Union Power Block 1

Deactivation currently assumed for Union 1 is 2033. This is a generic planning assumption only and does not reflect unit-specific analysis or decisions. As stated above, this resource will be reevaluated as it ages and operating conditions change. As shown in Table 2, above, Union 1 accounts for approximately 495 MW of capacity for ENO.

3.2.2 Affiliate PPAs

ENO receives allocations of several units through affiliate life-of-unit Purchased Power Agreements ("PPAs") that could deactivate during the planning period. These resource deactivations are assumed to total approximately 150 MW of capacity for ENO.

3.3 Load Forecasting Methodology

A wide range of factors will affect electric load over the planning horizon, including:

- Levels of economic activity and growth;
- The potential for technological change to affect the efficiency of electricity consumption;
- Potential changes in the purposes for which customers use electricity (e.g., replacement of vehicles that operate using internal combustion engines with vehicles that operate using electric motors);
- The potential adoption of end-use (behind-the-meter) self-generation technologies (e.g., rooftop solar panels); and
- The level of energy efficiency, conservation measures, and distributed generation adopted by customers.

Such factors may affect both the levels and patterns of electricity consumption in the future. Peak loads may be higher or lower than projected levels. Uncertainties in load levels and patterns may affect both the amount and type of resources required to efficiently meet customer needs in the future.

The long-term load forecast is an hour-by-hour, 20-year forecast of MW consumption. The preparation of the long-term load forecast involves two distinct and sequential processes: (1) electric sales forecasting and (2) load forecasting. In the first process, the monthly sales are forecasted assuming normal weather across the forecast horizon. The second process takes the monthly sales forecast and develops monthly peaks and allocates the monthly MWh to individual hourly MW based on hourly consumption profiles or shapes. These processes are discussed in more detail below.

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performed for resource retirement proceedings to be performed for every portfolio considered in an IRP process would be unduly burdensome and create a proceeding that would consume an unreasonable amount of time and resources.")

[6] It should be noted that actual deactivation decisions are confidential due to the commercial sensitivity of the decision.

For the 2018 IRP three load forecasts were produced as part of the analytical framework. As described further in Section 5: Portfolio Design Analytics, the IRP relies on a number of assumptions to assess Resource Portfolios across a range of economic outcomes. This includes sensitivities around the load forecast impacting both ENO, specifically, and the broader MISO market.[7]

Table 3: Forecast Sensitivities

Sensitivity	Drivers

Low	• Residential and Commercial customer growth rates decreased by 15% and 25% respectively
	  ○ Job growth does not materialize in the area
	  ○ Brick and mortar retail stores continue closing in the face of online competition
	  ○ Residential and Commercial Energy Efficiency increases 25%
	  ○ Energy efficient appliance technology continues to advance
	  ○ LED light bulbs continue to get cheaper with higher adoption
	  ○ Commercial electricity prices increase by 10% with elasticity of -0.2
	• Industrial
	  ○ Fewer new projects come online as well as reduced output from existing customers
	  ○ Large and Small Industrial growth rates decreased by 20%
	  ○ Customers add more cogeneration and solar to offset power consumption

Reference	• Louisiana's natural resources and tax structure create opportunities for new large and small industrial sales • Increases in heating and cooling efficiency • LED lighting becoming more affordable and common • Use per customer declines in Residential and Commercial, partially offset by growth in customer counts

[7] Pursuant to Council Resolution R-19-78, ENO and the Sewerage & Water Board of New Orleans ("S&WB") have formed a Joint Reliability Team ("JRT") to collaborate in developing solutions to help ensure the reliability of electric service to S&WB facilities, and to facilitate the transition of S&WB from relying on aging and inefficient generation at its Carrollton plant, to ENO as the primary source of reliable and economic power. The team has been engaged in discussions regarding the construction of a new transmission voltage substation adjacent to S&WB's Carrollton plant that would enable ENO to serve the S&WB's electric loads related to drainage pumping and water purification. It should be noted that the load forecast used in the IRP analysis does not include any assumption around load that might be added as a result of this long-term solution.

High	• Residential and Commercial customer count growth rate increased by 25% and 10% respectively
	    ○ Residential appliance energy efficiency decreased by 25%
	    ○ LED light bulb penetration weaker than anticipated
	• Department of Energy discontinues Energy Star program used to incentivize businesses to create more efficient appliances
	• Large and small industrial sales growth rates increased by 10% and realization of speculative projects

3.3.1 Sales Forecasting

The sales forecast is developed using a bottom-up approach by customer class – residential, commercial, large industrial, small industrial, and governmental. The High and the Low scenarios are sensitivities based on the Reference Case, which is the same as was used in the Company's 2019 Business Plan or "BP19". The Reference Case forecast was developed using historical sales volumes and customer counts, as well as historical and estimated normal weather, economic, and energy efficiency measures. In addition, the forecast includes estimates for future growth in large industrial usage as well as estimates of future growth from electric vehicles and declines due to future rooftop solar adoption.

For each sensitivity, the monthly sales forecasts are converted to hourly load forecasts using historical hourly load shapes and specific shapes for the daytime effects of rooftop solar. Because many of the drivers of the load forecast are assembled to first develop the underlying sales forecast in terms of annual MWh, many of the explanations below refer to the sales forecasts.

Overall, the compound annual growth rate ("CAGR") for 2019-2038 for the Reference Case forecast is 0.22%/year. This growth is primarily driven by growth for the industrial class of customers and is offset somewhat by slight growth for the residential, commercial, and governmental classes. Those forecasts are discussed further below.

Methodology: The sales forecasts for the residential, commercial, small industrial, and governmental classes are developed individually using statistical regression software and a mix of historical data and forward-looking data. The historical data primarily includes monthly sales volumes by class and temperature data expressed as cooling degree days ("CDDs") and heating degree days ("HDDs"). Some of the forecasts also use historical indices for elements such as population, employment, and levels of end-use consumption for things such as heating/cooling, refrigeration, and lighting. These historical data are used in econometric forecasting software called Metrix ND, which is licensed from Itron. This software is used to develop statistical relationships between historical consumption levels and explanatory variables such as weather, economic factors, and/or time periods and those relationships are applied going forward to estimates of normal weather, economic factors, and/or time periods to develop the forecast. Autoregressive and moving average variables are also included in the models to account for time series effects when significant. Explanatory variables are included in each forecast model if the significance is greater than 95%.

The sales forecasts assume weather to be "normal." For this purpose, normal weather is defined as a 20-

year average of temperatures by month. The use of 20 years strikes a reasonable balance between longer periods (30 years), which may take longer to pick up changing weather trends and shorter periods (10 years), which may not provide enough data points to smooth out volatility. The 20-year averages are built from hourly temperatures and are allocated to each calendar month based on the billing cycles for each month to ensure that the resulting averages appropriately consider the temperatures on the days when the power was consumed.

Residential: Growth in residential sales is expected to be relatively flat through 2038 with a forecast CAGR of 0.3%/year for 2019-2038 due to several factors. By 2021, residential sales are assumed to decline by 1.5% due to ENO's installation of the AMI metering and the accompanying consumption information that will be available to customers to help them manage their usage. The 1.5% expected reduction is the combination of a 1.75% reduction in electricity consumption offset by a 0.25% increase in billed sales related to unaccounted for energy. The decrement is phased in over three years starting in 2019. In addition, the forecast assumes future levels of energy efficiency putting downward pressure on electricity consumption. The energy efficiency is expected to come primarily from cooling and lighting and is based on future consumption estimates from the Energy Information Agency ("EIA") and is separate from company-sponsored DSM discussed further below. Overall, average annual kWh consumption per household is expected to decline by 0.3%/year for 2019 – 2038.

The monthly model for residential use per customer, taking into account expected efficiency, is:

Residential use per customer per day =

$$\textit{Heating Degree Days}_m * \textit{Heating efficiency index}_m * \textit{Heating coefficient}_m +$$

$$\textit{Cooling Degree Days}_m * \textit{Cooling efficiency index}_m * \textit{Cooling coefficient}_m +$$

$$\textit{other use coefficient} * \textit{other use efficiency index}_m$$

Forecasting use per billing day increases the monthly forecast accuracy because the days in a billing cycle vary from month to month. Monthly heating and cooling coefficients are used in the regression because generally a degree day in August has more effect than a degree day in May. Actual historical weather is used in the regression model. The twenty-year normal weather is used for forecasting normal sales.

Offsetting declines in use per customer are expectations for customer count growth. Based on historical growth in customer counts as well as expected future growth in the population and numbers of households in New Orleans, ENO has forecasted residential customer growth of 0.6%/year for 2019-2038. The combined effect of lower usage per customer ("UPC") (resulting from AMI, energy efficiency, etc.) and increasing customer count growth leads to a net forecasted CAGR in residential electricity sales of 0.3%/year for 2019-2038.

See Table 4 showing the breakdown for the 2019-2038 CAGRs in Residential energy, customer counts, and household counts.

Table 4: YoY Growth Residential

	2019-2038 CAGR
Energy	0.3%
Customers	0.6%
UPC	-0.3%

Commercial Forecast: Commercial sales are forecasted to have very modest growth for 2019-2038 with a CAGR of 0.1%/yr. This is being driven by forecasted customer count growth of 0.4% per year offset by commercial UPC declines of 0.3%/year.

The explanations for the commercial class are very similar to those for the residential class in that the commercial forecast includes a net decrement of 1.5% by 2021 (phased-in starting in 2019) for the AMI installations and related customer information that will be available to help customers manage their electricity usage. In addition, the commercial forecast accounts for increased energy efficiency, primarily from HVAC, lighting, and refrigeration, that is separate from company-sponsored DSM discussed further below.

Monthly commercial sales are forecasted in total rather than by use per customer because of the diversity of commercial customers.

$\textit{Commercial Sales}_m =$

$\textit{Heating Degree Days} * \textit{Heating efficiency index} * \textit{Heating coefficient}_m +$

$\textit{Cooling Degree Days} * \textit{Cooling efficiency index} * \textit{Cooling coefficient}_m +$

$\textit{other use coefficient} * \textit{other use efficiency index}_m$

See Table 5 showing the breakdown for the 2019-2038 CAGRs for commercial sales, commercial customer counts, and average use per customer.

Table 5: YoY Growth Commercial

	2019-2038 CAGR
Energy	0.1%
Customers	0.4%
UPC	-0.3%

DSM: The forecast for ENO also considers the effects of company-sponsored DSM programs. Historical levels of DSM effects are added back to historical sales to produce an initial forecast as if there had been no DSM. The estimated future levels of DSM are then subtracted from the forecasted levels based on the accumulated and carry-forward effects of historical programs as well as budgeted estimates for future DSM savings. For example, a program from two years prior to encourage conversion of incandescent lighting to LED lighting is still expected to lower consumption this year and beyond as the newer, more efficient lighting continues to operate. As such, DSM programs have useful lives that extend beyond the first measure year of the program. The DSM effects are calculated at the class level for residential and commercial sales and reduce the forecasted load based on the residential and commercial load shapes and the expected future DSM volumes. ENO's DSM programs are expected to reduce Residential and Commercial sales by 2% and 3.5%, respectively, for 2019 and by almost 4% and 9%, respectively, by 2038.

Electric Vehicles ("EVs") and Solar: Forecasts for incremental EVs and rooftop solar are included in the base residential and commercial forecasts.

The EV forecast is based on the estimated historical EV adoption rates in Louisiana and allocated to New Orleans based on population since vehicles are registered at the state level and not at the parish level. Future levels of EV adoption and related electricity consumption are projected based on a long-term adoption curve that assumes 95% of all light-duty vehicles will be powered by electricity by the year 2100. By 2038, EVs are expected to add just under 2% to ENO's residential and commercial electricity consumption.

The rooftop solar forecast is based on historical adoption levels as well as future estimates for the installed costs of rooftop panels, tax incentives, and electricity prices. In the base forecast, future levels of rooftop solar adoption are relatively low due to the low electricity prices in New Orleans and the end of state tax credits. By 2038, incremental rooftop solar additions are expected to reduce electricity consumption by less than 2%.

Industrial Growth: The industrial class of customers is divided into two groups, small and large. The customers in the large industrial class are forecasted individually and are the main growth driver in the forecast overall. The 2019-2038 CAGR for ENO large industrial sales is 0.95%/year. Forecasts for new or prospective large industrials are based on information from the new/prospective customer and ENO's Economic Development team as to their expected MW size, operating profile, and ramping schedule. The forecasts are also risk-adjusted based on the status of the customer along the path of signing an electric service agreement and progress towards achieving commercial operations. Existing industrial customers are forecasted based on historical usage, planned future outages, expansions or contractions.

The small industrial forecast includes industrial sales that are not forecast individually in the large industrial forecast described above. Forecasts are based on historical trends and IHS economic indices for labor force, refining, and chemicals. Small industrial sales can be volatile and are generally not temperature related.

See Table 6 for the forecasted year-over-year growth in sales to industrials.

Table 6: Industrial Growth

YoY Growth in:	2019 - 2025 CAGR
Large Industrial Energy Sales	0.95%
Small Industrial Energy Sales	0.05%
Total Industrial Energy Sales	0.68%

3.3.2 Load Forecasting

The long-term hourly load forecast is the result of the calibration of a monthly peak forecast, the monthly sales forecast, and estimated load shapes for each customer class.

Like the process used for the sales forecast, twenty years of normal weather data is used to convert historical load shapes into "normal load shapes." This adjusts the historical consumption profiles by month and hour for year-over-year changes in days of the week, holiday schedules, and temperatures. For example, if the actual sales for ENO's residential customers occurred during very hot weather conditions, the normal load shape would flatten the historic load shape. If the actual weather were mild, the normal load shape would raise the historic load shape. Each customer class reacts differently to weather, so each has its own weather response function.

The peak forecast is developed using historical calendarized sales, historical peaks, and degree days to develop relationships between peaks and energy. Those relationships are applied to the forecasted energy and use normal weather for the future forecast period.

As mentioned previously, the forecasted energy, the forecasted peaks, and the forecasted hourly profiles are calibrated together to ensure that all the forecasted energy is accounted for while maintaining, as closely as possible, the forecasted peaks and shapes. Typical load shapes for incremental solar and electric vehicle consumption are used to allocate reduced or increased consumption to the appropriate month, day, and hour of electricity use. The final load forecasts are grossed up to include transmission and distribution losses, which are computed by class. The resulting forecast is for estimated hourly load at the generator.

3.4 Resource Portfolio Needs

3.4.1 Long-term Capacity Considerations

Consistent with its planning guidelines, ENO plans to meet its projected peak load requirement plus a 12 percent planning reserve margin based on installed capacity for conventional generation and effective capacity for renewable generation. The requirements shown below reflect this assumption and are adjusted to account for ENO's current Resource Portfolio reflected in

Table *1* and Table 2 above. The requirements evolve over time as forecasted energy use changes and resources are assumed to deactivate. The Low, Medium, and High load sensitivities attempt to bookend the effect that changes to customer use patterns could have on ENO's energy and peak requirements.

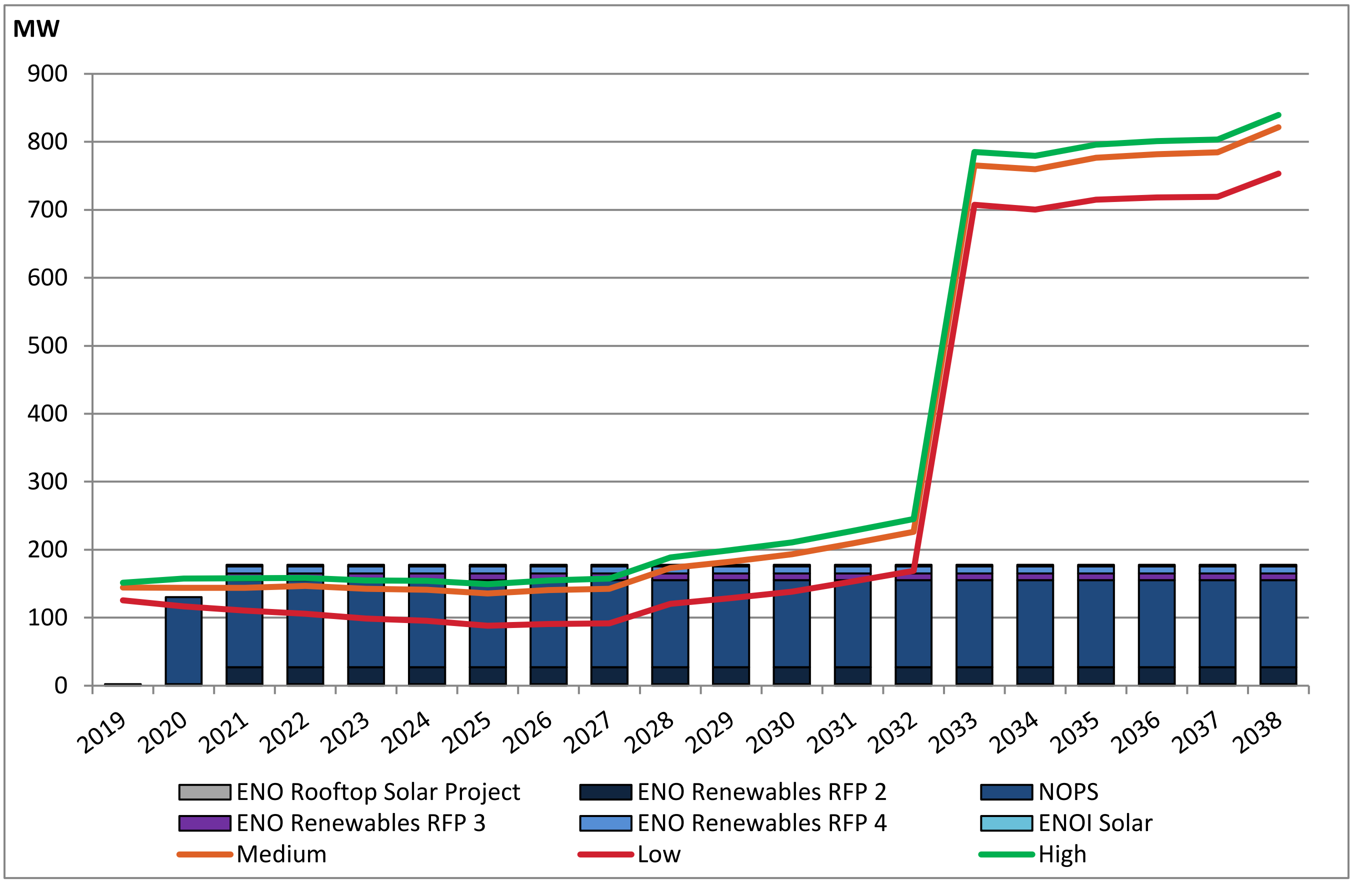

Figure 2: ENO's Projected Long-Term Resource Requirements

Given approved and planned resource additions, across each forecasted load sensitivity ENO expects that around 600 MW of replacement capacity is necessary to account for deactivating generation and load growth over the 20-year planning horizon.

3.4.2 ENO's Expected Energy Coverage

Shown below is ENO's annual projected energy generation based on the expected commitment and dispatch of its total allocated share of resources in MISO's energy market. This is compared to the total amount of ENO's forecasted annual energy requirements. Any gap between generation and load on an annual basis indicates net purchases from the MISO market, and as such, is an indication of the magnitude of customer energy price exposure.

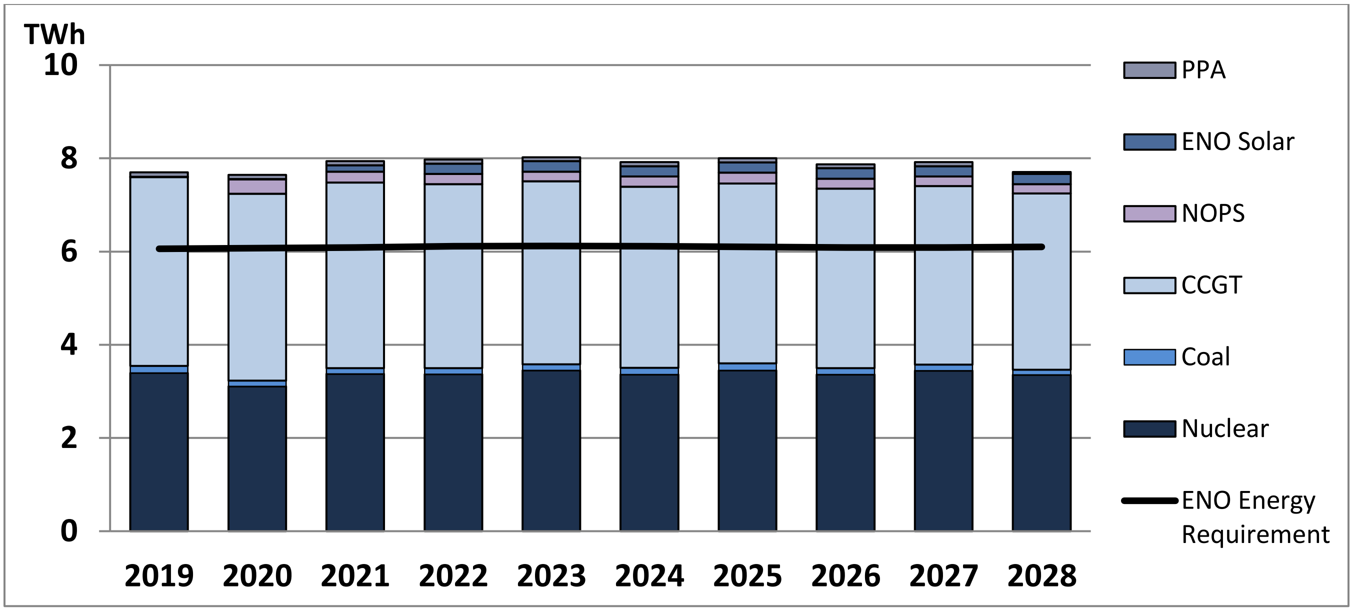

Figure 3: ENO's Expected Energy Coverage

ENO is expected to remain a net seller in MISO's energy markets during the planning horizon. This energy position provides price stability for ENO's customers relative to MISO's day ahead and real time energy markets for economic energy consistent with ENO's guiding principles of maintaining Base Load Production Costs and Price Stability.

3.4.3 Resource Life Assumptions

ENO must make assumptions regarding the longevity of generating assets to conduct Portfolio analytics. For CT and CCGT technology, consistent with guidance from the Electric Power Research Institute ("EPRI"), ENO assumes a 30-year useful life unless unit-specific information is available to support a different assumption.

ENO maintains generic useful life assumptions of 30 years and 25 years for tracking solar and onshore wind respectively due to its lack of experience with renewables having operated to the end of their useful lives and deactivated. As more information on useful life of renewables becomes available ENO will look to update these assumptions.

As with all assets in its Portfolio, ENO evaluates whether to make investments necessary to keep a particular unit in service for an additional period of time at an acceptable level of operational reliability as the unit nears the end of its assumed useful life, as equipment failures at the unit occur, or as unit operating performance diminishes.

3.5 Summary of Types of Resources Needed

As discussed in Section 4.2, there are a number of supply-side and demand-side alternatives available to address ENO's long-term resource needs. These include incremental long-term resource additions from self-supply alternatives, acquisitions, and long-term PPAs. Demand-side alternatives including Energy

Efficiency, Demand Response, and customer-focused products and services can also provide solutions to meet long-term needs.

The Portfolio design analytics outlined in more detail below explore the value of renewables, dispatchable supply-side alternatives, and demand-side measures. As the solar industry matures and the capital costs associated with these resources continue to decline, solar is anticipated to become increasingly feasible as a utility-scale supply solution. As intermittent generating additions increase, and ENO's legacy fleet deactivates, ENO will require additional flexible and quick-start capability. ENO will continue to assess this need over the long-term planning horizon.

Transmission

3.6 Participation in MISO

ENO has been a market participant in the MISO Regional Transmission Organization ("RTO") since December 19, 2013. MISO is a non-profit, member-based organization, which exists to provide an independent platform for efficient regional energy markets. MISO conducts transmission planning and manages buying and selling of wholesale electricity across 15 U.S. states and the Canadian province of Manitoba.

As shown below, ENO is located within Local Resource Zone ("LRZ") 9 of the MISO footprint.

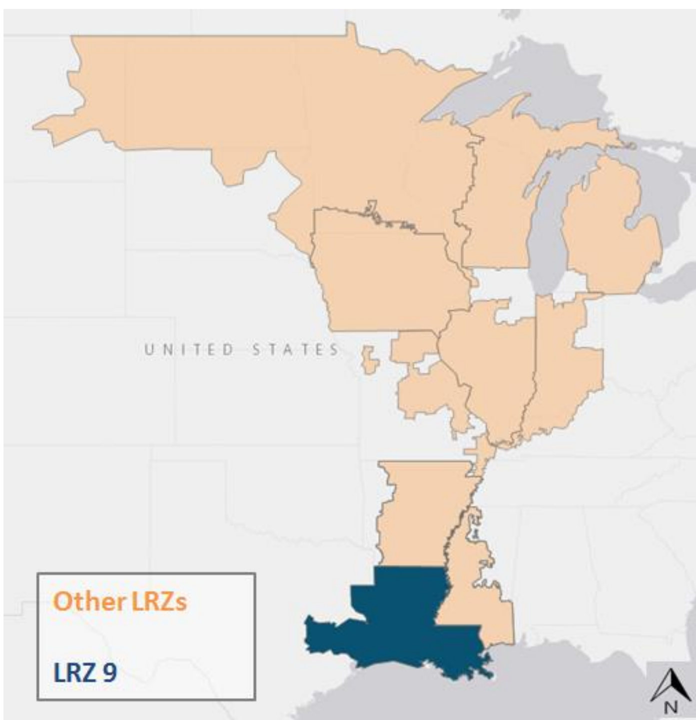

Figure 4: LRZ 9 within MISO

As a MISO member, ENO has access to a large, structured market that enhances the resource alternatives available to meet customers' near-term power needs. Over the long term, risk associated with the availability and price of power in the MISO market affects ENO's resource planning. Additionally, ENO retains responsibility for providing safe and reliable service to its customers. Thus, the 2018 ENO IRP is designed to help ensure development of a long-term integrated resource plan for ENO that reflects that responsibility and balances the objective of minimizing the cost of service while considering factors that affect risk and reliability.

3.7 Transmission Planning

The Company's transmission planning ensures that its transmission system:

(1) remains compliant with applicable North American Electric Reliability Corporation ("NERC") standards and the Company's related local planning criteria, and

(2) is designed to efficiently deliver energy to end use customers at a reasonable cost. Since joining MISO, ENO also plans its transmission system in accordance with the MISO Tariff.

Expansion of, and enhancements to, transmission facilities must be planned well in advance of the need for such improvements given that regulatory approvals, right-of-way acquisition, and construction can take years to complete. Advanced planning requires that computer models be used to evaluate the transmission system in future years, taking into account the planned uses of the system, generation and load forecasts, and planned transmission facilities. On an annual basis, the Company's Transmission Planning Group performs analyses to determine the reliability and economic performance needs of ENO's portion of the interconnected transmission system. The projects developed are included in the Long Term Transmission Plan ("LTTP") for submission to the MISO Transmission Expansion Planning ("MTEP") process as part of a bottom up planning process for MISO's consideration and review. The LTTP consists of transmission projects planned to be in service in an ensuing 10-year planning period. The projects included in the LTTP serve several purposes: to address specific customer needs, to provide economic benefit to customers, to meet NERC transmission planning reliability standards, to facilitate incremental load additions, and to enable transmission service to be sold and generators to interconnect to the electric grid.

A key aspect of ENO's engagement with MISO is its active participation in MISO's bottom up reliability planning process. This process is designed to ensure that the performance of the ENO transmission system continues to meet reliability standards and is also a key input into MISO's Market Congestion Planning Study ("MCPS") process. Through the MCPS, transmission system efficiency is ensured by monitoring and eliminating congestion when benefits outweigh costs. Reliability projects submitted by Transmission Owners are reviewed to determine if potential synergies exist between congestion relief and reliability.

In the case of ENO's transmission system, the baseline reliability plan that includes both transmission upgrades and the New Orleans Power Station currently under construction is expected to ensure compliance with NERC requirements for reliability of the bulk electric system by reducing the risk of cascading outages in New Orleans. In addition, that reliability plan is expected to eliminate much of the congestion in the ENO footprint. The levels of congestion remaining in the ENO footprint once those projects are placed in service are projected to be minimal and thus do not justify additional transmission projects at this time. ENO has identified various reliability projects through the MISO process since 2013.

Recent transmission projects resulting in reliability and congestion benefits in the ENO service area include the Ninemile to Derbigny and Ninemile – Napoleon 230 kV line upgrades (completed in 2016) and the Paterson to Pontchartrain Park 115 kV Line Reconductor (projected to be completed at the end of 2019).

Details of the ENO LTTP projects can be found in the current and past MISO MTEP reports.[8]

3.7.1 Integration of Transmission and Resource Planning

The availability and location of current and future generation on the transmission system can have a significant impact on the long-term transmission plan, the requirements for meeting NERC reliability standards, and efficiently delivering energy to customers at a reasonable cost. Like transmission, new generation must be planned well in advance, and due to the interrelationship of generation and transmission planning, looking far enough into the future and addressing potential supply needs is critical in meeting ENO's planning objectives of cost, reliability, and risk. As part of its ongoing planning process, ENO considers transmission and capacity requirements and the impacts of generation siting on transmission reliability and voltage support.

Inverter-based technology, including solar PV, can produce significant energy benefits and fill an important role as part of ENO's resource mix. However, consideration must be given to the increased role that dispatchable resources may need to play in maintaining regional reliability as reliance on inverter-based resources increase. First, it is important to note that the load in the region just after sunset is often only slightly less than the peak load for that day. In fact, there are times when the daily peak for the city of New Orleans actually occurs at night. Thus, conventional resources must be capable of quickly ramping up to offset the loss of solar PV energy as the sun sets. Second, inverter-based resources do not contribute to system inertia, which is produced by the rotating mass of conventional resources and which allows the entire electrical system to resist changes to system frequency and maintain stable operating characteristics. Going forward, as the role of renewables increases in ENO's resource portfolio, it will be important to consider transmission projects and the need for supportive dispatchable generation to ensure reliability and economic planning principles are met.

The Resource Portfolios identified through the IRP analysis are designed based on energy import/export capability between MISO South and North. These Portfolios are designed primarily to meet projected capacity and energy needs as prescribed by ENO's guiding principles and Council policies. While the implementation of a sound transmission plan is necessary to ensure reliability and can facilitate the efficient flow of energy within a system, it does not address capacity needs. Other analyses, which are part of ongoing planning processes, such as for the siting of specific future generation resources, will take into account transmission planning by applying the transmission topology, including approved MISO MTEP projects.

[8] https://www.misoenergy.org/planning/planning/

3.8 Resource Adequacy and Planning Reserve Requirements

As a load serving entity ("LSE") within MISO, ENO is responsible for planning and maintaining a Resource Portfolio to meet its customers' power needs. To meet its customers' needs, ENO must maintain the right type and amount of capacity in its Portfolio. With respect to the amount of capacity, two considerations are relevant: 1) MISO Resource Adequacy Requirements; and 2) Long-Term Planning Reserve Margin Targets.

3.8.1 MISO Resource Adequacy Requirements

Resource Adequacy is the process by which MISO obligates participating LSEs to procure sufficient capacity, through the procurement of zonal resource credits ("ZRC") equal to their Planning Reserve Margin Requirement ("PRMR") in order to ensure regional reliability. ZRCs are provided by both supply-side generation and demand side alternatives. An LSE's PRMR is based on its forecasted peak load coincident with MISO's forecasted peak load, plus a planning reserve margin established by MISO annually for the MISO footprint.

Under MISO's Resource Adequacy process, the planning reserve margin is determined annually by November 1st prior to the upcoming planning year (June - May). Additionally, through MISO's annual Resource Adequacy process, MISO determines the annual capacity needs for a particular region or LRZ based on load requirements, capability of the existing generation, and import capability of the LRZ. Those generation needs are articulated through a Local Clearing Requirement for the LRZ for each Planning Year.

At present, the MISO Resource Adequacy process is a short-term construct. Requirements are set annually and apply only to the next year. Similarly, the cost of zonal resource credits, as determined annually through the MISO auction process, apply only to the forthcoming year. Both the level of required ZRCs and the cost of those ZRCs are subject to change from year to year. In particular, the cost of ZRCs can change quickly as a result of, among other things, changes in bidding strategy of market participants, the availability of generation within MISO and a specific LRZ, and an LRZ's Local Clearing Requirement. As a result, although the MISO Resource Adequacy process establishes minimum requirements that must be met in the short term and are reviewed regularly as part of the resource planning process, it does not provide an appropriate basis for determining ENO's long-term resource needs. In other words, and as the Council has previously acknowledged, relying on the short-term market for ZRCs to meet customers' long-term power needs involves significant risk. A more stable basis for long-term planning is needed if ENO is to meet its long-term planning objectives.

3.8.2 Long-Term Planning Reserve Margin Targets

ENO plans to meet its projected peak load, plus a 12 percent planning reserve margin, based on installed capacity. The long-term planning reserve margin is intended as a generation supply safety margin to maintain reliable service during unplanned events, like generating unit outages and extreme weather, over the long-term planning horizon, while still benefitting from participation in MISO's broader energy markets. This long-term planning approach (as opposed to relying heavily on MISO's short-term capacity and energy markets) not only helps reduce unnecessary reliability and economic risk to customers but also allows ENO to be more agile in serving customers' needs.

3.9 Distribution

3.9.1 DER/Distribution Planning Requirements

Section 6.E. of the Council's new IRP Rules requires that ENO evaluate the extent to which reliability of the distribution system can be improved through the strategic location of distributed energy resources or other resources identified as part of the IRP planning process. To the extent ENO does not currently have the capability to meet this requirement, it is required to demonstrate progress toward developing this capability in its IRP report.

In response to this requirement, the following section explains in detail various steps being undertaken to implement foundational systems, software, and processes that will be necessary for ENO to develop the ability to evaluate locational and reliability benefits and impacts of DERs in the future.

3.9.2 Company Work to Develop DER Planning Capabilities

The Company discussed the three pillars of its plan for grid modernization in the Grid Modernization and Smart Cities Report filed April 10, 2018, in Docket UD-18-01: 1) Upgrading existing Grid Infrastructure with newer assets to improve reliability and support technologically advanced options for meeting customers' needs, 2) Deploying Grid Technology to collect, analyze, and deliver information for real time decision making and automation, and 3) Advanced Planning processes that will leverage the data received from the modern grid technologies to enable the Company to meet customer demands for interconnection of DERs while improving reliability and resiliency.[9]

3.9.3 Grid Infrastructure

The first pillar, upgrading existing grid infrastructure, is being addressed through reliability work the Company has identified in filings to the Council in Docket UD-17-04.[10] That work is ongoing and continues to be the subject of periodic progress reports. This pillar is also being addressed through the Grid Modernization projects reported in Dockets UD-18-01 and UD-18-07. Specifically, Docket UD-18-01 is considering how certain Smart City functionalities can be enabled by Grid Modernization and how those applications can benefit all residents of New Orleans in an equitable manner. In Docket UD-18-07, ENO has proposed for the Council's review and approval: (i) a process for reviewing the planning and execution of all Grid Modernization projects for ENO's distribution grid, and (ii) a cost recovery mechanism (the Distribution Grid Modernization Rider, or Rider DGM) that would enable ENO to modernize the distribution grid in New Orleans in the most cost-efficient and timely manner possible.

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9 Grid Modernization and Smart Cities Report, at 5-6.

10 *See*, ENO Reliability Plan (November 11, 2017), Quanta Assessment (October 31, 2018), and ENO 2019 Reliability Plan (January 18, 2019)

3.9.4 Smart Infrastructure & Software Systems

The second pillar, deploying grid technology, is being pursued through several deployments of smart infrastructure and software systems. The foundational investment of AMI, specifically implementation of the communications network, head-end system, and advanced meter installations as approved through Docket UD-16-04, will enable enhanced sensing and awareness of the distribution grid. The advanced meters act as smart sensors on the distribution grid to inform other systems on the status of the grid. This information will be integrated with other data sources such as customer phone calls and input from ENO's Supervisory Control and Data Acquisition ("SCADA") system into a new Distribution Management and Outage Management ("DMS/OMS") system.

The distribution management system ("DMS") is a software platform that supports the full suite of distribution management and the optimization of the distribution grid. The DMS platform utilizes all available information collected from AMI meters, Distribution Automation ("DA") enabled devices, asset topology, and SCADA to perform load flow modeling. The DMS enables several smart grid capabilities including fault location, isolation, and restoration ("FLISR"), volt/volt-ampere (var) optimization, and integration of distributed resources. The ability to monitor and actively manage the distribution grid with real time sensing and analysis is foundational to enable future safe and reliable operation for all of ENO's customers.

An outage management system ("OMS") is a utility network management software application that models network topology for safe and efficient field operations related to outage restoration. The OMS tightly integrates with the call centers to provide timely, accurate, customer-specific outage information, and with the SCADA system for real-time confirmed switching and breaker operations. These systems track, group, and display outages to safely and efficiently manage service restoration activities.

Combined, the DMS and OMS systems will deliver several important grid management capabilities complementary to AMI:

- Distribution Grid Analysis: The ability to perform distribution planning, as well as operational analysis to support strong engineering and quality improvement. This will enable engineers to visualize how the distribution system should be built and set the state for optimization by placing electrical equipment at appropriate locations along the feeders, and
- Distribution Grid restoration: This capability will provide maximum value when major events, such as hurricanes, ice storms, and wind storms, stress system operations. Operations change significantly during major events, so dedicated outage management software is required. With this capability, utilities can model network topology and correlate incidents with customers, assets, and crews. The OMS system is expected to enable predictive analysis for fault location during outage events, improved estimation of restoration times, and analysis for management of crews assisting in restoration and calculation of manpower needed in outage events. The OMS system models how each customer is connected to the network and can provide critical information necessary to calculate network performance indices.

The DMS/OMS deployment is coordinated with the deployment of the AMI meters and is expected to be fully operational in 2020.

In September 2018, ENO replaced and consolidated its transmission and distribution data historian systems to allow users easier access to SCADA information and increase the rate of data retrieval. The new SCADA historian, Pi Historian, enables users to graphically view analog data, recognize trends, and customize displays. The Pi Historian is a foundational investment to collect and analyze important grid information that will be utilized in the advanced planning process. The costs associated with DMS/OMS, which includes Pi Historian, were approved by the Council in conjunction with approval of the deployment of AMI. ENO continues to submit quarterly reports to the Council and Advisors concerning the progress with and cost of AMI deployment, including the integration of these foundational components, which are necessary to achieve the goal of optimizing the distribution grid as described in the IRP Rules.

To help facilitate transition to the new Distribution Management system, additional important functionality is being deployed through the Enterprise Asset Management ("EAM") project. EAM seeks to install an integrated system to manage the asset, maintenance, renewal, and replacement records of all distribution, transmission, gas, and transportation fleet assets. The combination of technology and the redesign of processes will modernize and significantly improve the way ENO and the other Entergy Operating Companies manage the assets used to serve customers, while also providing functionalities required to execute on the goal describe in the Rules.

Integration of work processes and systems allows a more streamlined approach to, and greater ability to track, work across field operations, customer contact centers, and back office operations to provide an improved overall customer experience. The EAM project consists of the: 1) EAM System, 2) a modernized Workforce Management System ("WFMS"), 3) Field Mobility Devices, 4) verification, collection, and correction of the current asset records, 5) an advanced Geospatial Information System ("GIS"), and 6) Intelligent Electronic Device Management System ("IEDMS"). As ENO and the other Entergy Operating Companies continue to move through the EAM project, ENO will be able to develop and disclose a more refined cost estimate of these initiatives. However, at present time, a high-level estimate of the costs associated with the EAM project for ENO is approximately $17 million. More information on the components of the EAM project are below.

<u>EAM System</u>:

The EAM system, which will use IBM's Maximo Asset Management software ("Maximo"), will enable more proactive asset maintenance, renewal, and replacement policies and practices, as well as more complete and more accurate asset history records. Using an EAM System like Maximo creates the opportunity to have a single platform to record asset information (e.g., manufacturer, date installed, and model number), track asset performance (installation and retirement dates, any available asset health information from testing if available) and derive asset-centric analytics for a variety of utility assets.

<u>WFMS & Field Mobility Devices</u>:

Integrated into the EAM system, a modernized WFMS will empower field employees to make real-time, asset-driven maintenance, renewal, and replacement decisions and provide them the latest technology devices. A new WFMS uses advanced work, schedule, and route optimization algorithms to facilitate more efficient job routing and completion.

Asset Data Inventory:

The EAM project includes analysis and validation of existing asset data in addition to the capture and inventory of new asset data because data quality is critical to the success of any system implementation.

Geographic Information System ("GIS"):

To properly calculate and model real time conditions of the distribution grid, all changes must be captured and incorporated into the model on a timely basis. ENO is currently making enhancements to its business processes to update its GIS with the necessary frequency. ENO's system architecture syncs all relevant asset data into a network-connected model that serves as the basis for the DMS/OMS analysis. An accurate network model is critical to distribution grid management especially with the addition of distributed energy resources that can change the potential load flows on the distribution system. This project seeks to implement a new map layer or land-base inside a new GIS system so additional layers of data such as transmission and distribution line routes can be easily located on a map. The application included in the project estimate is an enterprise license for ESRI ArcGIS. The ArcGIS enterprise application allows multiple sources of data to be viewed in a single web-based platform.

Intelligent Electronic Device Management System ("IEDMS"):

An IEDMS is a collection of software packages that act as a data warehouse for settings and configurations of relays and smart devices for both transmission and distribution.

Other smart grid technologies being deployed are DA devices that are installed on the distribution grid and communicate the status and configuration of the distribution grid through the AMI integrated communication network to the DMS/OMS. The DA devices work in conjunction with the AMI meter data and the DMS/OMS system to automatically reconfigure the path of power to isolate any outage conditions and restore power to unaffected customers. The DA devices will provide additional monitoring of the system and introduce control of the distribution grid. DA devices are another foundational technology required to safely and reliably incorporate distributed resources on to the distribution grid. DA enabled devices also facilitate the mitigation of line losses through the active management of reactive power (vars) that can result in reduced fuel costs for customers. DA-enabled devices require the AMI communication network for status and control functions and are being deployed as a part of the Grid Modernization projects proposed in Docket UD-18-07. ENO provided the cost estimates associated with the first five Grid Modernization projects, including the DA-related components, in Docket UD-18-07 and intends to continue submitting cost estimates of new Grid Modernization projects to the Council in conjunction with the process ENO has proposed for Council review and approval of such future projects. As demonstrated by testimony submitted in Docket UD-18-07, the Council's approval of this proposed process, as well as the proposed Rider DGM, will enable execution and completion of Grid Modernization work in the most timely and cost-efficient manner possible.

Additionally, ENO is actively monitoring the commercial availability of products and components for a Distributed Energy Management System ("DERMS"). A DERMS is a system that integrates with ENO's other new technologies to enable the monitoring and control of distributed energy resources on the ENO distribution grid. ENO will continue to develop the IT system architecture to support the enhanced capabilities of a DERMS, but the foundational Grid Modernization investments described above must be in place before a full-scale DERMS will be viable.

3.9.5 Advanced Planning

The third pillar, developing advanced planning processes, is focused on providing planning, engineering, and related technical services to support adoption of both customer-owned and Company-owned DERs. As noted above, in Docket UD-18-07, ENO has proposed for the Council's review and approval a process for reviewing the planning and execution of all Grid Modernization projects for ENO's distribution grid. The Grid Modernization projects were developed through a planning approach that begins with the customer experience. The new planning criteria consider upgrades to the distribution system that enable the integration of DERs in addition to minimizing the likelihood that customers in particular areas will experience interruptions. The new planning criteria include analysis to consider loading from traditional growth, DER penetration, and potential for electrification. The Grid Modernization projects represent ENO's efforts to take concrete and immediate steps to prepare ENO's distribution system for new capabilities. The addition of smart infrastructure and technology as described above will continue to improve the data available for distribution planners to evaluate projects for ENO.

Currently, the distribution planning organization supports the system impact studies for customers requesting interconnection of DERs to ENO's distribution grid. As these requests increase, ENO will require resources to conduct the additional analysis and design potential infrastructure projects necessary to support the addition of distributed resources. Efforts are being made to identify personnel, knowledge, and skills that will be needed to accommodate higher penetrations of DERs on the distribution grid. This includes reviewing how best to utilize existing tools, what new tools or analysis will be needed, how to work with transmission planning, and how to train engineers in these new areas. It is important to create effective interconnection processes and standards that use data to understand the effects and impacts of DERs on the grid.

Customers today are adopting DERs without the Company fully understanding the operational and/or grid impacts. To address this issue, Entergy Corporation's Transformation organization is leading two efforts to improve the distribution planning process, one focused on improving the studies performed today in the Company's current engineering software, and the other focused on implementing new tools with advanced analytics to better forecast adoption impacts to the distribution system.

In the first effort, ENO is working with Quanta Technologies to develop a process to model and study various DER program impacts on the distribution system using our existing engineering software. These studies utilize customer load and generation shapes, along with projected adoption rates, to demonstrate the impacts of DER programs on a distribution feeder. This study will allow ENO to better plan for increased penetrations of DER programs and demonstrate their value as Non-Wire Alternatives ("NWAs"). Following completion of the studies and planning methodology by Quanta, Company engineers will be fully briefed and trained in the use of any new processes.

Additionally, the Transformation organization is working with Integral Analytics to deploy additional software to support the analysis of DER penetration. ENO is implementing a new software package, LoadSEER, a spatial load forecasting tool which can integrate with the current planning analysis software, SynerGi. Together, along with AMI, its associated software applications, and resulting data, these tools will enable the Company to prioritize distribution grid needs in light of planned DER and DSM projects, perform locational analyses, and develop traditional (i.e., distribution asset) or alternative (i.e., non-wires) solutions to address grid needs. The upfront license and implementation cost for LoadSEER is approximately $395K, with an ongoing annual maintenance cost of about $80K.

Another Transformation organization workstream is addressing the need for formalized DER standards to help avoid grid reliability and safety concerns. The team, alongside distribution planning, is working with the distribution and transmission design basis groups to develop technical specifications, requirements, and standards for better integration of customer- and Entergy-owned DERs. The joint effort is also developing a streamlined interconnection study process to reduce time required to perform studies for DER interconnection applications, while using industry-standard practices to ensure adequacy of results.

Figure 5, below, depicts the systems and processes being addressed through the Transformation organization efforts:

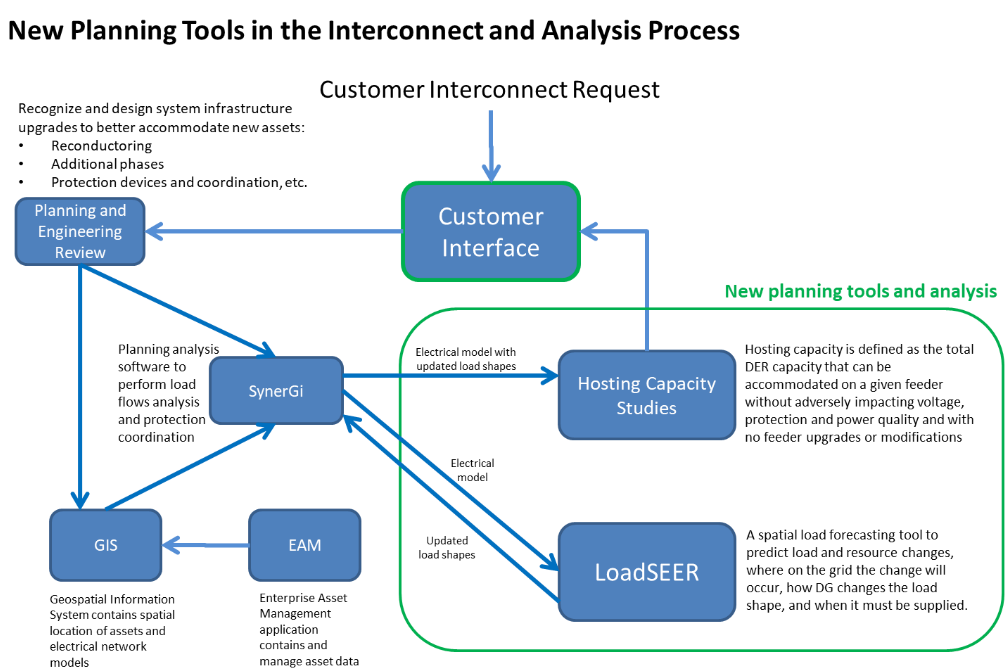

Figure 5: New Planning Tools in the Interconnect and Analysis Process

In summary, the investments being made over the next two years to implement the smart infrastructure of AMI and DA-enabled devices and the smart systems of DMS/OMS and LoadSEER will provide essential components of the foundation for ENO to develop the capability of evaluating DERs for safe and reliable integration into the ENO grid in the future. Grid Modernization constitutes another broader, yet necessary component, required to enable optimal integration of DERs and other advanced functionalities into the distribution grid.

3.10 DOE Grant Proposal—DERadio

In addition to the workstreams and implementations described above, the Company also recently pursued a DOE grant for functionality that could facilitate more robust integration and operation of DERs in the future. The project, known as DERadio (Distributed Energy Resources Analytics, Dispatch, Interoperability and Optimization), would have built a foundational element of a robust, secure, and interoperable infrastructure utilizing utility-scale solar PV, energy storage systems, residential solar PV and controllable loads on the ENO system. The project would have sought to develop and demonstrate a novel, vendor-agnostic platform at the grid edge to enhance situational awareness of DERs and strengthen the cyber and physical security and resilience for the ENO distribution grid and its critical customer infrastructure. This solution would have addressed several industry core needs such as enhanced monitoring and analysis of solar energy systems, distributed control at the grid edge, dynamic energy dispatch for both normal grid operations and emergent outage operations, and facilitated interoperability of a diverse array of DERs to provide reliable, secure and resilient electricity for critical infrastructure. While this grant proposal was not selected, the Company plans to continue looking for innovative approaches to develop and monitor the distribution grid in New Orleans.

Section 4

4. Planning Assumptions, Inputs, and Considerations

The IRP analysis is built on a variety of planning assumptions and inputs. As required by the IRP Rules and Initiating Resolution, these assumptions and inputs were the focus of presentations and discussions among ENO, the Advisors, and the Intervenors at Technical Meetings held as part of the Stakeholder process. This 2018 IRP uses the assumptions and inputs developed in the Company's 2019 Business Plan, which was the most current as of the December 7, 2018 procedural deadline for finalizing the inputs. Also, as stipulated in the procedural schedule, this IRP incorporates the policies articulated by the Council as of October 31, 2018.[11]

4.1 Evolving Customer Preferences

In developing this 2018 IRP, ENO recognized that customer expectations of the utility are changing due to advances in technology and customers' own evolving priorities. Customers increasingly want and rely on technology and innovations that give them more control over parts of their daily lives that historically were overseen or provided by third parties. The available mix of technologies used to generate and control electricity in homes, factories, and businesses has changed, impacting the way customers think about electricity. Additionally, customers are increasingly interested in the use of cleaner, more sustainable energy sources.

[11] With Council Resolution No. R-19-109, dated March 28, 2019, the Council opened a rulemaking to consider, among other things, whether to establish a Renewable Portfolio Standard ("RPS") or Clean Energy Standard ("CES") for ENO. The Council's rulemaking is ongoing. Future IRP cycles would be able to incorporate any policy goals established as a result of this proceeding; but this IRP cycle has not taken any possible results of this ongoing proceeding into account, nor is this IRP report a substitute for the kinds of analyses that should inform the Council's decision in that ongoing rulemaking.

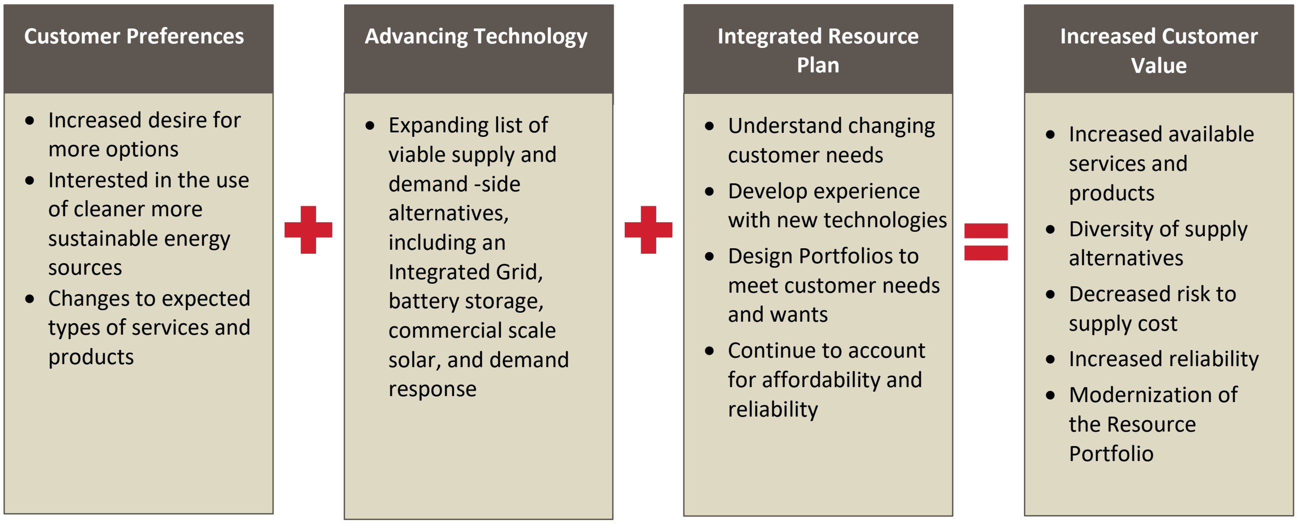

Figure 6: Changes and Opportunities within the Utility Industry

An expanding and changing selection of available supply alternatives and technologies has provided more ways to address planning objectives and to meet customer needs reliably and affordably. Additionally, new and emerging technologies that may be able to support integrated grids, such as battery storage and utility-scale solar, may enable the delivery of more sustainable energy that can help serve customers' evolving needs while also addressing ENO's long-term planning objectives.

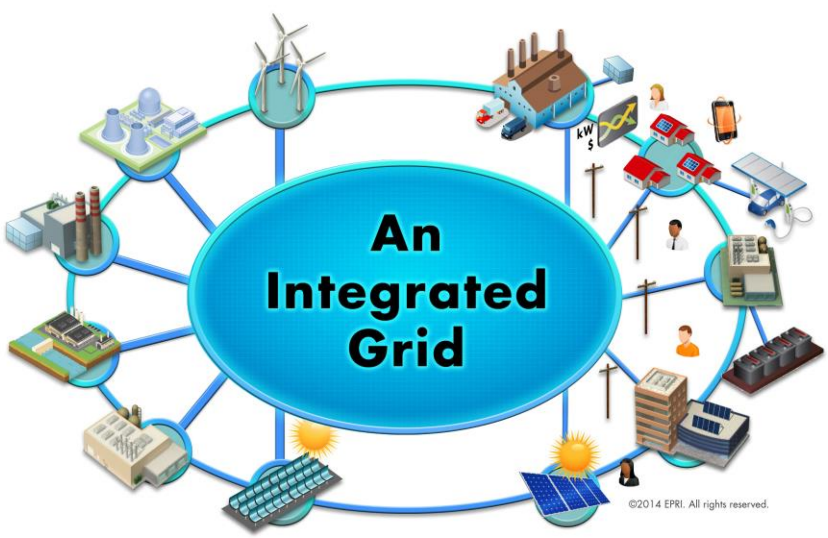

Figure 7: An Integrated Grid

By combining an understanding of what its customers want with sound and comprehensive planning, ENO can ensure that it continues to deliver the types of products and services its customers expect without losing sight of the traditional and critical planning objectives of low cost, high reliability, and risk mitigation. A diverse resource portfolio mitigates exposure to price volatility associated with uncertainties in fuel and purchased power costs, and other risks that may arise through unbalanced concentrations of portfolio attributes such as technology type, location, capital expenditures, or uncertain supply channels.

4.2 Assessing Alternatives to Meet Customer Resource Needs

4.2.1 Technology Assessment

The IRP process considers a range of alternatives available to meet the planning objectives, including the existing fleet of generating units, new demand-side management programs, and supply-side resource alternatives. As part of this process, a Technology Assessment was conducted to identify a wide range of potential supply-side resource alternatives that merit more detailed analysis due to their potential to meet ENO's planning objectives of balancing reliability, cost, and risk. Alternatives evaluated are technologically mature and could reasonably be expected to be operational in or around the ENO service territory. As discussed in the Technical Meetings, the technologies selected for further, more detailed evaluation in the IRP included:

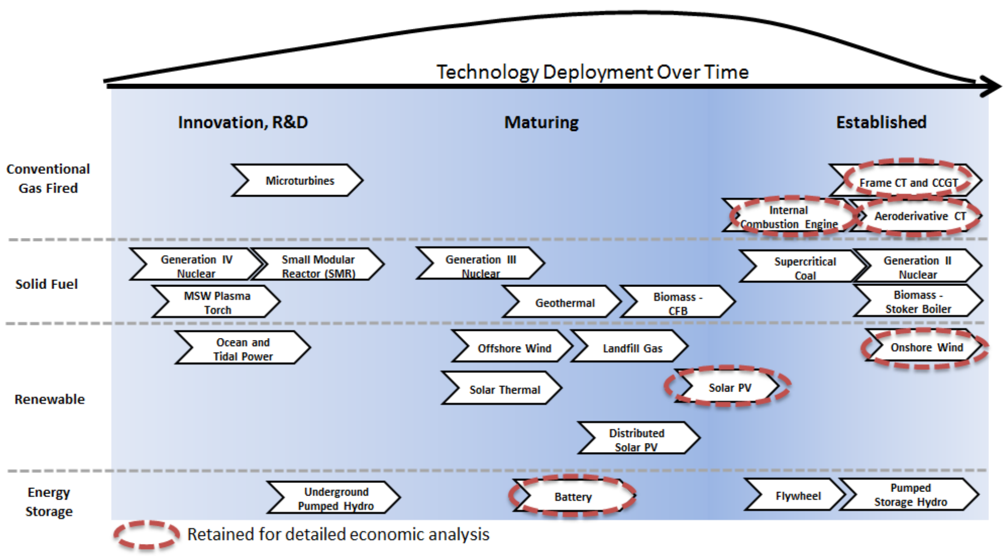

Figure 8: Technology Screening Curves Illustration

I. Natural Gas Fired Technologies
   a. Combustion Turbine (CT)
   b. Combined Cycle Gas Turbine (CCGT)
   c. Aeroderivative CT
   d. Internal combustion engine ("ICE") or reciprocating internal combustion engine ("RICE")
II. Renewable Technologies
   a. Solar Photovoltaic ("PV") (Tracking)
   b. Wind (Onshore)
III. Energy Storage
   a. Battery storage technologies

Each of these technologies has advantages and disadvantages to consider when designing a Resource Portfolio to meet customers' capacity needs. The information below summarizes some of those various considerations which were utilized in the Portfolio analyses discussed later.

Table 7: Gas-Fired Technology Considerations

	CT	CCGT	Aeroderivative CT	RICE
Description	Frame CTs are a mature technology. Low gas prices and continual heat rate and capacity improvements have made CTs the industry's technology of choice for peaking applications. CTs can also help integrate renewables by providing quickstart (~10 minutes) backup power.	Modern combined cycle facilities provide efficiencies, moderate flexibility, and improved CO_2 emissions relative to coal plants, making them suitable for a variety of supply roles (baseload, load-following, limited peaking). CCGT efficiency and flexibility is expected to continue to improve.	Aeroderivative CTs trade increased cost for greater flexibility (start time, ramp times), lower heat rates, and higher reliability relative to frame CTs.	RICEs are useful for applications requiring heavy cycling and ramping, as they incur lower O&M penalties when operated in this manner relative to other conventional peaker technologies. As renewable penetration increases, this technology will likely see increased deployment in North American power markets due to its flexibility and efficiency.
Advantages	-Low capital and staffing costs -Existing operating expertise -Flexible, quick start capability	-Lowest heat rates -Moderate capital cost -Synergies with existing and planned fleet (e.g., parts, staff)	-Higher flexibility -Moderate heat rates -High reliability	-Low heat rates -Highest flexibility -No gas compression needed -Modular additions
Disadvantages	-Higher heat rates -Difficult to neatly match need (blocky	-Increases reliance on natural gas	-Moderate capital cost -High gas pressure	-Moderate capital cost -High variable

	additions) -High gas pressure requirements	-Blocky additions -High gas pressure requirements	requirements -Less experience with technology	operating cost -Less experience with technology

In addition to the qualitative factors considered above, the table below summarizes the cost information from the Technology Assessment for gas-fired generation.

Table 8: Gas-Fired Resource Assumptions

Technology		**Summer Capacity [MW]**	**Capital Cost [2017$/kW]**	**Fixed O&M [2017$/ kW-yr]**	**Variable O&M [2017$/ MWh]**	**Heat Rate [Btu/kWh]**	**Expected Capacity Factor [%]**
CT / CCGT	1x1 501JAC	605	$1,244	$16.70	$3.14	6,300	80%
	501JAC	346	$809	$2.37	$13.35	9,400	10%
Aeroderivative CT	LMS100PA	102	$1,543	$5.86	$2.90	9,400	20%
RICE	7x Wartsila 18V50SG	128	$1,545	$31.94	$7.30	8,400	30%

4.2.2 Renewables (Solar PV and Wind)

In the last decade, the renewable energy industry has experienced substantial growth, driven in large part by cost declines, technological improvements, and environmental concerns. As shown in Figure 9, renewables' capital cost declines are particularly evident in utility-scale solar installations within the U.S. over the past five years. Among all technologically feasible renewable energy options, solar and onshore wind resources are the most cost effective, commercially-available alternatives to meet ENO's capacity and energy needs.

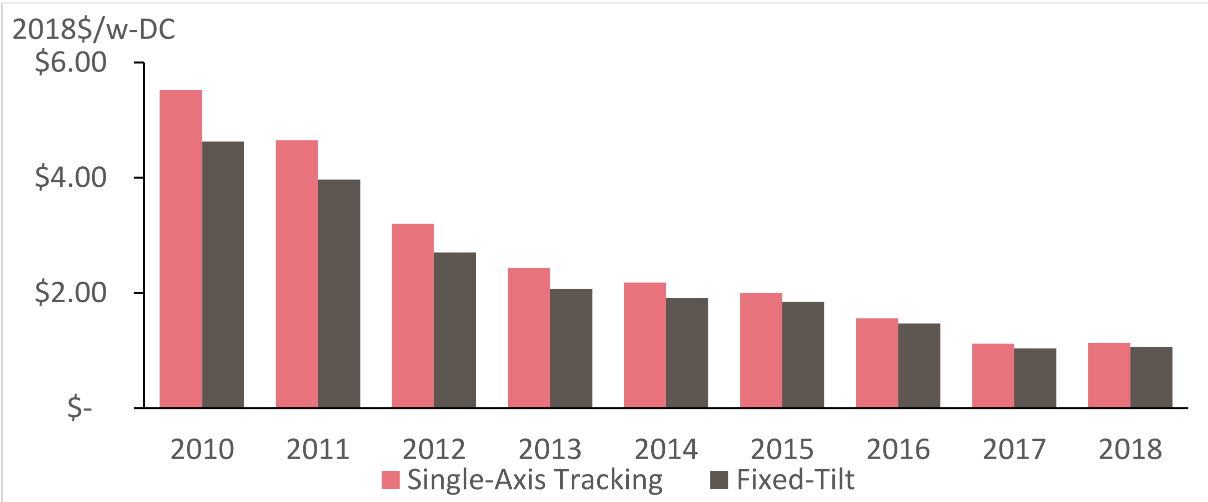

Figure 9: Historical Utility-Scale Solar Capital Costs[12]

The costs of renewable generation have declined significantly in the previous five years, and this trend is expected to continue. As depicted below, installed costs of utility-scale renewables (wind and solar) in real dollars are expected to decline throughout the planning horizon.

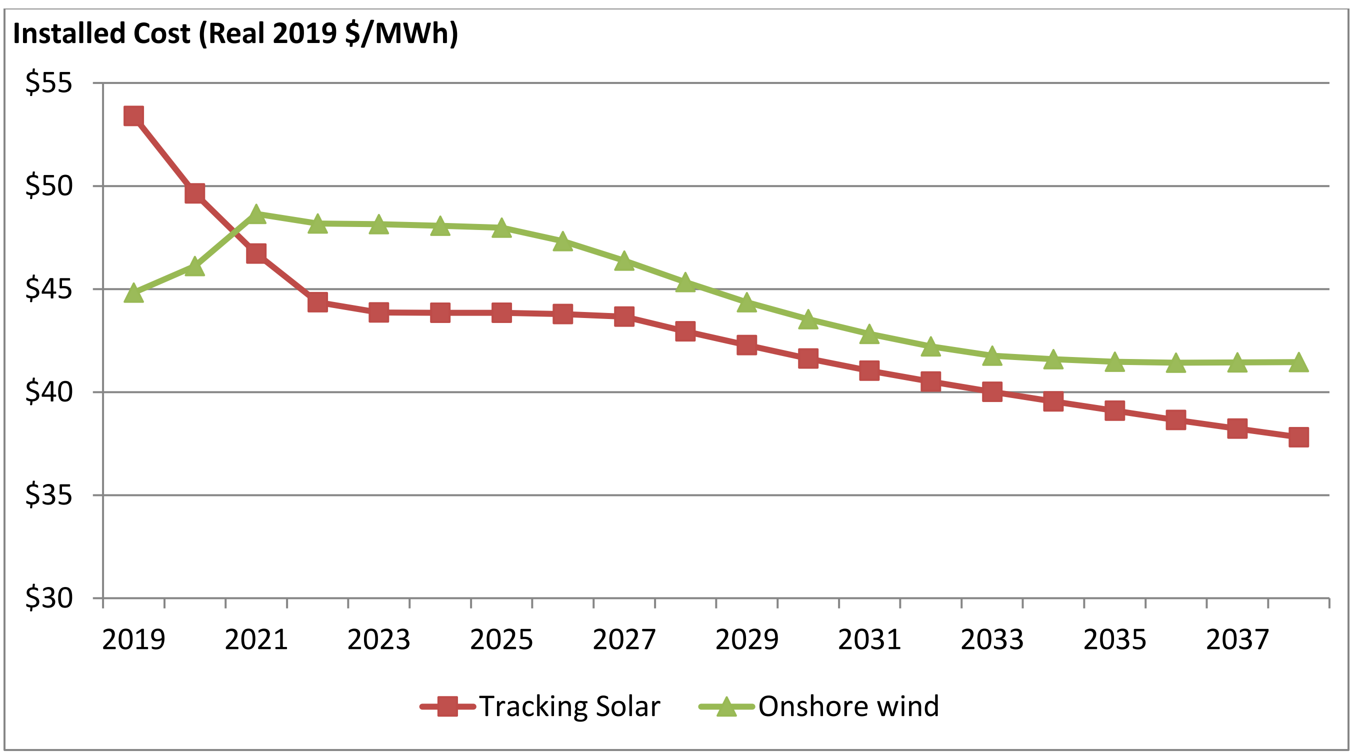

Figure 10: Projected Installed Costs of Renewable Alternatives

[12] Data adapted from NREL U.S. Solar Photovoltaic System Cost Benchmark, Q1 2017.

The table below details the opportunities presented by solar and wind generation. In general, advantages of renewables include zero emissions and fuel costs, which decrease reliance on fuel commodities. Disadvantages are related to land use compared with traditional alternatives as well as relative capacity contribution due to the intermittent nature of these energy sources.

Table 9: Renewable Technology Considerations

	Solar	**Wind**
Description	Solar capital costs have fallen dramatically in the last decade and continue to decline as the industry matures. Solar production aligns partially with customer load patterns, but grid flexibility and quickstart backup generation are necessary to ensure reliability in the absence of large-scale, economic energy storage alternatives. The industry will continue to mature and utility scale solar energy is expected to continue to compete with gas-fired generation within the planning horizon, constrained mainly by site-specific performance and market conditions (e.g., construction cost, energy value).	The wind industry is mature relative to the solar industry. Current research focuses more on improving performance, rather than cost, through larger, taller turbines and improved control technologies (e.g., turbine alignment sensors, integrated battery storage). Wind is not likely to see extensive local deployment within the MISO South region but could play a role in the region's energy mix if storage economics improve or significant high voltage direct current ("HVDC") projects are completed.
Advantages	• Zero Emissions • No fuel cost • Capital costs continue to decline • Federal investment tax credits (ITCs) • Predictable energy curve	• Zero Emissions • No fuel cost • Federal production tax credits • Efficiency continues to increase
Disadvantages	• Relative capacity value to traditional generation • Land-intensive • Integration requirements (responsive, quickstart generation is necessary to integrate large amounts of solar PV) • Site-specific performance	• Relative capacity value to traditional generation • Land-intensive • Integration requirements (responsive, quickstart generation is necessary to integrate large amounts of wind) • MISO South not ideal for wind without incurring transmission or congestion costs

Additional benefits associated with renewable generation are summarized below.

Table 10: Additional Benefits of Renewables

Additional Benefits of Renewables	
Diversity	Renewables add fuel diversity and provide a hedge within gas-centric Resource Portfolios as ENO's ability to rely on coal for fuel diversity becomes uncertain
Infrastructure	Reduced infrastructure requirements (e.g., gas pipelines, water supply) increase siting flexibility
Scalability	Deployment can be scaled up or down to meet capacity needs more easily relative to conventional alternatives
Carbon and other emissions	Renewables offer customers protection against uncertainty related to potential CO_2 costs and the increasing stringency of other emissions regulations
Customer Engagement	Gaining experience with renewables can help ENO take advantage of opportunities such as community solar, deployment of DERs, and opportunities provided by the integration of AMI

The table below provides a summary of operational costs and performance assumptions for solar and wind technology used in the 2018 IRP, as discussed during the Technical Meetings.

Table 11: Renewable Modeling Assumptions

	Solar	**Wind**
Fixed O&M (2017$/kW-yr)	$15.78	$36.01
Useful Life (yr)	30	25
Capacity Factor	26%	34%
Capacity Value	50%	15.6%
Tracking Type	Single Axis	N/A

4.2.3 Energy Storage Systems

Energy storage, particularly in the case of battery-enabled storage, provides a range of attributes that differ from traditional supply-side options discussed previously, such as:

1. The ability to store limited amounts of energy for later commitment and dispatch;
2. Ability to discharge in milliseconds and fast ramping capability;
3. Rapid construction (on the order of months);
4. Modular deployment;
5. Portability and capability to be redeployed in different areas;
6. Small footprint (typically less than an acre), allowing for flexible siting; and
7. Low round-trip losses compared to other storage technologies (such as compressed air).

Battery storage system benefits lie in the attributes highlighted above and the ability to offer stacked values through multiple revenue streams to benefit customers. Battery storage has the potential to effectively enable an intra-day temporal shift between energy production and energy use. Energy can be absorbed and stored during off-peak/low cost hours and discharged during on-peak/high cost hours. The spread (i.e., cost difference) between the time periods creates cost savings for customers and may produce a reduction in emissions. In addition to energy market attributes, battery storage systems qualify in some markets for various ancillary service applications such as regulation, reserves, and voltage regulation, and qualify for MISO's capacity market, given sufficient discharge duration. Lastly, energy storage may, depending on location and characteristics, offer the capability of transmission and distribution cost deferral.

Given the current higher installed cost, energy storage faces challenges for high-deployment potential. The typical on-peak/off-peak cost spread remains low in MISO South, which may limit arbitrage potential. Additionally, MISO's ancillary services market is limited today and fully met with existing resources but continues to evolve. ENO will continue to monitor MISO's energy and ancillary market conditions to identify energy storage potential. At the time of this report, the fixed costs of energy storage today remain above a new build CT, as depicted below.

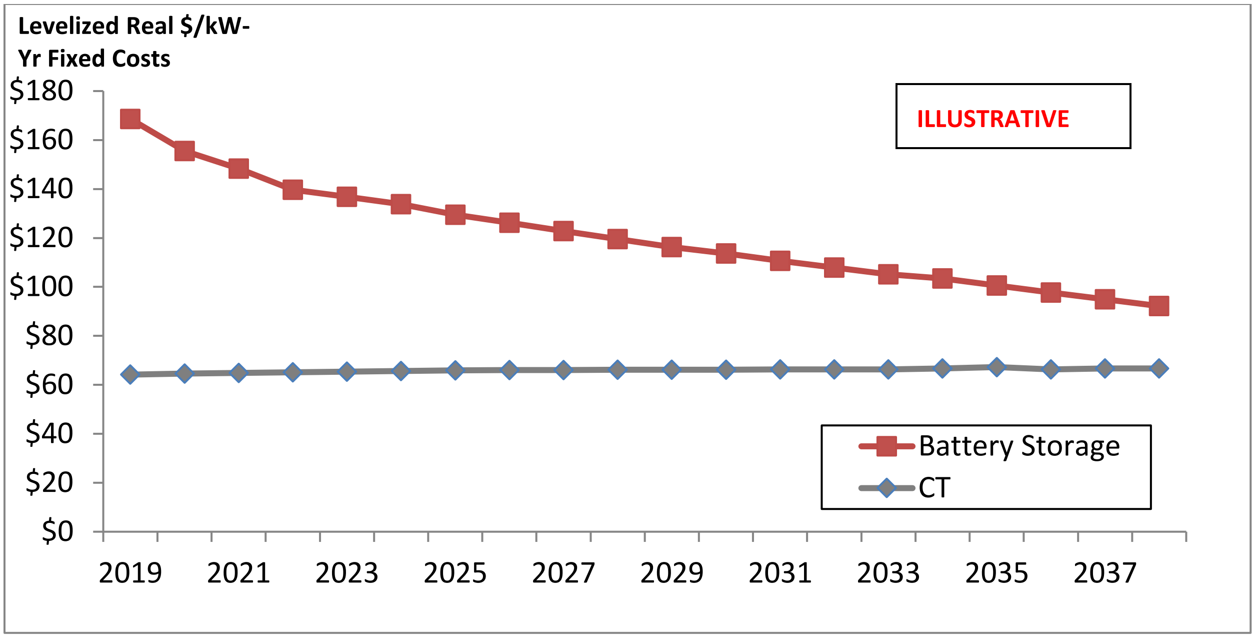

Figure 11: Storage and CT Cost Comparison

For storage, the key to achieving positive net benefits today is identifying the right location-specific use-case that can off-set transmission or distribution investment. For example, battery storage can provide avoided cost benefits by preventing distribution investments required due to line overloads. In addition to these peak-shaving applications, energy storage sited in location-specific areas provide voltage support, which mitigates the effects of electrical anomalies and disturbances. However, if sited and/or operated sub-optimally, storage can increase congestion and could drive otherwise unnecessary transmission or distribution improvements. Also, charge and discharge cycles must be optimized so as not to conflict with reliability and/or any potential economic benefits.

Similar to what has been seen in recent years within the solar industry, it is expected that battery storage costs will decline within the planning horizon. Therefore, while limited deployment may make sense today for ENO's customers, this technology will continue to evolve, and additional applications could present themselves in the future.

4.2.4 Demand-Side Management

For the 2018 IRP, ENO engaged the services of Navigant Consulting to perform a DSM potential study to assess the long-term potential for reducing ENO customer energy consumption through energy efficiency ("EE") and peak load reduction measures and improving end-user behaviors. Navigant utilized its DSMSim™ model to calculate various levels of EE savings potential across the ENO service area and its DRSim™ model to estimate various levels of demand response ("DR") potential. Navigant analyzed both EE and DR under Low, Base, and High cases, and EE under a "2% case" constructed to comply with the Council's goal of increasing EE savings .2% annually until a total 2% of sales reduction was achieved. In total, the Navigant Base case identified cost-effective potential of ~1,100 GWh of EE savings at a cost of about $390 million over 20 years, with an associated demand reduction of 220 MW. Navigant also estimated ~35 MWs of cumulative peak reduction from DR by 2038.

Additionally, the Council engaged Optimal Energy to perform a DSM potential study to assess potential for energy savings and peak demand reduction in the city through utility-run energy efficiency, peak demand, and rate design programs. Optimal provided ENO with a 20-year forecast of energy and demand savings in the form of energy efficiency and demand response programs. The energy efficiency potential study included results for a Program Achievable case and a Max Achievable case. In total, the Optimal Program Achievable case identified potential of ~2,335 GWh of EE savings at a cost of about $434 million over 20 years with an associated demand reduction of 243 MW. Thus, Optimal's Program Achievable case identified a 112% greater EE potential than the Navigant Base case at only a ~10% greater cost. In addition, Optimal's demand response potential study analyzed two cases, identified by Optimal as "Scenario One" and "Scenario Two," which utilized low and high participation and identified 53 MW and 81 MW of potential, respectively over the 20-year horizon.[13]

Navigant and Optimal received the same sets of data from ENO, relied on the New Orleans Technical Resource Manual ("NOTRM") as a source document for measure information, and considered the historical results and current implementation plans for the Energy Smart programs. However, the significant divergence between identified EE potential and costs to achieve savings indicate fundamental differences in assumptions. An obvious difference is Optimal's use of a 25% administrative cost / 75% incentive cost split where Navigant used a 50/50 split in its Base case. Under Energy Smart, administrative costs have historically run closer to the 50% level, although in Program Year 9 administrative costs are tracking closer to 40% due to increased experience on the part of ENO's third-party implementer and improvements in program delivery. An additional point of comparison is Entergy Arkansas's experience in its most recent program year, 2018, for which it reported approximately 40% administrative costs to implement a much larger program than Energy Smart. Additionally, Optimal's Study notes, at page 74, that data concerning administrative costs was "sourced from recent program performance in New England, the MidAtlantic states, and Minnesota." The study also notes that data from these sampled jurisdictions shows that the "average administrative costs for the various program types range from 25 percent to 37 percent." Optimal provided no explanation as to why its study avoided including data from Southeastern utilities, or why Optimal chose to assume costs at the absolute lowest level supported by its sample set. Optimal also admitted in discovery that it made no adjustments to account for changes to economies of scale attributable to the fact that its selected samples were from jurisdictions with state-wide programs, whereas Energy Smart is only available to customers in New Orleans. Considering these facts, the actual

[13] Both the Navigant and Optimal studies assessed potential over the 20-year period 2018-2037. To align the studies with the IRP analysis that focused on 2019-2038, the Navigant potential study results were extrapolated to include the year 2038. For the Optimal potential study ENO was advised by Optimal to change the start date of results to 2019 while keeping all costs constant to cover the 2019-2038 study timeline.

results of the Energy Smart program in New Orleans, and the long-running Entergy Arkansas programs, a 25% assumption for administrative costs seems overly aggressive and unrealistic.

Given Optimal's general conclusions that significantly more kWh savings can be achieved at a lower cost per kWh than Navigant projects, it seems likely that Optimal may have more aggressive assumptions about measure costs, initial measure saturation levels, and adoption rates as well.[14] These, coupled with Optimal's position on administrative costs, would explain, at least in part, the substantial differences in identified EE potential. Further, Optimal identifies significant potential associated with low-income programs using a definition that seems to assume 49% of the residential class is low-income.[15] This assumption seems high as compared to ENO's experience with Energy Smart which uses a more restrictive definition of low income (i.e., 200% of the Federal Poverty Standard)[16]

The differences highlighted here do not mean that one study is "right" and the other "wrong." However, in the context of an IRP analysis, Portfolios built using input cases from these divergent studies will present fundamentally different points of view about the resources required to serve customer needs over the 20-year planning horizon, and therefore the related total supply costs. And more immediately, in the context of short-term DSM implementation planning, ENO must consider the different perspectives offered by the studies as it designs an Energy Smart Implementation Plan that it believes is reasonable, cost-effective, and achievable for the Council to review. To that end, ENO intends to develop the Energy Smart Implementation Plan by drawing on information from both studies.

4.2.5 Energy Efficiency

The International Energy Agency defines Energy Efficiency as, "achieving the same services with less energy." This ensures an opportunity for ENO to serve its customers by providing energy savings. The method utilized by Navigant for determining EE is summarized below.

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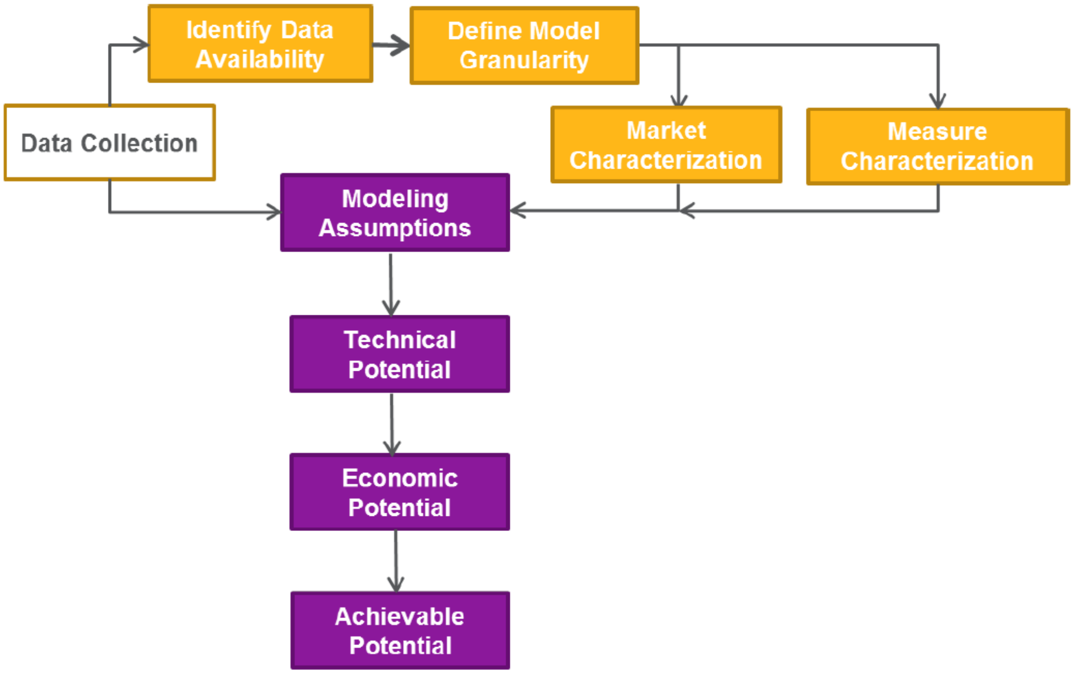
[14] One measure-level comparison between the studies is worth noting. Low-flow showerheads accounted for the largest percentage of savings among residential measures in Optimal's Study at 14%. Low-flow showerheads have been a direct install measure in the Energy Smart program for several years but have had a very low acceptance rate. Navigant's study includes low-flow showerheads but at a more reasonable 3.6% of residential savings.

[15] *See*, Appendix E, Optimal DSM Potential Study, Table 47.

[16] https://aspe.hhs.gov/poverty-guidelines



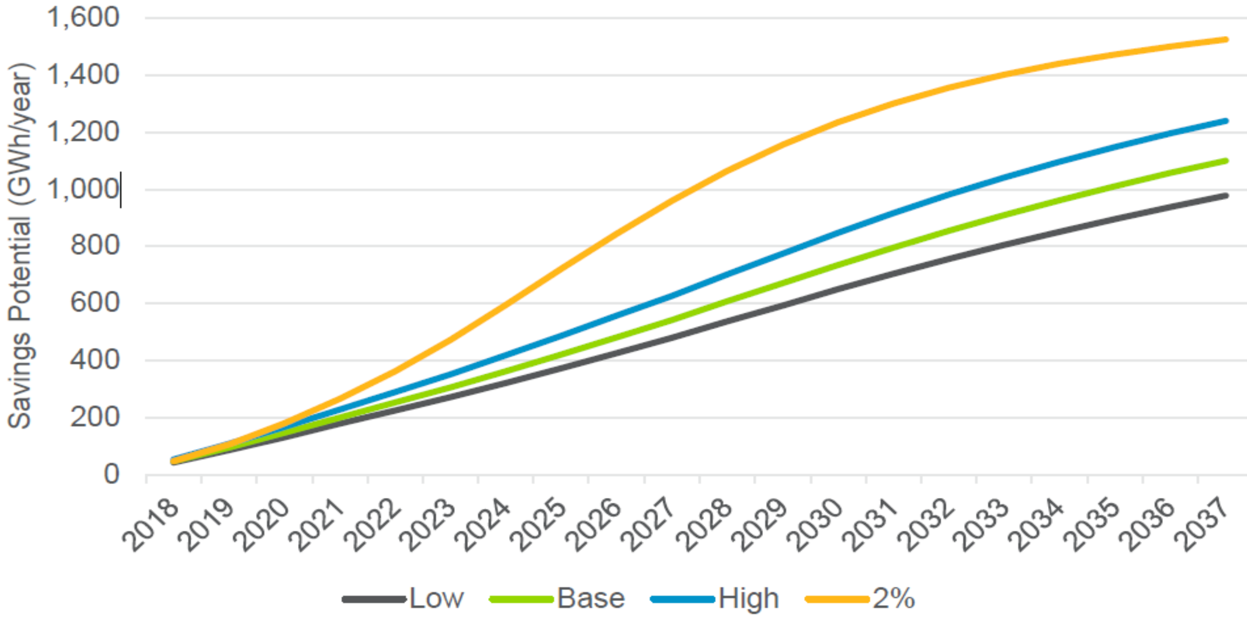
Source: Navigant

Figure 12: Energy Efficiency study approach

Navigant's energy efficiency modeling included 4 potential cases:

- **Base Case:** Reflects current program spend targets with incentives on average at 50% of incremental measure cost
- **Low Case:** Uses the same inputs as the base case except incentives are at 25% of incremental measure cost.
- **High Case:** Uses the same inputs as the base case except incentives are at 75% of incremental measure cost.
- **2% Case:** Achieves a 2% reduction during the forecast period with a 0.2% ramp year over year starting in the first modeled year (2018). To achieve 2% Navigant modified model parameters**:**
    - Increased marketing factor through 2022
    - Increased incentive percent of incremental measure cost from 50% in 2019 then ramping up to 100% in 2025 (and maintaining 100% in remaining years)
    - Ramped down TRC ratio threshold from 1 in 2018 to 0.87 in 2023 and remaining years.

The total potential of each Navigant EE case is outlined in Figure 13.



Source: Navigant analysis

Figure 13: Current and Expanded EE Program Potential

The method utilized by Optimal for determining EE potential is summarized below.

Optimal used the following major steps to conduct the energy efficiency potential study:

1. Develop energy use forecasts
2. Disaggregate energy forecasts by sector (e.g., residential vs. commercial), and end uses (e.g., lighting, cooling, refrigeration)
3. Characterize efficiency measures
4. Screen measures and programs for cost-effectiveness
5. Develop measure penetrations for "achievable" scenarios
6. Determine scenario potential and develop outputs

In addition to the steps listed above, Optimal utilized a "top-down" methodology. Optimal began with the entirety of ENO's electric sales and broke the electric sales down into separate groups representing consumption by customer and building type. Optimal applied energy efficiency measures to the applicable distinct groups of customers and building types.

Optimal's energy efficiency potential analysis included three levels of potential, defined in its Potential Study as follows:

- **Economic:** Everything that is cost-effective and technically feasible, assuming no market barriers. A measure is considered to be cost-effective if the net present value of the avoided energy and capacity costs over its effective useful life is equal to or greater than the net present value of the measure cost.

- **Maximum Achievable:** The maximum level of program activity and savings that is possible given the market barriers to adoption of energy efficient technologies, with no limits on incentive payment, but including administrative costs necessary to implement programs.
- **Program Achievable:** Optimal's view of a feasible and practical level of achievable savings given a specific set of programs targeting specific markets, with Optimal's estimates of realistic estimates of incentive payments. Administrative costs are again included.

The total potential energy savings of the Optimal cases are outlined in Figure 134.

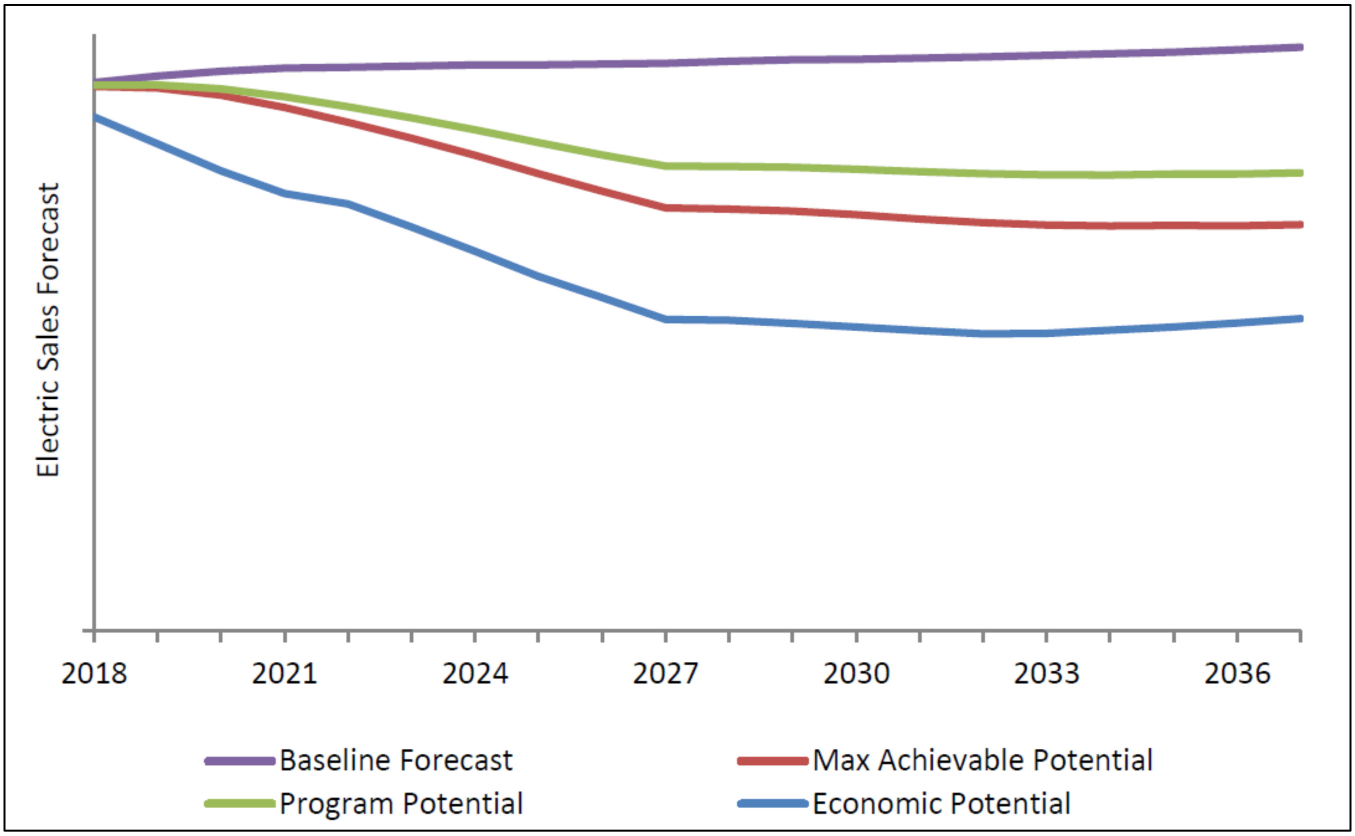


Figure 14: Optimal Cumulative Current and Expanded EE Program Potential Savings Relative to Sales Forecast

4.2.6 Demand Response

Additionally, Navigant and Optimal performed DR studies. DR offerings which Navigant found to be cost effective using the Total Resource Cost test are shown below, and Optimal's DR offerings follow.

Table 12: Navigant Cost Effective DR

DR Option	Eligible Customer Class	Measure
DLC	Residential and Small C&I	Thermostat-HVAC
		Switch- HVAC
C&I Curtailment	Large C&I	Manual HVAC Control
Dynamic Pricing	All Customer Classes	Dynamic Pricing w/o Enabling Technology
		Dynamic Pricing w/ Enabling Technology

These programs were made available to the AURORA model for a Base, Low, and High case, differing in terms of pricing signals and adoption rates. The total annual MW savings made available for selection is illustrated below, representing approximately 34 MW in the medium case and 35 MW in the high case.

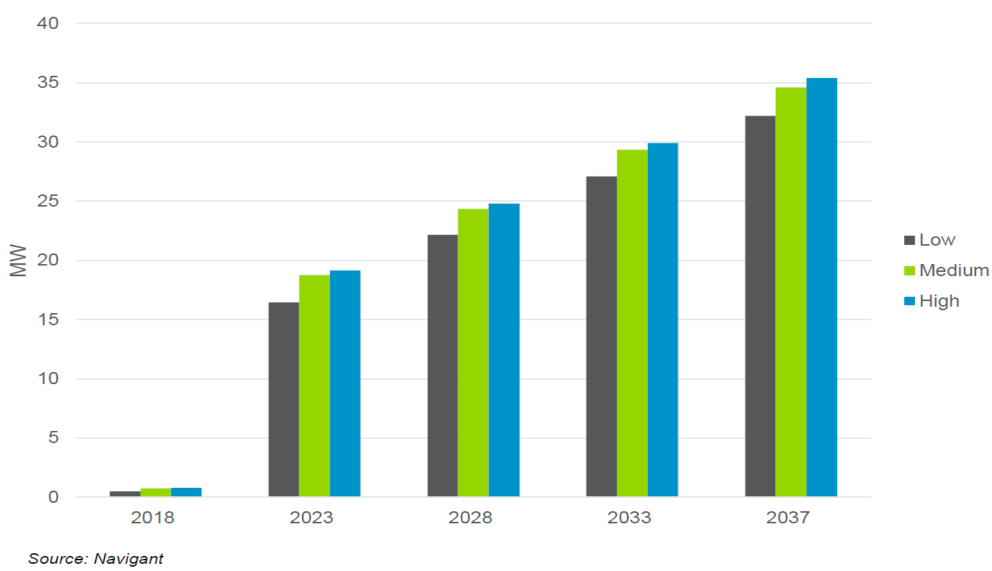


Figure 15: Navigant Cumulative Achievable DR

DR program costs utilized in the IRP include program start-up cost, marketing and recruitment costs, metering cost, program administration, incentives paid to participants, and program delivery costs. Program delivery costs are a fixed contracted payment for the third-party delivery of the DR programs. The program results reflect an assumption that over the planning horizon, customers will re-opt measures at the end of the program life at the same level of program efficiency. In other words, customers who opt-in are assumed to remain in the program through the remainder of the IRP planning period at the same level of savings.

The DR offerings Optimal found to be cost effective using the Total Resource Cost test are as follows.

Table 13: Optimal Cost Effective DR

DR Option	Measure
Residential	Direct Load Control and Automated Demand Response
	Peak Time Rebate Pricing with and without AMI technology
	Critical Peak Pricing with and without AMI Technology
Large Customer	Standard Offer Program
	Standard Offer Program plus a Direct Load Control/Automated Demand Response offering

These programs were assumed to be economic in the AURORA model for two Scenarios, differing in terms of participation rate and program pricing type. The total annual MW savings made available for selection is illustrated below, representing approximately 50 MW in Optimal Scenario 1 and 80 MW in Optimal Scenario 2.

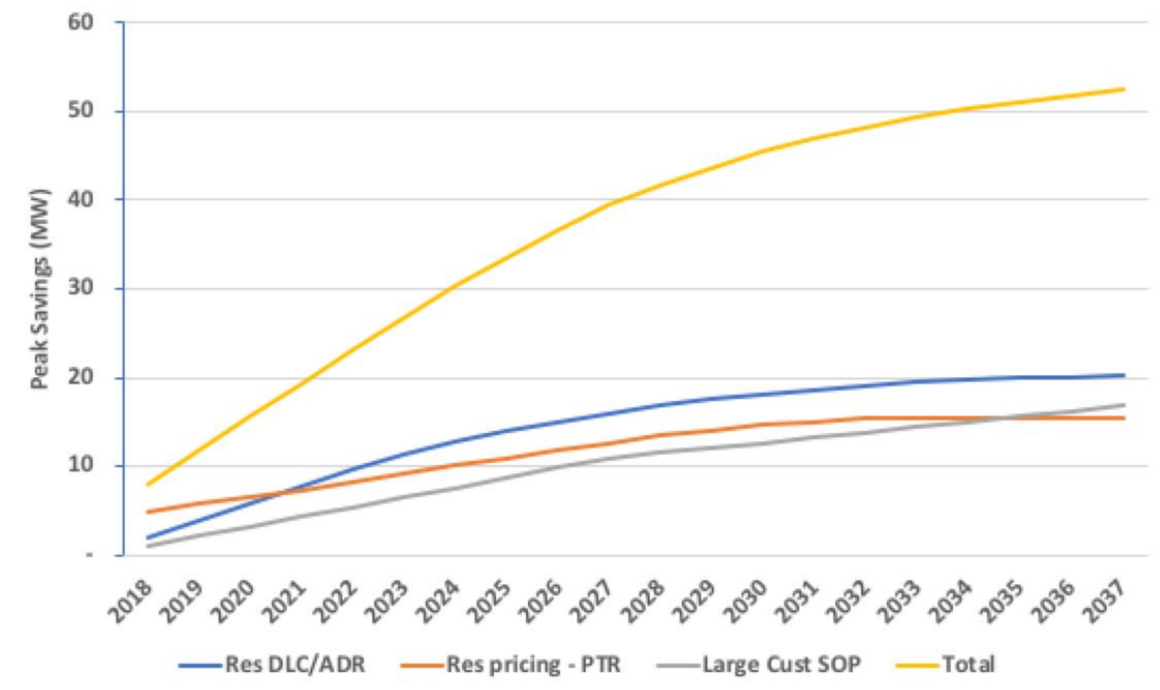


Figure 16: Optimal Scenario 1 Achievable DR Savings Potential

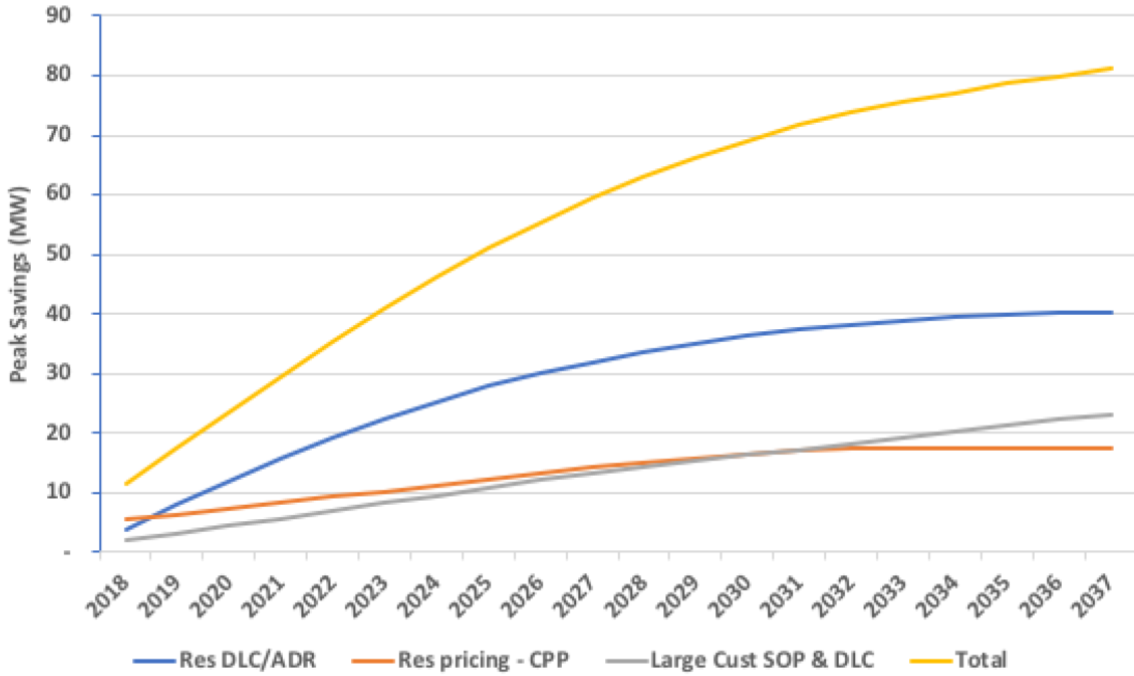


Figure 17: Optimal Scenario 2 Achievable DR Savings Potential

DR program costs utilized in the IRP include program start-up costs, incentive cost, administrative cost, marketing, and program operations and maintenance costs. Program rates are a fixed estimate over the delivery life of the DR programs. The study did not attempt to project the future changes in codes that are not currently planned, nor changes in costs and savings from current technologies over time. Due to this assumption, future DSM program goals and implementation plans should consider this data constraint.

4.3 Natural Gas Price Forecast

The near-term portion (first year) of the natural gas price forecast is based on NYMEX Henry Hub forward prices, which are market future prices as of July 2018. Because the NYMEX futures market becomes increasingly illiquid as the time horizon increases, NYMEX forward prices are not a reliable predictor of future prices in the long term. Due to this limitation, the long-term point of view regarding future natural gas prices utilizes a consensus average of several expert independent, third-party consultant forecasts. The long-term natural gas price forecast used in the IRP also includes cases for high and low gas prices to support analysis across a range of future Scenarios. In levelized 2019 dollars per MMBtu through the IRP period (2019-2038), the natural gas price forecast in the medium case is $3.61, in the low case is $2.53, and in the high case is $4.86, as discussed in the Technical Meetings.

Each gas price sensitivity is illustrated below and is described in more detail later in this section. Each of the IRP Planning Scenarios assumes one of the three natural gas price forecast sensitivities as agreed to by the parties.

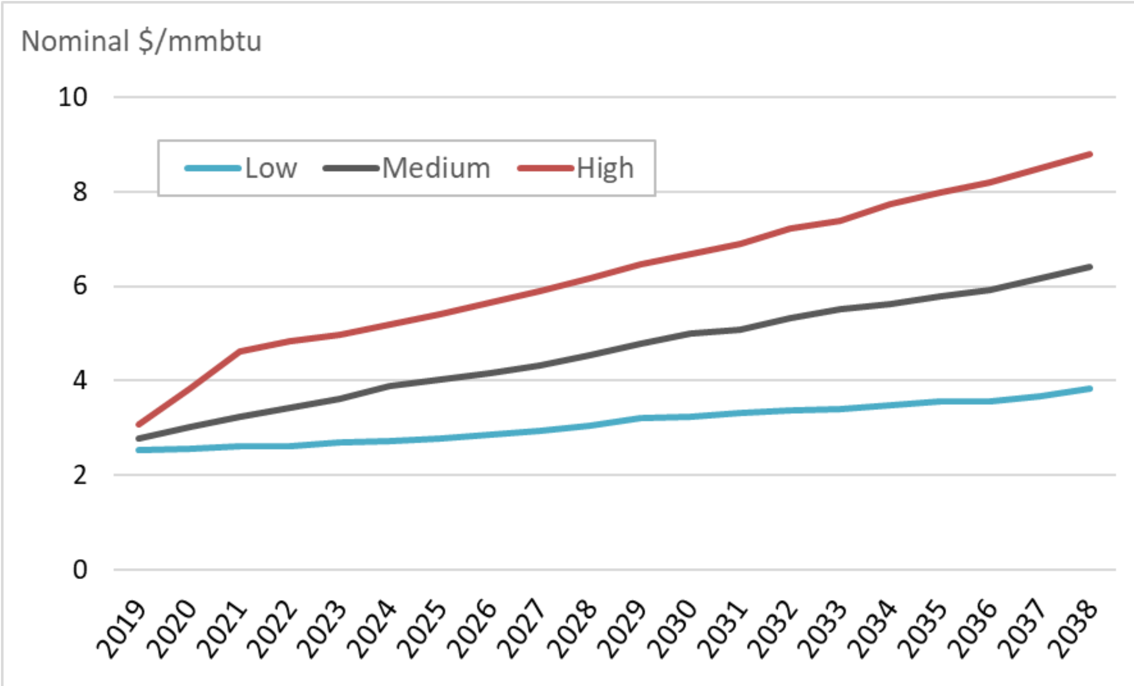


Figure 18: Natural Gas Price Forecast

4.4 CO_2 Price Assumptions

ENO's point of view is that national carbon regulation for the power generation sector will occur; however, the timing, design, and outcome of any carbon-control program remain uncertain.

The CO_2 pricing forecasted and utilized in the IRP analysis is based on the following three cases:

1. ***Low Case*** - A $0/ton CO_2 price, representing either no program or a program that requires "inside-the-fence" measures at generating facilities, such as efficiency improvements, that do not result in a tradable CO_2 price. This Scenario is basically consistent with the Affordable Clean Energy ("ACE") rule proposed by the EPA in August 2018.

2. ***Medium Case*** - A "CPP Delay" case reflects a 6-year delay in the implementation of the Clean Power Plan or similar national regulation and represents a regional mass-based cap consistent with achieving the final CPP requirements but delayed by approximately 4-6 years due to the federal administration change in 2017 and consistent with the President's executive order in March 2017; and

3. ***High Case*** - A "National Cap and Trade" High Case assumes a national cap and trade program that begins in 2028 and targets an approximately 80 percent reduction from 2005 sector Emissions by 2050. This case is generally consistent with the 2030 and 2050 emission reduction targets developed by the Intergovernmental Panel on Climate Change and anticipated by the Paris Agreement. For the purposes of modeling in Planning Scenario 3, the start year is moved up to

2022 in accordance with the consensus reached by the parties.

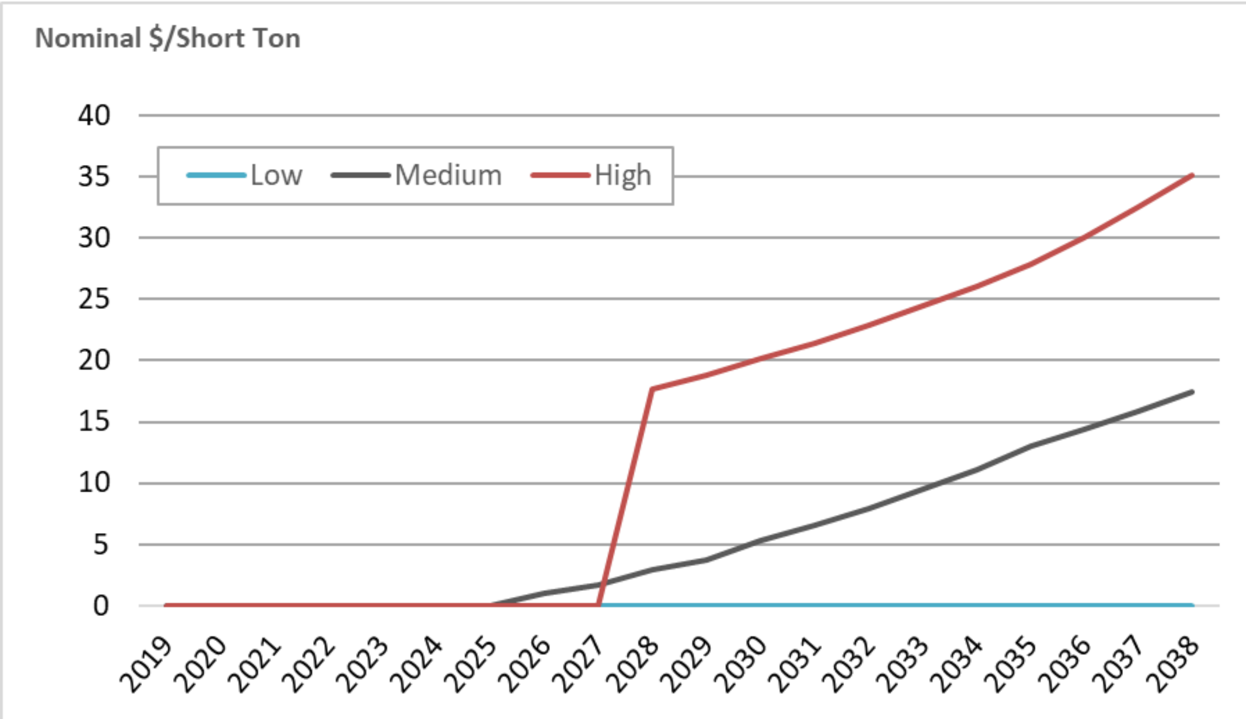


Figure 19: CO_2 Price Forecast

Section 5

5. Portfolio Design Analytics

To support the development of a broad range of Resource Portfolios, ENO, the Advisors, and the Intervenors agreed to use three planning Scenarios representing a range of market drivers and possible futures. Additionally, the parties came to consensus on five planning Strategies that informed or constrained the Portfolio development process consistent with defined objectives or policies. Using the AURORA Capacity Expansion Model, fifteen Portfolios were developed based on a combination of each Scenario and Strategy.

5.1 Planning Scenarios

For the 2018 IRP, ENO utilized a set of three Scenarios which vary based on economic, policy, and customer behavior assumptions that impact market prices, including:

- Peak load and energy growth
- Natural gas prices
- Coal and legacy gas generation deactivations
- Renewable penetration
- CO_2 prices

The three Scenarios utilized by ENO for the 2018 IRP are given below.

Table 14: Overview of Scenarios

	Scenario 1	Scenario 2	Scenario 3
Peak Load & Energy Growth	Medium	High	Low
Natural Gas Prices	Medium	Low	High
Market Coal & Legacy Gas Deactivations	60 years	55 years	50 years
Magnitude of Coal & Legacy Gas Deactivations[1]	17% by 2028 57% by 2038	31% by 2028 73% by 2038	46% by 2028 76% by 2038
MISO Market Additions Renewables / Gas Mix	34% / 66%	25% / 75%	50% / 50%[2]
CO_2 Price Forecast	Medium	Low	High (Start 2022)

Each Scenario represents a set of key market drivers as described below.

5.1.1 Scenario 1:

The market experiences flat to declining electric UPC in residential and commercial sectors due to increases in energy efficiency. This trend is partially offset by industrial growth and growth in residential and commercial customer counts. In the MISO region outside of ENO's service area, renewables and gas play balanced roles in replacing retiring capacity to promote fuel diversity in long-term resource planning.

5.1.2 Scenario 2:

Residential and commercial customer growth rates increase due to economic development and decreased energy efficiency gains driven by a shift in public policy. Combined with increased industrial sales growth due to realization of lower-probability projects, this results in high peak and energy load growth. Sustained low gas prices accelerate legacy gas and coal retirements due to economic pressure. Sustained low gas pricing, a low (zero) CO_2 price, and a shift in public policy lead to gas-fired generation comprising the majority of capacity additions in the MISO region outside of ENO's service area, complemented by some renewables.

5.1.3 Scenario 3:

Residential, commercial, and industrial growth rates are decreased due to strong customer preferences for energy efficiency and distributed energy resources, resulting in a low (compared to medium) energy and peak load growth. High CO_2 cost starting in 2022 and gas prices drive coal and legacy gas plants to retire earlier than anticipated. In the MISO region outside of ENO's service area, the capacity and energy are replaced by a high penetration of renewables complemented by gas-fired generation.

5.2 Planning Strategies Overview

The Strategies were developed to support a range of potential planning objectives, DSM policies, and clean energy priorities. The details provided in Table 15 below were used to constrain the capacity expansion modeling to conform to the objectives defined by each Strategy.

Table 15: Strategy Overview

	Strategy 1	Strategy 2	Strategy 3	Strategy 4	Strategy 5
Objective	Least Cost Planning	0.2/2% DSM Goal	Optimal Program Achievable DSM	Navigant High DSM	Stakeholder Strategy
Capacity Portfolio Criteria and Constraints	Meet 12% Long-term Planning Reserve Margin (PRM) target using least-cost resource portfolio	Include a portfolio of DSM programs that meet the Council's stated 2% goal	Meet peak load need + 12% PRM target using Optimal Program Level DSM and resources selected by model	Meet peak load need + 12% PRM target using Navigant High Case DSM and resources selected by model	Meet peak load need + 12% PRM target using Optimal Program Level DSM, renewables, and energy storage
Description	Assess demand- and supply-side alternatives to meet projected capacity needs with a focus on total relevant supply costs	Assess portfolio of DSM programs that meet Council's stated 0.2/2% goal along with consideration of additional supply-side alternatives	Assess portfolio of DSM from Optimal Program Achievable case along with consideration of additional supply side alternatives	Assess portfolio of DSM from Navigant High case along with consideration of additional supply side alternatives	Assess demand and Supply-side alternatives to meet projected capacity need with a focus on adding renewables and storage
DSM Input Case	Navigant Base (Optimized)	Navigant 2%	Optimal Program Achievable	Navigant High	Optimal Program Achievable (Optimized)

5.2.1 Strategy 1:

Strategy 1, using a 12% long-term Planning Reserve Margin, focuses on least cost alternatives to meet planning needs as required by Section 7.D.1. of the new IRP Rules. Demand and supply side alternatives are selected based solely on need and cost. Strategy 1 utilizes the Navigant Base case EE and DR program penetration and costs and allows the AURORA model to select only the economic EE programs, whereas all DR programs are assumed to be selected.

5.2.2 Strategy 2:

Strategy 2 is focused on meeting the Council's stated 2% DSM savings goal as required by Section 7.D.3 of the new IRP Rules. The Strategy utilizes the Navigant 2% case EE programs and Navigant Medium DR programs and forces the selection of all EE and DR programs to meet the 2% goal.

5.2.3 Strategy 3:

Strategy 3 optimized Portfolios utilizing a 12% Planning Reserve Margin, Optimal Program Achievable EE, and Optimal Scenario 1 DR inputs. The EE and DR programs are assumed to be economic within this Strategy, so all programs are selected in the optimized Portfolios.

5.2.4 Strategy 4:

Strategy 4 aims to meet a 12% Planning Reserve Margin using the Navigant High case DR and EE programs. Both the EE and DR programs are assumed to be economic within Strategy 4, so all programs are included in all Strategy 4 optimized Portfolios.

5.2.5 Strategy 5:

Strategy 5 is similar to Strategy 3, but represents a Stakeholder Strategy as contemplated by Section 7.D.2. of the new IRP Rules and optimized Portfolios utilizing a 12% Planning Reserve Margin, Optimal Program Achievable EE, and Optimal Scenario 1 DR inputs. However, resources available for selection were limited to DSM, renewable, and energy storage resources. In Strategy 5 the EE programs were optimized in AURORA and only economic programs were selected, whereas all DR programs are assumed to be economic within this Strategy, so all programs were selected in the optimized Portfolios.

5.3 Market Modeling

The first step within the market modeling process is to utilize the AURORA[17] production cost model to develop a projection of the future market supply based on the specific characteristics of each Scenario. The energy market simulation results in hourly energy prices (Locational Marginal Prices, or "LMPs") for each of the three Scenarios. This projection encompasses the power market for the entire MISO footprint (excluding ENO). Projected LMPs for MISO-South (excluding ENO) were extracted to assess potential Portfolios for ENO within each Scenario. Figure 20 below represents projected annual MISO (excluding ENO) power prices for each Scenario.

[17] The AURORA model is the primary production cost tool used to perform MISO market modeling and long-term variable supply cost planning for ENO. AURORA supports a variety of resource planning activities and is well suited for Scenario modeling and risk assessment modeling through hourly simulation of the MISO market. It is widely used by a range of organizations, including large investor-owned utilities, small publicly-owned utilities, regulators, planning authorities, independent power producers and developers, research institutions, and electric industry consultants.

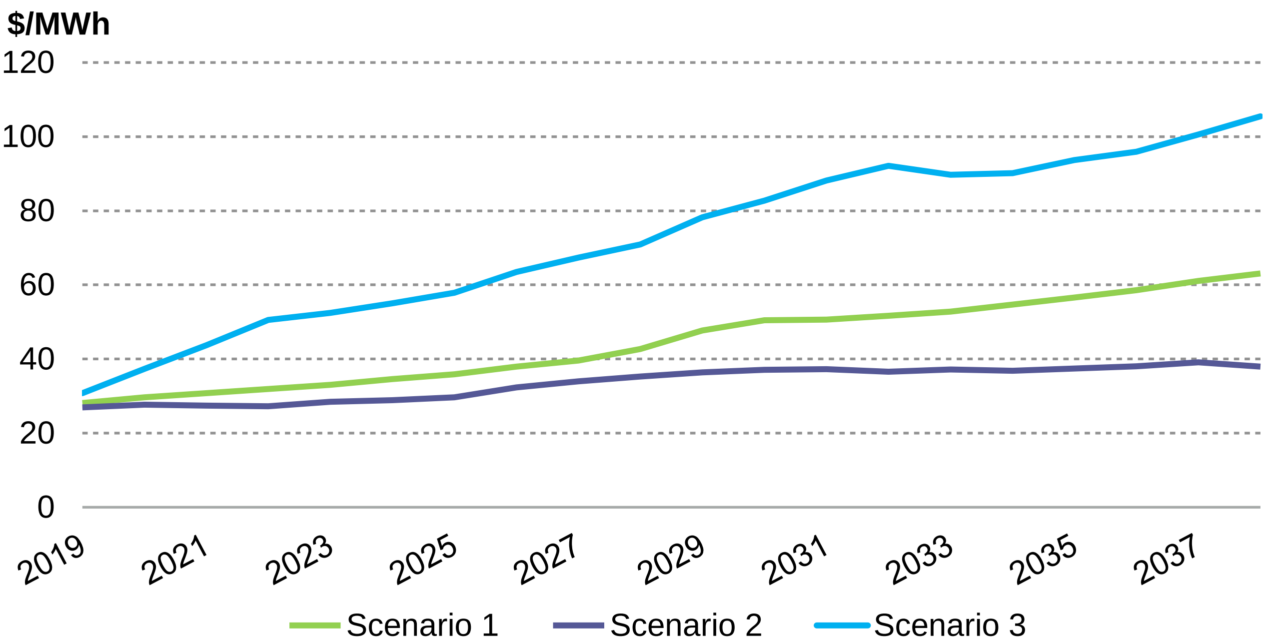
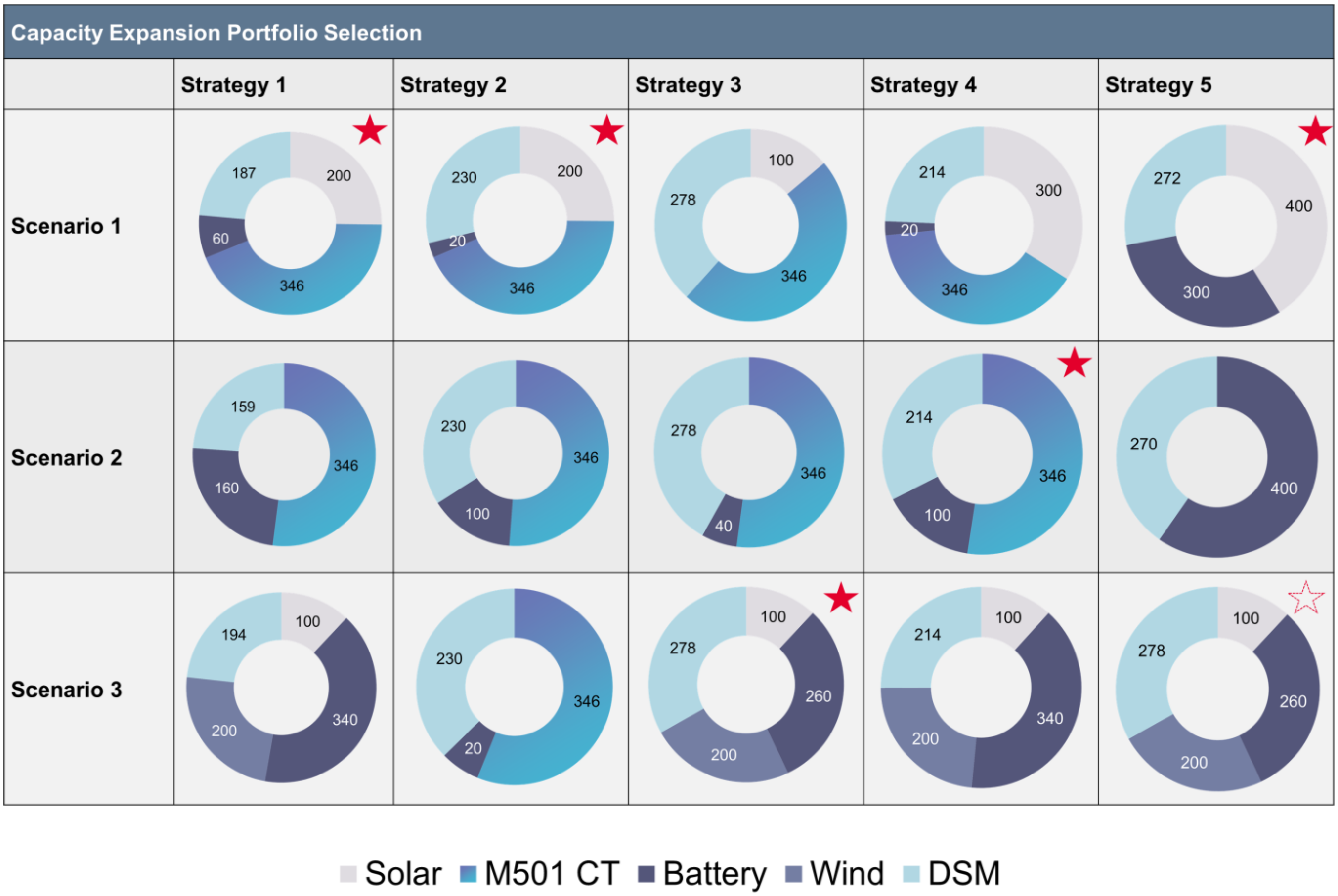


Figure 20: Average Annual MISO South Non-ENO LMP

5.4 Capacity Optimization and Results

Following the market modeling process, the AURORA Capacity Expansion Model was used to identify economic type, amount, and timing of demand-side and supply-side resources needed to meet reserve margin requirements subject to the constraints imposed by each Strategy. The result of this process was a set of Portfolios of resources ("optimized Portfolios") that produce the lowest total supply cost to meet the identified need within the constraints defined in each of the Strategy and Scenario combinations. Table 16 below depicts the optimized Portfolios that resulted from each Scenario and Strategy combination. The stars in the table depict the selected Portfolios that the parties agreed would be moved through the total supply cost evaluation as described in Section 5.4, below.

Table 16: ENO Optimized Portfolios[18]



Consistent with the scope of the Strategies, Strategies 2-4 include all programs identified in the DSM input case assigned to the particular Strategy and each program contributes towards meeting ENO's resource needs. Table 17 and Table 18 below provide a summary of the DSM results for Strategies 1 and 5.

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[18] As noted above, Strategy 3, Scenario 3 Portfolio is identical to Strategy 5, Scenario 3 Portfolio, expressed by the outlined star seen in Table 16.

Table 17: Strategy 1 DSM Selections

Strategy 1 (Navigant Base DSM)			
Program	**Scenario 1**	**Scenario 2**	**Scenario 3**
Com Behavior	✓	✓	✓
Large C&I	✓	✓	✓
Small C&I	✓	✓	✓
Consumer Products	✓ *2033*	✓ *2033*	✓
HPwES	✓	✓ *2033*	✓
HVAC	✓	✓ *2033*	✓
Low Income and Multi Family	✓	✓ *2033*	✓
Res Behavior	✓	✓	✓
School Kits	✓	✓	✓

Table 18: Strategy 5 DSM Selections

Strategy 5 (Optimal Program Achievable DSM)			
Program	**Scenario 1**	**Scenario 2**	**Scenario 3**
Home Energy Services	✓	✓ *2033*	✓
Res HVAC	✓	Not Selected	✓
Res Efficient Products	✓	✓	✓
Res Lighting	Not Selected	Not Selected	✓
Efficient New Homes	Not Selected	Not Selected	✓
Appliance Recycling	✓	✓	✓
CVR- Res	✓	✓	✓
Small Business DI	✓	✓	✓
Commercial Prescriptive	✓	✓	✓
Commercial Custom	✓	✓	✓
Retro commissioning	✓	✓	✓
New Construction	✓	✓	✓
CVR – C&I	✓	✓	✓

In Strategy 1, under all Scenarios, all DSM was selected in either the first year of the study or subsequently in 2033[19]. In Strategy 5, all DSM programs were selected under Scenario 3, and the majority under Scenario 1 and 2. The Residential Lighting program was not available in 2033 in Scenarios 1 and 2 and the Efficient New Homes program was not selected in either Scenario 1 or 2; Residential HVAC was not selected under Scenario 2.

Scenario 1 Portfolio Results: As discussed above, Scenario 1 is defined by Medium assumptions and a 1/3 to 2/3 split of renewables to gas for incremental market additions. With the moderate market generation mix and energy prices, the capacity optimization, under Strategies 1-4, resulted in a balance of DSM, Solar, CT generation, and a minimal amount of battery storage. Strategy 5 did not select a CT due to Strategy characteristics that limited new generation technologies to renewables and battery storage resources, so the Portfolio selection resulted in 400 MWs of solar generation and 300 MWs of battery storage.

Scenario 2 Portfolio Results: Scenario 2 is defined by high load growth, low gas prices, and a 1/4 to 3/4 split of renewables to gas for incremental market additions. In Scenario 2, due to low energy prices and zero CO_2 pricing, the optimized Portfolios mostly consisted of a CT addition and battery storage to fill the remaining capacity need. Strategy 5 was restricted to only allow for renewable and battery storage additions, so the Portfolio did not select a CT, but instead covered all the capacity need utilizing battery storage.

Scenario 3 Portfolio Results: Scenario 3 is defined by high energy prices due to gas and CO_2 assumptions. Additionally, the 50/50 renewables to gas incremental market additions mix lead to volatile LMPs over the planning horizon. Due to these characteristics, Portfolios optimized in Scenario 3 saw high penetrations of wind generation and battery storage, complementing the high solar penetration assumed within the MISO South non-ENO market. With the exception of Scenario 3/ Strategy 2, no CT resources were selected in the optimized Portfolios. With the combination of low energy needs and high DSM, Strategy 2 selected a peaking CT to meet the capacity need most economically.

5.4.1 Solar Capacity Credit Modeling:

For the 2018 IRP, ENO sought to take into account integration considerations of intermittent generation. In order to reasonably account for the diminishing contribution of solar towards capacity and energy requirements as the level of solar penetration increases, it was assumed for modeling purposes that the capacity contribution of solar diminished as a function of the amount of incremental solar added in the ENO footprint consistent with the curve MISO studied in the Renewable Integration Impact Assessment ("RIIA"). The concept that increasing amounts of solar provide diminishing returns in capacity and energy

[19] During the Technical Meetings, the parties agreed that, if the capacity expansion did not select a particular program in year 1, additional inputs would be provided to allow the model to consider selecting the program in 2033, the first year with an identified capacity need. This approach increased the chances that DSM would be selected to serve customer needs.

value is a relatively recent notion that has been further explored in detailed work by CAISO[20]and MISO[21] and generally is due to solar production shifting a load serving entity's net peak such that every incremental unit of solar provides less value in supporting reliability needs. As discussed during the Technical Meetings,[22] for the purposes of capacity expansion within the IRP, ENO used the following capacity credit for solar in AURORA when making Portfolio selections through capacity expansion.

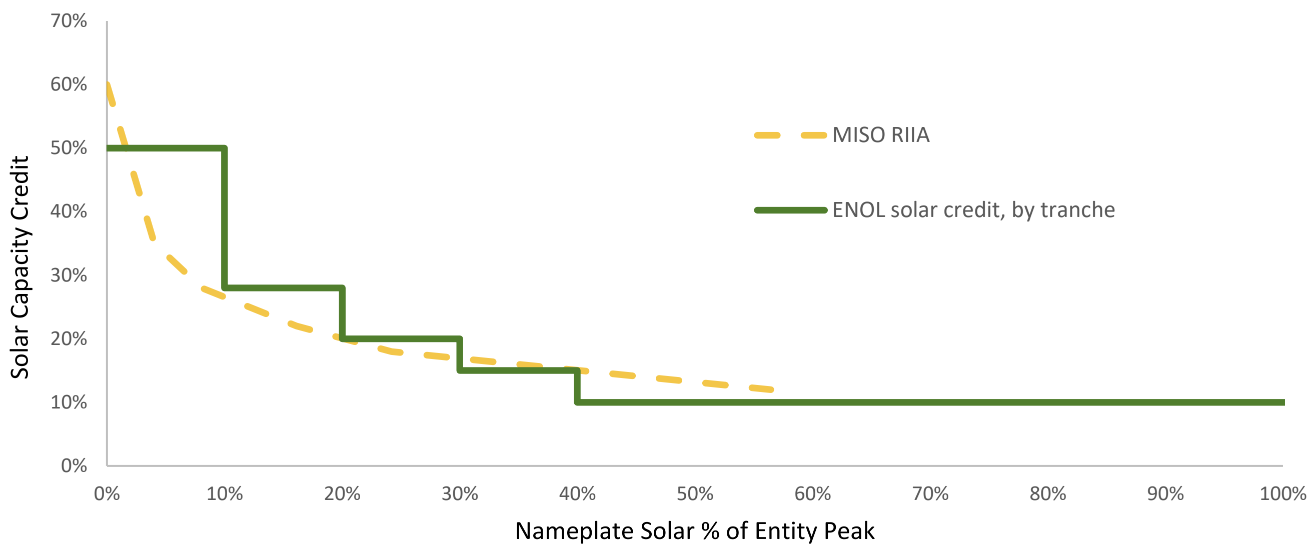

Figure 21: Solar Credit Step-Down as Penetration23 Increases

This is a heuristic approach which utilizes a step-down from 50% credit (the current first year capacity credit a solar resource is granted in MISO) to attempt to capture the diminishing returns solar has for designing Portfolios to meet capacity needs. This assumption was applied only to the AURORA capacity expansion; for the purpose of computing the total supply cost to customers of a Portfolio that includes solar, ENO defaulted to the 50% credit consistent with current MISO practice.

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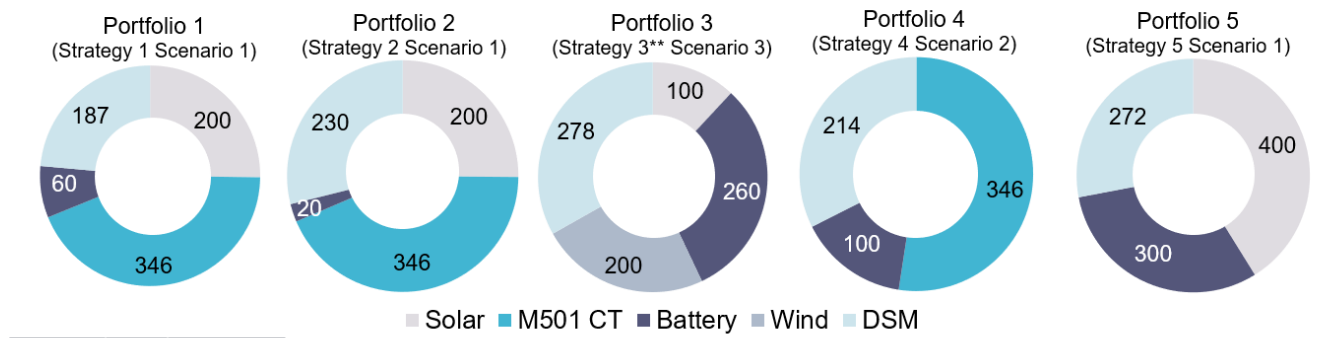
[20] https://www.nrel.gov/docs/fy16osti/65023.pdf

[21] https://cdn.misoenergy.org/20180605%20RIIA%20Workshop%20Presentation213125.pdf

[22] *See*, Appendix G.

[23] "Solar Penetration" is defined as nameplate capacity of installed solar as a percentage of peak demand.

5.5 Total Relevant Supply Cost Results



Resource	Year	Cap (MW)
M 501 J CT	2033	346
Solar	2033	200
Battery	2033	20
Battery	2034	20
Battery	2035	20

Resource	Year	Cap (MW)
M 501 J CT	2033	346
Solar	2033	200
Battery	2038	20

Resource	Year	Cap (MW)
Solar	2033	100
Battery	2033	240
Battery	2034	20
Wind	2038	200

Resource	Year	Cap (MW)
M 501 J CT	2033	346
Battery	2033	60
Battery	2034	20
Battery	2035	20

Resource	Year	Cap (MW)
Battery	2033	240
Solar	2033	400
Battery	2034	40
Battery	2038	20

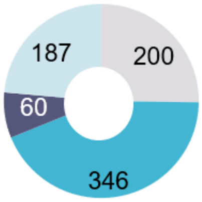
Figure 22: Five Portfolios Selected for Total Relevant Supply Cost Analysis

Through discussions at Technical Meeting #4, ENO, the Intervenors, and the Advisors agreed upon a representative subset of five of the fifteen optimized Portfolios to be run through a Total Relevant Supply Cost Analysis. The Total Relevant Supply Cost ("TRSC") for each of the five selected Portfolios shown in Figure 22, above, was calculated in each of the three planning Scenarios. The TRSC is calculated using:

- ***Variable Supply Cost*** - The variable output from the AURORA model for each Portfolio in each of the futures, which includes fuel costs, variable O&M, CO_2 emission costs, startup costs, energy revenue, and uplift revenue.
- ***Levelized Real Non-Fuel Fixed Costs*** - Return of and on capital investment, fixed O&M, and property tax for the incremental resource additions in each Portfolio.
- ***Demand Side Management (DSM) Costs***
- ***Capacity Purchases/(Sales)*** - The capacity surplus (or deficit) in each Portfolio multiplied by the assumed capacity price.

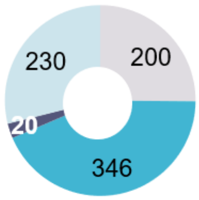
It is important to note that, given the significant differences in program cost and savings assumptions between the two DSM potential studies, there is no meaningful way to compare the total relevant supply costs of Portfolios constructed using DSM input cases from different studies. It is, however, possible to compare Portfolios developed using different input cases from the same DSM potential study. Therefore, the two tables immediately below present the Navigant-based Portfolios and Optimal-based Portfolios separately. Figure 23 shows the present value of the total relevant supply cost for each Navigant-based Portfolio by Scenario. The red boxes indicate the Scenario in which the Portfolio was initially optimized under the applicable Strategy.

Portfolio 1



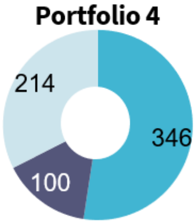
Strategy 1: Scenario 1		Scenario 1	Scenario 2	Scenario 3
Variable Supply Costs	[$MM]	$1,114	$912	$1,248
Resource Additions (Levelized Real)	[$MM]	$134	$134	$134
Capacity Purchases/(Sales)	[$MM]	($35)	($28)	($59)
DSM Fixed Costs	[$MM]	$198	$198	$198
TOTAL SUPPLY COST (2019$ NPV)	[$MM]	**$1,411**	**$1,217**	**$1,521**

Portfolio 2



Strategy 2: Scenario 1		Scenario 1	Scenario 2	Scenario 3
Variable Supply Costs	[$MM]	$961	$799	$991
Resource Additions (Levelized Real)	[$MM]	$121	$121	$121
Capacity Purchases/(Sales)	[$MM]	($46)	($38)	($69)
DSM Fixed Costs	[$MM]	$542	$542	$542
TOTAL SUPPLY COST (2019$ NPV)	[$MM]	**$1,577**	**$1,423**	**$1,584**

Portfolio 4

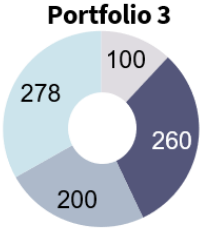


Strategy 4: Scenario 2		Scenario 1	Scenario 2	Scenario 3
Variable Supply Costs	[$MM]	$1,104	$902	$1,224
Resource Additions (Levelized Real)	[$MM]	$97	$97	$97
Capacity Purchases/(Sales)	[$MM]	($33)	($25)	($56)
DSM Fixed Costs	[$MM]	$333	$333	$333
TOTAL SUPPLY COST (2019$ NPV)	[$MM]	**$1,501**	**$1,307**	**$1,597**

Figure 23: Total Relevant Supply Cost Results (2019$ NPV) for Navigant-Based Portfolios

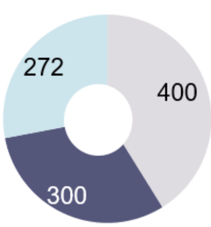
In addition, the present value of the total relevant supply cost for each Optimal-based Portfolio by Scenario is shown in the following figure.

Portfolio 3



Strategy 3: Scenario 3		Scenario 1	Scenario 2	Scenario 3
Variable Supply Costs	[$MM]	$986	$814	$1,030
Resource Additions (Levelized Real)	[$MM]	$114	$114	$114
Capacity Purchases/(Sales)	[$MM]	($47)	($39)	($70)
DSM Fixed Costs	[$MM]	$258	$258	$258
TOTAL SUPPLY COST (2019$ NPV)	[$MM]	**$1,311**	**$1,147**	**$1,331**

Portfolio 5



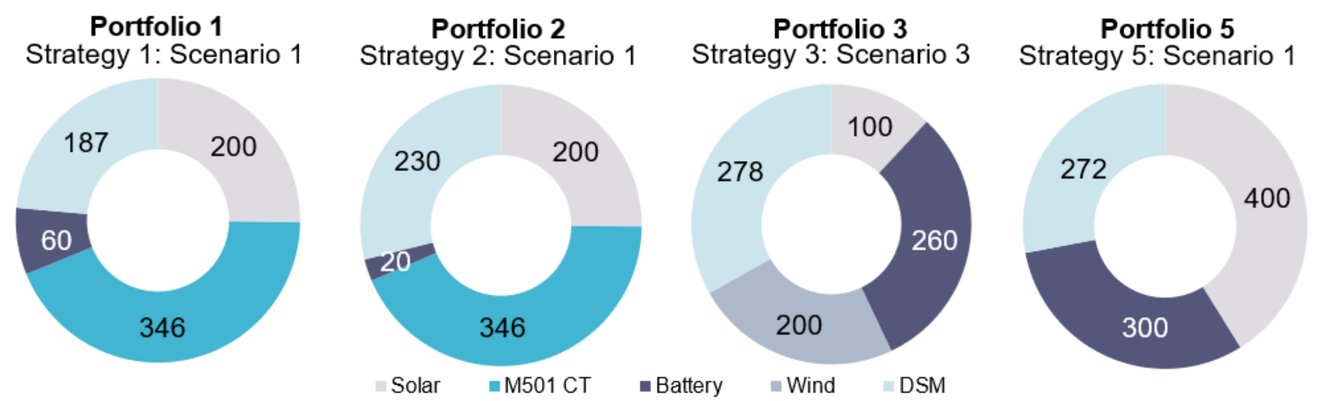
Strategy 5: Scenario 1		Scenario 1	Scenario 2	Scenario 3
Variable Supply Costs	[$MM]	$942	$784	$964
Resource Additions (Levelized Real)	[$MM]	$181	$181	$181
Capacity Purchases/(Sales)	[$MM]	($75)	($67)	($98)
DSM Fixed Costs	[$MM]	$247	$247	$247
TOTAL SUPPLY COST (2019$ NPV)	[$MM]	**$1,295**	**$1,146**	**$1,294**

Figure 24: Total Relevant Supply Cost Results (2019$ NPV) for Optimal-Based Portfolios

To reiterate, ENO separated the total relevant supply costs for the Navigant and Optimal Portfolios due to the major differences in DSM program assumptions of the two vendors. While the spread from the lowest (Portfolio 5 with the Optimal program achievable case) to the highest (Portfolio 2 with the Navigant 2% case) is relatively small at about 18%, the use of DSM input cases from different studies prevents a direct comparison of the total relevant supply costs of those Portfolios. The comparative value of the analyses comes from considering the different inputs, assumptions, and risk sensitivities of each Portfolio as a guide for the future, not from focusing on the costs of one Portfolio versus another, particularly given that actual costs in the future will be driven by resource certifications and DSM implementations that rely on then-current, actual market costs.

5.6 Stochastic Assessment of Risks

The stochastic risk assessment gives an indication of the variability of a Portfolio's costs as underlying assumptions change (e.g., gas, CO_2). Given schedule and resource constraints, the parties agreed at Technical Meeting #4 to run the stochastic assessment for the following four optimized Portfolios.



Resource	Year	Cap (MW)
M 501 J CT	2033	346
Solar	2033	200
Battery	2033	20
Battery	2034	20
Battery	2035	20

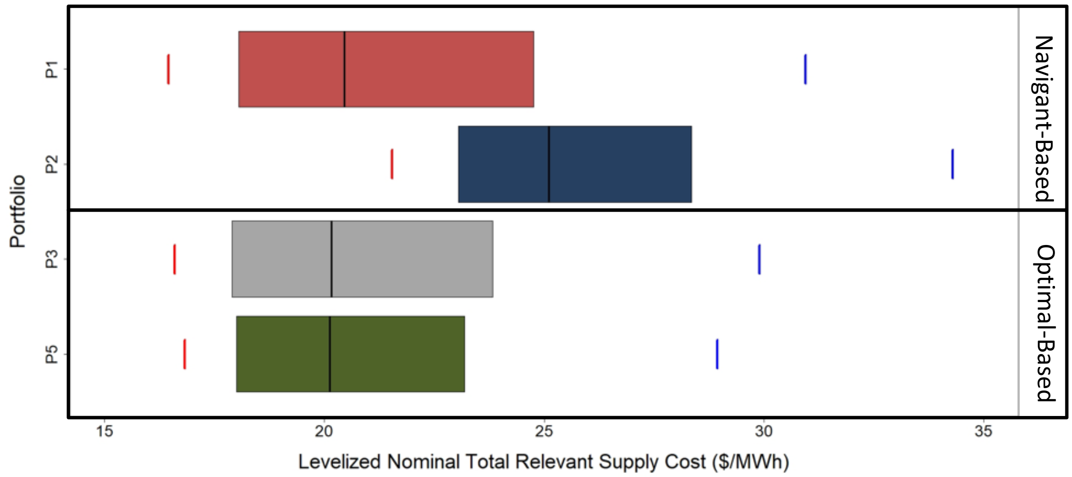
Resource	Year	Cap (MW)
M 501 J CT	2033	346
Solar	2033	200
Battery	2038	20

Resource	Year	Cap (MW)
Solar	2033	100
Battery	2033	240
Battery	2034	20
Wind	2038	200

Resource	Year	Cap (MW)
Battery	2033	240
Solar	2033	400
Battery	2034	40
Battery	2038	20

Figure 25: Portfolios Analyzed in Stochastic Risk Assessment

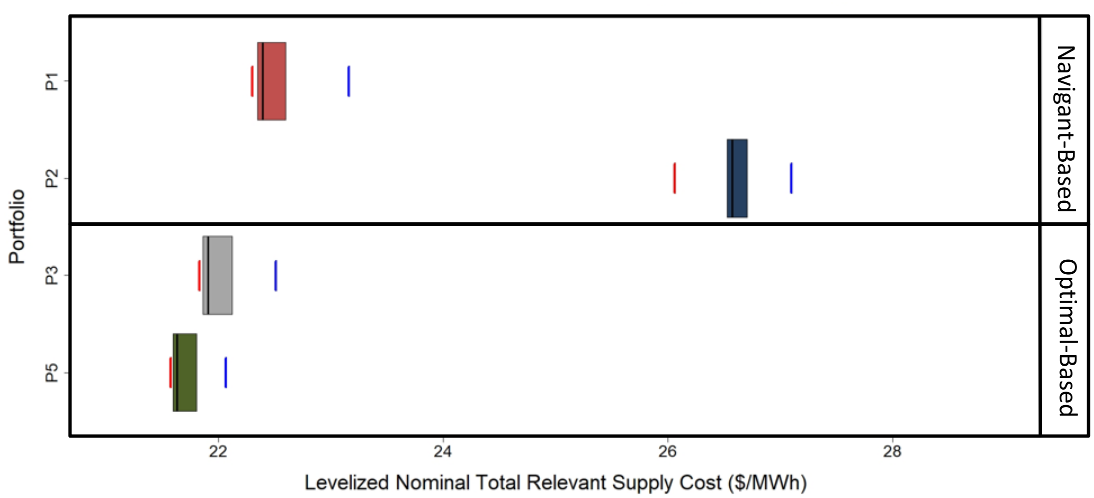
The sensitivity of a Portfolio's performance was assessed relative to changes in assumptions for natural gas prices and CO_2 emission prices through stochastic analysis. Distributions of potential prices for each variable were developed that were lower-bounded by zero and positively skewed toward higher prices, which is consistent with the expectation that commodity prices would not be less than zero and would have some potential for high price spikes. In total, 400 production cost simulations were performed for the four Portfolios using the same set of the 200 gas price outcomes and 200 CO_2 price outcomes and a resulting total relevant supply cost per MWh was determined for each price variant, as described by the following box plot charts.



Percentile	Levelized Real Gas Price (2019 $/mmBtu)
10	*$1.03*
20	*$1.41*
30	*$1.82*
40	*$2.22*
50	*$2.61*
60	*$3.02*
70	*$3.81*
80	*$4.72*
90	*$7.06*
95	*$9.84*
99	*$24.66*

Figure 26: Natural Gas Price Stochastic Results

The 10th, 25th, 50th, 75th, and 90th percentiles are denoted by the vertical markers for each Portfolio. The natural gas price is described by the distribution shown to the right. The variance of total relevant supply cost for each Portfolio indicates the sensitivity of that Portfolio to natural gas prices; however, as discussed above, direct comparison of TRSC results across Portfolios that incorporate DSM input cases from different studies is not possible because of the varying cost and performance assumptions for the DSM programs.



Percentile	Levelized Real CO2 Price $2019
10	*$0.39*
20	*$0.66*
30	*$0.90*
40	*$1.29*
50	*$1.70*
60	*$2.23*
70	*$3.29*
80	*$5.08*
90	*$9.44*
95	*$14.32*
99	*$26.74*

Figure 27: CO_2 Price Stochastic Results

The 10th, 25th, 50th, 75th, and 90th percentiles are denoted by the vertical markers for each Portfolio. The CO_2 price is described by the distribution shown to the right. The variance of total relevant supply cost for each Portfolio indicates the sensitivity of that Portfolio to CO_2 prices; however, as discussed above, direct comparison of TRSC results across Portfolios that incorporate DSM input cases from different studies is not possible because of the varying cost and performance assumptions for the DSM programs. Due to the makeup of the Portfolios and the assumed start date of carbon regulation farther out in the future, the Portfolios are more sensitive to natural gas price variance (which can occur throughout the planning period) than CO_2 price variance.

5.7 Scorecard Metrics and Results

As required by the IRP Rules, ENO, with the help of the Advisors and Intervenors, developed a scorecard to attempt to assist the Council in assessing the IRP based on the Resource Portfolios. The reasons discussed above regarding the difficulty in comparing the total relevant supply costs of Portfolios designed with input cases from different DSM potential studies apply as well to the comparisons attempted through the scorecard. Thus, it must be noted that any comparison across Portfolios does not provide a complete view of ranking, risk, or total benefit given the fundamental difference in DSM inputs. The metrics discussed at Technical Meetings #3 and #4 and utilized in the scorecard are stated below.

Table 19: Scorecard Metrics

Metric	Description	Measure
Expected Value	The average total relevant supply cost of Portfolios across Scenarios and relative to other optimized Portfolios (all Scenarios are weighted equally)	1-10 Grading Scale
Net Present Value	The Total Relevant Supply Cost of the Portfolio in the Scenario it was optimized in	1-10 Grading Scale
Nominal Portfolio Value	A sum of the initial 5 years of the planning period	1-10 Grading Scale
Distribution of Potential Utility Costs	The standard deviation of total relevant supply cost across Scenarios divided by the expected value to get to a coefficient of variation	1-10 Grading Scale
Range of Potential Utility Costs	The sum of the total relevant supply cost upside and downside risk of Portfolios	1-10 Grading Scale
Probability of High CO_2 Intensity	Probability of high CO_2 intensity in the initial 5 years of the planning period	1-100% Grading Scale
Probability of High Groundwater Usage	Probability of high groundwater usage in the initial 5 years of the planning period	1-100% Grading Scale

Flexible Resources	The total MW of ramp available in the final year of the planning period	1-10 Grading Scale
Quick-Start Resources	The total MW of quick start available in the final year of the planning period	1-10 Grading Scale
UCAP/ICAP Ratio	The total UCAP/ICAP ratio in the final year of the planning period	1-10 Grading Scale
CO_2 Intensity	The cumulative tons of CO_2/GWh over the planning period	1-10 Grading Scale
Groundwater Usage	The cumulative percentage of energy generated by resources that use ground water	1-100% Grading Scale
Climate Action Plan- 100% Low Carbon	The cumulative percentage of Carbon free energy from new resources over the planning period	1-100% Grading Scale
Climate Action Plan- 255 MW Solar Additions	The total MWs of solar additions over the planning period	0-255 MW Grading Scale
Climate Action Plan- 3.3% Annual Energy Savings	The compound annual growth rate (CAGR) of DSM over the planning period	0-3.3% Grading Scale
Macroeconomic Factors	DSM spending represents only quantifiable macroeconomic impact at this time. Future ability to evaluate/model DERs could provide additional basis for comparison.	N/A

Based on the metrics discussed above the Portfolios were given a grade determined by how the Portfolio performed in relation to the other Portfolios. Again, due to differing Scenario and Strategy characteristics the grades of the scorecard should not be relied upon at face value without considering the inherent compositional differences among the Portfolios. Metrics that consider costs inclusive of DSM program cost (e.g. Net Present Value) cannot be utilized to compare Portfolios that were optimized using different vendor DSM programs and costs; thus, the grade is not representative of ranking based on equal testing criteria. Acknowledging such, the results of the scorecard are described in Table 20 below.

Table 20: Scorecard Results

Scoring Parameters / Descriptions	Portfolio 1 Scenario 1:Strategy 1	Portfolio 2 Scenario 1:Strategy 2	Portfolio 3 Scenario 3:Strategy 3	Portfolio 4 Scenario 2:Strategy 4	Portfolio 5 Scenario 1:Strategy 5
Utility Cost (Portfolio optimization in Aurora					
Expected value (average cost across Scenarios & relative to other optimized portfolios)	B	D	A	C	A
Utility Costs Impact on ENO's Revenue Requirements					
Net present value of revenue requirements	B	D	A	A	A
Nominal Portfolio Value (residential/ other customer classes) - initial 5 years of planning period	A	D	A	B	A
Risk/Uncertainty					
Distribution of potential utility costs	D	A	B	C	A
Range of potential utility costs	D	A	A	D	A
Probability of high CO2 intensity - initial 5 years of planning period	A	A	A	A	A
Probability of high groundwater usage - initial 5 years of planning period	A	A	A	A	A
Operational Flexibility					
Flexible resources (MW of ramp)	B	D	C	A	A
Quick-Start resources (MW of Quick-Start)[2]	A	B	D	A	C
UCAP/ICAP Ratio (UCAP/ICAP)	C	C	D	A	D
Environmental Impact					
CO2 intensity (tons CO2/GWh)	C	C	B	D	A
Groudwater usage (% of energy generated using Groundwater)	A	A	A	A	A
Consistency with City Policies/ Goals					
Climate Action Plan -- 100% Low Carbon (% of Carbon Free Energy from New Resource)[3]	C	C	A	D	A
Climate Action Plan -- 255 MW Solar added (Total Solar MW in Portfolio)	A	A	C	D	A
Climate Action Plan -- 3.3% Annual Energy Savings (CAGR over 20 years)	A	A	A	A	A
Macroeconomic Impact to CNO					
Macroeconomic Factor (Jobs, local economy impacts)[4]	N/A	N/A	N/A	N/A	N/A

Notes:

1. Except as otherwise noted, A is the top quartile of Portfolios, B is the second quartile, C is the third quartile and D is the bottom quartile.
2. Quick-Start includes supply and demand side dispatchable resources
3. Carbon-free resources include Energy Efficiency
4. DSM spending represents only quantifiable macroeconomic impact at this time. Future ability to evaluate/model DERs could provide additional basis for comparison.

6. Action Plan

6.1 Recap of 2015 IRP Action Plan

The Company committed to, and followed through with, several actions as part of the 2015 IRP Action Plan as shown below.

Description	Action to be Taken	Resolution
Deactivation of Michoud Units 2 and 3	-Confirmed Attachment Y deactivation request complete for Michoud 2 and 3 pursuant to the MISO tariff. -Units 2 and 3 will be deactivated June 1, 2016 subject to completion of necessary transmission upgrades as required by Attachment Y.	-Deactivation completed June 1, 2016.
Union Power Station	-Obtained council approval on November 19, 2015 for ENO purchase of Union Power Block 1. -Transaction scheduled to close in early 2016.	-Unit purchase transaction closed in 2016.
ENO Solar Pilot	-Construction to begin 1st quarter 2016. -Target in service date Summer 2016.	-A.B. Paterson 1 MW Solar + .5 MWh battery storage project ("New Orleans Solar Pilot Project," or "NOSPP") commenced operation in June 2016.
In-region Peaking Generation	-Continue development activities and finalize preliminary design and site location. -File for Council approval in a timely manner. -Target 2019 in service date.	-New Orleans Power Station ("NOPS") 128 MW RICE alternative approved in Council Resolutions R-18-65 and R-19-78. -Project under construction; expected to achieve commercial operation in 2Q2020.
Clean Power Plan	-Continue to monitor pending litigation of the rule and the status of Louisiana Department of Environmental Quality plan to comply.	-Continue to monitor situation given Trump administration's decision to halt implementation at federal level.
DSM	-Continue implementation and performance monitoring of Council approved programs for	-Continue implementation and performance monitoring of Council approved programs for

	Energy Smart Years 5 and 6 through March 2017.	Energy Smart Years 7-9 through December 2019.
Resource Needs	-Continue to monitor resource needs (load, customer count, net metering, resource deactivations) and adjust near-term action plan accordingly.	-The Company continues to monitor its resource needs and report to the Council through the IRP process.
Renewable RFP	-Conduct a Renewable RFP to obtain actionable information on the cost and deliverability of renewable resources.	-Approval of 90 MW portfolio of solar resources (discussed above) selected from the Company's 2016 Renewables RFP was requested through an Application filed in Docket UD-18-06; an Agreement in Principle ("AIP") was filed on June 28, 2019, representing a settlement among the Company, Advisors, and Intervenors. Council Utility Committee approved AIP on July 17, 2019 -Council approved construction of 5 MW Distributed-Generation-scale solar project in Docket No. UD-17-05; construction is underway.
Distributed Generation	-Evaluate alternative methods for the treatment of DG in the integrated resource planning process for opportunities for improvement.	-As discussed in Section 3.9, above, the Company is taking numerous steps to develop its capabilities to analyze the impacts of DERs on the distribution system as contemplated by the Council's updated IRP Rules.
AMI	-Entergy is currently considering various future investments to modernize the distribution grid and more fully utilize new technologies. -AMI continues to be analyzed and ENO plans to talk further with the City Council and the Advisors regarding potential future AMI investments.	-The Council approved the Company's application to implement AMI throughout the city in Resolution R-18-37. -Accelerated implementation is ongoing and is expected to be complete in late 2020.

6.2 2018 IRP Action Plan

ENO has identified a number of actions it will pursue in the near term given the analysis of the Portfolios identified under the various planning Scenarios and Strategies.

Description	Action to be Taken
90 MW Portfolio Implementation	Upon final approval of the Company's Application in Docket UD-18-06, undertake construction of New Orleans Solar Station ("NOSS") project at NASA Michoud and monitor counterparty efforts to bring projects underlying the St. James and Iris solar PPAs online in accordance with contractual deadlines.
Commercial Rooftop Program	Complete installation of 5 MW_{AC} rooftop solar projects approved in Resolution R-18-222. Report on project outcome to Council and consider whether requesting expansion of program beyond 5 MW limit is warranted.
Community Solar Program Implementation	Continue building internal resources and processes to support administration of Council's Community Solar program under rules approved in Docket UD-18-03.
Distribution Planning Capabilities	As discussed in Section 3.9, above, the Company is taking numerous steps to develop its capabilities to analyze the impacts of DERs on the distribution system as contemplated by the Council's updated IRP Rules.
DSM/DR Implementation	File Implementation Plan for Energy Smart Program Years 10-12 as required under Resolution R-17-430.
Grid Modernization Implementation	Continue implementing Grid Modernization as outlined in plans submitted in Docket UD-18-01.
One Hundred Homes Rooftop Solar Initiative	Complete implementation of rooftop solar pilot program with up to 100 low income residential customers in 2019.
Smart Cities Implementation	Continue working with Advisors and other stakeholders in Docket UD-18-01 to support implementation of Smart Cities technologies and EV charging infrastructure solutions.

Exhibits

- Appendix A—Rules Compliance Matrix
- Appendix B—Actual Historic Load and Load Forecast (HSPM in part)
- Appendix C—Total Resource Supply Costs - Detail (HSPM in part)
- Appendix D—Navigant Potential Study
- Appendix E—Optimal Potential Study
- Appendix F—Macro Inputs Workbook (HSPM)
- Appendix G—Technical Meeting Materials for Meetings 1-4

Appendix A: Rules Compliance Matrix

Requirement No.	Section No.	Page No.	Key phrase or Issue	Excerpt	Response and/or Citation to IRP Report
1	1.C.	1	Rules Matrix	*Each Utility IRP shall include a matrix of these rules, the corresponding section of the IRP responsive to that rule, and a brief description of how the Utility complied with the rules.*	**Appendix A**
2	3.A.	4	Specific Objectives	*The Utility shall state and support specific objectives to be accomplished in the IRP planning process, which include but are not limited to the following:*	**Pg 8: Planning Objectives**
3	3.A.1.	4	Integration of Supply Side and Demand Side Resources	*optimize the integration of supply-side resources and demand-side resources, while taking into account transmission and distribution, to provide New Orleans ratepayers with reliable electricity at the lowest practicable cost given an acceptable level of risk;*	**Pg 8: Planning Objectives** **Pg 22 Transmission** **Pg 26 Distribution** **Section 5 Portfolio Analytics**
4	3.A.2.	4	Maintain Financial Integrity	*maintain the Utility's financial integrity;*	**Pg 8: Planning Objectives**
5	3.A.3.	4	Mitigate Risks	*anticipate and mitigate risks associated with fuel and market prices, environmental compliance*	**Pg. 63: Stochastic Assessment of Risk**

				costs, and other economic factors;	
6	3.A.4.	4	Support Resiliency and Sustainability	*support the resiliency and sustainability of the Utility's systems in New Orleans;*	**Pg 22: Transmission** **Pg 26: Distribution** **Pg 65: Scorecard Metrics and Results**
7	3.A.5.	4	Comply with Requirements and Council Policies	*comply with local, state and federal regulatory requirements and regulatory requirements and known policies (including such policies identified in the Initiating Resolution) established by the Council;*	**Pg 54: Planning Strategy Overview** **Pg 65: Scorecard Metrics and Results**
8	3.A.6.	4	Evaluate Incorporation of new technology	*evaluate the appropriateness of incorporating advances in technology, including, but not limited to, renewable energy, storage, and DERs, among others;*	**Pg 34: Assessing Alternatives to Meet ENO Resource Needs**
9	3.A.7.	4	Acceptable Risk	*achieve a range of acceptable risk in the trade-off between cost and risk;*	**Pg. 63: Stochastic Assessment of Risk**
10	3.A.8.	4	Transparency and Engagement	*maintain transparency and engagement with stakeholders throughout the IRP process by conducting technical conferences and providing for stakeholder feedback regarding the Planning Scenarios, Planning Strategies, input parameters, and assumptions.*	**Technical Meeting #1: 1/22/18** **Technical Meeting #2: 9/14/18** **Technical Meeting #3: 11/28/18** **Technical Meeting #4: 5/1/19**

11	3.B.	4	Efforts to Achieve Objectives	*In the IRP Report, the Utility shall discuss its efforts to achieve the objectives identified in Section 3A and any additional specific objectives identified in the Initiating Resolution.*	**Pg 8: Planning Objectives Section 5, Portfolio Design Analytics**
12	4.A.	5	Reference Load Forecasts and alternatives	*The Utility shall develop a reference case Load Forecast and at least two alternative Load Forecasts applicable to the Planning Period which are consistent with the Planning Scenarios identified in Section 7C. The following data shall be supplied in support of each Load Forecast:*	**Pg 12: Load Forecasting Methodology**
13	4.A.1.	5	Forecast of Demand and Energy by Customer Class	*The Utility's forecast of demand and energy usage by customer class for the Planning Period;*	**Pg 12: Load Forecasting Methodology**
14	4.A.2.	5	Methodology	*A detailed discussion of the forecasting methodology and a list of independent variables and their reference sources that were utilized in the development of the Load Forecast, including assumptions and econometrically evaluated estimates. The details of the Load Forecast should identify the energy and demand impacts of customer-owned DERs and then existing Utility-sponsored DSM programs;*	**Pg 12: Load Forecasting Methodology**

15	4.A.3.	5	Independent Variables	*Forecasts of the independent variables for the Planning Period, including their probability distributions and statistical significance;*	**Pg 12: Load Forecasting Methodology**
16	4.A.4.	5	Expected Value of forecast	*The expected value of the Load Forecast as well as the probability distributions (uncertainty ranges) around the expected value of the Load Forecast;*	**Pg 12: Load Forecasting Methodology; Appendix B**
17	4.A.5.	5	Line Losses	*A discussion of the extent to which line losses have been incorporated in the Load Forecast.*	**Pg 12: Load Forecasting Methodology**
18	4.B.	5	Composite Customer Hourly Load Profiles	*The Utility shall construct composite customer hourly load profiles based on the forecasted demand and energy usage by customer class and relevant load research data, including the factors which determine future load levels and shape.*	**Pg 12: Load Forecasting Methodology and Appendix B**
19	4.C.	5	Demand and Energy data for 5 preceding years	*Concurrent with the presentation of the Load Forecasts to the Advisors, CURO, and stakeholders, the Utility shall provide historical demand and energy data for the five (5) years immediately preceding the Planning Period. At a minimum, the following data shall be provided:*	**Pg 12: Load Forecasting Methodology and Appendix B**

20	4.C.1.	5	Monthly energy consumption by class	*monthly energy consumption for the Utility in total and for each customer class;*	**Pg 12: Load Forecasting Methodology and Appendix B**
21	4.C.2.	5	Monthly CP for utility and classes	*monthly coincident peak demand for the Utility and estimates of the monthly coincident peak demand for each customer class;*	**Pg 12: Load Forecasting Methodology and Appendix B**
22	4.C.3.	5	Monthly peak demand by class	*estimates of the monthly peak demand for each customer class;*	**Pg 12: Load Forecasting Methodology and Appendix B**
23	4.D.	5	Section 4 data in attachment	*The data and discussions developed pursuant to Section 4A and Section 4B, and Section 4C shall be provided as an attachment to the IRP report and summarized in the IRP report.*	**Pg 12: Load Forecasting Methodology and Appendix B**
24	4.E.	6	Known cogen and >300kW DER resources	*The Utility shall also provide a list of any known co-generation resources and DERs larger than 300 kW existing on the Utility's system, including resources maintained by the City of New Orleans for city/parish purposes, (e.g. Sewerage and Water Board, Orleans Levee District, or by independent agencies or entities such as universities, etc.).*	**Paterson Solar + Storage Pilot; Sites constructed under Commercial Rooftop Project (UD-17-05): TCI and Dwyer Rd.**

25	5.A.	6	Identification of resource options	*Identification of resource options. The Utility shall identify and evaluate all existing supply-side and demand-side resources and identify a variety of potential supply-side and demand-side resources which can be reasonably expected to meet the Utility's projected resource needs during the Planning Period.*	**Appendix D and E: Optimal and Navigant Studies Pg 34: Assessing Alternatives to Meet ENO Resource Needs**
26	5.A.1.	6	Existing supply side resource costs	*Existing supply-side resources. For existing supply-side resources, the Utility should incorporate all fixed and variable costs necessary to continue to utilize the resource as part of a Resource Portfolio. Costs shall include the costs of any anticipated renewal and replacement projects as well as the cost of regulatory mandated current and future emission controls.*	**Appendix C-- Variable Supply Cost reflects the optimized run time of existing units**
27	5.A.1.a.	6	Changes to resource mix	*The Utility shall identify important changes to the Utility's resource mix that occurred since the last IRP including large capital projects, resource procurements, changes in fuel types, and actual or expected operational changes regardless of cause.*	**Pg 10: Figure 2**

28	5.A.1.b.	6	Supply side resource info	*Data supplied as part of the Utility's IRP filing should include a list of the Utility's existing supply-side resources including: the resource name, fuel type, capacity rating at time of summer and winter peak, and typical operating role (e.g. base, intermediate, peaking).*	**Pg. 11: Table 2**
29	5.A.2.	6	Load reductions from existing DSM resources	*For existing demand-side resources, the Utility should account for load reductions attributable to the then-existing demand-side resources in each year of the Planning Period. Each existing demand-side resource will be identified as either a specific energy efficiency program or DR program with an individual program lifetime and estimated energy and demand reductions applicable to the Planning Period, or as a then-existing Utility owned or Utility-managed distributed generation resource with energy and demand impacts that are estimated for applicable years of the Planning Period. Data supplied as part of the Utility's IRP filing should include:*	**Pg 12: Load Forecasting Methodology** **Pg 42: Demand-Side Management** **Pg 68: Action Plan**

30	5.A.2.a.	6	Projected reductions	*Details of projected kWh/kW reductions from existing DSM programs based on quantifiable results and other credible support derived from Energy Smart New Orleans, or any successor program, using verified data available to the Utility from prior DSM program implementation years.*	**Appendix B**
31	5.A.2.b.	6	Existing DSM resources	*A list categorizing the Utility's existing demand-side resources including anticipated capacity at time of summer and winter peak.*	**Pg 42: Demand-Side Management** **Pg 68: Action Plan**
32	5.A.3.	6	Potential SS resources	*With respect to potential supply-side resources, the Utility shall consider: Utility-owned and purchased power resources; conventional and new generating technologies including technologies expected to become commercially viable during the Planning Period; technologies utilizing renewable fuels; energy storage technologies; cogeneration resources; and Distributed Energy Resources, among others.*	**Pg 34: Technology Assessment**
33	5.A.3.a.	7	Incorporate known policy goals	*The Utility should incorporate any known Council policy goals (including such policy goals identified in the Initiating Resolution) with respect to*	**Section V, Portfolio Design Analytics** **Pg 68: Action Plan** **Pg 25: Distribution**

				resource acquisition, including, but not limited to, renewable resources, energy storage technologies, and DERs.	
34	5.A.3.b.	7	Required data for resources	*Data supplied as part of the Utility's IRP filing should include: a description of each potential supply-side resource including a technology description, operating characteristics, capital cost or demand charge, fixed operation and maintenance costs, variable charges, variable operation and maintenance costs, earliest date available to provide supply, expected life or contractual term of resource, and fuel type with reference to fuel forecast.*	**Pg 34: Assessing Alternatives to Meet ENO Resource Needs**
35	5.A.4.	7	Potential DSM Resources	*Potential demand-side resources. With respect to potential demand-side resources, the Utility should consider and identify all cost-effective demand-side resources through the development of a DSM potential study. All DSM measures with a Total Resource Cost Test value of 1.0 or greater shall be considered cost effective for DSM measure screening purposes.*	**Appendix D and E--Navigant and Optimal Potential Studies**
36	5.A.4.a.	7	DSM Potential Study	*The DSM potential study shall include, but not be limited to: identification of eligible measures, measure life expectancies,*	**Appendix D and E--Navigant and Optimal Potential Studies**

				baseline standards, load reduction profiles, incremental capacity and energy savings, measure and program cost assumptions, participant adoption rates, market development, and avoided energy and capacity costs for DSM measure and program screening purposes.	
37	5.A.4.b.	7	N.O. TRM	*The principal reference document for the DSM potential study shall be the New Orleans Technical Reference Manual.*	**Appendix D and E--Navigant and Optimal Potential Studies**
38	5.A.4.c.	7	CA Standard Practice Tests	*In the development of the DSM potential study, all four California Standard Practice Tests (i.e. TRC, PACT, RIM and PCT) will be calculated for the DSM measures and programs considered.*	**Appendix D and E--Navigant and Optimal Potential Studies**
39	5.A.4.d.	7	Known policy goals re: DSM	*The Utility should incorporate any known Council policy goals or targets (including such policy goals or targets identified in the Initiating Resolution) with respect to demand-side resources.*	**Pg 54: Planning Strategy Overview Pg 65: Scorecard Metrics and Results**
40	5.A.4.e.	7	Cost effective DR programs	*The cost-effective DR programs should include consideration of those programs enabled by the deployment of Advanced Meter Infrastructure, including both direct load control and DR pricing programs for both Residential and*	**Appendix D and E--Navigant and Optimal Potential Studies**

				Commercial customer classes.	
41	5.A.4.f.	8	Required data for DSM analysis	*Data supplied as part of the Utility's IRP filing should include: a description of each potential demand-side resource considered, including a description of the resource or program; expected penetration levels by planning year; hourly load reduction profiles for each DSM program utilized in the IRP process; and results of appropriate cost-benefit analyses and acceptance tests, as part of the planning assumptions utilized within the IRP planning process.*	**Appendix D and E-- Navigant and Optimal Studies** **Pg 42: Demand-Side Management** **Pg 44: Energy Efficiency** **Pg 47: Demand Response**
42	5.B.	8	Stakeholder process	*Through the Stakeholder Process, the Utility shall strive to develop a position agreed to by the Utility, the Advisors, and a majority of the Intervenors regarding the potential supply-side and potential demand-side resources and their associated defining characteristics (e.g., capital cost, operating and maintenance costs, emissions, DSM supply curve, etc.).*	**Consensus among parties reached at Technical Meeting #3**

43	5.B.1.	8	Reference Planning Strategy	*To the extent such a consensus can be achieved among the Utility, the Advisors, and a majority of the Intervenors, the resulting collection of potential supply-side and demand-side resources and their associated defining characteristics will be utilized in the reference Planning Strategy developed pursuant to Section 7D.*	**Consensus among parties reached at Technical Meeting #3**
44	5.B.2.	8	Stakeholder Strategy	*To the extent such a consensus cannot be achieved, the Utility shall model, in coordination with the requirements in Section 7D, two distinct Planning Strategies: a reference Planning Strategy and a stakeholder Planning Strategy. The reference Planning Strategy will be based on the Utility's assessment of the collection of potential supply-side and demand-side resources and their associated defining characteristics. The stakeholder Planning Strategy will be determined by a majority of the Intervenors and modeled by the Utility based on inputs provided to the Utility describing the collection of potential supply-side and demand-side resources and their associated defining characteristics. To maintain consistency in the modeling process, the Advisors will work*	**Consensus among parties reached at Technical Meeting #3**

				with the Intervenors and the Utility to ensure that input that is provided for the stakeholder Planning Strategy can be accommodated within the framework of the existing model and software.	
45	6.A.	8	Integration of T&D planning into IRP	*The Utility shall explain how the Utility's current transmission system, and any planned transmission system expansions (including regional transmission system expansion planned by the RTO in which the Utility participates) and the Utility's distribution system are integrated into the overall resource planning process to optimize the Utility's resource portfolio and provide New Orleans ratepayers with reliable electricity at the lowest practicable cost.*	**Pg 22: Transmission** **Pg 26: Distribution**
46	6.B.	9	Planned transmission topology	*Models developed for the integrated resource planning process should incorporate the planned configuration of the Utility's transmission system and the interconnected RTO during the Planning Period.*	**Pg 22: Transmission**

47	6.C.	9	Major changes to T&D systems	*To the extent major changes in the operation or planning of the transmission system and/or distribution system (including changes to accommodate the expansion of DERs) are contemplated in the Planning Period, the Utility should describe the anticipated changes and provide an assessment of the cost and benefits to the Utility and its customers.*	**Pg 22: Transmission** **Pg 26: Distribution**
48	6.D.	9	Transmission solutions for reliability	*To the extent that new resource additions are selected by the Utility for a Resource Portfolio based on reliability needs rather than as a result of the optimized development of a Resource Portfolio, the Utility shall identify reasonable transmission solutions that can be employed to either reduce the size, delay, or eliminate the need for the new reliability-driven resource additions and provide economic analyses demonstrating why the new reliability-driven resource addition was selected in lieu of the transmission solutions identified.*	**Pg 22: Transmission**

49	6.E.	9	Evaluation of DERs	*It is the Council's intent that, as part of the IRP, the Utility shall evaluate the extent to which reliability of the distribution system can be improved through the strategic location of DERs or other resources identified as part of the IRP planning process. The Utility should provide an analysis, discussion, and quantification of the costs and benefits as part of the evaluation. To the extent the Utility does not currently have the capability to meet this requirement, the utility shall demonstrate progress toward accomplishing this requirement until such time as it acquires the capability.*	**Pg 26: Distribution**
50	7.A.	9	IRP Modeling parameters	*The integrated resource planning process should include modeling of specific parameters and their relationships consistent with market fundamentals, and as appropriate for long-term Portfolio planning. This overall modeling approach is an accepted analytic approach used in resource planning considering the range of both supply-side and demand-side options as well as uncertainty surrounding market pricing. To represent and account for the different characteristics of alternative types of resource*	**Section 5, Portfolio Design Analytics**

				options, mathematical methods such as a linear programming formulation should be used to optimize resource decisions.	
51	7.B.	9	External Capacity sales	*The optimization process shall be constrained to mitigate the over-reliance on forecasted revenues from external capacity market sales and external energy market sales driving the selection of resources.*	**Pg 56: Market Modeling** **Pg 56: Capacity Optimization and Results**
52	7.C.	9	Planning Scenarios	*The Utility shall develop three to four Planning Scenarios that incorporate different economic and environmental circumstances and national and regional regulatory and legislative policies.*	**Consensus among parties reached at Technical Meeting #3**
53	7.C.1.	10	Reference and Alternative Scenarios	*The Planning Scenarios should include a reference Planning Scenario that represents the Utility's point of view on the most likely future circumstances and policies, as well as two alternative Planning Scenarios that account for alternative circumstances and policies.*	**Consensus among parties reached at Technical Meeting #3**
54	7.C.2.	10	Scenario Assumptions	*In the development of the Planning Scenarios, the Utility should seek to develop a position agreed to by the Utility, Advisors, and a*	**Consensus among parties reached at Technical Meeting #3**

				majority of Intervenors regarding the assumptions surrounding each of the Planning Scenarios. To the extent such a consensus is not reasonably attainable regarding the Planning Scenarios, the Utility shall model a fourth Planning Scenario which is based upon input agreed to by a majority of the Intervenors.	
55	7.C.3.	10	Data for Scenarios	*For each IRP Planning Scenario, data supplied as part of the Utility's IRP filing should include:*	
56	7.C.3.a.	10	Fuel Price Forecast	*a fuel price forecast for each fuel considered for utilization in any existing or potential supply-side resource;*	**Pg 50: Natural Gas Price Forecast**
57	7.C.3.b.	10	Hourly Market Price Forecast for Energy	*an hourly market price forecast for energy (e.g. locational marginal prices);*	**Pg 56: Market Modeling**
58	7.C.3.c.	10	Annual Capacity Price Forecast	*an annual capacity price forecast for both a short-term capacity purchase (e.g. bilateral contract or Planning Resource Credit) and a long-term capacity purchase (e.g. long-run marginal cost of a new replacement gas combustion turbine);*	**Appendix F--Macro Inputs Workbook**
59	7.C.3.d.	10	Other Price Components	*forecasts of price for any other price related components that are defined by the Planning Scenario*	**Pg 51: CO_2 Price forecast**

				(e.g. CO_2 price forecast, etc.).	
60	7.D.	10	Strategies	*Distinct from the Planning Scenarios, the Utility shall identify two to four Planning Strategies which constrain the optimization process to achieve particular goals, regulatory policies and/or business decisions over which the Council, the Utility, or stakeholders have control.*	**Consensus among the parties reached at Technical Meeting #3**
61	7.D.1.	10	Lowest Cost Strategy	*The Utility shall develop a Planning Strategy that allows the optimization process to identify the lowest cost option for meeting the needs identified in the IRP process.*	**Pg 54: Planning Strategy Overview**
62	7.D.2.	10	Reference Strategy	*The Utility shall develop a reference Planning Strategy agreed to by the Utility, Advisors, and a majority of the Intervenors. To the extent such a consensus cannot be reasonably achieved, the reference Planning Strategy shall reflect the Utility's point of view on resource input parameters and constraints, and the Utility shall model a separate stakeholder Planning Strategy based upon input determined by a majority of the Intervenors.*	**Consensus among the parties reached at Technical Meeting #3**

63	7.D.3.	11	Alternate Strategies	*As necessary, the Utility shall develop alternate Planning Strategies to reflect known utility regulatory policy goals of the Council (including such policy goals or targets identified in the Initiating Resolution) as established no later than 30 days prior to the date the Planning Strategy inputs must be finalized.*	**Consensus among the parties reached at Technical Meeting #3**
64	7.E.	11	Finalization of Scenario and Strategy Parameters	*Prior to the development of optimized Resource Portfolios, the parameters developed for the Planning Scenarios and Planning Strategies shall be set, considered finalized, and not subject for alteration during the remainder of the IRP planning cycle. The IRP Report shall describe the parameters of each Planning Scenario and each Planning Strategy, including all artificial constraints utilized in the optimization modeling.*	**Section 5, Portfolio Design Analytics**
65	7.F.	11	Portfolio Optimization	*Resource Portfolios shall be developed through optimization utilizing the Utility's modeling software. The Utility shall identify the least-cost Resource Portfolio for each Planning Scenario and Planning Strategy combination, based on total cost. Resource Portfolios shall consist of optimized combinations of supply-*	**Pg 56: Capacity Optimization and Results**

				side and demand-side resources, while recognizing constraints including transmission and distribution.	
66	7.G.	11	Results of Scenario&Strategy combinations	*The Utility shall provide a discussion and presentation of results for each Planning Scenario/Planning Strategy combination, the annual total demand related costs, energy related costs, and total supply costs associated with each least-cost Resource Portfolio identified under each Planning Scenario/Planning Strategy combination, a load and capability table indicating the total load requirements and identifying all supply-side and demand-side resources included in the Resource Portfolio (including identifying the impacts of existing demand-side resources on the total load requirements), and a description of the supply-side and demand-side resources that are planned and, if applicable, their principal rationale for selection (i.e., supply peak demand, supply non-peak demand or operational constraints, achieve more economical production of energy, etc.).*	**Pg 61: Total relevant supply Cost Results; Appendix C**

67	7.G.1.	11	Annual and Cumulative portfolio costs	*Data supplied as part of the Utility's IRP filing shall include a cumulative present worth summary of the results as well as the annual estimates of costs that result in the cumulative present worth to enable the Council to understand the timing of costs and savings of each least-cost Resource Portfolio.*	**Pg 61: Total relevant supply Cost Results; Appendix C**
68	7.H.	11	Discussion of Portfolio Results	*The IRP report's discussion and presentation of results for each Resource Portfolio should identify key characteristics of that Resource Portfolio and significant factors that drive the ultimate cost of that Resource Portfolio such that the Council may understand which factors could ultimately and significantly affect the preference of a Resource Portfolio by the Council.*	**Pg 61: Total Relevant Supply Cost Results**
69	7.I.	11	Scorecard template	*The Utility will develop and include a scorecard template or set of quantitative and qualitative metrics to assist the Council in assessing the IRP based on the Resource Portfolios. The scorecard should rank the resource portfolios by how well each portfolio achieves each metric. Such metrics should include but not necessarily be limited to: cost; impact on the*	**Pg 65: Scorecard Metrics and Results**

				Utility's revenue requirements; risk; flexibility of resource options; reasonably quantifiable environmental impacts (such as national average emissions for the technologies chosen, amount of groundwater consumed, etc.); consistency with established, published city policies, such as the City's sustainability plan; and macroeconomic impacts in New Orleans.	
70	8.A.	12	Cost/Risk Analysis	*The Utility shall develop a cost/risk analysis which balances quantifiable costs with quantifiable risks of the identified least-cost Resource Portfolios. The risk assessment must be presented in the IRP to allow the Council to comprehend the robustness of each Resource Portfolio across the cost/risk range of possible Resource Portfolios.*	**Pg 63: Stochastic Assessment of Risk**
71	8.A.1.	12	Assessment of social and environmental costs	*In quantifying Resource Portfolio costs/risks, the IRP shall assess any social and environmental effects of the Resource Portfolios to the extent that: 1) those effects can be quantified and have been modeled for a Resource Portfolio, including the applicable Planning Period years and ranges of uncertainty surrounding each*	**Pg 65: Scorecard Metrics and Results**

				externality cost, and 2) each quantified cost must be clearly identified by the portion which relates to the Utility's revenue requirements or cost of providing service to the Utility's customers under the Resource Portfolio.	
72	8.A.2.	12	Probabilities of outcomes	*It is the Council's intent that, as part of the IRP, a risk assessment be conducted to evaluate both the expected outcome of potential costs as well as the distribution and potential range and associated probabilities of outcomes. To the extent the Utility believes the risk assessment described herein is beyond the current modeling capabilities of the Utility or that the risk assessment cannot be accomplished within the procedural schedule set forth in the Initiating Resolution, the Utility shall so inform the Council and meet with the Intervenors and Advisors to agree upon an alternative form of risk analysis to recommend to the Council.*	**Pg 63: Stochastic Assessment of Risk**
73	8.A.2.a.	12	Cost/MWh in future years	*The risk assessment shall include the expected cost per MWh of the Resource Portfolios in selected future years, along with the range of annual average costs foreseen for the 10th and 90th percentiles*	**Pg 63: Stochastic Assessment of Risk**

				of simulated possible outcomes.	
74	8.A.2.b.	12	Supporting Methodology Included	*The supporting methodology shall be included, such as the iterations or simulations performed for the selected years, in which the possible outcomes are drawn from distributions that describe market expectations and volatility as of the current filing date.*	**Pg 63: Stochastic Assessment of Risk**
75	9.A.	12	IRP Process Requirements	*At a minimum, the IRP process shall include, but not be limited to, the following elements:*	
76	9.A.1.	12	Collaboration on IRP inputs	*The opportunity for Intervenors to participate in the concurrent development of inputs and assumptions for the major components of the IRP in collaboration with the Utility within the confines of the IRP timeline and procedural schedule.*	**Stakeholder process conducted in accordance with IRP Rules and Initiating Resolution**

77	9.A.2.	12	Four Technical Meetings	*At least four technical meetings attended by the parties in the Docket focused on major IRP components that include the Utility, Intervenors, CURO, and the Advisors with structured comment deadlines so that meeting participants have the opportunity to present inputs and assumptions and provide comments, and attempt to reach consensus while remaining mindful of the procedural schedule established in the Initiating Resolution.*	**Technical Meeting #1: 1/22/18** **Technical Meeting #2: 9/14/18** **Technical Meeting #3: 11/28/18** **Technical Meeting #4: 5/1/19** **Technical Meeting #5: TBD**
78	9.A.3.	13	Three Public Meetings	*At least 3 public engagement technical conferences advertised through multiple media channels at a minimum of 30 days prior to the public technical conference.*	**Public Meeting #1: 9/25/17** **Public Meeting #2: 8/9/19** **Public Meeting #3: TBD**
79	10.A.	13	Public Review of IRP	*The Utility shall make its IRP available for public review subject to the provisions of the Council Resolution initiating the current IRP planning cycle and referenced in Section 1B.*	**Public IRP Available on ENO IRP Website**
80	10.B.	13	Filing of IRP	*The Utility shall file its IRP with the Council consistent with and subject to the provisions of the Council Resolution initiating the current IRP planning cycle*	**IRP Filed: 7/19/19**

				referenced in Section 1B.	
81	10.C.	13	Discussion of Stakeholder engagement	*The IRP report should discuss the stakeholders' engagement throughout the IRP process; the access to data inputs and specific modeling results by all parties; the consensus reached regarding all demand-side and supply-side resource inputs and assumptions; specific descriptions of unresolved issues regarding inputs, assumptions, or methodology; the formulation of the stakeholder Planning Scenario and/or stakeholder Planning Strategy as needed; and recommendations to improve the transparency and efficiency of the IRP process for prospective IRP cycles.*	**Pg 4: Executive Summary; Pg 53: Portfolio Design Analytics**
82	10.D.	13	Action Plan	*The IRP shall include an action plan and timeline discussing any steps or actions the Utility may propose to take as a result of the IRP, understanding that the Council's acceptance of the filing of the Utility's IRP would not operate as approval of any such proposed steps or actions.*	**Pg 68: Action Plan**

Appendix B: Actual Historic Load and Load Forecast

Historic Peak Demand and Energy

Table 1: Annual Billed Sales at the Meter (GWh)

	Residential	Commercial	Industrial	Governmental	Total
2010	1,858	1,899	503	810	5,069
2011	1,888	1,939	498	795	5,120
2012	1,772	1,968	484	785	5,009
2013	1,867	1,998	481	758	5,105
2014	1,963	2,046	452	768	5,230
2015	2,104	2,167	461	814	5,547
2016	2,231	2,268	441	794	5,733
2017	2,155	2,248	429	790	5,621
2018	2,401	2,270	448	795	5,914

Table 2: Summer and Winter Historical Peaks with Distribution Losses (MW)

	Summer	Winter
2010	1,101	975
2011	1,115	993
2012	1,104	830
2013	1,104	903
2014	1,066	1,056
2015	1,161	1,008
2016	1,142	952
2017	1,118	1,023
2018	1,150	1,181

Table 3: Historic Monthly Billed Sales at the Meter (MWh)

	Residential	Commercial	Industrial	Governmental	Total
1/1/2010	179,921	151,178	40,363	65,903	437,366
2/1/2010	159,381	142,735	32,322	59,204	393,643
3/1/2010	146,460	134,268	35,021	57,458	373,206
4/1/2010	92,298	135,186	43,730	57,566	328,780
5/1/2010	114,665	151,184	41,015	63,780	370,645
6/1/2010	172,176	171,779	49,094	69,876	462,925
7/1/2010	199,176	186,908	46,230	77,750	510,064
8/1/2010	216,973	188,679	50,137	77,149	532,938
9/1/2010	191,740	179,188	42,450	76,541	489,920
10/1/2010	147,993	161,356	42,863	76,771	428,983
11/1/2010	110,358	153,488	41,678	65,151	370,676
12/1/2010	127,019	142,588	38,240	62,425	370,273

1/1/2011	181,190	153,844	35,871	63,459	434,365
2/1/2011	164,921	139,287	38,053	58,554	400,815
3/1/2011	120,894	145,897	37,792	60,941	365,524
4/1/2011	107,134	147,743	41,150	62,692	358,718
5/1/2011	128,907	154,333	41,538	63,959	388,736
6/1/2011	187,998	177,707	46,731	69,557	481,993
7/1/2011	207,021	188,637	45,380	74,520	515,558
8/1/2011	207,089	186,587	47,720	74,318	515,715
9/1/2011	206,174	186,007	46,512	74,375	513,068
10/1/2011	147,396	169,136	41,381	70,540	428,453
11/1/2011	103,867	147,240	41,280	61,653	354,041
12/1/2011	125,248	142,290	34,472	60,837	362,847
1/1/2012	146,027	151,302	37,679	60,852	395,860
2/1/2012	120,258	144,784	37,216	59,637	361,897
3/1/2012	117,043	150,577	36,108	60,944	364,672
4/1/2012	110,747	151,841	37,289	63,109	362,986
5/1/2012	130,405	163,704	40,159	62,845	397,112
6/1/2012	194,937	191,287	46,755	71,588	504,567
7/1/2012	207,621	191,295	43,023	72,967	514,906
8/1/2012	196,602	187,542	43,944	72,930	501,018
9/1/2012	174,737	174,459	42,683	72,773	464,651
10/1/2012	145,664	168,165	44,742	66,937	425,508
11/1/2012	113,255	150,617	36,138	61,995	362,005
12/1/2012	114,992	142,360	38,576	57,998	353,925
1/1/2013	161,718	156,576	33,536	59,472	411,303
2/1/2013	140,035	149,482	34,265	62,904	386,685
3/1/2013	130,082	144,781	35,598	59,970	370,430
4/1/2013	109,798	141,019	37,511	57,269	345,597
5/1/2013	106,279	150,277	33,565	59,552	349,673
6/1/2013	176,880	183,333	44,523	65,513	470,249
7/1/2013	199,988	189,754	45,683	67,921	503,347
8/1/2013	206,422	190,508	45,739	67,432	510,101
9/1/2013	206,555	196,753	47,547	69,604	520,459
10/1/2013	172,771	185,164	43,988	68,988	470,911
11/1/2013	112,254	155,326	41,032	61,036	369,648
12/1/2013	144,472	155,452	38,258	58,608	396,790
1/1/2014	203,822	163,569	39,652	59,589	466,633
2/1/2014	199,387	159,754	30,515	57,316	446,972
3/1/2014	137,747	148,471	35,494	57,741	379,453
4/1/2014	106,718	152,772	36,419	57,670	353,580
5/1/2014	117,880	154,766	37,176	58,727	368,549

6/1/2014	169,678	183,369	40,333	64,815	458,195
7/1/2014	198,382	194,327	40,870	72,084	505,662
8/1/2014	211,035	198,126	41,264	70,154	520,580
9/1/2014	204,812	196,301	41,964	77,161	520,238
10/1/2014	152,295	173,345	38,716	67,667	432,022
11/1/2014	127,234	168,444	36,104	65,619	397,400
12/1/2014	134,386	153,250	33,975	59,297	380,907
1/1/2015	168,087	162,304	35,337	59,914	425,642
2/1/2015	176,838	159,758	33,355	59,578	429,530
3/1/2015	148,446	153,380	33,656	62,515	397,997
4/1/2015	118,379	162,760	38,132	61,054	380,325
5/1/2015	133,556	169,522	34,485	67,526	405,088
6/1/2015	175,745	183,660	42,760	65,792	467,957
7/1/2015	225,248	211,817	44,721	71,322	553,108
8/1/2015	249,885	210,776	43,165	83,999	587,825
9/1/2015	242,074	211,902	44,023	76,832	574,830
10/1/2015	187,021	195,552	40,933	70,740	494,247
11/1/2015	139,019	175,382	35,927	68,433	418,760
12/1/2015	139,562	170,363	34,742	66,596	411,264
1/1/2016	178,568	177,522	36,821	62,336	455,247
2/1/2016	175,616	160,036	31,585	55,476	422,711
3/1/2016	145,066	172,416	32,223	60,035	409,740
4/1/2016	119,352	165,316	34,945	59,261	378,873
5/1/2016	135,321	171,054	34,929	62,566	403,871
6/1/2016	204,623	201,329	37,081	67,746	510,780
7/1/2016	264,987	223,156	42,085	73,904	604,133
8/1/2016	239,623	209,788	40,528	75,202	565,141
9/1/2016	247,790	219,512	42,709	75,363	585,375
10/1/2016	220,888	209,712	38,250	72,836	541,685
11/1/2016	156,298	186,334	36,451	66,449	445,532
12/1/2016	142,745	171,370	33,001	63,157	410,273
1/1/2017	177,349	179,242	31,260	62,288	450,139
2/1/2017	144,210	166,961	35,949	62,623	409,744
3/1/2017	134,177	168,723	31,116	58,862	392,878
4/1/2017	135,116	170,949	34,094	59,930	400,089
5/1/2017	149,105	178,925	33,880	60,373	422,282
6/1/2017	183,982	191,567	36,783	67,370	479,702
7/1/2017	227,517	208,816	39,083	71,921	547,337
8/1/2017	249,650	216,178	39,204	71,035	576,068
9/1/2017	233,404	208,945	40,375	73,969	556,693
10/1/2017	210,577	206,058	38,924	70,943	526,502

11/1/2017	153,747	178,674	34,209	66,347	432,976
12/1/2017	155,809	172,821	33,989	64,397	427,016
1/1/2018	237,027	183,430	33,687	62,394	516,539
2/1/2018	206,863	174,067	31,683	59,377	471,991
3/1/2018	133,384	166,744	33,404	59,355	392,887
4/1/2018	121,577	156,580	34,884	58,840	371,882
5/1/2018	138,072	166,998	35,024	58,485	398,579
6/1/2018	229,864	202,967	41,466	67,743	542,040
7/1/2018	261,418	226,463	41,675	72,711	602,266
8/1/2018	267,772	213,686	43,081	75,663	600,201
9/1/2018	249,569	220,494	43,389	76,821	590,274
10/1/2018	225,794	211,439	40,343	74,443	552,019
11/1/2018	160,357	184,564	35,107	68,619	448,647
12/1/2018	169,266	162,711	33,942	60,528	426,447

Evaluation of Previous IRP Load Forecast

Table 4: Peak Forecasted vs Actual (Includes T&D Losses)

Peak (MW)	2016	2017	2018
Previous IRP Peak Forecast (BP15)*	1,125	1,136	1,143
Weather Normalized Actual Peak	1,116	1,152	1,153
Deviation	9	-16	-10
% Deviation	1%	-1%	-1%

**From ENO's 2015 IRP Final Report, Table 28, Stakeholder Input Case*

2018 IRP Load Forecast

Table 5: Annual Energy Forecasts (GWh) (Includes T&D Losses)

[redacted]

[redacted]

Table 6: Monthly Energy Forecasts (GWh) (Includes T&D Losses)

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Table 7: Annual Coincident Peaks (MW) Forecast

Date	Res	Com	Ind	Gov	Company Use	Total
2019	539	433	63	139	1	1,175
2020	532	438	64	139	1	1,174
2021	530	435	65	143	1	1,174
2022	532	435	65	143	1	1,176
2023	529	436	65	143	1	1,172
2024	528	434	65	143	1	1,171
2025	523	434	66	143	1	1,166
2026	523	431	66	142	1	1,164
2027	527	429	67	142	1	1,166
2028	527	426	66	142	1	1,162
2029	545	415	64	138	1	1,162
2030	531	425	67	141	1	1,165
2031	547	416	65	138	1	1,166
2032	537	426	68	141	1	1,172
2033	544	425	68	140	1	1,179
2034	556	415	65	137	1	1,173
2035	559	414	65	136	1	1,175
2036	561	416	66	136	1	1,180
2037	564	416	66	136	1	1,182
2038	555	426	70	139	1	1,191

Table 8: Annual Load Factor Forecast

Date	Res	Com	Ind	Gov	Total
2019	49%	62%	78%	69%	58%
2020	50%	63%	77%	71%	59%
2021	50%	64%	78%	68%	59%
2022	49%	64%	79%	70%	59%
2023	50%	65%	80%	72%	59%
2024	50%	65%	79%	72%	60%
2025	50%	65%	79%	72%	60%
2026	50%	65%	79%	72%	60%
2027	50%	65%	79%	72%	60%
2028	50%	65%	80%	72%	60%
2029	48%	67%	83%	74%	60%
2030	50%	65%	79%	72%	60%
2031	49%	67%	83%	74%	60%
2032	50%	65%	79%	72%	60%
2033	49%	66%	79%	73%	60%
2034	48%	67%	84%	75%	60%

2035	49%	68%	84%	75%	60%
2036	49%	67%	84%	75%	60%
2037	49%	68%	84%	75%	60%
2038	50%	66%	80%	73%	60%

2018 IRP DSM Summary

Table 9: Annual DSM by Program Year (kWh) (Historic and Forecast)

Note: DSM kWh broken out by program year incremental impact as well as carryover effects from previous Energy Smart years. Carryover effects are calculated using a straight-line depreciation based on individual program life assumptions.

	PY1	PY2	PY3	PY4	PY5	PY6	PY7	PY8	PY9
	11,538,009	14,818,896	14,360,232	15,604,754	20,092,094	23,433,485	19,948,677	46,099,307	53,894,394
		10,435,749	13,350,334	12,869,828	13,937,714	17,984,619	16,932,189	18,393,567	37,863,514
			9,333,490	11,881,772	11,379,424	12,270,674	12,705,293	18,805,230	16,838,457
				8,231,230	10,413,210	9,971,333	8,232,390	14,239,122	16,221,994
					7,128,970	8,944,648	6,647,226	9,698,826	12,304,397
						6,044,813	5,996,857	7,920,342	8,371,647
							4,137,336	6,437,738	6,780,614
								4,226,307	5,057,272
									3,209,906
Total	**11,538,009**	**25,254,646**	**37,044,056**	**48,587,583**	**62,951,411**	**78,649,571**	**74,599,969**	**125,820,439**	**160,542,194**

PY10	PY11	PY12	PY13	PY14	PY15	PY16	PY17	PY18	PY19	PY20
53,894,394	53,894,394	53,894,394	53,894,394	53,894,394	53,894,394	53,894,394	53,894,394	53,894,394	53,894,394	53,894,394
42,330,649	42,330,649	42,330,649	42,330,649	42,330,649	42,330,649	42,330,649	42,330,649	42,330,649	42,330,649	42,330,649
34,627,721	38,766,904	38,766,904	38,766,904	38,766,904	38,766,904	38,766,904	38,766,904	38,766,904	38,766,904	38,766,904
15,283,347	31,391,928	35,203,160	35,203,160	35,203,160	35,203,160	35,203,160	35,203,160	35,203,160	35,203,160	35,203,160
13,842,463	13,728,237	28,156,135	31,639,415	31,639,415	31,639,415	31,639,415	31,639,415	31,639,415	31,639,415	31,639,415
10,369,672	11,462,933	12,222,909	24,986,717	28,075,670	28,075,670	28,075,670	28,075,670	28,075,670	28,075,670	28,075,670
7,113,114	8,586,900	9,556,180	10,717,580	21,817,298	24,511,926	24,511,926	24,511,926	24,511,926	24,511,926	24,511,926
5,640,886	5,854,581	6,804,129	7,649,427	9,212,251	18,647,880	20,948,181	20,948,181	20,948,181	20,948,181	20,948,181
3,676,805	4,501,159	4,596,048	5,021,358	5,742,673	7,706,923	15,478,462	17,384,437	17,384,437	17,384,437	17,384,437
2,193,504	2,296,338	3,361,431	3,337,515	3,238,587	3,835,920	6,201,594	12,309,044	13,820,692	13,820,692	13,820,692
	1,177,103	915,871	2,221,703	2,078,982	1,455,816	1,929,167	4,696,265	9,139,626	10,256,947	10,256,947
		941,682	732,697	1,777,363	1,663,186	1,164,653	1,543,334	3,202,606	5,997,431	6,720,425
			706,262	549,522	1,333,022	1,247,389	873,489	1,157,500	1,724,974	2,892,622
				470,841	366,348	888,681	831,593	582,326	771,667	859,035
					235,421	183,174	444,341	415,796	291,163	385,833
						0	0	0	0	0
							0	0	0	0
								0	0	0
									0	0
										0
188,972,555	**213,991,125**	**236,749,490**	**257,207,779**	**274,797,710**	**289,666,633**	**302,463,420**	**313,452,802**	**321,073,283**	**325,617,610**	**327,690,291**

PY21	PY22	PY23	PY24	PY25	PY26	PY27	PY28
53,894,394	53,894,394	53,894,394	53,894,394	53,894,394	53,894,394	53,894,394	53,894,394
42,330,649	42,330,649	42,330,649	42,330,649	42,330,649	42,330,649	42,330,649	42,330,649
38,766,904	38,766,904	38,766,904	38,766,904	38,766,904	38,766,904	38,766,904	38,766,904
35,203,160	35,203,160	35,203,160	35,203,160	35,203,160	35,203,160	35,203,160	35,203,160
31,639,415	31,639,415	31,639,415	31,639,415	31,639,415	31,639,415	31,639,415	31,639,415
28,075,670	28,075,670	28,075,670	28,075,670	28,075,670	28,075,670	28,075,670	28,075,670
24,511,926	24,511,926	24,511,926	24,511,926	24,511,926	24,511,926	24,511,926	24,511,926
20,948,181	20,948,181	20,948,181	20,948,181	20,948,181	20,948,181	20,948,181	20,948,181
17,384,437	17,384,437	17,384,437	17,384,437	17,384,437	17,384,437	17,384,437	17,384,437
13,820,692	13,820,692	13,820,692	13,820,692	13,820,692	13,820,692	13,820,692	13,820,692
10,256,947	10,256,947	10,256,947	10,256,947	10,256,947	10,256,947	10,256,947	10,256,947
6,720,425	6,720,425	6,720,425	6,720,425	6,720,425	6,720,425	6,720,425	6,720,425
3,221,290	3,221,290	3,221,290	3,221,290	3,221,290	3,221,290	3,221,290	3,221,290
1,236,848	1,379,360	1,379,360	1,379,360	1,379,360	1,379,360	1,379,360	1,379,360
379,716	584,572	659,800	659,800	659,800	659,800	659,800	659,800
0	112,084	166,852	173,763	173,763	173,763	173,763	173,763
0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0
		0	0	0	0	0	0
			0	0	0	0	0
				0	0	0	0
					0	0	0
						0	0
							0
328,390,655	**328,850,106**	**328,980,102**	**328,987,013**	**328,987,013**	**328,987,013**	**328,987,013**	**328,987,013**

Appendix C: Total Relevant Supply Costs – Detail

Scenario 1 – Present Value (2019$) of Total Relevant Supply Costs

Note: Fixed costs are calculated on a levelized real basis for all futures

Portfolio titles denoted by red font were optimized in the above Scenario

Strategy 1 - Total Relevant Supply Cost		
		PV 2019$ [2019-2038]
Variable Supply Cost	[$MM]	$1,114
Resource Additions -Fixed Costs	[$MM]	$134
Capacity Purchases / (Sales)	[$MM]	($35)
DSM - Fixed Costs	[$MM]	$198
Total Supply Cost	[$MM]	$1,411

Strategy 2 - Total Relevant Supply Cost		
		PV 2019$ [2019-2038]
Variable Supply Cost	[$MM]	$961
Resource Additions - Fixed Costs	[$MM]	$121
Capacity Purchases / (Sales)	[$MM]	($46)
DSM - Fixed Costs	[$MM]	$542
Total Supply Cost	[$MM]	$1,577

Strategy 3 - Total Relevant Supply Cost		
		PV 2019$ [2019-2038]
Variable Supply Cost	[$MM]	$986
Resource Additions - Fixed Costs	[$MM]	$114
Capacity Purchases / (Sales)	[$MM]	($47)
DSM - Fixed Costs	[$MM]	$258
Total Supply Cost	[$MM]	$1,311

Strategy 4 - Total Relevant Supply Cost		
		PV 2019$ [2019-2038]
Variable Supply Cost	[$MM]	$1,104
Resource Additions - Fixed Costs	[$MM]	$97
Capacity Purchases / (Sales)	[$MM]	($33)
DSM - Fixed Costs	[$MM]	$333
Total Supply Cost	[$MM]	$1,501

Strategy 5 - Total Relevant Supply Cost		
		PV 2019$ [2019-2038]
Variable Supply Cost	[$MM]	$942
Resource Additions - Fixed Costs	[$MM]	$181
Capacity Purchases / (Sales)	[$MM]	($75)
DSM - Fixed Costs	[$MM]	$247
Total Supply Cost	[$MM]	$1,295

Scenario 1 – Annual Total Relevant Supply Costs

[redacted]

Scenario 2 – Present Value (2019$) of Total Relevant Supply Costs

Note: Fixed costs are calculated on a levelized real basis for all futures

Portfolio titles denoted by red font were optimized in the above Scenario

Strategy 1 - Total Relevant Supply Cost		
		PV 2019$ [2019-2038]
Variable Supply Cost	[$MM]	$912
Resource Additions -Fixed Costs	[$MM]	$134
Capacity Purchases / (Sales)	[$MM]	($28)
DSM - Fixed Costs	[$MM]	$198
Total Supply Cost	[$MM]	$1,217

Strategy 2 - Total Relevant Supply Cost		
		PV 2019$ [2019-2038]
Variable Supply Cost	[$MM]	$799
Resource Additions - Fixed Costs	[$MM]	$121
Capacity Purchases / (Sales)	[$MM]	($38)
DSM - Fixed Costs	[$MM]	$542
Total Supply Cost	[$MM]	$1,423

Strategy 3 - Total Relevant Supply Cost		
		PV 2019$ [2019-2038]
Variable Supply Cost	[$MM]	$814
Resource Additions - Fixed Costs	[$MM]	$114
Capacity Purchases / (Sales)	[$MM]	($39)
DSM - Fixed Costs	[$MM]	$258
Total Supply Cost	[$MM]	$1,147

Strategy 4 - Total Relevant Supply Cost		
		PV 2019$ [2019-2038]
Variable Supply Cost	[$MM]	$902
Resource Additions - Fixed Costs	[$MM]	$97
Capacity Purchases / (Sales)	[$MM]	($25)
DSM - Fixed Costs	[$MM]	$333
Total Supply Cost	[$MM]	$1,307

Strategy 5 - Total Relevant Supply Cost		
		PV 2019$ [2019-2038]
Variable Supply Cost	[$MM]	$784
Resource Additions - Fixed Costs	[$MM]	$181
Capacity Purchases / (Sales)	[$MM]	($67)
DSM - Fixed Costs	[$MM]	$247
Total Supply Cost	[$MM]	$1,146

Scenario 2 – Annual Total Relevant Supply Costs

[redacted]

Scenario 3 – Present Value (2019$) of Total Relevant Supply Costs

Note: Fixed costs are calculated on a levelized real basis for all futures

Portfolio titles denoted by red font were optimized in the above Scenario

Strategy 1 - Total Relevant Supply Cost		
		PV 2019$ [2019-2038]
Variable Supply Cost	[$MM]	$1,248
Resource Additions -Fixed Costs	[$MM]	$134
Capacity Purchases / (Sales)	[$MM]	($59)
DSM - Fixed Costs	[$MM]	$198
Total Supply Cost	[$MM]	$1,521

Strategy 2 - Total Relevant Supply Cost		
		PV 2019$ [2019-2038]
Variable Supply Cost	[$MM]	$991
Resource Additions - Fixed Costs	[$MM]	$121
Capacity Purchases / (Sales)	[$MM]	($69)
DSM - Fixed Costs	[$MM]	$542
Total Supply Cost	[$MM]	$1,584

Strategy 3 - Total Relevant Supply Cost		
		PV 2019$ [2019-2038]
Variable Supply Cost	[$MM]	$1,030
Resource Additions - Fixed Costs	[$MM]	$114
Capacity Purchases / (Sales)	[$MM]	($70)
DSM - Fixed Costs	[$MM]	$258
Total Supply Cost	[$MM]	$1,331

Strategy 4 - Total Relevant Supply Cost		
		PV 2019$ [2019-2038]
Variable Supply Cost	[$MM]	$1,224
Resource Additions - Fixed Costs	[$MM]	$97
Capacity Purchases / (Sales)	[$MM]	($56)
DSM - Fixed Costs	[$MM]	$333
Total Supply Cost	[$MM]	$1,597

Strategy 5 - Total Relevant Supply Cost		
		PV 2019$ [2019-2038]
Variable Supply Cost	[$MM]	$964
Resource Additions - Fixed Costs	[$MM]	$181
Capacity Purchases / (Sales)	[$MM]	($98)
DSM - Fixed Costs	[$MM]	$247
Total Supply Cost	[$MM]	$1,294

Scenario 3 – Annual Total Relevant Supply Costs

[redacted]

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

***EX PARTE: IN RE*: 2018 TRIENNIAL**	**)**	
INTEGRATED RESOURCE PLAN OF	**)**	
ENTERGY NEW ORLEANS, INC.	**)**	
	)	**DOCKET NO. UD-17-03**

APPENDIX D

Demand Side Management Potential Study prepared by Navigant Consulting, Inc.

JULY 2019

Entergy New Orleans, LLC
2018 Integrated Resource Plan
DSM Potential Study

FINAL REPORT

Prepared for:

Submitted by:

Navigant Consulting, Inc.
101 California Street | Suite 4100
San Francisco, CA 94111

navigant.com

Reference No.: 198692
August 31, 2018

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Disclaimer

This report was prepared by Navigant Consulting Inc. (Navigant) for Entergy New Orleans. The work presented in this report represents Navigant's professional judgment based on the information available at the time this report was prepared. Navigant is not responsible for the reader's use of, or reliance upon, the report, nor any decisions based on the report. NAVIGANT MAKES NO REPRESENTATIONS OR WARRANTIES, EXPRESSED OR IMPLIED. Readers of the report are advised that they assume all liabilities incurred by them, or third parties, as a result of their reliance on the report, or the data, information, findings and opinions contained in the report.

List of Acronyms

BP18U	Business plan 2018 Update
BTMS	Behind-the-meter storage
BYOT	Bring your own thermostat
C&I	Commercial and industrial
CAC	Central air conditioner
CBECS	Commercial Buildings Energy Consumption Survey
CBSA	Commercial Building Stock Assessment
CFL	Compact fluorescent lamp
CFR	Code of Federal Regulations
CNO	Council of the City of New Orleans
CPP	Critical peak pricing
DEER	Database for Energy Efficient Resources
DI	Direct install
DLC	Direct load control
DOE	Department of Energy (US)
DR	Demand response
DRAS	DR automation server
DRSim™	Demand Response Simulator
DSM	Demand-side management
DSMSim™	Demand-Side Management Simulator
EE	Energy Efficiency
EIA	Energy Information Administration (US)
EISA	Energy Independence and Security Act
EMS	Energy Management Systems
ENO	Entergy New Orleans, LLC
EUI	End-use intensities
EUL	Effective useful life
FERC	Federal Energy Regulatory Commission
GHG	Greenhouse gas
GWh	Gigawatt-hour
HVAC	Heating, ventilation, and air conditioning
IOU	Investor-Owned Utility
IRP	Integrated Resource Plan
kWh	Kilowatt-hour
LED	Light emitting diode
LMP	Locational marginal price
MISO	Midcontinent Independent System Operator
MW	Megawatt
NEEP	Northeast Energy Efficiency Partnership
NEW	New construction
NPV	Net present value
NREL	National Renewable Energy Laboratory
NTG	Net-to-gross
O&M	Operations and maintenance
PAC	Program administrator cost
PCT	Programmable communicating thermostat
POU	Publicly-owned utility
PV	Present value
PY	Program year
RBSA	Residential Building Stock Assessment
RET	Retrofit
RIM	Ratepayer impact measure
ROB	Replace-on-burnout
RTF	Regional Technical Forum
RUL	Remaining useful life
SEER	Seasonal energy efficiency ratio
SIC	Standard industrial classification
T&D	Transmission and distribution
TCO	Total cost of ownership
TMY	Typical meteorological year
TOU	Time-of-use
TRC	Total resource cost
TRM	Technical resource manual
TSD	Technical support documents
UCT	Utility cost test

Executive Summary

Introduction

In support of the process to develop the 2018 IRP, Entergy New Orleans, LLC (ENO) engaged Navigant Consulting, Inc. (Navigant or the team) to prepare a DSM potential study.[1] The study's objective was to assess the long-term potential for reducing energy consumption in the residential and C&I sectors by analyzing energy efficiency and peak load reduction measures and improving end-user behaviors.

The EE component of the potential study began with a rigorous analysis of input data necessary for Navigant to run the DSMSim™ model, which calculates various levels of EE savings potential across the ENO service area. Achievable potential was further delineated using a range of reasonable assumptions for alternative cases to estimate the effect on customer participation of funding for customer incentives, awareness, as well as other factors.

The DR potential component of this study also began with a rigorous analysis of input data necessary for Navigant's DRSim™ model. Using a range of reasonable assumptions, the DRSim™ model was used to estimate the DR potential for a low, base, and high case.

While ENO explicitly plans to use the results from the potential study to inform the IRP, these results may also be used to further ENO's DSM planning and long-term conservation goals, energy efficiency program design efforts, and long-term load forecasts. However, it should be noted that long-term potential studies do not replace the need for detailed near-term implementation planning and program design. As such, this study, as with any long-term potential study, should only be used to inform those planning and design efforts in combination with ENO's EE and DR Energy Smart program experience and the market intelligence and insights of the Council of the City of New Orleans (Council), its Advisors, and stakeholders.

Study Objectives

ENO intends to use the results of the potential study as an input to its 2018 IRP. More specifically, ENO plans to use the results of this potential study to provide a long-range outlook on the cost-effective potential for delivering demand-side resources such as EE and DR and the associated levels of investment required to implement such programs.

Given ENO's objectives and Council's rules, Navigant designed its project approach to ensure the study results adequately address those needs. Table ES-1 below provides a

[1] The study period for the potential study is 2018-2037.

high-level overview of the study's objectives and how Navigant met those objectives.

Table ES- 1. Study Objectives Overview

	Objective		Navigant's Approach
1	Use consistent methodology and planning assumptions	✓	Navigant has developed a variety of analytical tools and approaches to inform DSM planning and the establishment of long-term conservation targets and goals (details provided in the following sections). The team also worked closely with ENO to vet methodology, assumptions, and inputs at each stage of this project.
2	Reflect current information	✓	Navigant leveraged learnings from its prior work with ENO to create a bottom up analysis that includes inputs, such as the New Orleans TRM, and other up-to-date information (new codes and standards, saturation data from surveys and Energy Smart programs, avoided costs, etc.) are included in this study.
3	Quantify achievable potential	✓	Navigant quantifies achievable potential for both EE and DR by first calculating the technical and economic potential. The achievable potential base case is then calibrated to the historical Energy Smart program data and the current programs approved by the Council for Energy Smart PYs 7-9.
4	Provide input to the IRP	✓	Navigant's approach provides the following for all modeled cases: • Supply curve of conservation potential for input to ENO's IRP • Outputs available with 8,760 hourly impact load shapes
5	Present the scope and methodology of the study	✓	Navigant's approach to stakeholder engagement offers relevant information to key stakeholders

Source: Navigant

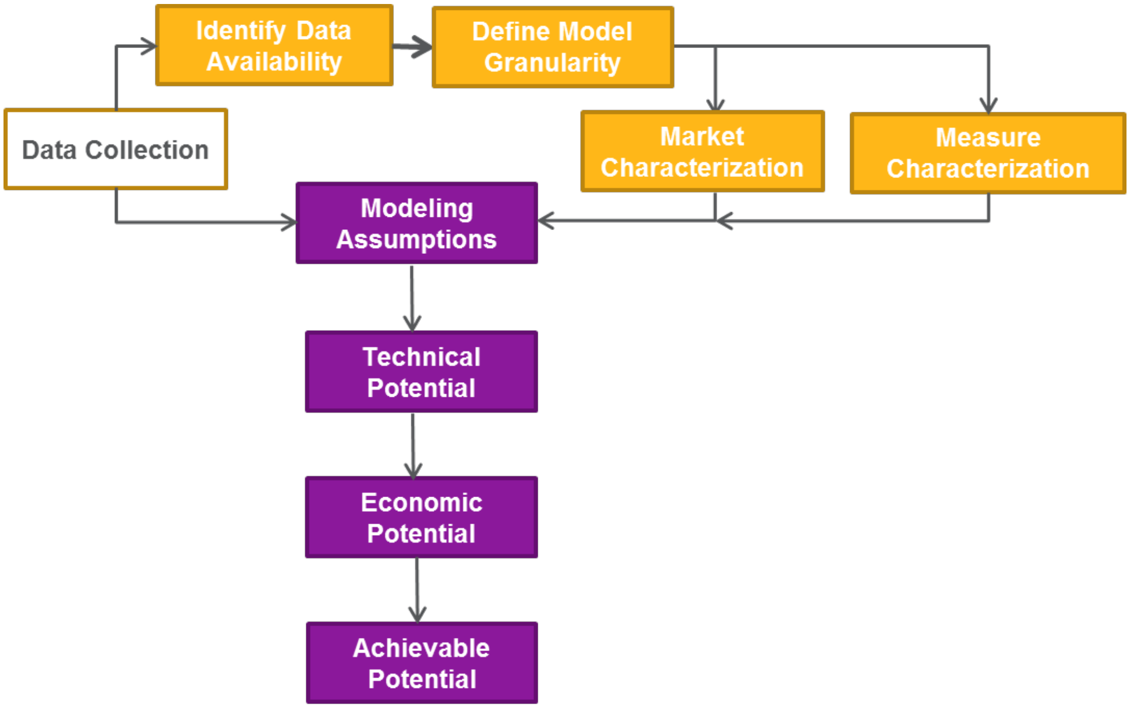
The team incorporated this high-level approach into both the EE and DR analyses.

Energy Efficiency

Detailed Approach

For the EE analysis, Navigant analyzed potential in the ENO service area from 2018 through 2037. After gathering existing data sources, the team followed three steps: (1) characterize the market, (2) characterize measures, and (3) estimate potential, using the DSMSim^{TM} tool, a bottom-up stock forecasting model. The third step involved three sub-steps, which included calculating technical, economic, and achievable potential. The figure below illustrates the EE analysis approach.

Figure ES-1. EE Analysis Approach Overview



Source: Navigant

Market Characterization

This part of the analysis involved understanding and defining key service area, or market, characteristics. Specifically, the market characterization required defining the sales and stock for 2016, the study's base year, and then projecting the numbers from 2018 – 2037, the reference case, to provide a baseline for the study. To complete this effort, Navigant collected multiple datasets, which include, but are not limited to:

- 2016 ENO billing and customer account data
- ENO forecast sales and customer counts
- US EIA CBECS
- US Department of Labor SIC
- Navigant research

After defining the sales and stock, the team determined energy use at the customer segment and end-use levels. Navigant based the level of disaggregation for the segments and end-uses on existing program definitions, data availability, and requirements to sufficiently characterize the data at a granular level. The report contains further details on the selected customer segments as well as assumptions about the stock, electricity sales, end-use breakdown, and EUI for each segment and end-use.

In addition to identifying sales, energy use, and stock data, the team aggregated additional inputs from ENO for input into the model. These inputs include various economic and financial parameters, such as carbon pricing estimates, avoided costs, inflation assumptions, and historic program costs.

Measure Characterization

The measure characterization portion of the analysis sought to define key data points for the measures included in the study. These characteristics include assumptions about codes and standards, measure life, and measure costs. This analysis relied on data from ENO, other regional efficiency programs and utilities, and TRMs from New Orleans,[2] Arkansas, Pennsylvania, Illinois, Minnesota, Vermont, New York, and Massachusetts.

The team used the measure list in this study to appropriately focus on those technologies likely to have the highest effect on savings potential over the study horizon. The study however, does not account for unknown emerging technologies that may arise that could increase savings opportunities over the forecast horizon. It also does not account for broader societal changes that may affect levels of energy use in ways not anticipated by this study.

Estimation of Potential

After defining the market and measure characteristics, Navigant employed its proprietary DSMSim potential model to estimate the technical, economic, and achievable savings potential for electric energy and demand across ENO's service area.

The list below defines each of these types of potential, as used in the study:

- **Technical potential** is the total energy savings available assuming all installed measures can immediately be replaced with the efficient measure/technology—wherever technically feasible—regardless of cost, market acceptance, or whether a measure has failed and must be replaced.
- **Economic potential** is a subset of technical potential, using the same assumptions regarding immediate replacement as in technical potential, but including only those measures that have passed the benefit-cost test chosen for measure screening; in this study, that is the TRC test.
- **Achievable potential** is a subset of economic potential. The team determined achievable potential by incorporating measure adoption ramp rates and the diffusion of technology through the market.

Figure ES-2 provides an overview of each of these potential types and the data inputs for each.

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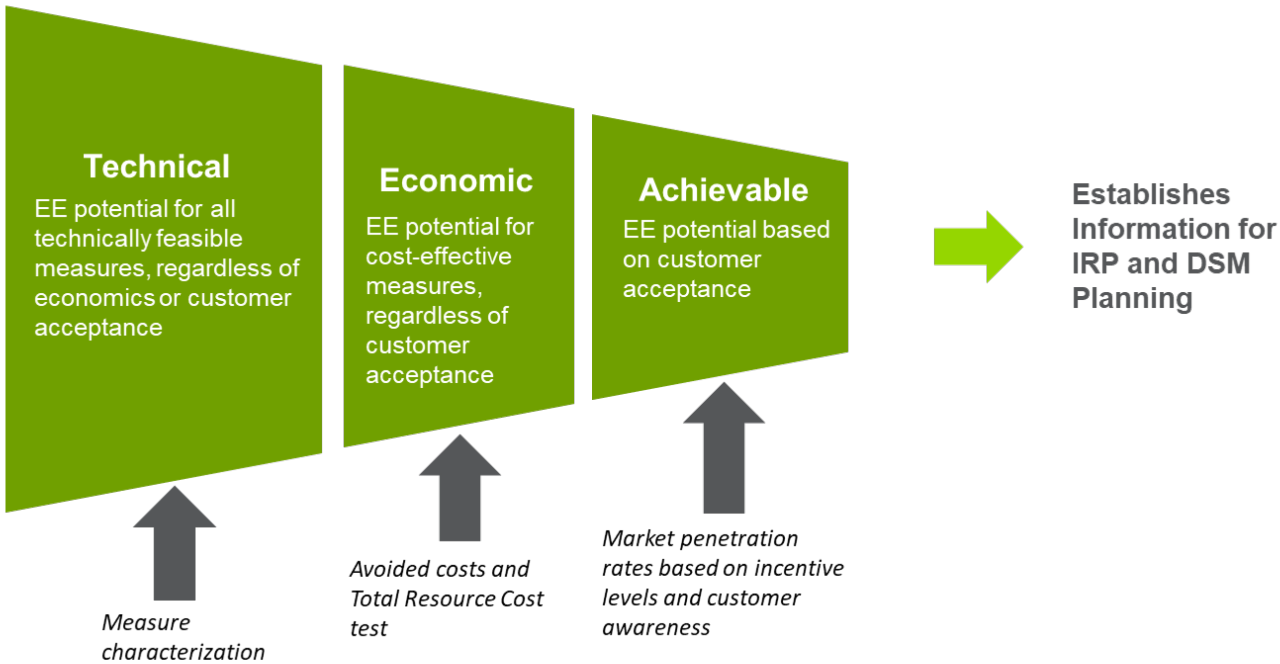
[2] *New Orleans Energy Smart Technical Reference Manual: Version 1.0*, September 2017, prepared by ADM Associates, Inc.

Figure ES-2. EE Potential Types



Source: Navigant

Using these definitions and data inputs, the DSMSim uses a bottom-up technology diffusion and stock tracking model implemented using a System Dynamics framework to estimate the different potential types.[3] The model reports these potential savings for the service area, sector, customer segment, end-use category, and highest impact measures.

Results

Given that ENO's objective for this study was to quantify the achievable potential for use in the 2018 IRP and gain a better understanding as to the best path for planning ENO's Energy Smart programs, the project team modeled various future cases to further inform Energy Smart program preparation. These cases include:

- **Base case:** Reflects current program spend targets with incentives on average at 50% of incremental measure cost
- **Low case:** Uses the same inputs as the base case except incentives are at 25% of incremental measure cost

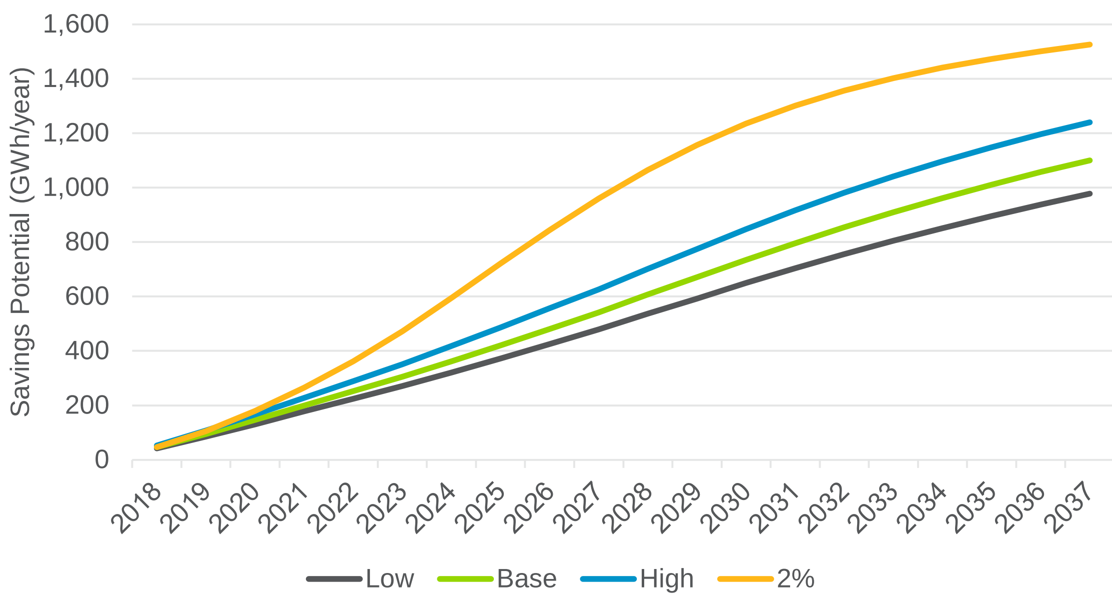
[3] See Sterman, John D. *Business Dynamics: Systems Thinking and Modeling for a Complex World*. Irwin McGraw-Hill. 2000 for detail on System Dynamics modeling.

- **High case:** Uses the same inputs as the base case except incentives are at 75% of incremental measure cost
- **2% case:** Achieve a 2% reduction during the forecast period with a 0.2% ramp year over year starting in the first modeled year (2018). To achieve 2%, Navigant modified model parameters:
    - o Increased marketing factor through 2021
    - o Increased incentive percent of incremental measure cost from 50% in 2018 then ramping up to 100% in 2024 (and maintaining 100% in remaining years)
    - o Ramped down TRC Ratio threshold from 1 in 2018 to 0.87 in 2022 and remaining years.

The study reports savings as gross rather than net, meaning they do not include the effects of natural change. Providing gross potential is advantageous because it permits a reviewer to more easily calculate net potential when new information about NTG ratios or changing EUIs become available. These results can then be used to define the portfolio energy savings goals, projected costs, and forecasts.

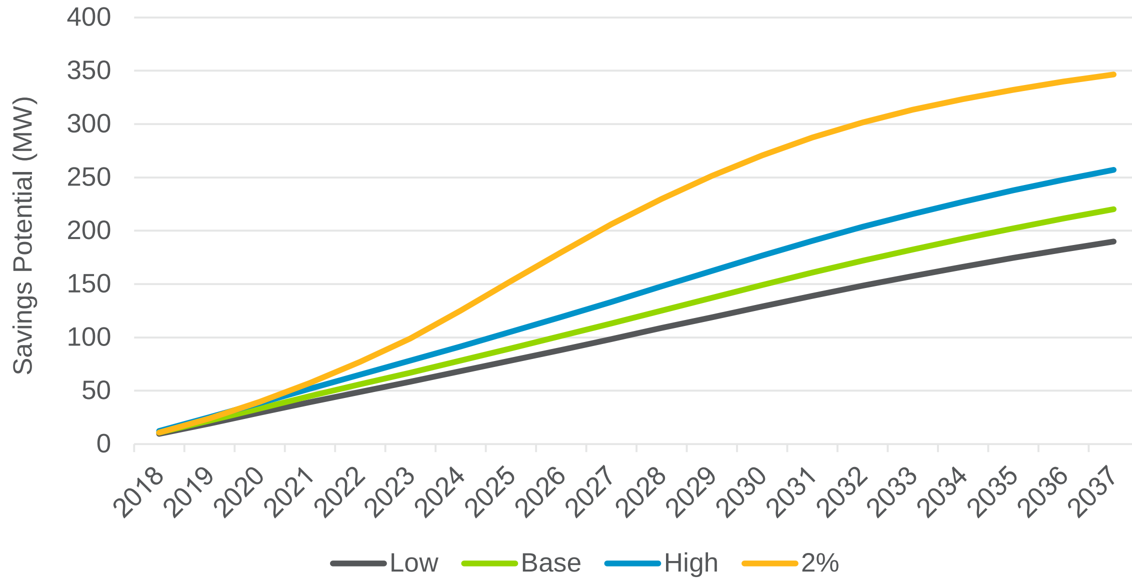
Figure ES-3 and Figure ES-4 show the cumulative annual energy and demand savings for each case.

Figure ES-3. Cumulative Energy Achievable Savings EE Potential by Case (GWh/year)



Source: Navigant analysis

Figure ES-4. Cumulative Peak Demand Achievable Savings EE Potential by Case (MW)



Source: Navigant analysis

Table ES-2 lists the energy efficiency potential study results, showing the achievable annual incremental energy and peak demand savings in 5-year increments by case. The calculated total energy efficiency potential savings for the base case is 1,100 GWh and 220 MW in 2037.

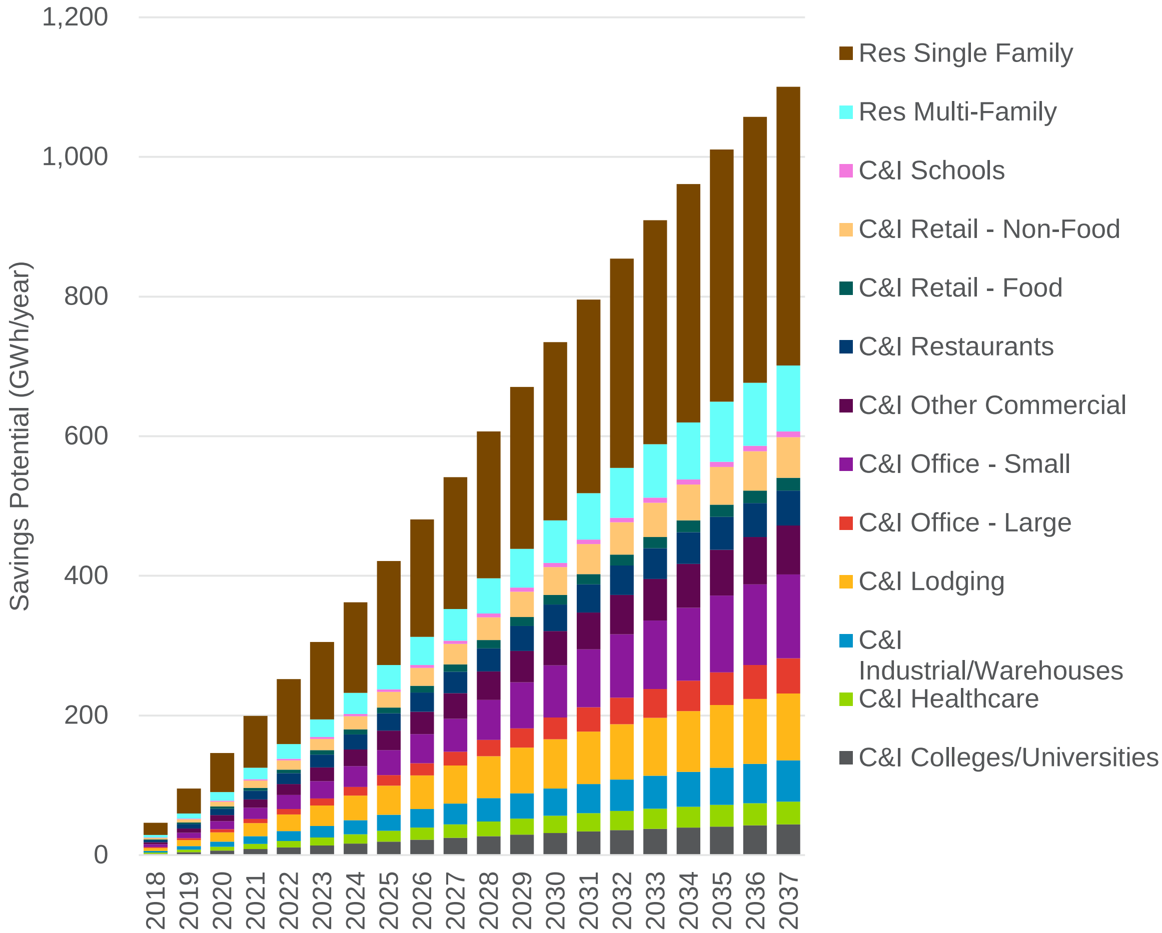
Table ES- 2. Annual Incremental Achievable Energy Efficiency Savings by Case

Year	Electric Energy (GWh/Year)				Peak Demand (MW)			
	Base	Low	High	2%	Base	Low	High	2%
2018	46	41	52	46	11	10	12	11
2022	53	46	61	97	11	10	13	20
2027	61	54	70	116	12	10	14	26
2032	58	52	65	55	11	9	13	14
2037	43	39	43	25	9	8	9	7
Total	**1,100**	**977**	**1,240**	**1,526**	**220**	**190**	**257**	**346**

Source: Navigant analysis

Figure ES-5 shows the cumulative electric energy achievable potential by customer segment. Residential single family is the largest segment. Small office and lodging contribute the most savings for the C&I sector.

Figure ES-5. Base Case Cumulative Achievable Potential Savings Customer Segment Breakdown



Source: Navigant analysis

Table ES-3 shows the incremental electric energy achievable savings as a percentage of ENO's total sales for each case in 5-year increments. For the 2% case, 2% of sales savings is achieved in 2024 through 2026. In later years, the 2% case falls below the base case because most of the measures have been adopted, depleting the available potential in the future years. As mentioned above, this study only includes known, market-ready, quantifiable measures. However, over the lifetime of energy efficiency programs, new technologies and innovative program interventions could result in additional cost-effective energy savings. Therefore, ENO should periodically revisit and reanalyze the potential forecast to account for these technologies and programs.

Table ES- 3.

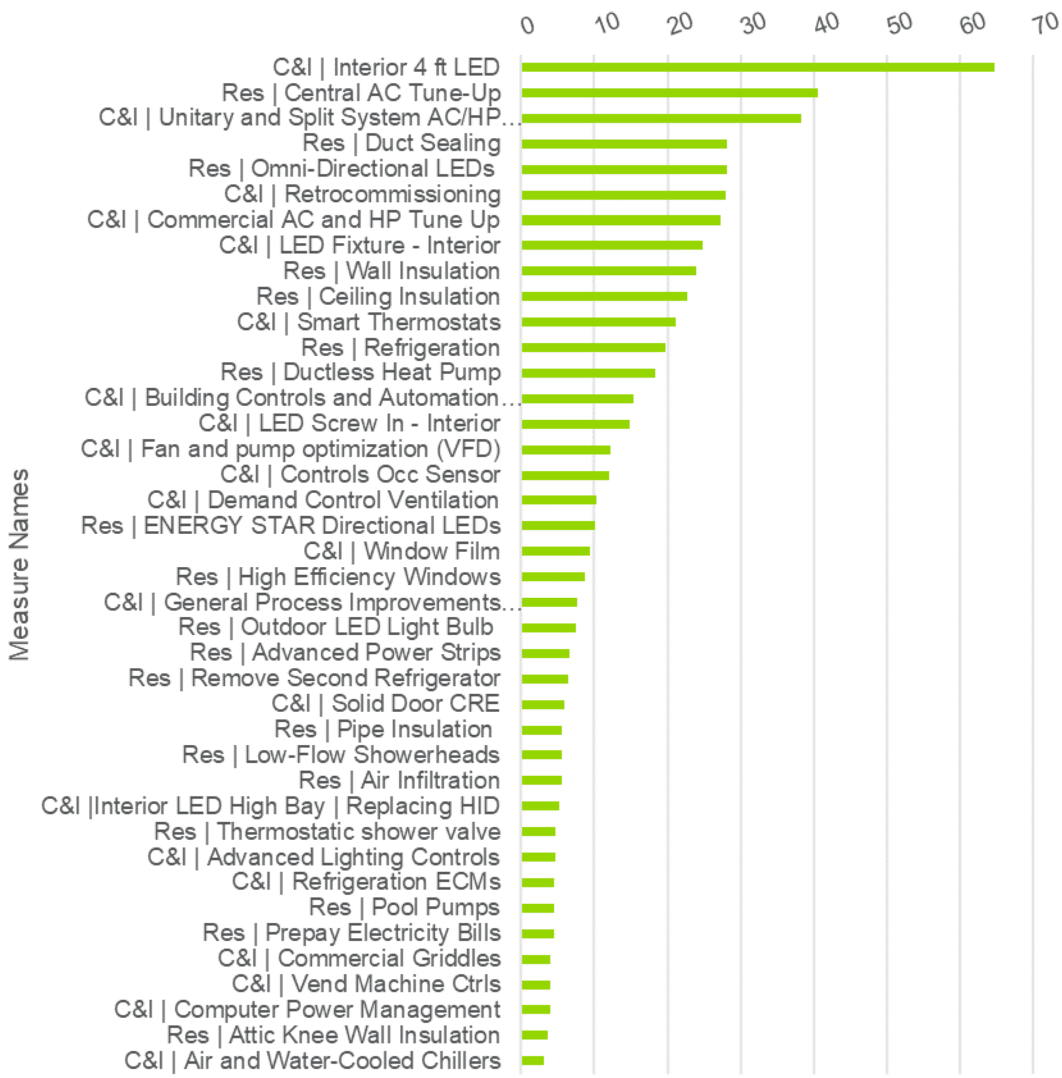
Incremental Energy Achievable Savings Potential as a Percentage of Sales by Case (%, GWh)

Year	Base	Low	High	2%
2018	0.8%	0.7%	0.9%	0.8%
2022	0.9%	0.8%	1.0%	1.6%
2027	1.0%	0.9%	1.1%	1.9%
2032	0.9%	0.8%	1.0%	0.8%
2037	0.6%	0.6%	0.6%	0.3%
Total	**17.3%**	**15.3%**	**19.5%**	**24.0%**

Source: Navigant analysis

Figure ES-6 shows the top 40 measures contributing to the electric energy achievable potential in 2028 (the middle of the study period and representative of the 20-year results). Interior 4 ft. LEDs in the C&I sector provide the most potential, followed by residential central air conditioning tune-up and commercial unitary and split system air conditioning/heat pump equipment.

Figure ES-6. Top 40 Measures for Electric Energy Base Case Achievable Savings Potential: 2028 (GWh/year)



Source: Navigant analysis

The total, administrative, and incentive costs for each case are provided in Table ES-4 in 5-year increments for the study period. It is important to note the differences in these cases as compared to the savings achieved. The administrative spending is relatively consistent between the cases, while the incentive spending varies significantly between the cases, with higher spending correlated to higher savings.

Table ES- 4. Spending Breakdown for Achievable Potential ($ millions/year)[4]

	Total				Incentives				Admin			
	Base	Low	High	2%	Base	Low	High	2%	Base	Low	High	2%
2018	$13	$8	$20	$13	$6	$2	$13	$6	$7	$6	$8	$7
2022	$15	$10	$25	$43	$7	$3	$16	$28	$8	$7	$10	$15
2027	$20	$12	$32	$79	$10	$4	$20	$59	$10	$9	$12	$20
2032	$24	$14	$37	$47	$13	$5	$25	$36	$11	$9	$12	$11
2037	$21	$13	$30	$25	$12	$5	$20	$20	$9	$8	$9	$5
Total	**$390**	**$238**	**$617**	**$960**	**$202**	**$75**	**$400**	**$698**	**$188**	**$162**	**$217**	**$262**

Source: Navigant analysis

Table ES-5. shows the portfolio TRC to be cost-effective for all cases.

Table ES- 5. Portfolio TRC Benefit-Cost Ratios for Achievable Potential (Ratio)

Year	Base	Low	High	2%
2018-2037	1.7	1.9	1.6	1.4

Source: Navigant analysis

Demand Response

Detailed Approach

Navigant developed ENO's DR potential and cost estimates using a bottom-up analysis. The analysis involved 5 steps: (1) characterize the market, (2) develop baseline projections, (3) define and characterize DR options, (4) develop key assumptions for potential and costs, and (5) estimate potential and costs. Navigant used both primary data from ENO and relevant secondary sources for this analysis as documented in this report. Figure ES-7 summarizes the DR potential estimation approach.

[4] The values in this table are shown in nominal dollars and are rounded to the nearest million which may result in rounding errors.

Figure ES-7. DR Potential Assessment Steps

Step 1: Market Characterization	Characterize market for DR potential estimation (no. of customers and coincident peak load estimates by customer class- residential, small/med/large C&I).
Step 2: Develop Baseline Projections	Develop baseline projections for customer count and load over the study period
Step 3: Define DR Options and Characterize	Define and characterize DR options and map applicable options to relevant customer classes.
Step 4: Develop Key Assumptions for Potential & Costs	Develop participation and unit load reduction assumptions under each DR option; also develop itemized cost assumptions.
Step 5: Estimate Potential Costs and Benefits	Present potential estimates by DR option and customer class, along with annual and levelized costs; also estimate program benefits and calculate cost-effectiveness of programs.

Source: Navigant

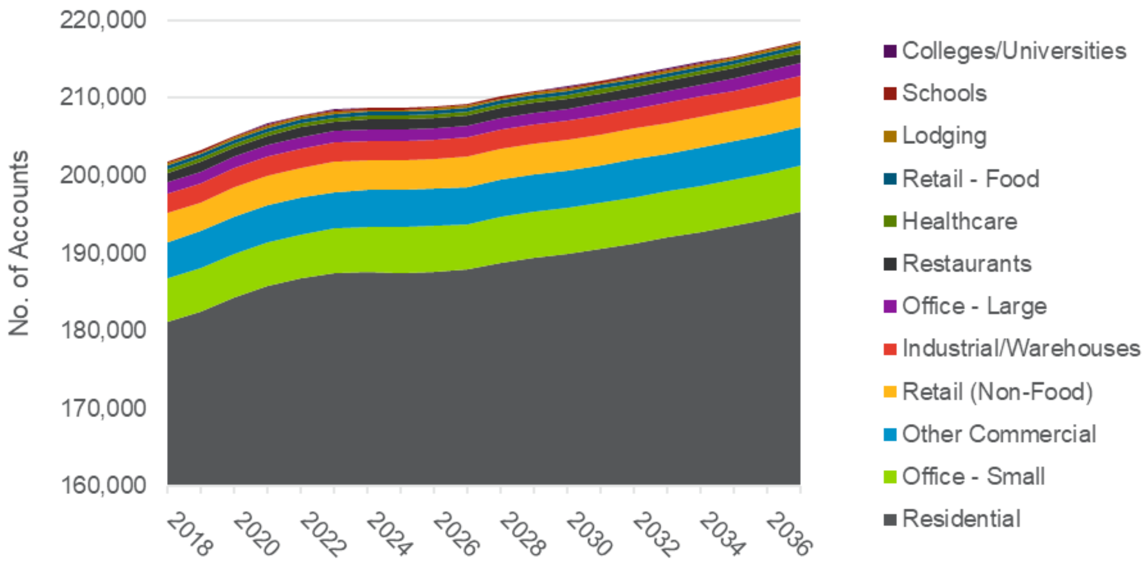
Market Characterization

The market characterization process for the DR assessment aimed to segment the market appropriately for the analysis. Specifically, Navigant aggregated data on key pieces of information, such as customer count and peak load, by customer segment and end-use to use as inputs into the model. The team based the segmentation on the examination of ENO’s rate schedules and the customer segments established in the energy efficiency potential study.

Baseline Projections

The baseline projections aimed to define and forecast customer data for the study period, similar to the market characterization in the EE assessment. The project team used these projections as a basis for modeling savings. More specifically, Navigant applied the year-over-year change in the stock forecast to the 2016 customer count data segmented by customer class and customer segment to produce a customer count forecast for the study. The team then trued up this forecast to the sector-level customer count forecast provided by ENO. Figure ES-8 shows the aggregate customer count forecast by segment only, summed across all customer classes.

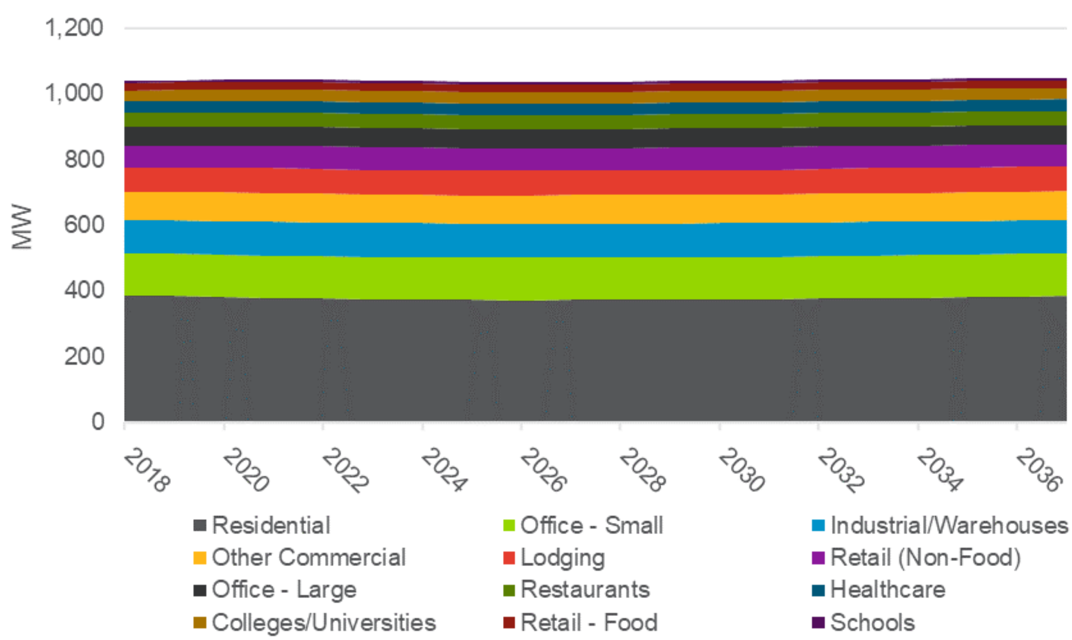
Figure ES-8. Customer Count Projections for DR Potential Assessment



Source: Navigant analysis

Figure ES-9 shows the peak load forecast that Navigant developed based on the BP18U forecast data provided by ENO for ENO's service area by customer segment.

Figure ES-9. Peak Load Forecast by Customer Segment (MW)



Source: Navigant analysis

DR Options

Once the baseline peak demand projections had been developed, the team characterized the different types of DR options that could be used to curtail peak demand. Table ES-6 summarizes the DR options included in the analysis. Most of these DR options are representative of DR programs commonly deployed in the industry.

Table ES- 6. Summary of DR Options

DR Option	Characteristics	Eligible Customer Classes	Targeted/ Controllable End Uses and/or Technologies
DLC ✓ Load control switch ✓ Thermostat	Control of water heating/cooling load using either a load control switch or PCT	Residential Small C&I	Cooling, water heating
C&I curtailment ✓ Manual ✓ Auto-DR enabled	Firm capacity reduction commitment $/kW payment based on contracted capacity plus $/kWh payment based on energy reduction during an event	Large C&I	Various load types including HVAC, lighting, refrigeration, and industrial process loads
Dynamic pricing[5] ✓ Without enabling technology ✓ With enabling technology	Voluntary opt-in dynamic pricing offer, such as CPP	All customer classes	All

Source: Navigant

Estimation of Potential

With the market, baseline projections, and options characterized, Navigant estimated technical and achievable potential by inputting the parameters into its model. To do this, Navigant used two key variables in addition to participation opt-out rates, technology market penetration, and enrollment attrition rates:

1. Customer participation rates; and
2. Amount of load reduction that could be realized from different types of control

[5] Navigant did not include TOU rates in the DR options mix because this study only includes event-based dispatchable DR options. TOU rates lead to a permanent reduction in the baseline load and are not considered a DR option.

mechanisms, referred to as unit impacts

For purposes of the DR analysis, Navigant used the following definitions for calculating technical and achievable potential:

- **Technical potential** refers to load reduction that results from 100% customer participation. This is a theoretical maximum.
- **Achievable potential** accounts for customers opting out during DR events. The team calculated this by multiplying achievable participation assumptions (subject to program participation hierarchy) by the technical potential estimates.

Results

Achievable potential is estimated to grow from 0.7 MW in 2018 to 34.6 MW in 2037. Cost-effective achievable potential makes up approximately 3.3% of ENO's peak demand in 2037. Navigant observed the following:

- DLC has the largest achievable potential: 49% share of total potential in 2037. DLC potential grows from 0.5 MW in 2018 to 17.0 MW in 2037.
- This is followed by dynamic pricing with a 47% share of the total potential in 2037. The dynamic pricing offer begins in 2020 because it is tied to ENO's AMI implementation plan. The program ramps up over a 5-year period (2020-2024) until it reaches a value of 14 MW. From then on, potential slowly increases until it reaches a value of 16 MW in 2037.
- C&I curtailment makes up the remainder of the cost-effective achievable potential with a 4% share of the total potential in 2037. C&I curtailment potential grows rapidly from 0.2 MW in 2018 to 1.9 MW in 2022. This growth follows the S-shaped ramp assumed for the program over a 5-year period. Beyond 2022, the program attains a steady participation level, and its potential slightly decreases over the remainder of the forecast period, ending at 1.2 MW in 2037.

Table ES- 7 lists the DR results by option in 5-year increments. The calculated achievable potential for peak load reduction is 34.6 MW in 2037. This report provides the methodology, data inputs, and assumptions used to calculate these potentials.

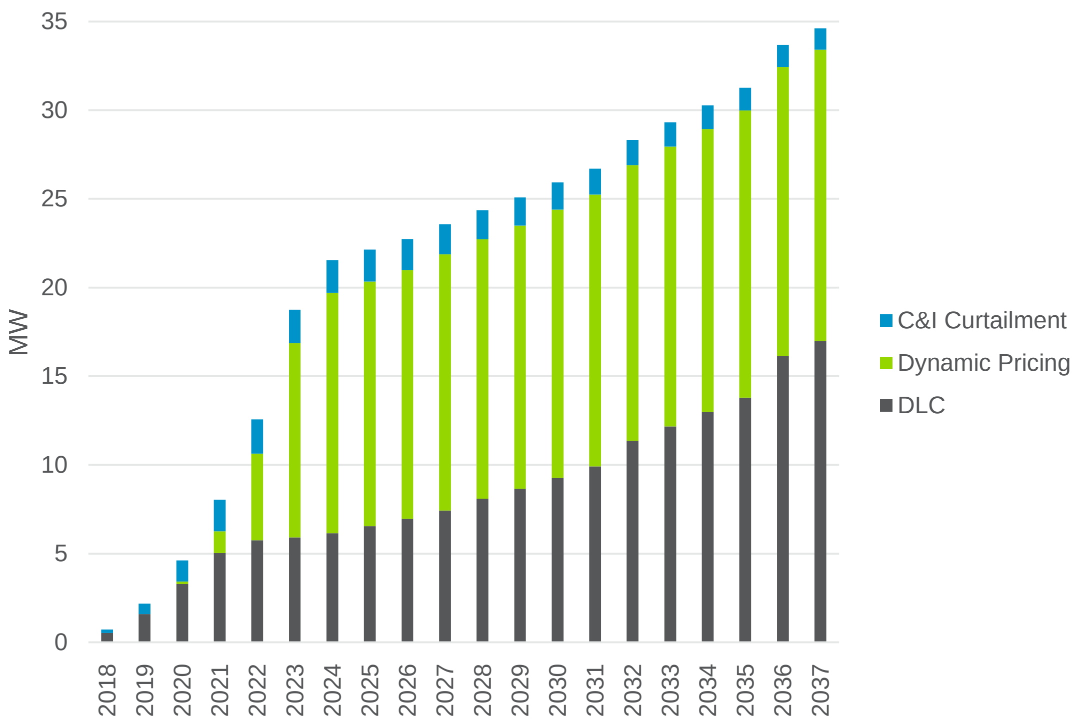
Table ES- 7. Annual Incremental Achievable Summer DR Potential by Option

Year	DLC	Dynamic Pricing	C&I Curtailment	Total
2018	0.5	0.0	0.2	0.7
2022	5.7	4.9	1.9	12.6
2027	7.4	14.4	1.7	23.6
2032	11.3	15.6	1.4	28.3
2037	17.0	16.4	1.2	34.6

Source: Navigant analysis

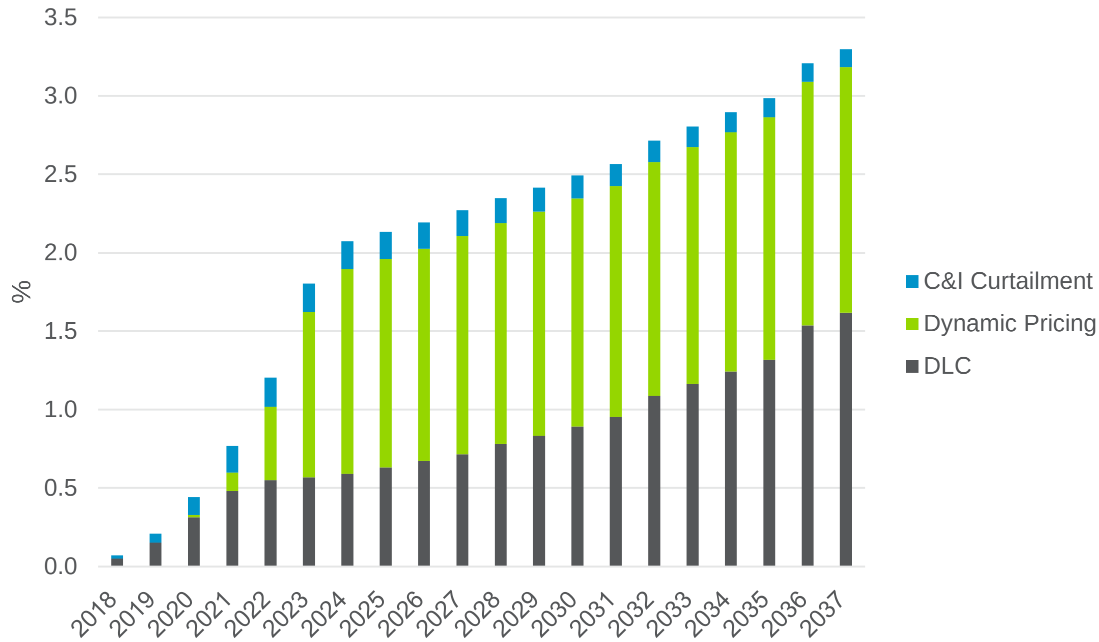
Figure ES-10 summarizes the cost-effective achievable potential by DR option for the base case. Figure ES-11 shows the cost-effective achievable potential as a percentage of ENO's peak demand.

Figure ES-10. Summer DR Achievable Potential by DR Option (MW)



Source: Navigant analysis

Figure ES-11. Summer DR Achievable Potential by DR Option (% of Peak Demand)

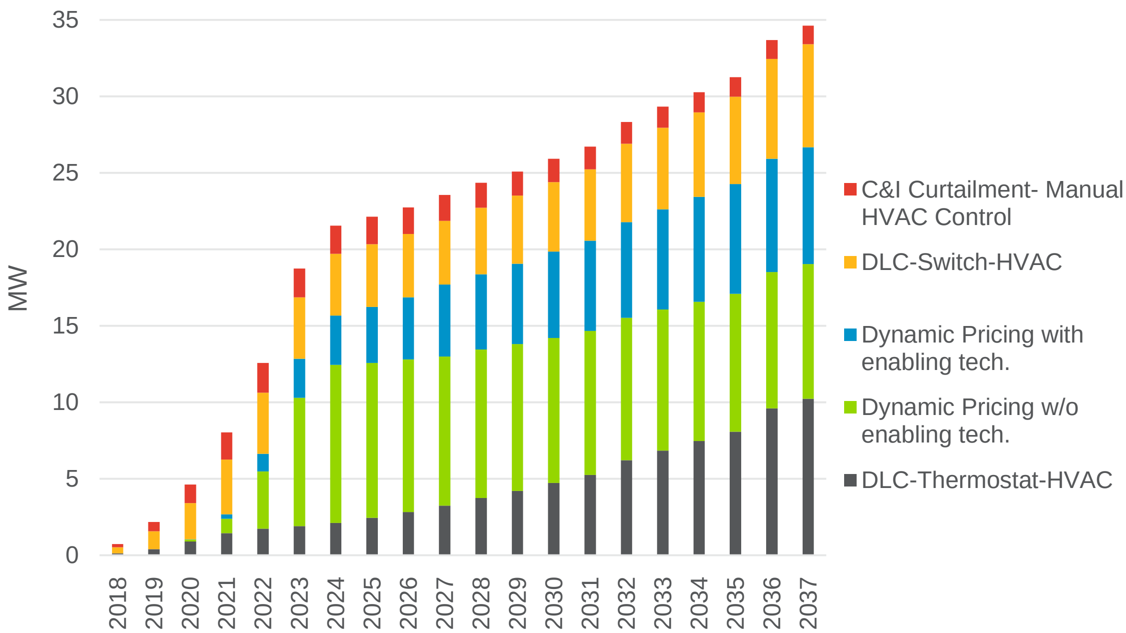


Source: Navigant analysis

Figure ES-12 summarizes the cost-effective achievable potential by DR option for the base case. The team had the following key observations:

- Only direct control of HVAC loads by small C&I customers (DLC-Switch-HVAC and DLC-Thermostat-HVAC in Figure ES-12) is cost-effective. This sub-option makes up nearly 50% of the total cost-effective achievable potential in 2037 at 17.0 MW. Of this 17.0 MW, 10.2 MW is from thermostat-based control, while the remaining 6.7 MW is from switch-based control.
- Dynamic pricing makes up 47% of the total cost-effective achievable potential in 2037. Potential from customers with enabling technology in the form of thermostats/ EMS is slightly higher than that from customers without enabling technology—8.8 MW versus 7.6 MW in 2037.
- Under the C&I curtailment program, reductions associated with manual HVAC control make up 4% of the total cost-effective potential in 2037.

Figure ES-12. Summer DR Achievable Potential by DR Sub-Option

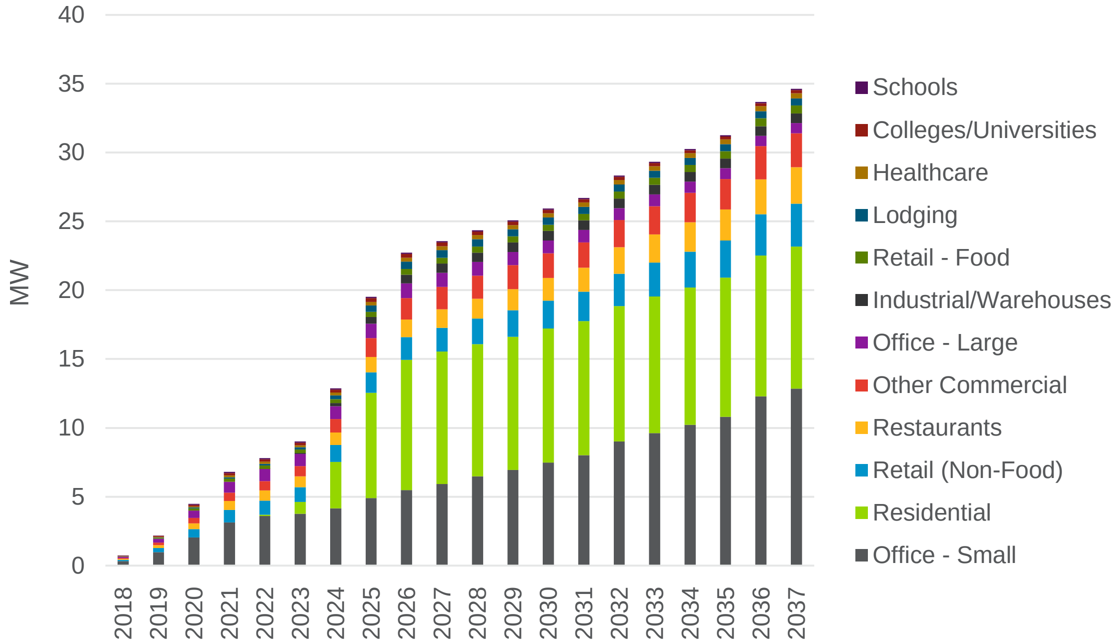


Source: Navigant

Figure ES-13 summarizes the cost-effective achievable potential by customer segment for the base case. The team observed the following:

- Potential from C&I customers primarily comes from small offices, which make up 37% (12.9 MW) of the total cost-effective achievable potential in 2037. This is followed by retail buildings, restaurants, and the other C&I building category, which each make up between 7% and 9% of the total cost-effective achievable DR potential in 2037—3.1 MW, 2.7 MW, and 2.5 MW, respectively.
- All other C&I segments make up less than 2.2% of the cost-effective achievable potential in 2037, which is less than 0.75 MW.

Figure ES-13. Summer DR Achievable Potential by Customer Segment



Source: Navigant analysis

Conclusions and Next Steps

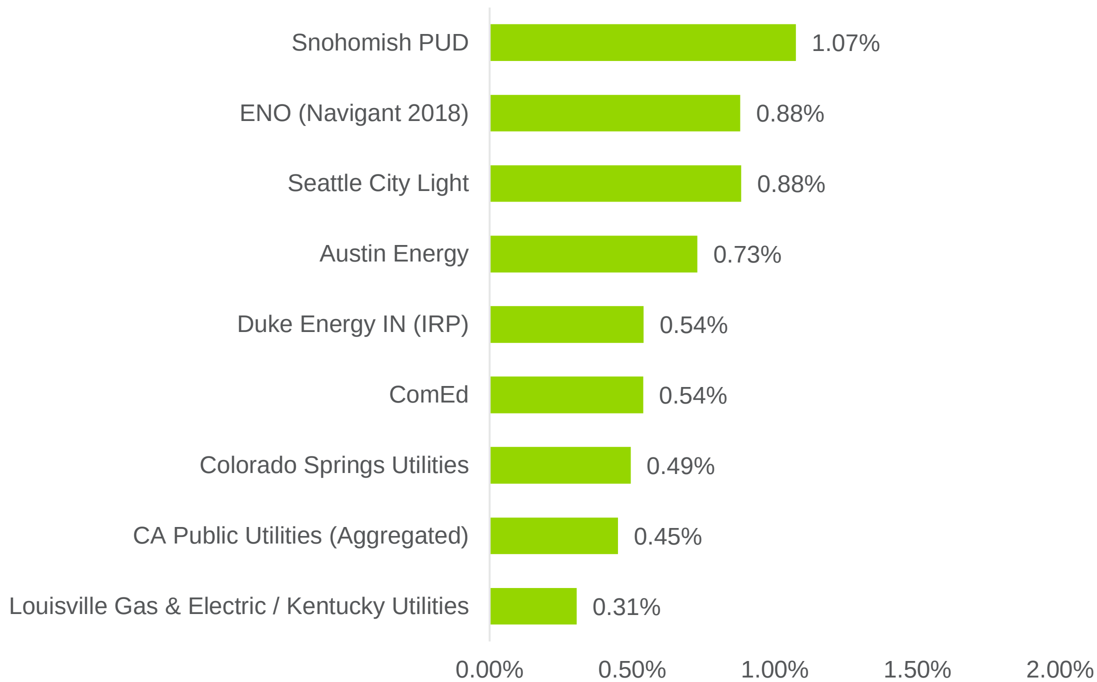
After reviewing the study results, the team benchmarked them against similar utilities, identified how the results could be used in ENO's 2018 IRP.

Benchmarking

Navigant benchmarked the energy efficiency achievable potential results against similar studies by other utilities. The goal of this exercise was to provide context for Navigant's results and to understand how various factors such as region or program spend may affect the results.

Based on the sources (provided in Section 5.1), Navigant aggregated the results into the figures below.

Figure ES-14. Benchmarking Pool Average EE Achievable Potential Savings (% of Sales)[6]



Source: Navigant analysis

When comparing potential estimates, it is important to note that although the utilities included in the benchmarking pool may have some similar characteristics, no two utilities are the same; therefore, the results may vary based on the inputs each utility provided to its respective potential study evaluator. Study methodologies may also differ based on the potential study evaluator, providing additional room for variances across studies.

ENO's achievable potential falls within the range of the benchmarking pool at an average of 0.88% savings per year over the study period (2018-2037). This is similar to Seattle City Light and slightly above Austin Energy (0.73%). Interestingly, the three all operate in large metropolitan areas and have similar governance structures in that they are regulated by a city council.[7]

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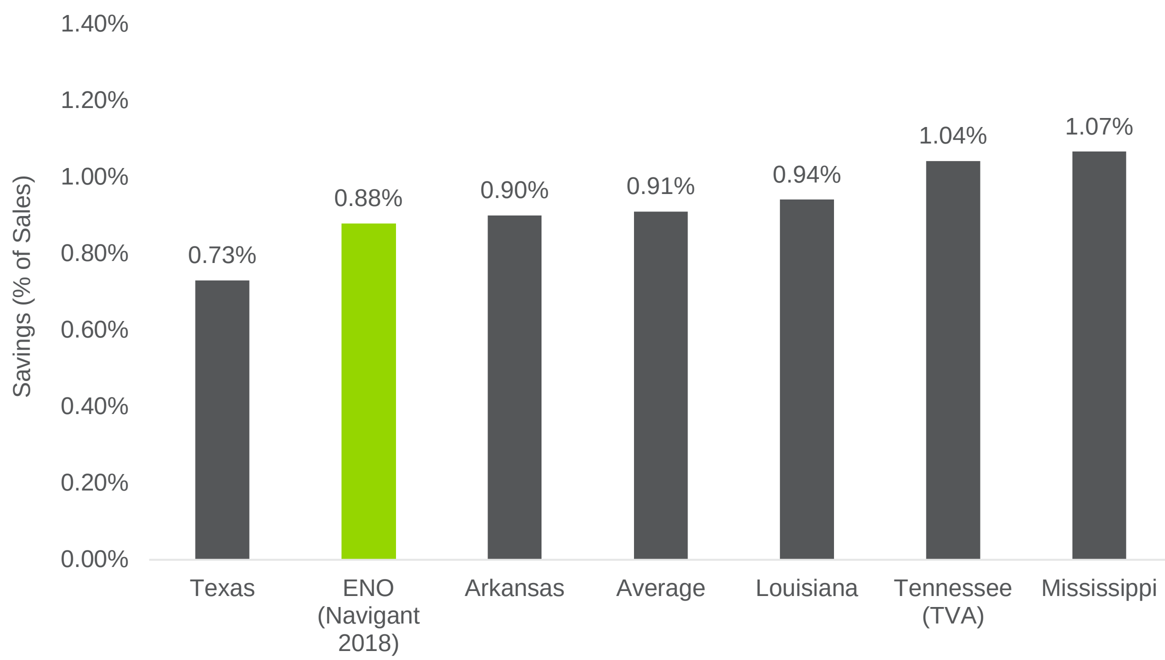
[6] These savings are shown as an annual average, which Navigant derived by dividing the cumulative study averages by the number of years in the study. Navigant used this approach since study years tend to differ greatly.

[7] It should be noted that, unlike ENO, which is an IOU, Austin Energy and Seattle City Light are both POUs that function as departments within their respective municipalities. However, all three must comply with the mandates of the local regulatory body.

In addition to benchmarking the results at the utility level, Navigant created a peer pool at the state level. The goal of this analysis was to understand ENO's potential savings within the broader context of the state of Louisiana and its neighbors. Given that the states are mostly clustered within the Southeast region of the US, they have the same general climate (hot-humid) and, therefore, may experience similar levels of achievable potential savings. Figure ES-15 shows how ENO's achievable potential fits into the broader state-level context.

Figure ES-15. Benchmarking Pool State Level EE Achievable Potential (% of Savings)

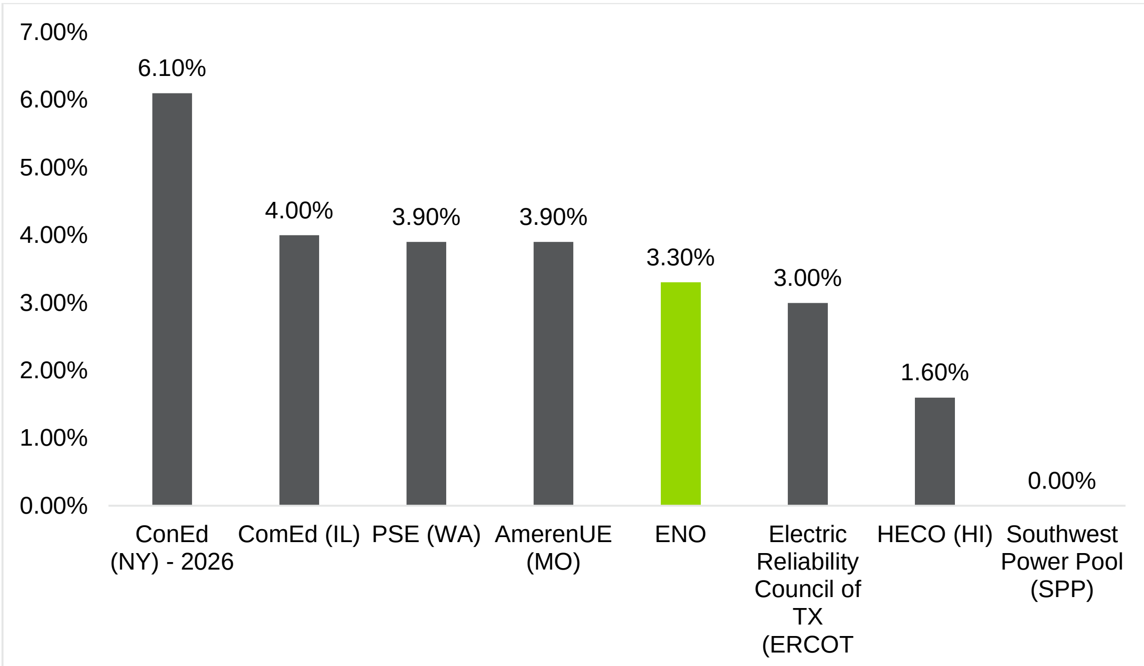


As shown in the figure above, ENO's achievable potential savings are within the range of the benchmarking pool (0.73%-1.07%), which makes sense given the similarities across the region. Its potential savings are only slightly less than the overall pool average and the state of Louisiana. The slight difference in savings between this ENO potential study and the overall state may be caused by several factors:

- Updated inputs
- Utilities outside New Orleans had not begun implementing energy efficiency programs at the time ACEEE conducted the Louisiana study in 2013
- Broader region covered (some areas may have potential savings based on stock type and other utilities' energy efficiency spending)

Navigant also benchmarked DR. The results are shown below in Figure ES-16.

Figure ES-16. Benchmarking Pool DR Potential (% of Savings)



As shown above, ENO falls in the middle of the benchmarking pool, only slightly higher than ERCOT and slightly below Ameren in Missouri. Given that DR, like EE, varies based on program administration and geographic location, amongst other factors, ENO's DR potential aligns closely to its peers.

IRP

The potential study provides forecasted savings inputs for use in the IRP modeling. These inputs are provided by sector, segment, and end use because each combination of these items is mapped to a load shape (see Appendix C). Each measure is mapped to one or more DSM programs. Navigant then developed a load shape representative of each DSM program. The DSM program load shapes represent the aggregate hourly energy savings for the group of measures included in the program over the 20-year planning period. These load shapes are what define the hourly usage profiles for the DSM program portfolio.

Program Planning

This potential study provides ENO with a wealth of data to support and inform the DSM program planning efforts. However, it is important to note that programmatic design (such as delivery methods and marketing strategies) will have implications for the overall savings goals and projected cost. As mentioned above, **near-term savings**

potential, actual achievable goals, and program costs for a measure-level implementation will vary from the savings potential and costs estimated in this long-term study. This potential study is one element to be considered in program design, along with historical program participation and current market conditions with the program implementation team.

Some observations on the potential study results that can provide input to program planning are:

- There is strong potential with promoting advanced lighting, which includes networked lighting technology and controls in all sectors.
- There is high potential in O&M and behavior-type programs such as retrocommissioning if they are cost-effective.
- HVAC unitary equipment has high potential in both sectors.

1. Introduction

1.1 Context and Study Goals

Entergy New Orleans, LLC (ENO) engaged Navigant Consulting, Inc. (Navigant or the team) to prepare a DSM potential study for electricity as an input to ENO's 2018 IRP for the 2018-2037 period. The study's objective was to assess the long-term potential for reducing energy consumption in the residential and C&I sectors by analyzing energy efficiency and peak load reduction measures and improving end-user behaviors. The energy efficiency potential analysis efforts provide input data to Navigant's DSMSim™ model, which calculates achievable savings potential across the service area. This study also includes DR program potential analyzed within Navigant's DRSim™. While ENO explicitly plans to use the results from the potential study to inform the IRP, these results may also be used as inputs to DSM planning and long-term conservation goals and energy efficiency program design.

1.1.1 Study Objectives

Potential studies provide a long-range outlook on the cost-effective potential for delivering demand-side resources such as EE and DR. Having a comprehensive review of achievable potential across ENO's service area helps forecast the effects customer actions can have over the forecast period. The level of detail and accuracy provided by the current study will allow ENO to incorporate DSM in its IRP modeling and analysis, inform the design of future customer efficiency programs, and have a clear understanding of the level of investment needed to pursue the demand-side resource options.

Given ENO's objectives and Council's rules, Navigant designed its project approach to ensure the study results adequately address those needs. Table 1-1 details these objectives and offers Navigant's approach to meeting each objective.

Table 1-1.Navigant's Approach to Addressing ENO's Objectives

Objective		Navigant's Approach	
1	Use consistent methodology and planning assumptions	✓	Navigant has developed a variety of analytical tools and approaches to inform DSM planning and the establishment of long-term conservation targets and goals (details provided in the following sections). Navigant's model is transparent. The team also worked closely with ENO to vet methodology, assumptions, and inputs at each stage of this project.

Objective			Navigant's Approach
2	Reflect current information	✓	Navigant leveraged learnings from its prior work with ENO to create a bottom up analysis that includes inputs, such as the New Orleans TRM, and other up-to-date information (new codes and standards, saturation data from surveys and Energy Smart programs, avoided costs, etc.) are included in this study.
3	Quantify achievable potential	✓	Navigant quantifies achievable potential by first calculating the technical and economic potential. The achievable potential base case is calibrated to the historical Energy Smart program data and the current programs approved by the Council for Energy Smart PYs 7-9.
4	Provide input to the IRP	✓	Navigant's approach will provide the following for all modeled cases: • Supply curve of conservation potential for input to ENO's IRP • Output available with 8,760 hourly impact load shapes
5	Present the scope and methodology of the study	✓	Navigant's approach to stakeholder engagement will provide relevant information to key stakeholders.

Source: Navigant

1.2 Organization of the Report

Navigant organized this report into five sections that detail the study's approach, results, and conclusions. The list below provides a description of each section.

- **Section 1** provides an overview of the study, including its background and purpose.
- **Section 2** describes the methodologies and approaches Navigant used to estimate energy efficiency and demand reduction potential, including discussions of base year calibration, reference case forecast, and measure characterization.
- **Section 3** details the energy efficiency achievable potential forecast, including the approach and results by case, segment, end use, and measure.
- **Section 4** details the process for estimating DR potential and offers the achievable potential savings forecast for ENO, including the modeling results by customer segment.
- **Section 5** summarizes the next steps that result from developing this potential study. Additionally, the section benchmarks the study's results against similar studies and actual achieved savings from other utilities.

The accompanying appendices provide detailed model results and additional context around modeling assumptions.

1.3 Caveats and Limitations

There are several caveats and limitations associated with the results of this study, which are detailed below. Potential studies are typically a bottom-up effort and calibrated to system and sector base load and forecasted reference case. They are an exercise in data management and analysis and in balancing data abundance and data scarcity for different inputs. A study's team must understand the data gaps and how to fill these to provide reasonable and realistic potential estimates. This report documents what approach the Navigant team took and the decisions made when appropriate data was not available.

1.3.1 Forecasting Limitations

Navigant obtained historic and forecasted energy sales and customer counts from ENO by sector. Each rate class (residential and C&I) forecast contains its own set of assumptions based on ENO's expertise and models. The team leveraged these assumptions as much as possible as inputs to develop the reference case stock and energy demand projections. Where sufficient and detailed information could not be extracted due to the granularity of the information available, Navigant developed independent projections based on best practices. These independent projections were based on secondary data resources and produced in collaboration with ENO. The secondary resources and any underlying assumptions used are referenced throughout this report.

1.3.2 Segmentation

Navigant obtained several pieces of data from ENO to segment the two sectors (residential and C&I), including customer counts by premise type for residential and industry type for C&I. The team supplemented this data using its expertise and ENO's input to ensure the allocation of sales and stock data aligned to the appropriate segments. Government customers are included as part of the C&I sector. Savings potential analysis from city-owned street lighting is not included in this study since the majority has been converted to LED.

1.3.3 Measure Characterization

Efficiency potential studies may employ a variety of primary data collection techniques (e.g., customer surveys, onsite equipment saturation studies, and telephone interviews) that can enhance the accuracy of the results, though not without associated cost and time requirements.

Energy efficiency measures: The scope of this study did not include primary data collection. Rather, the energy efficiency analysis relied on data from ENO, other regional efficiency programs and utilities, and TRMs from New Orleans,[8] Arkansas Pennsylvania, Illinois, Minnesota, Vermont, New York, and Massachusetts to inform inputs to DSMSim.

Navigant used the measure list in this study to appropriately focus on those technologies likely to have the highest impact on savings potential over the study horizon. However, there is always the possibility that emerging technologies may arise that could increase savings opportunities over the forecast horizon and broader societal changes may affect levels of energy use in ways not anticipated by this study.

DR programs: The scope of this study leveraged available ENO data from the direct load control pilot over the last two PYs to characterize DR program participation and costs. Additional DR characterization is based on Navigant's research on programs nationwide and other potential studies. This study leveraged ENO load and account data to size the market eligible for DR program participation.

1.3.4 Measure Interactive Effects

This study models energy efficiency measures independently. Thus, the total aggregated energy efficiency potential estimates may be higher or lower than the actual potential available if a customer installs multiple measures in their home or business. Multiple measure installations at a single site generate two types of interactive effects: within end-use interactive effects and cross end-use interactive effects. An example of a within end-use interactive effect is when a customer implements temperature control strategies but also installs a more efficient cooling unit. To the extent that the controls reduce cooling requirements at the cooling unit, the savings from the efficient cooling unit would be reduced. An example of a cross end-use interactive effect is when a homeowner replaces heat-producing incandescent light bulbs with efficient LEDs. This influences the cooling and heating load of the space—however slightly—by increasing the amount of heat and decreasing the amount of cooling generated by the heating, ventilation, and air conditioning (HVAC) system.

Navigant employed the following methods to account for measure interactive effects:

- Where measures clearly compete for the same application (e.g., an air source heat pump being replaced by either a more efficient air source heat pump or a ground source heat pump), the team created competition groups to eliminate the potential for double counting savings.
- For measures with significant interactive effects (e.g., HVAC control upgrades and building automation systems), the team adjusted applicability percentages to reflect varying degrees of interaction.
- Wherever cross end-use interactive effects were appreciable (e.g., lighting and

[8] New Orleans Energy Smart Technical Reference Manual: Version 1.0, September 2017, prepared by ADM Associates, Inc.

HVAC), the team typically characterized those interactive effects for same fuel (e.g., lighting and electric heating) applications but not for cross fuel because no natural gas savings or consumptions were considered in this study.

There may be instances where the stacking of savings was not considered. These included mostly measures from the TRM, the primary source for the measure characterization. For example, if an efficient cooling unit is installed at the same time as improved insulation, the overall effects will be lower than the sum of individual effects. Appendix E provides further discussion of the challenges involved with accurately determining interactive effects.

1.3.5 Measure-Level Results

This report includes a high level account of potential results across the ENO service area and focuses largely on aggregated forms of potential. Navigant mapped the measure-level data to the customer segments and end-use categories so a reviewer can easily create custom aggregations.

1.3.6 Gross Savings Study

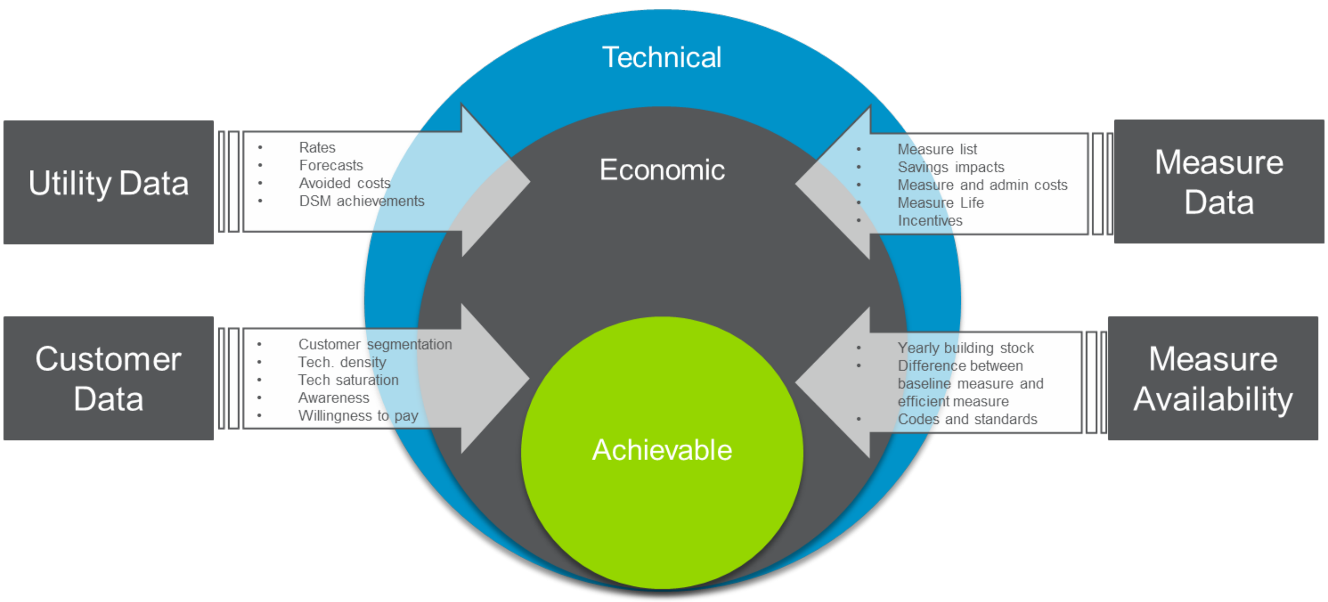
Savings in this study are shown at the gross level, meaning natural change (either natural conservation or natural growth in consumption) or, in other words, free-ridership, is not included in the savings estimates. Providing gross potential is advantageous because it permits a reviewer to easily calculate net potential when new information about changing EUIs, considerations of program design, or NTG ratios becomes available.

2. Study Approach and Data

2.1 Energy Efficiency

Navigant developed forecasts of technical, economic, and program achievable electric savings potential in the ENO service area from 2018 through 2037 using a bottom-up potential model. These efficiency forecasts relied on disaggregated estimates of building stock and electric energy sales before conservation and a set of detailed measure characteristics for a comprehensive list of energy efficiency measures relevant to ENO's service region. This section details the team's approach and methodology to develop the key inputs to the potential model, as illustrated in Figure 2-1.

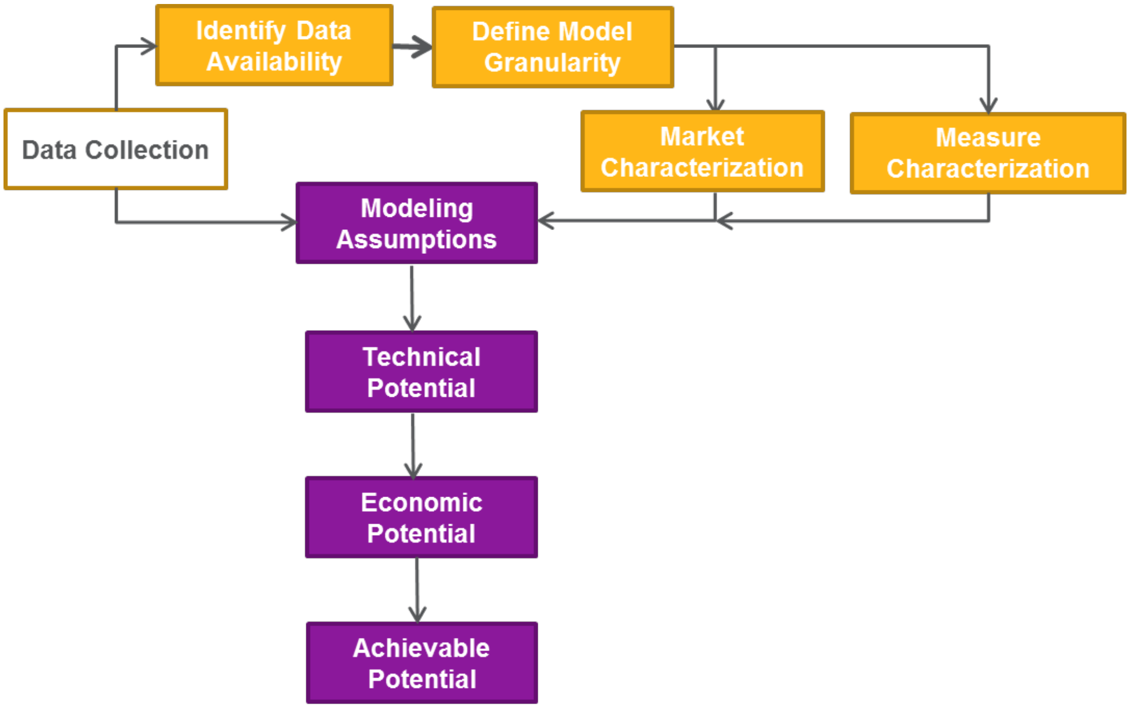
Figure 2-1. Potential Study Inputs



Source: Navigant

The methodology to calculate achievable potential includes several elements such as a base year calibration, a reference case forecast, and full measure characterization. Figure 2-2 shows how these elements interact to result in the achievable savings potential.

Figure 2-2. High Level Overview of Potential Study Methodology



Source: Navigant

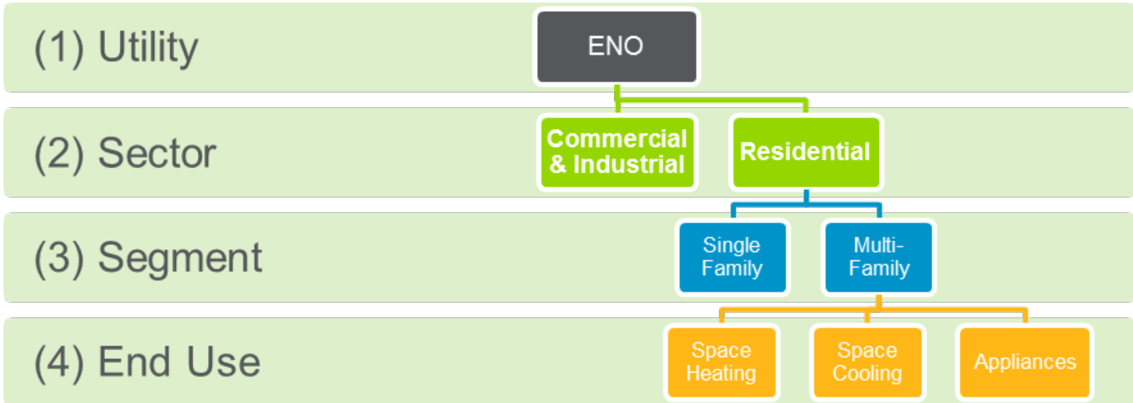
2.1.1 Market Characterization

Navigant's model uses inputs from two workflows: Market Characterization and Measure Characterization. This section describes the steps involved in the first workflow, Market Characterization. The Market Characterization workflow aims to define both the base year profile and reference case used to calculate potential.

2.1.1.1 Base Year Profile

This section describes the approach used to develop the base year (2016) profile of electricity use in ENO's service area, a key input to the potential model. The objective of the base year is to define a detailed profile of electricity sales by customer sector, segment, and end use (Figure 2-3). The model uses the base year as the foundation to develop the reference case forecast of electricity demand from 2018 through 2037.

Figure 2-3. Base Year Electricity Profile – Residential Example



Source: Navigant

Navigant developed the base year profile based on 2016 billing and customer account data provided by ENO because it was the most recent year with a fully complete and verified dataset. Where ENO-specific information was unavailable, Navigant used data from publicly available sources such as the US EIA CBECS and the US Department of Labor SIC System, in addition to internal Navigant data sources. The team used these resources to support the data sources provided by ENO and to ensure consistency with ENO data.

2.1.1.2 Defining Customer Sectors and Segments

The first major task to develop the base year electricity calibration involved disaggregating the main sectors—residential and C&I—into specific customer segments. The team selected customer segments based on several factors, including data availability and level of detail. Table 2-1 shows the segmentation used for the residential and C&I sectors. The following subsections detail the segmentation used for these sectors.

Table 2-1. Customer Segments by Sector

Residential	Commercial & Industrial
Single Family	Colleges/Universities
Multifamily	Healthcare
	Industrial/Warehouse
	Lodging
	Large Office
	Small Office
	Other
	Restaurants
	Retail – Food
	Retail – Non-Food
	Schools

Source: Navigant analysis

2.1.1.3 Residential Segments

After establishing the study sectors and segments, Navigant aligned ENO's data to the definitions established above, working closely with ENO. For residential, the team divided the sector into two segments based on consumption: single family and multifamily. The data ENO provided did not align perfectly with these segments due to differences in disaggregation methods. Navigant took two steps to reconcile the data:

1. **Sorted out unnecessary premises.** Navigant analyzed the proportion of total consumption for the different premise types provided in ENO's data. More specifically, the team calculated the total kilowatt-hour (kWh) consumption of each premise type (by multiplying the number of accounts by the average monthly kWh sales for each account) and compared those to the total monthly residential kWh consumption (by adding up all the total consumptions of each premise type). Based on this analysis, the team decided to exclude certain premise types depending on their proportion of the total consumption. For instance, if the premise type made up less than 1% of the residential sector's kWh sales and did not align with the study's residential segments (e.g., Boat Slip, Not Assigned), it was excluded.
2. **Mapped the remaining premise types to the study segments.** Navigant sorted the remaining premise types—house, apartment, duplex, condo, and mobile home—to the study segments. This process involved looking at each premise type's average monthly kWh consumption. Based on this comparison, the team determined that houses, condos, and homes would be classified as Single Family and duplexes and apartments would be classified as Multifamily.

Table 2-2 provides the finalized descriptions for each of these residential segments.

Table 2-2. Residential Segment Descriptions

Segment	Description
Single Family	Detached, attached row and/or townhouses (condominium), and mobile homes residential dwellings
Multifamily	Apartment units located in low rise or high rise apartment buildings and duplexes

Source: Navigant

2.1.1.4 C&I Segments

Navigant combined the C&I sectors into one, noted as C&I, because ENO's industrial sector made up roughly 13% of the total load based on ENO's load forecast analysis. Working closely with ENO, the team divided the C&I sector into 11 customer segments. Table 2-3 provides descriptions for each segment.

The team selected these C&I segments to be representative of the population of C&I customers in ENO's service area by comparing similar building characteristics such as patterns of electricity use, operating and mechanical systems, and annual operating hours. Generally, the selection of these segments aligned with the New Orleans TRM v1 and the SIC code for the account and kWh sales data provided by ENO. This study differs from those sources in that it includes industrial/warehouses and other as standalone segments and aggregates fast food and full menu restaurant into a single segment.

Appendix A.3 details on the allocation of the sales and stock data into the C&I sector.

Table 2-3. C&I Segment Descriptions

Segment	Description
Large Office	Larger offices engaged in administration, clerical services, consulting, professional, or bureaucratic work; excludes retail sales.
Small Office	Smaller offices engaged in personal services (e.g., dry cleaning), insurance, real estate, auto repair, and miscellaneous work; excludes retail sales.
Retail – Food	Retail and distribution of food; excludes restaurants.
Retail – Non-Food	Retailing services and distribution of merchandise; excludes retailers involved in food and beverage products services.
Healthcare	Health services, including diagnostic and medical treatment facilities, such as hospitals and clinics.
Lodging	Short-term lodging and related services, such as restaurants and recreational facilities; includes residential care, nursing, or other types of long-term care.
Restaurant	Establishments engaged in preparation of meals, snacks, and beverages for immediate consumption including restaurants, taverns, and bars.

Segment	Description
School	Primary schools, secondary schools (K-12), and miscellaneous educational centers, like libraries and information centers.
College/University	Post-secondary education facilities such as colleges, universities, and related training centers.
Industrial/Warehouse	Establishments that engage in the production, manufacturing, or storing of goods, including warehouses, manufacturing facilities, and storage facilities for general merchandise, refrigerated goods, and other wholesale distribution.
Other	Establishments not categorized under any other sector including but not limited to recreational, entertainment, and other miscellaneous activities.

Source: Navigant

2.1.1.5 Defining End Uses

The next step in the base year analysis was to establish end uses for each customer sector. Navigant defined these uses based on best practices, past ENO potential studies, and internal expertise.

The end uses selected in Table 2-4 are important for several reasons, including reporting and defining savings. For instance, the team uses the categories to report achievable savings with more granularity than at the sector and segment levels. Navigant derives these reported end-use savings by rolling up individual energy efficiency measures that map to the broader end-use categories. For example, savings from ENERGY STAR refrigerators and freezers are reported under the plug load end use.

Table 2-4. End Uses by Sector

Residential	C&I
Lighting Interior	Lighting Interior
Lighting Exterior	Lighting Exterior
Plug Loads	Plug Loads
Cooling	Cooling
Heating	Heating
Hot Water	Fans/Ventilation
Fans/Ventilation	Refrigeration
	Hot Water

Source: Navigant

Navigant used two additional end uses in Table 2-4 to report measure savings: total facility and heating and cooling*.* The team used these end uses to report savings from measures that affect electricity consumption across an entire home or facility or from measures that affect both heating and cooling consumption. For example, because smart thermostats result in electricity savings associated with both heating and cooling, savings from smart thermostats are assigned to the heating and cooling end use rather than individually to either heating or cooling.

2.1.1.6 Base Year Inputs

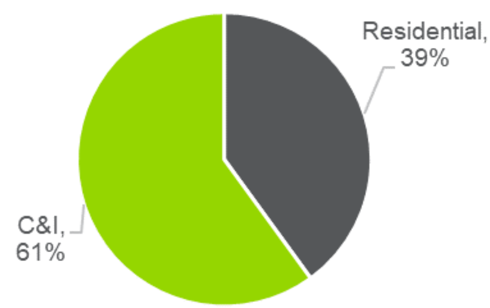
This section summarizes the breakdown of stock (households), electricity sales, and EUIs at the sector level, segment level, and end-use level. The team used these base year sales as direct inputs to the potential model. Appendix A provides a detailed description of the methodology used to develop these estimates. The DR portion of this study reconciles and derives the breakdown of demand across the sectors, segments, and end uses.[9]

Table 2-5 and Figure 2-4 show the high level breakdown of electricity sales by sector. Of total electricity sales, 61% comes from the C&I sector and 39% from the residential sector.

Table 2-5. 2016 Base Year Electricity Sector Sales (GWh)

Sector	GWh
Residential	2,230
C&I	3,503
Total	**5,733**

Figure 2-4. 2016 Base Year Electricity Sector Breakdown (%, GWh)



Source: Navigant analysis

All other base year inputs are shown and detailed below.

Residential Sector

To define the base year residential sector inputs, Navigant began by determining the base year stock and sales using ENO's account and billing data as the starting point. Although the account and billing data provided an approximation of ENO's stock by premise type (e.g., homes, condos, duplexes, etc.), the team further calibrated the

[9] Navigant developed the peak demand base case using the average peak demand factors from the 2016 sales data for the top 50 hours in each season.

numbers to ENO's account and load forecasts to ensure all datasets aligned. See Appendix A.2 for more detail about the calibration.

The next step in the base year definition process involved developing residential EUI values in kWh per household. Navigant used ENO's 2016 base year and the residential sales and count forecast to develop these values at the sector and segment levels by dividing the sales by the stock. Once the team determined the base year sector- and segment-level EUIs, it then determined the end-use-level EUIs, a more granular view of the EUIs. In the absence of local, ENO-specific data sources, Navigant used the US DOE's EnergyPLUS prototypical models in conjunction with its proprietary updates based on several different studies to determine the proportion of energy allocated to each of the study's end uses. The team used these proportions to further disaggregate the segment-level EUIs to the end-use level.

Table 2-6 shows the base year residential stock, electricity sales, and average electricity usage per home by segment. The base year residential stock is approximately 180,000 homes and accounts for just over 2,200 GWh of sales.

Table 2-6. Base Year Residential Results

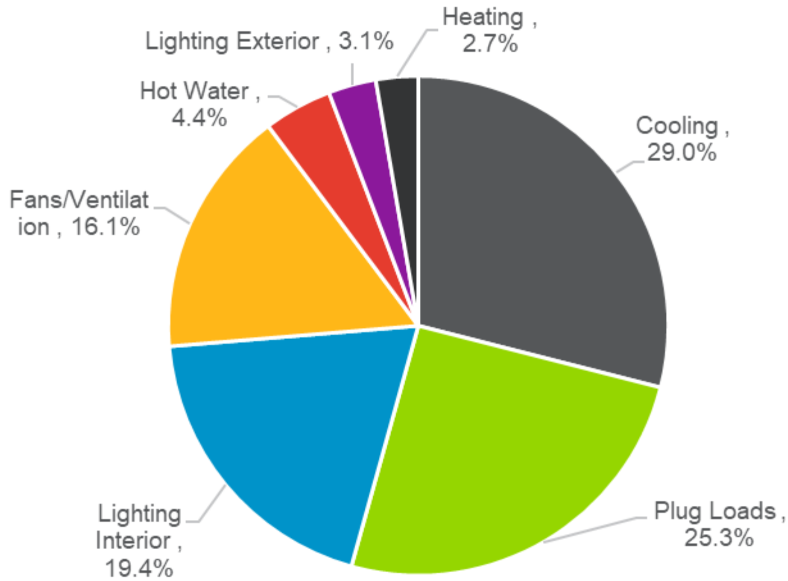
Segment	Stock (Accounts)	Electricity Use (GWh)	kWh per Account
Single Family	132,901	1,481	11,144
Multifamily	45,048	749	16,632
Total	**177,949**	**2,230**	**12,533**[10]

Source: Navigant analysis of ENO data

Figure 2-5 shows the breakdown of base year residential electricity sales by end use and segment, respectively. In terms of end uses, lighting, cooling, fans/ventilation, and plug loads represent the largest residential end uses and account for 90% of residential electricity sales.

[10] Note that this number represents the average annual kWh consumption for all households (total electricity use/ total accounts) and not the sum of the kWh per account for the two segments.

Figure 2-5. Base Year Residential Electricity End-Use Breakdown (%, GWh)



Source: Navigant analysis

C&I Sector

Similar to the residential sector, Navigant needed to determine the base year stock (thousands square feet [SF]) by segment, sales (kWh) by segment, and EUIs (kWh/thousands SF) by end use. Navigant followed three steps to determine these values for the base year:

1. Identify EUI by sector and segment for ENO
2. Define sales usage based on ENO's account and billing data
3. Determine the base year stock

This section will outline the general processes for each of these steps. Appendix A.3 provides specific details on the calibrations, data, and calculations used to define the base year values.

For step 1, Navigant used data from the EIA to determine 2016 EUIs at the sector and segment levels for ENO's climate region, hot-humid. The team then further calibrated this data to align with ENO's specific forecasts to finalize the EUIs. To disaggregate the EUIs by end use, Navigant created end-use allocations using the DOE's EnergyPLUS model in conjunction with proprietary Navigant models.

Once the EUIs were finalized, Navigant determined electricity usage, or sales, by segment by mapping ENO's account and billing data, which was classified by SIC, to the study's segments. The mapping process ultimately helped the team divide the total sales into segments, yielding the segment-level base year sales. This analysis included government accounts within the C&I sector.

Finally, Navigant determined the stock using the EUI and sales determined in the previous two steps. More specifically, the team divided the segment-level EUI, which was in kWh/thousands SF, by the segment-level sales, which was in kWh. This calculation yielded the stock by segment in thousands SF.

Table 2-7 shows the base year C&I stock (SF of floor space), electricity sales, and average electricity usage per SF by segment. C&I floor space stock is estimated at 188 million SF and contributes approximately 3,503 GWh of sales.

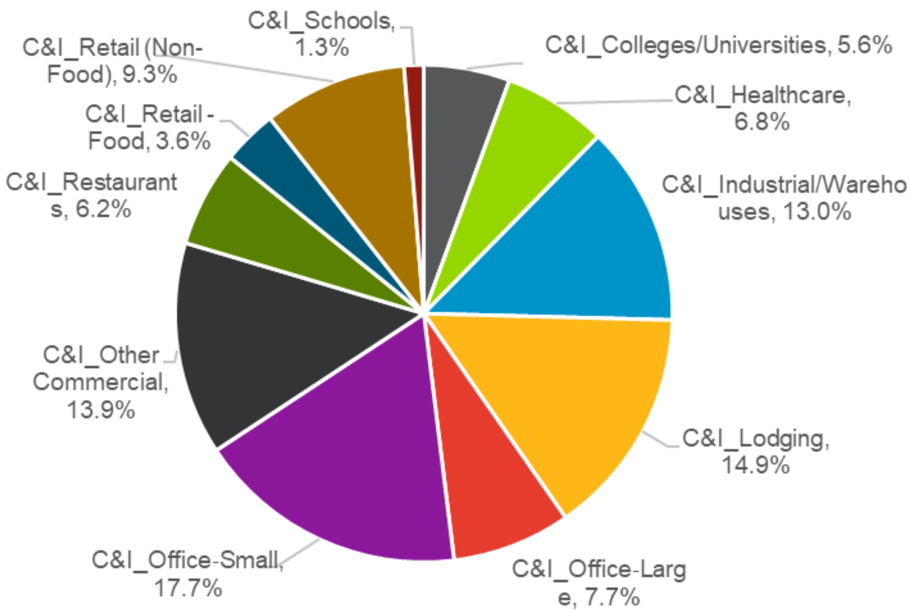
Table 2-7. Base Year C&I Results

Segment	Stock (thousands SF)	Electricity Use (GWh)	kWh per SF
College/University	15,388	196	12.7
Healthcare	8,318	237	28.5
Industrial/Warehouse	27,863	457	16.4
Lodging	34,693	523	15.1
Office – Large	15,875	270	17.0
Office – Small	36,365	619	17.0
Other Commercial	22,504	485	21.6
Restaurant	4,720	218	46.2
Retail – Food	2,574	125	48.7
Retail – Non-Food	16,548	327	19.8
School	3,494	45	12.7
Total	**188,340**	**3,503**	**--**

Source: Navigant analysis

Figure 2-6 shows the breakdown of base year C&I electricity sales by segment, respectively. Offices and lodging consume the most electricity, accounting for almost half (40%) of C&I electricity sales.

Figure 2-6. Base Year C&I Electricity Segment Breakdown (%, GWh)

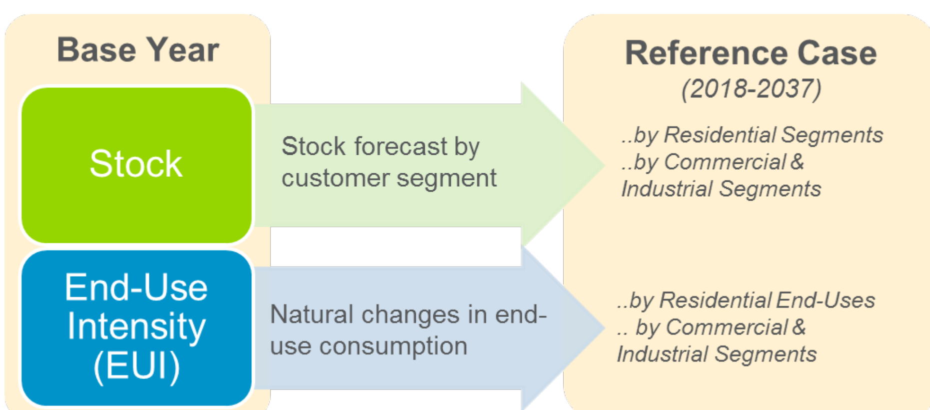


Source: Navigant analysis

2.1.2 Reference Case Forecast

This section presents the reference case forecast from 2018 to 2037. The reference case represents the expected level of electricity sales over the study period, absent incremental DSM activities or load impacts from rates. Electricity sales in the reference case are consistent with ENO's load forecast. The reference case is significant because it acts as the point of comparison (i.e., the reference) for the calculation of achievable potential cases. Figure 2-7 illustrates the process Navigant used to develop the reference case forecast. The reference case uses the base year profile as its foundation and applies changes in stock growth and EUI over time to develop the residential and C&I forecasts.

Figure 2-7. Schematic of Reference Case



Source: Navigant

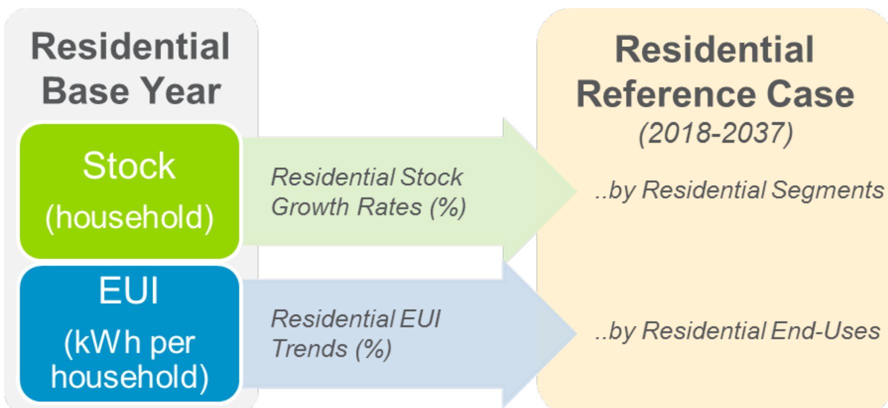
Navigant constructed the reference case forecast by applying growth rates from ENO's account and load forecasts directly to the base year stock, sales, and EUI values.

The following sections describe the approach and assumptions employed and present the results of the residential and C&I reference case forecasts.

2.1.2.1 Residential Reference Case

Figure 2-8 illustrates this process. Appendix A.2 provides a description of the process used to develop the residential stock forecast.

Figure 2-8. Residential Reference Case Schematic



Source: Navigant

For the residential reference case, the first step involved developing stock growth rates for each residential segment over the 2018-2037 period. Navigant derived residential stock growth rates based on ENO's residential account forecast and applied them to the base year residential stock. Table 2-8 shows the growth in residential stock forecast from 2018 to 2037. Residential stock increases at an average annual growth rate of 0.4% from approximately 178,000 accounts in 2016 to 194,000 accounts in 2037.

Table 2-8. Residential Reference Case Stock Forecast (Accounts)

Segment	2016	2037
Single Family	132,901	144,972
Multifamily	45,048	49,139
Total	**177,949**	**194,111**

Source: Navigant analysis of ENOs residential load forecast

Navigant followed a similar methodology for sales, leveraging ENO's forecasting. To forecast the sales, the team determined the growth rates for each year of ENO's load forecast and then applied these rates directly to the load.

Finally, Navigant needed to forecast the EUIs. Due to data availability, Navigant did not apply individual EUI trends by end use. Instead, the team applied ENO's residential account forecast growth rates at each level to determine the changes in EUI over time. Although it is unlikely that end-use EUI trends will follow the account-level trends exactly, Navigant did not have any other reliable estimates to leverage.[11] ENO currently does not estimate these values, and the team could not find any reliable secondary sources specifically for the New Orleans area.[12] Table 2-9 shows the resulting EUI trends by residential end use, which is an overall reduction per household.

Table 2-9. Residential Reference Case EUI Forecast (kWh/Account)

Segment	End Use	2016	2037
Single Family	Cooling	3,229	3,138
	Fans/Ventilation	1,790	1,740
	Heating	304	296
	Hot Water	493	479
	Lighting Exterior	345	335
	Lighting Interior	2,158	2,097
	Plug Loads	2,824	2,744
	Total	**11,144**	**10,829**
Multifamily	Cooling	4,819	4,683
	Fans/Ventilation	2,672	2,596
	Heating	454	441
	Hot Water	736	715
	Lighting Exterior	515	500
	Lighting Interior	3,221	3,130
	Plug Loads	4,215	4,095
	Total	**16,632**	**16,161**

Source: Navigant analysis

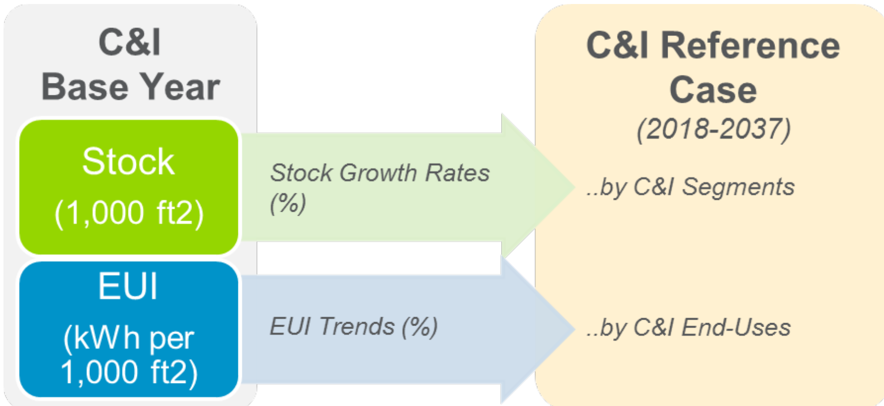
2.1.2.2 C&I Reference Case

Like the residential reference case, Navigant built the C&I reference case by applying growth rates from ENO's load forecast to the base year values. Figure 2-9 provides an overview of the inputs and the EUI and stock analyses for the C&I sector. Appendix A.3 provides a detailed description of the process used to develop the C&I stock forecast.

[11] In other studies, Navigant usually sees a decrease in lighting EUIs and an increase in plug load EUIs over time, which is consistent with the assumption made here. Other end-use EUI projection rates may also vary.

[12] Navigant reviewed national-level data from the US EIA and methodologies from other Navigant potential studies; however, the trends did not align well with ENO-specific trends.

Figure 2-9. C&I Reference Case Schematic



Source: Navigant

To forecast out the stock, Navigant applied the growth rate of 0.4% from ENO's account forecast for each study year.[13] Similarly, the team used the growth rate of 0.4% from ENO's load forecast to estimate sales by year. Because ENO only had sector-level forecasts, Navigant applied the growth rates evenly across all segments except for the industrial/warehouse segment. For that segment, the team applied the growth rate of 0.0% from the Industrial sector portion of ENO's forecasts to ensure alignment. Appendix A.3 provides more details about the source data for the growth rates. Given data availability, Navigant leveraged these growth rates to determine the EUI trends as well. Although it is unlikely that end-use EUI trends will follow the account-level trends exactly, the team did not have any other reliable estimates to leverage. ENO currently does not estimate these values, and Navigant could not find any reliable secondary sources specifically for the New Orleans area.

Table 2-10 and Table 2-11 show the results of the reference case analysis.

[13] Note that the growth rates presented in the paragraph represent the compound annual growth rate (CAGR) over the entire study period. The annual rates vary based on specific inputs, such as job, stock, and industry growth rates, according to ENO's load forecasting team.

Table 2-10. C&I Reference Case Stock Forecast (Thousands SF)

Segment	2016	2037
Colleges/Universities	15,388	16,580
Healthcare	8,318	8,962
Industrial/Warehouses	27,863	27,734
Lodging	34,693	37,381
Office – Large	15,875	17,105
Office – Small	36,365	39,183
Other Commercial	22,504	24,248
Restaurants	4,720	5,085
Retail – Food	2,574	2,773
Retail – Non-Food	16,548	17,830
Schools	3,494	3,765
Total	**188,340**	**200,648**

Source: Navigant analysis

Table 2-11. C&I Reference Case EUI Forecast (kWh/Thousands SF)

Segment	End Use	2016	2037
Colleges/Universities	Cooling	2,662	2,820
	Fans/Ventilation	2,468	2,615
	Heating	1,885	1,998
	Hot Water	196	207
	Lighting Exterior	347	367
	Lighting Interior	3,238	3,430
	Plug Loads	1,804	1,911
	Refrigeration	148	156
	Heating/Cooling	4,547	4,818
	Total Facility	**12,747**	**13,506**
Healthcare	Cooling	7,803	8,268
	Fans/Ventilation	2,806	2,974
	Heating	4,217	4,468
	Hot Water	356	377
	Lighting Exterior	224	238
	Lighting Interior	5,999	6,357
	Plug Loads	6,978	7,394
	Refrigeration	141	149
	Heating/Cooling	12,021	12,737
	Total Facility	**28,525**	**30,224**
Industrial/Warehouses	Cooling	64	74

Segment	End Use	2016	2037
	Fans/Ventilation	4,006	4,595
	Heating	3,171	3,637
	Lighting Exterior	266	305
	Lighting Interior	5,439	6,239
	Plug Loads	883	1,012
	Refrigeration	502	576
	Hot Water	2,071	2,375
	Heating/Cooling	3,235	3,711
	Total Facility	**16,402**	**18,813**
Lodging	Cooling	2,683	2,843
	Fans/Ventilation	2,006	2,125
	Heating	176	186
	Hot Water	3,812	4,040
	Lighting Exterior	176	187
	Lighting Interior	2,402	2,546
	Plug Loads	3,687	3,906
	Refrigeration	123	130
	Heating/Cooling	2,859	3,029
	Total Facility	**15,065**	**15,962**
Office – Large	Cooling	6,432	6,815
	Fans/Ventilation	495	524
	Heating	1,468	1,556
	Hot Water	61	64
	Lighting Exterior	34	36
	Lighting Interior	5,291	5,606
	Plug Loads	3,245	3,438
	Heating/Cooling	7,900	8,371
	Total Facility	**17,026**	**18,040**
Office – Small	Cooling	6,269	6,642
	Fans/Ventilation	482	511
	Heating	1,846	1,956
	Hot Water	76	81
	Lighting Exterior	33	35
	Lighting Interior	5,157	5,464
	Plug Loads	3,162	3,351
	Heating/Cooling	8,115	8,598
	Total Facility	**17,026**	**18,040**
Other Commercial	Cooling	687	727

Segment	End Use	2016	2037
	Fans/Ventilation	4,096	4,340
	Heating	1,805	1,912
	Hot Water	1,457	1,543
	Lighting Exterior	190	201
	Lighting Interior	2,953	3,129
	Plug Loads	9,608	10,181
	Refrigeration	777	823
	Heating/Cooling	2,491	2,640
	Total Facility	**21,572**	**22,857**
Restaurants	Cooling	8,553	9,062
	Fans/Ventilation	6,578	6,970
	Heating	1,970	2,088
	Hot Water	2,389	2,531
	Lighting Exterior	2,073	2,196
	Lighting Interior	3,422	3,626
	Plug Loads	19,710	20,884
	Refrigeration	1,481	1,569
	Heating/Cooling	10,523	11,150
	Total Facility	**46,175**	**48,925**
Retail – Food	Cooling	3,980	4,217
	Fans/Ventilation	5,927	6,280
	Heating	2,151	2,279
	Hot Water	45	48
	Lighting Exterior	595	631
	Lighting Interior	10,889	11,538
	Plug Loads	5,586	5,918
	Refrigeration	19,498	20,659
	Heating/Cooling	6,131	6,496
	Total Facility	**48,671**	**51,570**
Retail – Non-Food	Cooling	1,915	2,030
	Fans/Ventilation	2,916	3,089
	Heating	1,795	1,902
	Lighting Exterior	599	634
	Lighting Interior	8,770	9,293
	Plug Loads	980	1,039
	Refrigeration	642	680
	Hot Water	2,172	2,301
	Heating/Cooling	3,711	3,932

Segment	End Use	2016	2037
	Total Facility	**19,789**	**20,968**
Schools	Cooling	2,504	2,653
	Fans/Ventilation	2,322	2,460
	Heating	2,459	2,605
	Hot Water	255	271
	Lighting Exterior	326	346
	Lighting Interior	3,046	3,227
	Plug Loads	1,697	1,798
	Refrigeration	139	147
	Heating/Cooling	4,962	5,258
	Total Facilities	**12,747**	**13,506**

Source: Navigant analysis

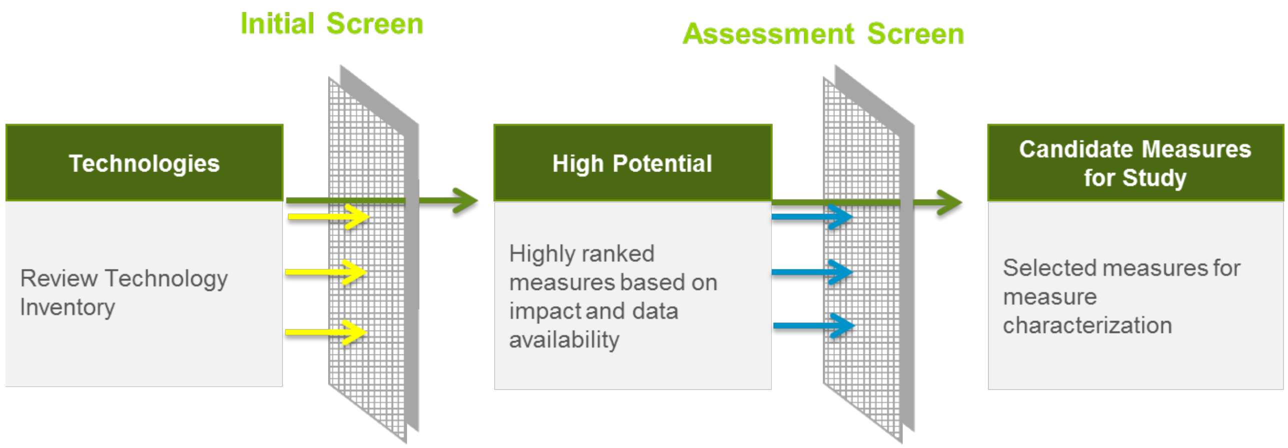
2.1.3 Energy Efficiency Measure Characterization

Navigant fully characterized over 100 measures or measure groupings across ENO's residential and C&I sectors. The team prioritized high-impact measures with good data availability that are most likely to be cost-effective for inclusion into DSMSim.

2.1.3.1 Measure List

Navigant developed a comprehensive list of energy efficiency measures likely to contribute to achievable potential. The team reviewed current ENO Energy Smart program offerings, other regional programs, and potential model measure lists from other states to identify energy efficiency measures with the highest expected economic impact. The team supplemented the measure list using secondary data from publicly available sources such as TRMs from various US regions including Arkansas, Illinois, and the mid-Atlantic. Navigant prioritized measures in existing ENO Energy Smart programs based on data availability for appropriate characterization and measures most likely to be cost-effective. The team also ensured that high impact measures were captured in the list. The team worked with ENO and ENO contractors, including program implementers, to finalize the measure list and ensure it contained technologies viable for future ENO program planning activities. Figure 2-10 shows the process Navigant implemented to narrow down the measure list.

Figure 2-10. Measure Screening Process



Source: Navigant

There were many measures included in the initial and assessment screens that did not make it into the study. The high potential measures that did not become candidate measures for the study are documented. Working sessions with ENO staff revealed topics of note regarding the following measures:

- **Residential lighting:** Low efficiency residential lighting types such as incandescent and halogen lamps can be replaced with higher efficiency CFL and LED bulbs. As LED bulbs have become more common in the market and less expensive over time, they offer cost-effectiveness advantages over CFL bulbs. Navigant anticipates that future programs will no longer incentivize CFLs. Therefore, this study included LEDs but not CFLs.
- **Residential thermostats:** Programmable thermostats control space temperatures according to a preset schedule, while smart thermostats are Wi-Fi controlled and implement a learning algorithm to control temperature to a desired level while managing HVAC energy use. ENO recently conducted a pilot study in low income housing in anticipation of developing a future program offering. Navigant included both programmable and smart thermostats in this study.
- **Industrial measures:** ENO reported that its industrial energy use is relatively low compared to the commercial and residential sectors. Navigant used industrial measure expertise from previous potential studies and industrial subject matter experts to develop a limited list of industrial sector measures; the team then aggregated the industrial sector potential together with the commercial sector potential.

2.1.3.2 Measure Characterization Key Parameters

The measure characterization effort consisted of defining nearly 50 individual parameters for each of the measures included in this study. This section defines the top nine key parameters and how each influences technical and economic, and therefore achievable, potential savings estimates.

1. **Measure Definition:** Navigant used the following variables to qualitatively define each characterized measure:
    - ***Replacement Type:*** Replacing the baseline technology with the efficient technology can occur in three variations:
        i. Retrofit (RET): In this variation, equipment is replaced before the end of its life. The model considers the baseline to be the existing equipment and uses the energy and demand savings between the existing equipment and the efficient technology during technical potential calculations. RET also applies the full installed cost of the efficient equipment during the economic screening.
        ii. Replace-on-Burnout (ROB): In this variation, equipment is replaced when it fails. The model considers the baseline to be the code-compliant technology option and uses the energy and demand savings between the current code option and the efficient technology during technical potential calculations. ROB also applies the incremental cost between the efficient and code-compliant equipment during the economic screening.
        iii. New Construction (NEW): In this variation, new equipment is installed in a new home or building. The model considers the baseline to be the least-cost, code-compliant option and uses the energy and demand savings between this specific current code option and the efficient technology during technical potential calculations. NEW also applies the incremental cost between the efficient and code-compliant equipment during the economic screening.
    - ***Baseline Definition:*** Describes the baseline technology.
    - ***Energy Efficiency Definition:*** Describes the efficient technology set to replace the baseline technology.
    - ***Unit Basis:*** The normalizing unit for energy, demand, cost, and density estimates.
2. **Sector and End-Use Mapping:** The team mapped each measure to the appropriate end uses, customer segments, and sectors across ENO's service area. Section 2.1.1 describes the breakdown of customer segments within each sector.
3. **Annual Energy Consumption:** The annual energy consumption in kWh for each base and energy efficient technology.
4. **Fuel Type Applicability Multipliers:** Applies an adjustment to the total equipment stock to account for the proportion applicable to a given measure's fuel type. For example, a measure that replaces a baseline efficiency resistance water heater with a more efficient unit is only applicable to existing electric resistance water heaters. The team used this multiplier to restrict the existing

water heater equipment stock to only those that use electricity. Table 2-12 provides the fuel share splits.

Table 2-12. Fuel Share Splits for Domestic Hot Water and Heating

Customer Segment	DHW – Elec Only	DHW – Gas Only	Heating – Elec Only	Heating – Gas
Residential	50%	50%	50%	50%
C&I	60%	40%	60%	40%

Source: Navigant analysis

5. **Measure Lifetime:** The lifetime in years for the base and energy efficient technologies. The base and energy efficient lifetimes only differ in instances where the two cases represent inherently different technologies, such as LEDs compared to a baseline incandescent bulb.
6. **Incremental Costs:** The incremental cost between the assumed baseline and efficient technology using the following variables:
    - ***Base Costs*****:** The cost of the base equipment, including both material and labor costs.
    - ***Energy Efficient Costs:*** The cost of the energy efficient equipment, including both material and labor costs.
7. **Technology Densities:** This study defines density as the penetration or saturation of the baseline and efficient technologies across the service area. For residential, these saturations are on a per-home basis and for C&I, they are per 1,000 SF of building space.[14]
    - ***Base Initial Saturation*****:** The initial saturation of the baseline equipment for a given customer segment as defined by the fraction of the end-use stock that has the baseline equipment installed.
    - ***Energy Efficiency Initial Saturation:*** The initial saturation of the efficient equipment for a given customer segment as defined by the fraction of the end-use stock that has the efficient measure installed.
    - ***Total Maximum Density:*** The total number of both the baseline and efficient units for a given technology.
8. **Technical Suitability:** The percentage of the base technology that can be reasonably and practically replaced with the specified efficient technology. For instance, occupancy sensors are only practical for certain interior lighting fixtures

[14] Navigant sourced density estimates from Energy Smart program data and other related secondary sources.

(suitability less than 1.0), while all existing incandescent exit signs can be replaced with efficient LED signs (suitability of 1.0).

9. **Competition Group:** Navigant combined efficient measures competing for the same baseline technology density into a single competition group to avoid the double counting of savings.

2.1.3.3 Measure Characterization Approaches and Sources

This section provides approaches and sources for the main measure characterization variables.

Table 2-13. Measure Characterization Input Data Sources

Measure Input	Data Sources
Measure Costs, Measure Life, Energy Savings	• Energy Smart program data • 2017 New Orleans TRM • 2017 ENO potential study data • US DOE Appliance Standards and Rulemakings supporting documents • Engineering analyses • TRMs and RTF measure workbooks • Navigant measure database and previous potential studies
Fuel Type Applicability Splits, Density, Baseline Initial Saturation, Technical Suitability, End-Use Consumption Breakdown	• Energy Smart program data • Navigant's previous potential studies
Codes and Standards	• US DOE CFR engineering analyses • Local building code

Source: Navigant

2.1.3.4 Energy Savings

Navigant used three general bottom-up approaches to analyze residential and C&I measure energy savings:

1. **New Orleans Technical Reference Manual Calculations:** Navigant used the New Orleans 2017 TRM as much as possible for unit energy savings calculations. The TRM provided deemed (default) savings values for most measures in this study.

2. **Standard algorithms:** Navigant used standard algorithms for unit energy savings calculations for most measures not contained in the New Orleans TRM. To supplement this, the team leveraged ENO data, DOE Appliance Standards and Rulemaking supporting documents, RTF measure workbooks, and other TRMs.

3. **Engineering analysis:** Navigant used appropriate engineering algorithms to calculate energy savings for any measures not included in the New Orleans TRM or available TRMs. The team leveraged its internal expertise and experience with potential studies to calculate the energy savings.

2.1.3.5 Peak Demand Savings

Peak demand savings were either from the New Orleans TRM or generally calculated by dividing the annual energy use by the annual hours of use and then multiplying by a coincidence factor. The coincidence factor is an expression of how much of the equipment's demand occurs during the system's peak period. The defined peak period according to the TRM is the average peak demand savings, Monday-Friday, non-holidays from 4-6pm in the months of June, July, and August.

2.1.3.6 Incremental Costs

Navigant relied on the cost information in the New Orleans TRM as much as possible. The team conducted secondary research and used other publicly available cost data sources such as regional TRMs, RTF measure workbooks, the California DEER, ENERGY STAR, US DOE Appliance Standards and Rulemaking, and other state databases for all other cost data.

2.1.3.7 Building Stock and Densities

Navigant developed building stock estimates for the residential sector in terms of residential accounts and the C&I sector in terms of floor space. The approaches used to develop the base year and reference case building stock assumptions are described in Section 2.1.1.

Measure densities—used to characterize the penetration or saturation of measures—were developed based on a variety of data sources including ENERGY STAR, the Northwest Energy Efficiency Alliance's Residential Building Stock Assessment (RBSA) and Commercial Building Stock Assessment (CBSA), and previous potential studies from other jurisdictions.

2.1.3.8 8,760 Load Profile

Appendix C provides detail on the development of the end-use profiles. These profiles are 8,760 (i.e., hourly annual) end-use load shapes. These profiles are by end use (e.g., heating, lighting, etc.), by sector (e.g., residential, commercial, etc.), and, where relevant and appropriate, by commercial and industrial segments (e.g., retail, office, etc.).

2.1.3.9 Codes and Standards Adjustments

The US DOE publishes federal energy efficiency regulations for many types of residential appliances and commercial equipment. The US DOE Technical Support Documents (TSD)[15] contain information on energy and cost impacts of each appliance standard. In the TSD, engineering analysis is available in Chapter 5, energy use analysis in Chapter 7, and cost impact in Chapter 8.

As these codes and standards take effect, the energy savings from existing measures impacted by these codes and standards decline and the reduction is transferred to the codes and standards savings potential. Navigant accounts for the effect of codes (including building code[16]) and standards through baseline energy and cost multipliers (sourced from the DOE's analysis), which reduce the baseline equipment consumption starting from the year a code or standard takes effect. The baseline cost of an efficient measure affected by codes and standards will often increase upon the code's implementation. For example, Navigant incorporated the 2023 residential central air conditioners standard in this study, which results in the baseline for residential air conditioners changing from 14 Seasonal Energy Efficiency Ratio (SEER) to 14.3 SEER in 2023. Accordingly, the model accounts for a reduction in energy consumption and an increase in cost in 2023 for the baseline technology through the codes and standards multipliers. As such, computed measure-level potential is net of these adjustments from codes and standards implemented after the first year of the study.[17]

2.1.3.10 *Measure Quality Control*

Navigant fully vetted and characterized each measure in terms of its energy savings, costs, and applicability. The characterization includes the following:

- Measure descriptions and baseline assumptions
- Energy savings and cost associated with the measure
- Cost of conserved energy, including O&M costs
- Lifetime of the measure (Effective useful life and remaining useful life)
- Applicability factors including initial energy efficient market penetration and technical suitability
- Load shape of measure
- Replacement type of measure

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[15] Appliance standards rulemaking notices and TSD can be found at:
https://www.energy.gov/eere/buildings/appliance-and-equipment-standards-program

[16] Section 26-15 of the New Orleans Code of Ordinances

[17] It is important to note that the second tier of Energy Independence and Security Act of (EISA) 2007 regulations go into effect beginning January 2020 where the general service lamps must comply with a higher standard. Because the EUL of some lamps extend beyond this date, the baseline per guidance from the New Orleans TRM is adjusted to the second tier in years after 2022. For commercial lighting, these retrofits are considered as RET and baseline changes start in 2020.

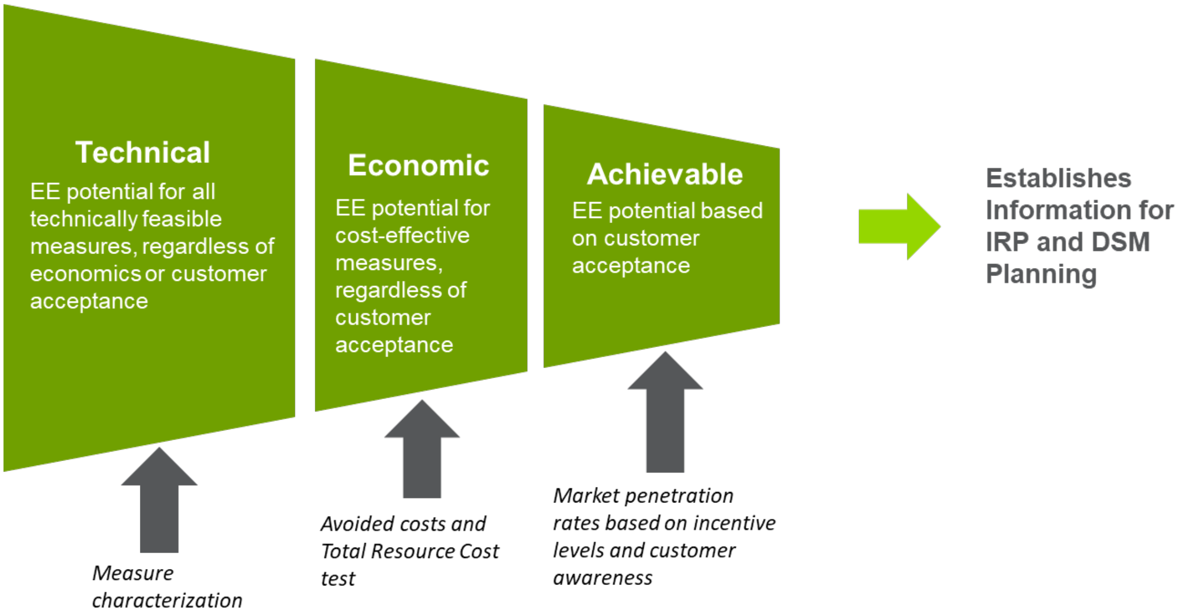
2.1.4 Potential Estimation Approach

Navigant employed its proprietary DSMSim potential model to estimate the technical, economic, and achievable savings potential for electric energy and demand across ENO's service area. DSMSim is a bottom-up technology diffusion and stock tracking model implemented using a System Dynamics[18] framework. The DSMSim model explicitly accounts for different types of efficient measures such as RET, ROB, and NEW and the effects these measures have on savings potential. The model then reports the technical, economic, and achievable potential savings in aggregate for the service area, sector, customer segment, end-use category, and highest impact measures.

This study defines technical potential as the total energy savings available assuming all installed measures can immediately be replaced with the efficient measure/technology—wherever technically feasible—regardless of the cost, market acceptance, or whether a measure has failed and must be replaced. Economic potential is a subset of technical potential, using the same assumptions regarding immediate replacement as in technical potential but including only those measures that have passed the benefit-cost test chosen for measure screening; in this case, that is the total resource cost (TRC) test. Finally, the achievable potential is analyzed based on the measure adoption ramp rates and the diffusion of technology through the market. Figure 2-11 provides an overview of the methodology.

[18] See Sterman, John D. *Business Dynamics: Systems Thinking and Modeling for a Complex World*. Irwin McGraw-Hill. 2000 for detail on System Dynamics modeling.

Figure 2-11. Potential Calculation Methodology



Source: Navigant

Savings reported in this study are gross rather than net, meaning they do not include the effects of natural change. Providing gross potential is advantageous because it permits a reviewer to more easily calculate net potential when new information about NTG ratios or changing EUIs become available.

Once the potential results and cases are analyzed, the output can be used to define the portfolio energy savings goals, costs, and forecast for alignment into other utility planning landscapes like the IRP.

2.1.4.1 Technical Potential

Approach to Estimating Technical Potential

This study defines technical potential as the total energy savings available assuming all installed measures can immediately be replaced with the efficient measure/technology—wherever technically feasible—regardless of the cost, market acceptance, or whether a measure has failed and must be replaced.

Navigant's modeling approach considers an energy efficient measure to be any change made to a building, piece of equipment, process, or behavior that can save energy.[19] The savings can be defined in numerous ways depending on which method is most appropriate for a given measure. Measures that consist of a change to a single, discrete

[19] This study does not examine the impact of end-user electricity rates on sales or energy efficiency's impact on electricity rates.

product or piece of equipment (e.g., lighting fixture replacements) are best characterized as some fixed amount of savings per fixture. Measures related to products or equipment that vary by size (e.g., air conditioning equipment) are best characterized on a basis that is normalized to a certain aspect of the equipment, such as per ton of air conditioning capacity. Other measures that could affect multiple pieces of equipment (e.g., behavior-based measures) are characterized as a percentage of customer segment sales saved.

The calculation of technical potential in this study differs depending on the assumed measure replacement type. Technical potential is calculated on a per-measure basis and includes estimates of savings per unit, measure density (e.g., quantity of measures per home for residential or per 1,000 SF of floor space for C&I), and total building stock in each service area. The study accounts for three replacement types, where potential from RET and ROB measures are calculated differently from potential for NEW measures. The formulae used to calculate technical potential by replacement type are shown below.

Retrofit and ROB Measures

RET measures, commonly referred to as advancement or early retirement measures, are replacements of existing equipment before the equipment fails. RET measures can also be efficient processes that are not currently in place and that are not required for operational purposes. RET measures incur the full cost of implementation rather than incremental costs to some other baseline technology or process because the customer could choose not to replace the measure and would, therefore, incur no costs. In contrast, ROB measures—sometimes referred to as lost opportunity measures—are replacements of existing equipment that have failed and must be replaced or are existing processes that must be renewed. Because the failure of the existing measure requires a capital investment by the customer, the cost of implementing ROB measures is always incremental to the cost of a baseline (and less efficient) measure.

RET and ROB measures have a different meaning for technical potential compared with NEW measures. In any given year, the model uses the existing building stock to calculate technical potential.[20] This method does not limit the calculated technical potential to any pre-assumed adoption rate of RET measures. Existing building stock is reduced each year by the quantity of demolished building stock in that year and does not include new building stock that is added throughout the simulation. For RET and ROB measures, annual potential is equal to total potential, thus offering an instantaneous view of technical potential. Navigant used Equation 2-1 to calculate technical potential for RET and ROB measures.

[20] In some cases, customer segment-level and end-use-level sales are used as proxies for building stock. These sales figures are treated like building stock in that they are subject to demolition rates and stock tracking dynamics.

Equation 2-1. Annual/Total RET/ROB Technical Savings Potential

$$\begin{aligned}&Total\ Potential\\&= Existing\ Stock\ x\ Measure\ Density\ x\ Savings\ x\ Technical\ Suitability\ \ x\ Baseline\ Initial\ Saturation\end{aligned}$$

Where:

- *Total Potential:* kWh
- *Existing Stock:*[21] C&I floor space per year or residential households per year
- *Measure Density:* Widgets per unit of stock
- *Savings:* kWh per widget per year
- *Technical Suitability:* Percentage of applicable stock
- *Baseline Initial Saturation:* Percentage of energy efficient stock

New Construction Measures

The cost of implementing NEW measures is incremental to the cost of a baseline (and less efficient) measure. However, NEW technical potential is driven by equipment installations in new building stock rather than by equipment in existing building stock.[22] New building stock is added to keep up with forecast growth in total building stock and to replace existing stock that is demolished each year. Demolished (sometimes called replacement) stock is calculated as a percentage of existing stock in each year, and this study uses a demolition rate of 0.5% per year for residential and C&I stock. New building stock determines the incremental annual addition to technical potential, which is then added to totals from previous years to calculate the total potential in any given year. The equations used to calculate technical potential for new construction measures are provided in Equation 2-2 and Equation 2-3.

Equation 2-2. Annual Incremental NEW Technical Potential (AITP)

$$AITP = New\ Stock\ x\ Measure\ Density\ x\ Savings\ x\ Technical\ Suitability$$

Where:

- *Annual Incremental NEW Technical Potential:* kWh

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[21] Units for building stock and measure densities may vary by measure and customer segment (e.g., 1,000 SF of building space, number of residential homes, customer segment sales, etc.).

[22] In some cases, customer segment-level and end-use-level sales are used as proxies for building stock. These sales figures are treated like building stock in that they are subject to demolition rates and stock tracking dynamics.

- *New Stock:*[23] C&I floor space per year or residential households per year
- *Measure Density:* Widgets per unit of stock
- *Savings:* kWh per widget per year
- *Technical Suitability:* Percentage of the total baseline measures that could be replaced with the efficient measure. For example, CFLs cannot replace all incandescent bulbs because of their size, inability to be dimmed, and sensitivity to temperature.

Equation 2-3. Total NEW Technical Potential (TTP)

$$\text{TTP} = \sum_{YEAR=2018}^{YEAR=2037} AITP_{YEAR}$$

Competition Groups

Navigant's modeling approach recognizes that some efficient technologies will compete against each other in the calculation of potential. The study defines competition as an efficient measure competing for the same installation as another efficient measure. For instance, a consumer has the choice to replace an air source heat pump with a more efficient air source heat pump or a ground source heat pump, but not both. These efficient technologies compete for the same installation.

There are several general characteristics of competing technologies that Navigant used to define competition groups in this study:

- Competing efficient technologies share the same baseline technology characteristics, including baseline technology densities, costs, and consumption.
- The total (baseline plus efficient) measure densities of competing efficient technologies are the same.
- Installation of competing technologies is mutually exclusive (i.e., installing one precludes installation of the others for that application).
- Competing technologies share the same replacement type (RET, ROB, or NEW).

To address the overlapping nature of measures within a competition group, Navigant's analysis only selected one measure per competition group to include in the summation of technical potential across measures (e.g., at the end use, customer segment, sector, service area, or total level). The measure with the largest energy savings potential in each competition group was used to calculate total technical potential of that

[23] Units for new building stock and measure densities may vary by measure and customer segment (e.g., 1,000 SF of building space, number of residential homes, customer segment consumption, etc.)

competition group. This approach ensures that the aggregated technical potential does not double count savings. The model does still, however, calculate the technical potential for each individual measure outside of the summations.

2.1.4.2 Economic Potential

This section describes the economic savings potential—potential that meets a prescribed level of cost-effectiveness—available in ENO's service area. The section explains Navigant's approach to calculating economic potential.

Approach to Estimating Economic Potential

Economic potential is a subset of technical potential, using the same assumptions regarding immediate replacement as in technical potential but including only those measures that have passed the benefit-cost test chosen for measure screening (in this study the TRC test, as per the Council's IRP rules). The TRC ratio for each measure is calculated each year and compared against the measure-level TRC ratio screening threshold of 1.0. A measure with a TRC ratio greater than or equal to 1.0 is a measure that provides monetary benefits greater than or equal to its costs. If a measure's TRC meets or exceeds the threshold, it is included in the economic potential.

The TRC test is a benefit-cost metric that measures the net benefits of energy efficiency measures from the combined stakeholder viewpoint of the utility (or program administrator) and the customers. The TRC benefit-cost ratio is calculated in the model using Equation 2-4.

Equation 2-4. Benefit-Cost Ratio for the TRC Test

$$TRC = \frac{PV(Avoided\ Costs)}{PV(Incremental\ Cost + Admin\ Costs)}$$

Where:

- *PV* is the present value calculation that discounts cost streams over time.
- *Avoided Costs* are the monetary benefits that result from electric energy and capacity savings—e.g., avoided or deferred costs of infrastructure investments and avoided long-run marginal cost (commodity costs) due to electric energy conserved by efficient measures.
- *Incremental Cost* is the measure cost as defined (see definition in Section 2.1.3.6).
- *Admin Costs* are the administrative costs incurred by the utility or program administrator (not including incentives).

Navigant calculated TRC ratios for each measure based on the present value of benefits and costs (as defined in the numerator and denominator, respectively) over each measure's life. Avoided costs, discount rates, and other key data inputs used in the TRC calculation are presented in Appendix B. Effects of free ridership are not present in the results from this study, so the team did not apply a NTG factor. Providing gross savings results will allow ENO to easily apply updated NTG assumptions in the future and allows for variations in NTG assumptions by reviewers. Although the TRC equation includes administrative costs, the study did not consider these costs during the economic screening process because the study is concerned with an individual measure's cost-effectiveness on the margin.

Like technical potential, only one economic measure from each competition group was included in the summation of economic potential across measures (e.g., at the end-use category, customer segment, sector, service area, or total level). If a competition group was composed of more than one measure that passes the TRC test, then the economic measure that provides the greatest electric savings potential was included in the summation of economic potential. This approach ensures that double counting is not present in the reported economic potential, though economic potential for each individual measure is still calculated and reported outside of the summation.

2.1.4.3 Achievable Potential

Achievable potential is defined as the subset of economic potential considered achievable given assumptions about the realistic market adoption of a given measure. It is the product of the economic potential with two measure-specific factors: 1) the assumed maximum long-run achievability of each measure, and 2) a time-dependent factor called ramp rate reflects barriers to market adoption. The adoption of measures can be broken down into calculation of the "equilibrium" market share and calculation of the dynamic approach to equilibrium market share.

The effects or program intervention result in applying ramp rates to the maximum achievable potential to model the changes in time-dependent barriers to market adoption. These ramp rates spread each measure's maximum achievable potential over the study horizon, accounting for assumptions about the timing of when this potential will be realized.

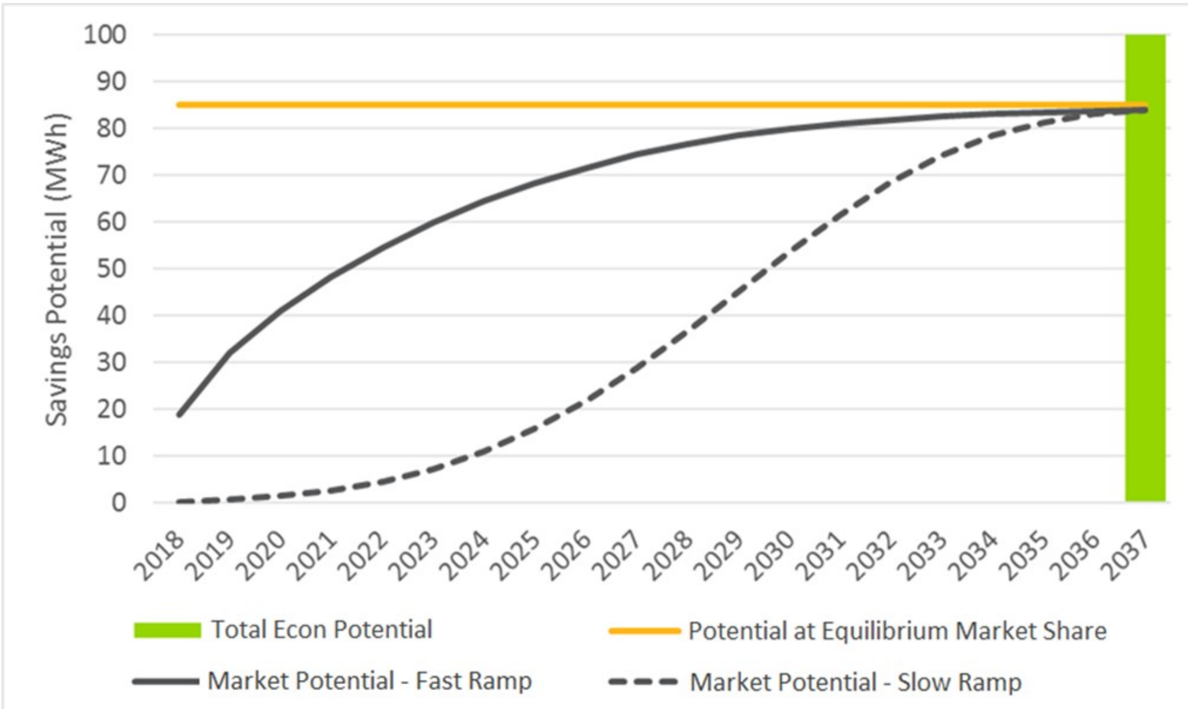
Using the definitions of cumulative total technical potential provided in Section 2.1.4.1, Equation 2-5 provides the formula to calculate achievable potential. As shown, Navigant calculated achievable potential by multiplying each measure's total economic potential by its maximum achievability factor and then applying a ramp rate for the adoption to the resulting maximum achievable potential.

Equation 2-5. Achievable Potential

$$Achievable\ Potential_{Year} = Total\ Economic\ Potential \times Max\ Achievability\ Factor \times Ramp\ Rate_{Year}$$

Figure 2-12 illustrates the relationship between total economic potential, maximum achievable potential, and final computed achievable potential in each year of the study as a function of ramp rate choice. The timing of achievable potential across the study horizon is driven by the choice of ramp rate. All values in the figure are for illustration purposes only.

Figure 2-12. Illustration of Achievable Potential Calculation



Source: Navigant

For measures involved in competition groups, an additional computational step is required to compute achievable potential to ensure no double counting of savings. While the technical and economic potential for a competition group reflects only the measure in that group with the greatest savings potential, all measures in a competition group may be allocated achievable potential based on their attractiveness (relative to one another).

Navigant allocated the economic potential proportionally across the various competing measures within the group based on their relative customer economics (payback). The team computed the relative customer economics ratio to reflect all costs and savings a customer would experience as a result of implementing the measure. The team multiplied the resulting market share splits by the maximum achievable potential for the group to get the achievable potential for each individual measure. This methodology ensured that final estimates of achievable potential reflected the relative economic attractiveness of measures in a competition group and that the sum of achievable potential from all measures in a competition group reflected the maximum achievable potential of the whole group.

2.2 Demand Response

Navigant prepared a DR potential assessment for ENO's electric service area from 2018 to 2037 as part of the DSM potential study. The objective of this assessment was to estimate the potential for using DR to reduce customer loads during peak summer periods.

Navigant identified and analyzed a suite of DR options for potential implementation in ENO's service area based on similar studies performed in other jurisdictions. These are:

1. **Direct load control (DLC):** This program controls water heating and cooling loads for residential and small business customers using either a DLC device (switch) or a PCT.
2. **C&I curtailment:** This program curtails a fixed amount of load reduction among C&I customers over a fixed contract period.
3. **Dynamic pricing:** This program encourages load reduction through CPP, with a 6:1 critical peak to off-peak price ratio. All customer types are eligible to participate.
4. **Behind-the-meter storage (BTMS):** This program triggers power dispatch from battery storage systems that are grid-connected during peak load conditions.

Navigant developed achievable potential estimates for each of these DR options at various levels of disaggregation, along with the costs associated with rolling out and implementing a DR program portfolio. The assessment considered both conventional and advanced control methods to curtail load at customer premises. Navigant also assessed the cost-effectiveness of the DR program options and measure types.

2.2.1 General Approach and Methodology

Navigant developed ENO's DR potential and cost estimates using a bottom-up analysis. The analysis used primary data from ENO and relevant secondary sources. The team configured its DRSim model, which uses this data as inputs, for this study. The following subsections detail Navigant's DR potential and cost estimation methodology:

- **Market Characterization:** Segment ENO's customer base into customer classes eligible to participate in DR programs.
- **Develop Baseline Projections:** Develop baseline projections for customer count and peak demand over the 20-year forecast period.
- **Characterize DR Options:** Define DR program options and map them to applicable customer classes.
- **Develop Model Inputs for Potential and Cost Estimates:** Develop participation, load reduction, and cost assumptions that feed the DRSim model.
- **Case Analysis:** Estimate DR potential and associated implementation costs for low and high cases relative to the base (medium) case.

2.2.2 Market Characterization for DR Potential Assessment

Market characterization was the first step in the DR potential assessment process. Table 2-14 presents the different levels of market segmentation for the DR potential assessment. It is based on Navigant's examination of ENO's rate schedules and the customer segments established in the energy efficiency potential study. The team finalized the market segmentation for the DR potential assessment in consultation with ENO.

The methodology Navigant used to segment the market at these levels is briefly described below. Government customers are included as part of the C&I sector. Savings potential analysis from street lighting is not included in this study.

Table 2-14. Market Segmentation for DR Potential Assessment

Level	Description
Level 1: Sector	• Residential • C&I
Level 2: Customer Class	• Residential • C&I customers by size based on maximum demand values: o Small C&I: <= 100 kW maximum demand o Large C&I: >100 kW maximum demand
Level 3: Customer Segment	• Residential • C&I customer segments[24] o Colleges/Universities o Healthcare o Industrial/Warehouse o Lodging o Office – Large o Office – Small o Other o Restaurants o Retail – Food o Retail – Non-Food o Schools

Source: Navigant

Navigant first segmented customers into residential and C&I. The team combined single family and multifamily customers into a single residential category because DR program and pricing offers are typically not distinguished by dwelling type. Next, Navigant

[24] Descriptions of these customer segments can be found in Table 2-3.

segmented C&I customers into two size categories (small and large) and further segmented them into customer segments. To do this, the team requested 2016 account-level maximum billed demand data from ENO. As mentioned in Section 2.1.1, 2016 was chosen as the base year for this analysis because it was the most recent year with a fully complete and verified dataset. Navigant mapped the SIC codes associated with these accounts to customer segments in the analysis, similar to the approach used by the energy efficiency potential study team in its market characterization effort. Then, the team calculated the split of customers between the small and large size categories by customer segment using a cutoff value of 100 kW.[25] This cutoff value was determined in consultation with ENO and is aligned to ENO's energy efficiency programs when there is a specific offer to the small C&I market segment. These splits were then used to develop a customer count and sales forecast by customer class and segment for the DR study. This segmentation is necessary because DR program offerings typically vary by customer size.

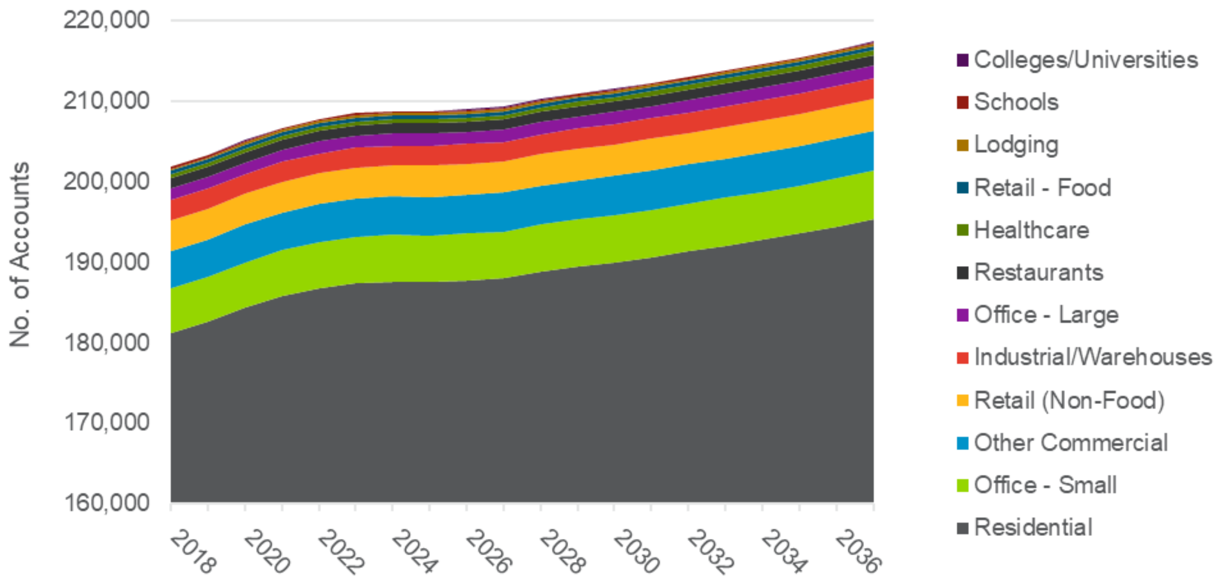
2.2.3 Baseline Projections

2.2.3.1 Customer Count Projections

Navigant applied year-over-year change in the stock forecast (described in Appendix A.2 and B.3) to the 2016 customer count data segmented by customer class and customer segment to produce a customer count forecast for the DR potential study. The team then trued up this forecast to the sector-level customer count forecast provided by ENO. Figure 2-13 shows the aggregate customer count forecast by segment only, summed across all customer classes.

[25] Since specific NAICS codes map to small and large offices, Navigant did not use the 100 kW cutoff to segment office customers into the small and large categories. The small versus large distinction for offices is solely based on the NAICS code mapping.

Figure 2-13. Customer Count Projections for DR Potential Assessment



Source: Navigant

2.2.3.2 Peak Demand Projections

Navigant worked with ENO to define the peak period for the DR potential assessment. The baseline peak demand forecast used the defined peak period; reduction estimates are applied to the peak period to estimate DR potential. ENO expressed a desire to align the peak period definition with times MISO is expected to see peak demand. This is so ENO can leverage the findings of the DR potential assessment should it seek to register any DR resources as load modifying resources with MISO. Per MISO's business practice manual, *"…the expected peak occurs during the summer (June through September) during the hours from 2:00 pm through 6:00 pm*." [26] Navigant added two additional constraints to this definition. First, the team only included weekdays in the peak period definition because it is not typical for utilities to call DR events on weekends. Second, Navigant only included the top 40 weekday hours within this window to better capture demand levels during a DR event. The team chose this threshold by studying ENO's historic 8,760 system load data and found that the top 25 and 35 hours in this window were within 5% of their maximum peak demand in 2014 and 2015, respectively, which is a typical margin for when DR events typically occur. Navigant selected the top 40 hours to stay conservative and refined the peak definition to include just those hours.

Once the peak period was defined, Navigant developed a disaggregated bottom-up peak demand forecast by customer class and segment. The team also estimated the

[26] MISO. *Business Practice Manual*. Demand Response. Effective date: June 1, 2016. pg 15.

end-use breakdown of the peak demand for C&I customers, as reduction estimates are typically expressed as a percentage of baseline load for these customers. The step-by-step methodology Navigant used to develop the baseline peak load projections is summarized as follows:

1. **Disaggregate sales forecast by customer class and customer segment:** Navigant first projected the base year (2016) sales data, segmented by customer class and customer segment, over the study horizon using the year-over-year change in building stock. The team then trued up the customer segment-level totals in this forecast to the sector-level totals in the forecast sent by ENO.[27]
2. **Develop 8,760 load shapes by customer segment:** The team used ENERGYPlus to develop hourly load shapes for ENO's service area to transform annual potential estimates into an 8,760 format (see Appendix C for description of load shape development).
3. **Calculate peak load factors:** Navigant calculated the average peak load factor over the hours that fell under the peak period definition for each customer class and customer segment combination. Per the industry-standard definition, peak load factor is defined as follows:

$$Peak\ Load\ Factor = \frac{Annual\ Sales}{Annual\ Peak\ Demand * 8{,}760}$$

Table 2-15 provides the calculated peak load factors by segment.

Table 2-15. Peak Load Factors by Customer Segment Type

Customer Segment	Peak Load Factor
Lodging	0.86
Healthcare	0.83
Schools	0.74
Colleges/Universities	0.70
Other	0.69
Retail – Food	0.66
Restaurants	0.62
Office – Small	0.59

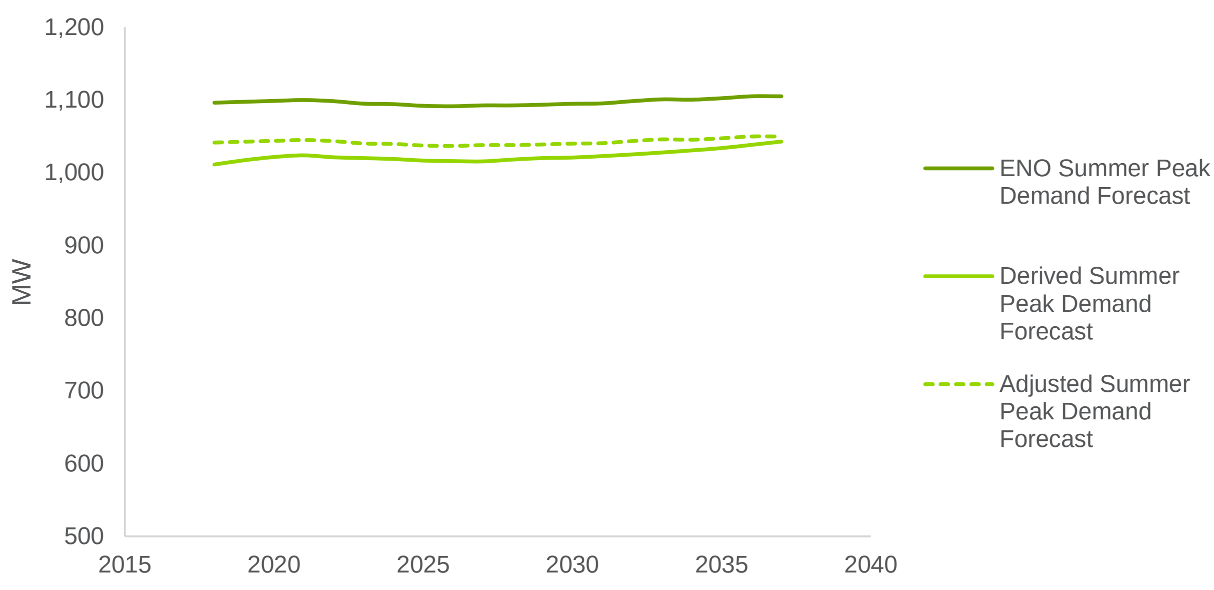
[27] Navigant did not directly use the account-level data provided by ENO to segment and roll up customer count and sales by customer class and customer segment. This is because the totals from this dataset did not match the totals from the SIC code-level data the energy efficiency potential study team received from ENO.

Customer Segment	Peak Load Factor
Retail – Non-Food	0.59
Office – Large	0.58
Industrial/Warehouses	0.55
Residential	0.68

Source: Navigant

4. **Disaggregate peak load forecast by customer class, customer segment, and end use (for C&I customers only):** Navigant applied the peak load factors derived in the previous step to the sales forecast developed in the first step. The team also used the 8,760 normalized load shapes to estimate the breakdown of peak load by end use for C&I customers (load reduction estimates associated with DR programs for these customers are typically available as a percentage of end-use load).
5. **Calibrate peak load forecast:** Navigant trued up the annual totals in the disaggregated derived peak demand forecast to 95% of ENO's BP18U peak forecast.[28]

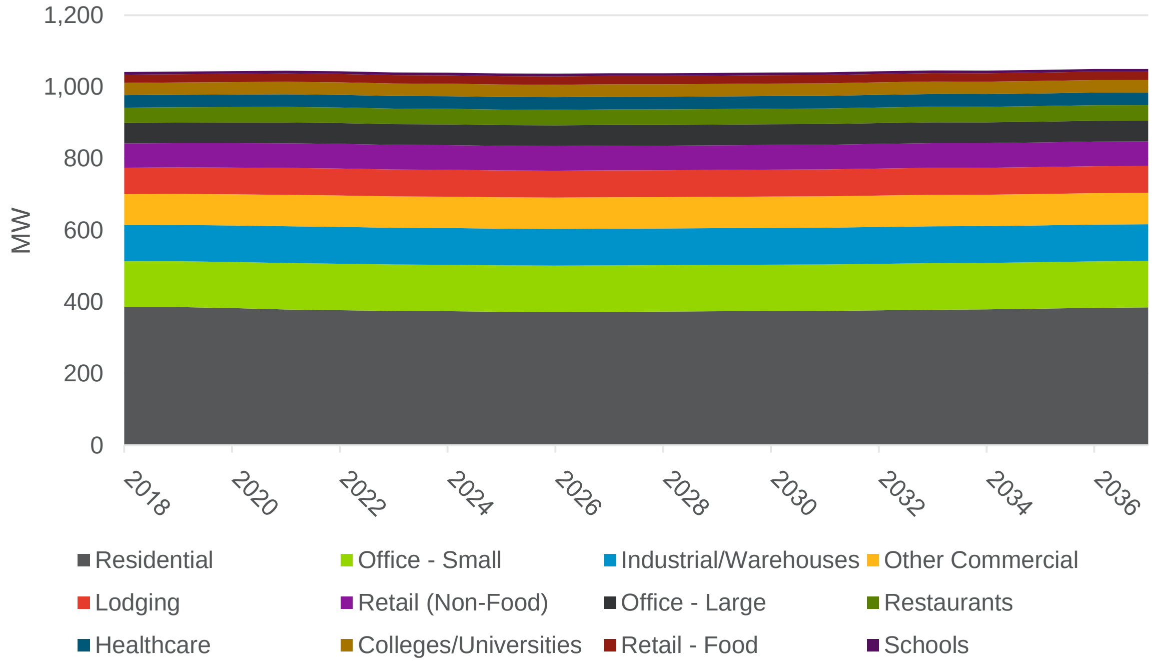
Figure 2-14. Peak Demand Forecast Comparisons



Source: Navigant

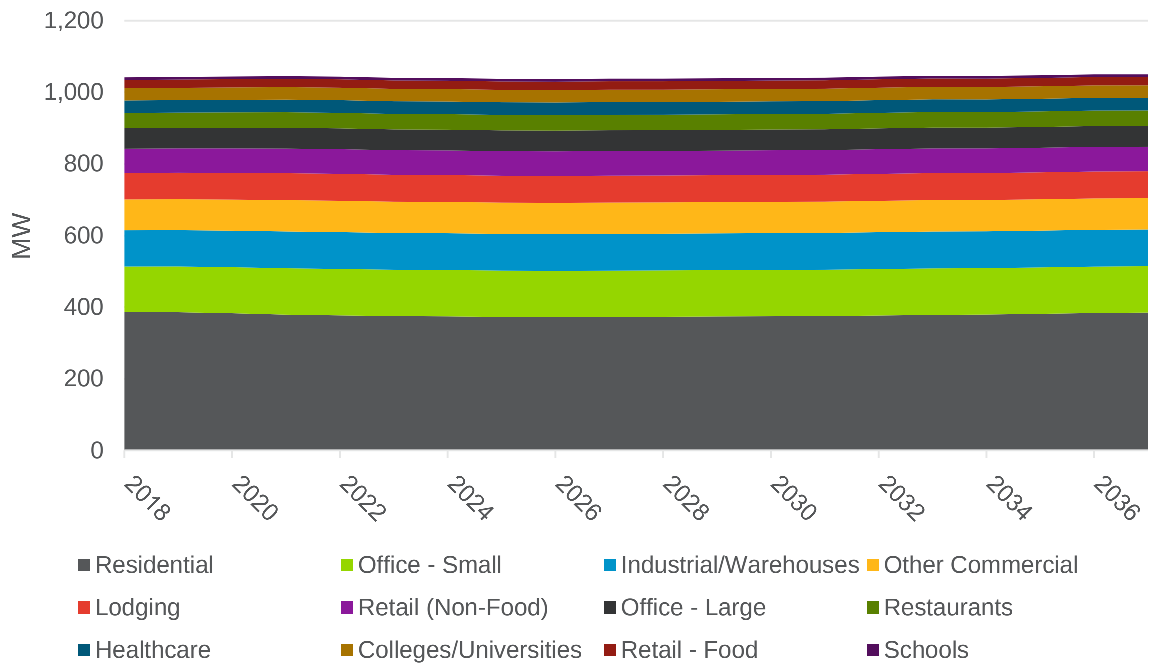
[28] This calibration target was chosen because utilities typically aim to reduce load within 5% of their annual system peak through DR events.

Figure 2-15. Peak Load Forecast by Customer Segment (MW)



Source: Navigant

Figure 2-16. Peak Load Forecast by End Use for C&I customers (MW)



Source: Navigant

2.2.4 Descriptions of DR Options

Once the baseline peak demand projections have been developed, the next step was to characterize the different types of DR options that could be used to curtail peak demand. Table 2-16 summarizes the DR options included in the analysis. Most of these DR options are representative of programs commonly deployed in the industry. These programs also align with Council's IRP rules, which state that DR programs should include those *"…enabled by the deployment of Advanced Meter Infrastructure, including both direct load control and DR pricing programs for both Residential and Commercial customer class".* The different types of DR options are described in detail below.

Table 2-16. Summary of DR Options

DR Option	Characteristics	Eligible Customer Classes	Targeted/ Controllable End Uses and/or Technologies
DLC ✓ Load control switch ✓ Thermostat	Control of water heating/cooling load using either a load control switch or PCT	Residential Small C&I	Cooling, water heating
C&I Curtailment ✓ Manual ✓ Auto-DR enabled	Firm capacity reduction commitment $/kW payment based on contracted capacity plus $/kWh payment based on energy reduction during an event	Large C&I	Various load types including HVAC, lighting, refrigeration, and industrial process loads
Dynamic Pricing[29] ✓ Without enabling technology ✓ With enabling technology	Voluntary opt-in dynamic pricing offer, such as CPP	All customer classes	All
BTMS ✓ Standalone battery storage	Power dispatch from battery storage systems installed by customers during peak load conditions	Small C&I Large C&I [30]	Batteries

[29] Navigant did not include time-of-use (TOU) rates in the DR options mix because this study only includes event-based dispatchable DR options. TOU rates lead to a permanent reduction in the baseline load and are not considered a DR option.

[30] Residential customers are not expected to significantly adopt standalone battery storage systems because ENO does not have any residential demand charge.

Source: Navigant

Each DR option was segmented into several DR sub-options, each of which was tied to a specific end use and/or control strategy. Table 2-17 summarizes this segmentation. The different types of DR options are described in detail below.

Table 2-17. Segmentation of DR Options into DR Sub-Options

DR Option	DR Sub-Option	Eligible Customer Classes
DLC	Switch-Water Heating	Residential Small C&I
	Thermostat-Heat Pump	Residential
	Thermostat-Central Air Conditioning	Residential
	Switch-Heat Pump	Residential
	Switch-Central Air Conditioning	Residential
	Thermostat-HVAC	Small C&I
	Switch-HVAC	Small C&I
C&I Curtailment	Curtailment-Manual HVAC Control	Large C&I
	Curtailment-Auto-DR HVAC Control	
	Curtailment-Standard Lighting Control	
	Curtailment-Advanced Lighting Control	
	Curtailment-Water Heating Control	
	Curtailment-Refrigeration Control	
	Curtailment-Compressed Air	
	Curtailment-Fans/Ventilation	
	Curtailment-Industrial Process	
	Curtailment-Pumps	
	Curtailment-Other	
Dynamic Pricing	Dynamic pricing with enabling tech	Residential Small C&I Large C&I
	Dynamic pricing without enabling tech	
BTMS	BTMS-Battery Storage	Small C&I Large C&I

2.2.4.1 Direct Load Control

DLC involves ENO directly controlling electric water heating and cooling load using a load control switch and cooling load using a PCT. There are two types of delivery models for DLC: DI and BYOT. In the DI approach, ENO would be responsible for installing the thermostat at the customer premises and bear part or all of the costs of thermostat purchase and installation and DR enablement. In the BYOT approach, the customer purchases and installs their own thermostat and is subsequently enrolled in the DR program. Therefore, the purchase and installation costs of the thermostat are borne by the customer, which would consequently lower ENO's costs. This study considers only a DI approach for switch-based control and a BYOT approach for thermostat-based control. Table 2-18 summarizes the DLC program characteristics considered in this study.

Table 2-18. DLC Program Characteristics

Item	Description
Program Name	Direct Load Control (DLC)
Program Description	This program controls electric water heating and cooling (including central air conditioning and heat pumps) loads for residential and small/medium business customers using either a DLC device (switch) or a PCT, where and when applicable. Water heating and cooling loads are cycled/turned off during the event period using a load control switch. For thermostat-based cooling load control, unit impact estimates are based on a 2°F-3°F temperature setback strategy using a smart thermostat.
Purpose/Trigger	DLC events will be called primarily to meet capacity shortfalls during summer, triggered primarily by a high day-ahead temperature forecast.
Key Program Design Parameters	• Events will be called during peak demand periods in summer. • Participants will not have any advance notification for DR events. However, they can choose to opt out of an event at any time during the event. • Average event duration is 4 hours. No more than one event is called in a day. Calling events for more than 2 consecutive days may lead to customer dissatisfaction and disenrollment.
Participation Eligibility	Residential and small C&I customers with HVAC and electric water heaters.

Item	Description
Dependent Technology and Metering	**Technology:** Switches control water heating, central air conditioning, or heat pumps. PCT temperature adjustment controls central air conditioning or heat pumps. **Metering:** Standard meter (no interval meter required). The program can use data loggers on a sample of participants to record interval usage for measurement and verification.

Source: Navigant

2.2.4.2 C&I Curtailment

The C&I curtailment program as represented in this study is the most commonly deployed program for large C&I customers in the industry. It involves a contract for a firm capacity reduction commitment from large C&I customers. Under this option, utilities typically enter into a turnkey implementation contract with a third-party DR service provider (commonly referred to as an aggregator) to deliver a certain fixed amount of megawatt (MW) load reduction.[31] Enrolled participants agree to curtail their demand to a pre-specified level. In return, they receive a fixed incentive payment in the form of capacity credits or reservation payments (expressed as $/kW-year). Customers are paid to be on-call even though actual load curtailments may not occur. The capacity payment level could vary with the load commitment level. In addition to the fixed capacity payment, participants typically receive a payment for energy reduction ($/kWh amount). Because it is a contractual arrangement for a specific level of load reduction, enrolled loads represent a firm resource. Once enrolled, participation during events is mandatory and there are penalty clauses. A specific site could curtail a variety of end-use loads depending on the types of business processes, either manually or automatically (Auto-DR-enabled). Auto-DR enablement can help provide greater reliability and higher predictability in load reductions. Table 2-19 describes the C&I curtailment program characteristics considered in this study.

[31] With the aggregator model, the service provider can aggregate multiple small customers to deliver capacity reduction.

Table 2-19. C&I Curtailment Program Characteristics

Item	Description
Program Name	C&I Curtailment
Program Description	Typically, this type of program is administered by a third-party DR service provider. This is usually a turnkey contract, in which the vendor is responsible for a fixed amount of load reduction over the contract period. The common approach is for the utility to pay a predetermined capacity payment ($/kW-yr.) based either on the nominated load reduction (if no event is called) or actual load reduction (if an event is called) to the third party administering the program. In addition, the utility would pay the vendor for actual energy reduced during an event based on a specified $/kWh level in the contract. Participating sites enrolled in the program curtail a variety of end uses (e.g., HVAC, water heating, lighting, refrigeration, process loads), depending on the business type. Load curtailment can be manual and/or Auto-DR[32]-enabled. Participants may also shift load to backup generators during the DR event period.
Purpose/Trigger	DR events are likely to be called to help meet summer capacity shortfalls.
Key Program Design Parameters	• Events will be called during summer peak demand periods. • Event notification is typically day-ahead and/or 1-2 hours ahead. • Average event duration is 4 hours. No more than one event is called in a day. Calling events for more than 2 consecutive days may lead to customer dissatisfaction and disenrollment. • Annual maximum event hours set at 80-100 hours.
Participation Eligibility	All Large C&I customers.

[32] Under Auto-DR, customer loads will be curtailed automatically via a building EMS in response to a signal from ENO. Auto-DR is a platform to automatically activate a preprogrammed load reduction strategy in response to a signal from a DR automation server (DRAS). Load is curtailed by the customer’s building management after being triggered by a signal sent from ENO’s control room to the vendor’s operations center and on to the customer’s facility. The customer always retains the ability to override the curtailment sequence in the event a site cannot participate in a specific DR dispatch. Auto-DR ensures higher reliability of response than manual curtailment.

Item	Description
Dependent Technology and Metering	**Dependent technology:** Manual DR requires a communication channel between the vendor and the customers, which might include text, email, or telephone. Auto-DR requires a building automation system, a load control device, or breakers on specific circuits. All control mechanisms must be able to receive an electronic signal from the program administrator and initiate the curtailment procedure without manual intervention. Auto-DR dispatches are called using an open communication protocol known as Open-ADR. For Auto-DR customers, the vendor installs an Open-ADR-compliant gateway at the participating site, which is then able to notify the EMS or other control systems at the facility to run their preprogramed curtailment scripts. The vendor monitors energy reduction in real time and provides visual access to this demand data to the participant through a web-based software platform. This platform may be integrated for overall energy optimization, which may help realize energy efficiency benefits along with DR benefits. **Metering:** Interval meters.

Source: Navigant

2.2.4.3 Dynamic Pricing

Dynamic pricing refers to a CPP rate offer across all customer classes. This is the most commonly deployed dynamic rate in the industry. Customers who opt to participate in the program are placed on a CPP rate with a significantly higher rate during certain critical peak periods in the year and a lower off-peak rate than the standard offer rate. Customers enrolled in the CPP rate pay the higher critical peak rate for electricity consumption during the critical peak periods, which incentivizes them to reduce consumption during those periods. Customers enrolled in the CPP rate receive either day-of or day-ahead notification of the critical peak period.

The unit impacts or per-customer load reductions depend on the critical peak to off-peak price ratio. This study assumes a 6:1 critical peak to off-peak price ratio. Industry experience suggests that enabling technology such as smart thermostats and Auto-DR can substantially enhance load reductions when customers on CPP rates are equipped with these technologies. CPP can be offered either as an opt-in rate or as a default rate with opt out. This study assumes an opt-in offer type for CPP.

The CPP offer requires AMI meters for settlement purposes. Hence, the rate offer is tied to AMI deployment. Per discussions with ENO, the utility's current plan is to fully deploy AMI by 2020. Table 2-20 describes the dynamic pricing program characteristics considered in this study.

Table 2-20. Dynamic Pricing Program Characteristics

Item	Description
Program Name	Dynamic Pricing

Program Description	Opt-in CPP offer to all customers with a 6:1 critical peak to off-peak price ratio.
Purpose/Trigger	Events are called to help meet summer capacity shortfalls.
Key Program Design Parameters	• Events will be called during summer peak demand periods. • Event notification is typically day-ahead and/or 1-2 hours ahead. • Average event duration assumed to be 4 hours. No more than one event is called in a day. Calling events for more than 2 consecutive days may lead to customer dissatisfaction and disenrollment. • Annual maximum event hours set at 80-100 hours.
Participation Eligibility	All customers.
Dependent Technology and Metering	All customers need smart meters for settlement purposes.

Source: Navigant

2.2.4.4 Behind-the-Meter Storage

BTMS refers to customers using their battery systems to discharge power to the grid during peak load conditions. Backup generators were not considered for this program in this study because ENO does not have data on the number or capacity of non-grid interconnected backup generators at customer sites in its service area. Navigant assumed the market adoption and size for battery storage systems using internal analysis. Therefore, BTMS only considers power dispatch from battery storage systems in this study. It is expected that customers would either charge their batteries during off-peak hours with grid power or by using solar PV. Table 2-21 describes the BTMS program characteristics considered in this study.

Table 2-21. BTMS Program Characteristics

Item	Description
Program Name	Behind-the-Meter Storage (BTMS)
Program Description	Customers install battery storage systems that are interconnected with the grid. When there are peak load conditions, the utility sends signals to the battery system, which would trigger power dispatch to the grid.
Purpose/Trigger	Events are called to help meet summer capacity shortfalls.
Key Program Design Parameters	• Events will be called during summer peak demand periods. • Average event duration assumed to be 4 hours. • Event notification is typically day-ahead and/or 1-2 hours ahead. • Annual maximum event hours set at 80-100 hours.
Participation Eligibility	Large C&I customers such as manufacturing or big box retail with battery storage systems. Grid dispatch from batteries could also include new technologies targeted at smaller commercial customers or even residential.

Dependent Technology and Metering	All customers need PV-tied or standalone batteries with grid interconnection.

Source: Navigant

2.2.5 Key Assumptions for DR Potential and Cost Estimation

There are two key variables that feed the DR potential calculation in this study:

- Customer participation rates
- Amount of load reduction that could be realized from different types of control mechanisms, referred to as unit impacts

Secondary variables that feed the DR potential calculation include participation opt-out rates, technology market penetration, and enrollment attrition rates.

Navigant calculated both the technical and achievable potential associated with implementing DR programs for this study. Technical potential refers to load reduction that results from 100% customer participation. This is a theoretical maximum. The team calculated technical potential by multiplying the eligible load/customers by the unit impact for each DR sub-option. The technical potential calculation does not account for participation overlaps between the DR sub-options. Therefore, technical potential across the various sub-options is not additive and should not be added together to obtain a total technical potential. In other words, the technical potential estimates for each DR sub-option should be considered independently. The technical potential calculation is summarized through Equation 2-6.

Equation 2-6. DR Technical Potential

$$\begin{aligned} &Technical\ Potential_{DR\ Sub\ Option,End\ Use,Year} \\ &\quad = Eligible\ Load_{DR\ Sub\ Option,Segment,End\ Use,Year} \\ &\quad * Unit\ Impact_{DR\ Sub\ Option,Segment,Year} \end{aligned}$$

Navigant then calculated the achievable potential by multiplying achievable participation assumptions (subject to the program participation hierarchy discussed below) by the technical potential estimates. Market potential also accounts for customers opting out during DR events. The achievable potential calculation is summarized through Equation 2-7.

Equation 2-7. DR Achievable Potential

$$\begin{aligned} &Achievable\ Potential \\ &\quad = Technical\ Potential_{DR\ Sub\ Option,Segment,End\ Use,Year} \\ &\quad * Achievable\ Participation\ Rate_{DR\ Sub\ Option,Segment,Year} \\ &\quad * (1 - Event\ Opt\ Out\ Rate)_{DR\ Sub\ Option,Year} \end{aligned}$$

In addition to the potential estimates, the team developed annual and levelized costs by DR option and sub-option. Navigant subsequently assessed the cost-effectiveness of each sub-option and DR option in aggregate. Developing annual and levelized costs involves itemizing various cost components such as program development costs, equipment costs, participant marketing and recruitment costs, annual program administration costs, product lifetimes, and a discount rate. Table 2-22 summarizes the key variables Navigant used to calculate DR potential and its associated costs in this analysis. These key variables are discussed further in the following subsections.

Table 2-22. Key Variables for DR Potential and Cost Estimates

Key Variables	Description
Participation Rates	Percentage of eligible customers by program type and customer class.
Unit Impacts	• kW reduction per device for DLC • Percentage of enrolled load by end use for C&I curtailment • Percentage of total facility load for dynamic pricing • Percentage of battery load for BTMS
Costs	• One-time fixed costs related to program development • One-time variable costs for customer recruitment, program marketing, and equipment installation and enablement • Recurring fixed and variable costs such as annual program admin. costs, customer incentives, O&M, etc.
Global Parameters	Program lifetime, discount rate, inflation rate, line losses, avoided costs

Source: Navigant

2.2.5.1 Participation Assumptions and Hierarchy

The participation assumptions differ by customer class and segment. Based on standard industry practice, Navigant assumed a 5-year S-shaped ramp for the DR options. For all DR options other than dynamic pricing, program participation is assumed to begin in 2018. As previously mentioned, dynamic pricing is tied to AMI deployment and starts in 2020.

The participation assumptions are also tied to the market penetration of DR-enabling technologies such as EMSs. For example, only C&I customers with EMS are eligible for Auto-DR HVAC control. All other customers are eligible for manual HVAC control.

Navigant also accounted for participation overlaps among the different DR programs in estimating potential. Table 2-23 presents the participation hierarchy considered in this study, whereby achievable participation estimates are applied to eligible customers only. The participation hierarchy presented here is a well-tested approach, initially established in the *National Assessment of DR Potential Study* conducted by the Federal Energy Regulatory Commission (FERC)[33] and adopted in other DR potential studies. The participation hierarchy helps avoid double counting of potential through common load participation across multiple programs and is necessary to arrive at an aggregate potential estimate for the entire portfolio of DR programs.

Table 2-23. Program Hierarchy to Account for Participation Overlaps

Customer Class	DR Options	Eligible Customers
Residential	DLC - Thermostat	Customers with central air conditioning or heat pumps controlled by thermostats
	DLC - Switch	Customers with central air conditioning or heat pumps that are not enrolled in DLC – Thermostat; customers with water heating load
	Dynamic Pricing	Customers not enrolled in DLC
Small C&I	BTMS	Customers with batteries
	DLC - Thermostat	Customers with HVAC controlled by thermostats
	DLC - Switch	Customers with HVAC that are not enrolled in DLC – Thermostat; customers with water heating load
	Dynamic Pricing	Customers not enrolled in DLC
Large C&I	BTMS	Customers with batteries
	C&I Curtailment	Customers with batteries not enrolled in BTMS; customers without batteries
	Dynamic Pricing	Customers with batteries not enrolled in BTMS or C&I curtailment; customers without batteries not enrolled in C&I curtailment

Source: Navigant

2.2.5.2 Unit Impact Assumptions

The unit impacts specify the amount of load that could be reduced during a DR event by customers enrolled in a DR program. Unit impacts differ by sub-option because they are tied to specific end uses and control strategies. For example, the load reductions associated with manual HVAC control and Auto-DR HVAC control are different and are specified accordingly. Unit impacts can be specified either directly as kW reduction per

[33] https://www.ferc.gov/legal/staff-reports/06-09-demand-response.pdfelow

participant or as percentage of enrolled load: [34]

- DLC sub-options use kW reduction per participant for residential and percentage of the end-use load for small C&I
- C&I curtailment sub-options use percentage of the end-use load
- Dynamic pricing uses a percentage of the total facility load
- BTMS uses a percentage of the battery load

This study leveraged ENO's DLC pilot program accomplishments and the latest available secondary sources of information for other programs for the unit impact assumptions.

2.2.5.3 Cost Assumptions

Navigant developed itemized cost assumptions for each DR option to calculate annual program costs and levelized costs for each option. These assumptions also feed the cost-effectiveness calculations in this study.

The cost assumptions fall into the following broad categories:

- **One-time fixed costs**, specified in terms of $/DR option, including the program startup costs—for example, the software and IT infrastructure-related costs and associated labor time/costs (in terms of full time equivalents (FTEs)) incurred to set up the program.
- **One-time variable costs**, which include marketing/recruitment costs for new participants, metering costs, and all other costs associated with control and communications technologies that enable load reduction at participating sites. The enabling technology cost is specified either in terms of $/new participant on a per-site basis or as $/kW of enabled load reduction on a participating load basis.
- **Annual fixed costs,** specified in terms of $/yr, which primarily includes FTE costs for annual program administration.
- **Annual variable costs,** which primarily includes customer incentives, specified either as a fixed monthly/annual incentive amount per participant ($/participant) or in terms of load and/or energy reduction ($/kW and $/kWh reduction) depending on the program type. It also includes additional O&M costs that may be associated with servicing technology installed at customer premises.
- **Program delivery costs,** which is a fixed contracted payment for third-party delivery of DR programs and is specified as $/kW-yr.

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[34] The unit impact values assume a 4-hour event duration, and the values represent the average load reduction over the 4-hour event duration.

In addition to these itemized program costs, the following variables feed the cost-effectiveness calculations in this study.

- **Nominal discount rate** of 7.72% used for net present value (NPV) calculations.
- **Inflation rate** of 2% used to inflate the costs over the forecast period (2018-2037).
- **Transmission and distribution (T&D) line loss** of about 2% for industrial/warehouse customers and 5% for all other customers; line loss is used to bring the potential at the customer meter up to the generator for the cost-effectiveness assessment.
- **Program life**, assumed to be 10 years for DLC, C&I curtailment, and BTMS and 20 years for dynamic pricing.
- **Derating factor,** used to derate the benefits from DR to bring it to par with generation. The derating factor is used to derate the benefits from DR to account for program design constraints, such as limitations on how often events can be called, annual maximum hours for which events can be called, window of hours during the day during which events can be called, and sometimes even the number of days in a row that events may be called. The derating factor lowers the benefits from DR so that a megawatt from DR is not considered the same as a megawatt from a generator, which does not have similar availability constraints and could be available round the clock.[35]

To assess the benefits associated with DR programs, Navigant used the avoided generation capacity projections provided by ENO. Navigant calculated benefit-cost ratios for the TRC, program administrator cost (PAC), ratepayer impact measure (RIM), and participant cost tests (PCT) for this study, consistent with the Council's IRP rules.

[35] "Valuing Demand Response: International Best Practices, Case Studies, and Applications." Prepared by the Brattle Group. January 2015. Page 10 of this report explains why the derating factor is important, though its inclusion varies across utilities and jurisdictions: http://files.brattle.com/files/5766_valuing_demand_response_-_international_best_practices__case_studies__and_applications.pdf

3. Energy Efficiency Achievable Potential Forecast

This section provides the results of the energy efficiency achievable potential analysis.

3.1 Model Calibration

Calibrating a predictive model imposes unique challenges, as future data is not available to compare against model predictions. While engineering models, for example, can often be calibrated to a high degree of accuracy because simulated performance can be compared directly with performance of actual hardware, predictive models do not have this luxury. Therefore, DSM models must rely on other techniques to provide both the developer and the recipient with a level of comfort that simulated results are reasonable. For this project, Navigant took several steps to ensure that the forecast model results are reasonable and consider historic adoption:

- Comparing forecast values by sector and end use, typically against historic achieved savings (e.g., program savings from 2016) and planned savings for Energy Smart PY8. Although some studies indicate that DSM potential models are calibrated to ensure first-year simulated savings precisely equal prior-year reported savings, Navigant notes that forcing such precise agreement has the potential to introduce errors into the modeling process by effectively masking the explanation for differences—particularly when the measures included may vary significantly. Additionally, there may be sound reasons for first-year simulated savings to differ from prior-year reported savings (e.g., a program is rapidly ramping up or savings estimates have changed). Thus, while the team endeavored to achieve agreement to a degree believed to be reasonable between past results and forecast first-year results, the team's approach did not force the model to do so, providing what the team believes is a degree of confidence that the model is internally consistent.
- Identifying and ensuring an explanation existed for significant discrepancies between forecast savings and prior-year savings, recognizing that some ramp up is expected, especially for new measures or archetype programs.
- Calculating $/first-year kWh costs and comparing them with past results.
- Calculating the split (percentage) in spending between incentives and variable administrative costs predicted by the model to historic values.
- Calculating total spending and comparing the resulting values to historical spending.

3.1.1 Achievable Potential Case Studies and Incentive Levels

A key component of any potential study is determining the appropriate level at which to set measure incentives for each case.

For ENO, the incentive-level strategy characterized is the ***percent of incremental cost approach.*** This approach calculates measure-level incentives based on a specified percentage of incremental measure costs. For example, if the specified incentive percentage was 50% and a measure's incremental cost was $100, then the calculated incentive for that measure would be $50.

3.1.2 Achievable Cases Analysis

Navigant ran multiple cases for achievable potential. These approaches are described briefly below.

3.1.2.1 2018 Savings Target Cases

Navigant reviewed historic ENO data from PY4 through PY6 and found an average annual savings of approximately 20 GWh. However, ENO's target in Energy Smart Program Year 8 (2018), which coincides with the first year of the potential analysis, is 46 GWh. The 2018 target is significantly higher than the historic average given the CNO's direction to implement programs that would seek to achieve the Council's goal of 0.2% annual and 2% overall energy savings. Therefore, Navigant targeted a savings value of 46 GWh for the base case and a $/kWh value of 0.27, which represents both the planned and historic average of portfolio cost. The base case used an incentive level of 50% of incremental cost to align with ENO's assessed value as currently implemented.

Navigant analyzed two additional cases that used the same inputs as the base case except for incentive values at 25% and 75% of incremental cost, respectively.

3.1.2.2 Council's 2% DSM Goal Case

In this case, Navigant started with incentives at 50% of the incremental cost in 2018 and then ramped up to 100% in 2024. When using the TRC test as the measure screen, incentive levels do not affect cost-effectiveness because incentives are treated as a pass through in the TRC test. Thus, setting incentives at 100% of incremental cost results in the highest forecast savings levels (effectively a zero-payback time) but also comes with a high level of investment forecasts.

Navigant also changed the adoption parameters for the 2% case, including a ramp up of the marketing factor through 2021. Additionally, Navigant ramped down the TRC ratio threshold from a value of 1.0 in 2018 to 0.87 in 2022 and remaining years. This change in TRC ratio allowed more measures to pass through to achievable potential modeling.

3.2 Energy Efficiency Achievable Potential Results

Values shown for achievable potential are termed *annual incremental potential*— they represent the incremental new potential available in each year. The total cumulative potential over the time period is the sum of each year's annual incremental achievable potential. Economic potential can be thought of as a reservoir of cost-effective potential[36] from which programs can draw over time. Achievable potential represents the draining of that reservoir, the rate of which is governed by several factors including the lifetime of measures (for ROB technologies), market effectiveness, incentive levels, and customer willingness to adopt, among others. If the cumulative achievable potential ultimately reaches the economic potential, it would signify that all economic potential in the reservoir had been drawn down or harvested. However, achievable potential levels rarely reach the full economic potential level due to a variety of market and customer constraints that inhibit full economic adoption.[37]

All tables and figures (except for Section 3.2.1) have the potential savings for the base case only.

3.2.1 Case-Level Results

As explained in Section 2.1.4.3, the achievable potential analysis was modeled with four different case studies. The case studies are based on the incremental measure cost:

- **Base case:** Reflects current program spend targets with incentives at 50% of incremental measure cost
- **Low case:** Uses the same inputs as the base case except incentives are at 25% of incremental measure cost
- **High case:** Uses the same inputs as the base case except incentives are at 75% of incremental measure cost
- **2% case:** Achieve 2% for at least 1 year during the forecast period with a 0.2% ramp year over year starting in the first modeled year (2018)

Table 3-1 shows the incremental energy and demand savings per year for each case. Figure 3-1 and Figure 3-2 show the cumulative annual energy and demand savings for each case.

[36] Cost-effectiveness threshold is a TRC = 1.0. Because the New Orleans TRM does not include gas or water savings in the benefit calculations, they were not calculated in this study. However, there were measures that were passed through with a TRC ratio <1.0 where it was reasonable to assume that the inclusion of gas or water savings would have enabled the measure to reach the 1.0 TRC threshold. These measures include: commercial clothes washer, commercial low flow showerheads, high efficiency windows, home energy report, and residential thermostatic shower valve.

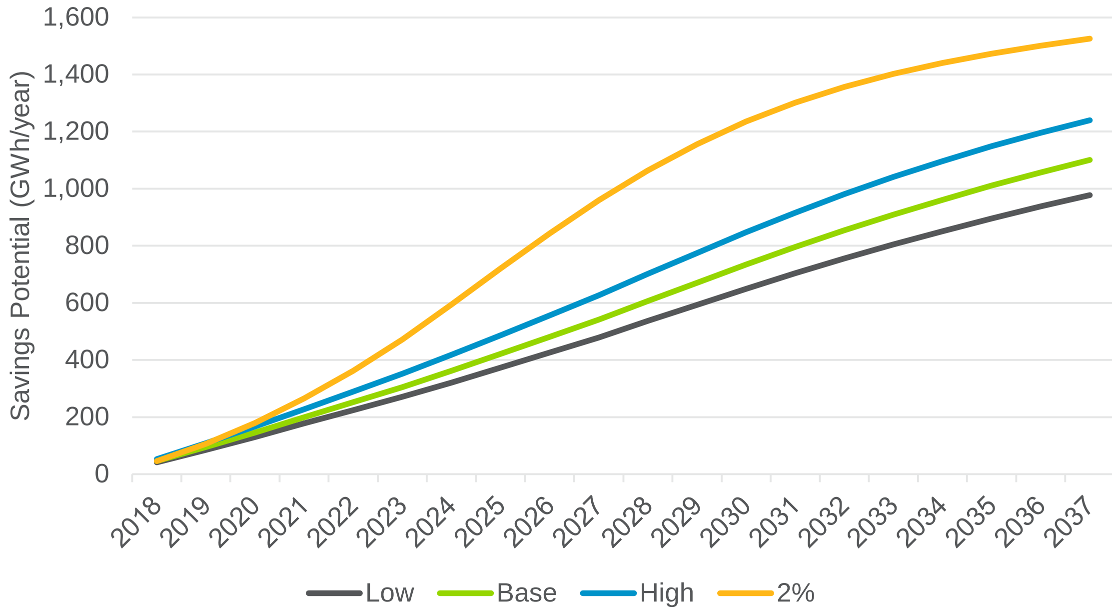
[37] Constraints on achievable potential that inhibit realization of the full economic potential include the rate at which homes and businesses will adopt efficient technologies, as well as the word of mouth and marketing effectiveness for the technology. If a technology already has high saturation at the beginning of the study, it may theoretically be possible to fully saturate the market and achieve 100% of the economic potential for that technology.

Table 3-1. Annual Incremental Achievable Energy Efficiency Savings by Case

Year	Electric Energy (GWh/Year)				Peak Demand (MW)			
	Base	Low	High	2%	Base	Low	High	2%
2018	46	41	52	46	11	10	12	11
2019	49	44	56	60	11	10	13	13
2020	51	45	58	74	11	10	13	16
2021	53	47	61	86	12	10	13	18
2022	53	46	61	97	11	10	13	20
2023	53	47	62	110	11	9	13	22
2024	57	50	66	123	11	10	13	26
2025	59	52	69	127	12	10	14	28
2026	60	53	70	122	12	10	14	27
2027	61	54	70	116	12	10	14	26
2028	65	58	75	104	12	10	15	24
2029	64	56	73	92	12	10	14	22
2030	64	57	73	79	12	10	15	19
2031	61	54	69	67	12	10	14	17
2032	58	52	65	55	11	9	13	14
2033	55	49	60	46	11	9	12	12
2034	52	46	56	38	10	9	11	10
2035	50	45	52	32	10	8	11	9
2036	47	42	48	29	9	8	10	8
2037	43	39	43	25	9	8	9	7
Total	**1,100**	**977**	**1,240**	**1,526**	**220**	**190**	**257**	**346**

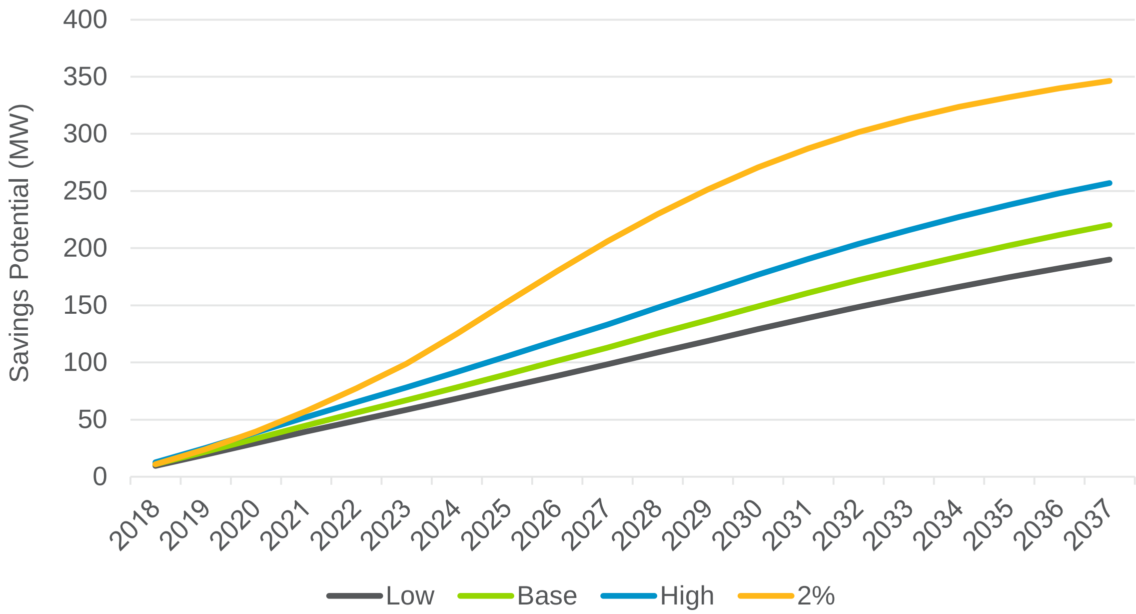
Source: Navigant analysis

Figure 3-1. Electric Energy Cumulative Achievable Savings Potential by Case (GWh/year)



Source: Navigant analysis

Figure 3-2. Peak Demand Cumulative Achievable Savings Potential by Case (MW)



Source: Navigant analysis

Table 3-2 shows the incremental electric energy achievable savings as a percentage of ENO's total sales for each case. For the 2% case, 2% of sales savings is achieved in 2024-2026. In later years, the 2% case falls below the base case since most of the measures have been adopted, depleting the available potential in the future years. This study only includes known, market-ready, quantifiable measures without introducing new measures in later years. However, over the lifetime of energy efficiency programs, new technologies and innovative program interventions could result in additional cost-effective energy savings. Therefore, the need to periodically revisit and reanalyze the potential forecast is necessary.

Table 3-2. Incremental Electric Energy Achievable Savings Potential as a Percentage of Sales, by Case (%, GWh)

Year	Base	Low	High	2%
2018	0.8%	0.7%	0.9%	0.8%
2019	0.8%	0.7%	0.9%	1.0%
2020	0.8%	0.7%	0.9%	1.2%
2021	0.9%	0.8%	1.0%	1.4%
2022	0.9%	0.8%	1.0%	1.6%
2023	0.9%	0.8%	1.0%	1.8%
2024	0.9%	0.8%	1.1%	2.0%
2025	1.0%	0.8%	1.1%	2.0%
2026	1.0%	0.8%	1.1%	2.0%
2027	1.0%	0.9%	1.1%	1.9%
2028	1.0%	0.9%	1.2%	1.6%
2029	1.0%	0.9%	1.1%	1.4%
2030	1.0%	0.9%	1.2%	1.2%
2031	1.0%	0.8%	1.1%	1.0%
2032	0.9%	0.8%	1.0%	0.8%
2033	0.8%	0.8%	0.9%	0.7%
2034	0.8%	0.7%	0.8%	0.5%
2035	0.7%	0.7%	0.8%	0.4%
2036	0.7%	0.6%	0.7%	0.4%
2037	0.6%	0.6%	0.6%	0.3%
Total	**17.3%**	**15.3%**	**19.5%**	**24.0%**

Source: Navigant analysis

The total, administrative and incentive costs for each case are provided in Table 3-3 for each year of the study period. It is important to note the differences in these cases as compared to the savings achieved. Administrative spending is relatively consistent between the cases, while incentive spending varies significantly between the cases, with higher spending correlated to higher savings.

Table 3-3. Spending Breakdown for Achievable Potential ($ millions/year)[38]

	Total				Incentives				Admin			
	Base	Low	High	2%	Base	Low	High	2%	Base	Low	High	2%
2018	$13	$8	$20	$13	$6	$2	$13	$6	$7	$6	$8	$7
2019	$14	$9	$22	$17	$7	$3	$13	$8	$7	$6	$8	$9
2020	$14	$9	$23	$24	$7	$3	$14	$13	$8	$7	$9	$11
2021	$15	$9	$24	$31	$7	$3	$15	$18	$8	$7	$9	$13
2022	$15	$10	$25	$43	$7	$3	$16	$28	$8	$7	$10	$15
2023	$16	$10	$26	$52	$8	$3	$16	$34	$8	$7	$10	$17
2024	$17	$11	$28	$75	$8	$3	$18	$55	$9	$7	$11	$20
2025	$18	$11	$30	$81	$9	$3	$19	$60	$9	$8	$11	$21
2026	$19	$12	$31	$81	$9	$3	$19	$60	$10	$8	$12	$21
2027	$20	$12	$32	$79	$10	$4	$20	$59	$10	$9	$12	$20
2028	$22	$13	$37	$74	$11	$4	$24	$56	$11	$9	$13	$19
2029	$23	$14	$37	$69	$12	$4	$25	$52	$11	$9	$13	$17
2030	$24	$14	$39	$62	$12	$5	$26	$47	$11	$10	$13	$15
2031	$24	$14	$38	$54	$13	$5	$25	$42	$11	$10	$13	$13
2032	$24	$14	$37	$47	$13	$5	$25	$36	$11	$9	$12	$11
2033	$23	$14	$36	$40	$13	$5	$24	$31	$11	$9	$12	$9
2034	$23	$14	$35	$35	$13	$5	$23	$27	$10	$9	$11	$8
2035	$23	$14	$34	$30	$13	$5	$23	$24	$10	$9	$11	$7
2036	$22	$13	$32	$28	$13	$5	$22	$22	$10	$9	$10	$6
2037	$21	$13	$30	$25	$12	$5	$20	$20	$9	$8	$9	$5
Total	**$390**	**$238**	**$617**	**$960**	**$202**	**$75**	**$400**	**$698**	**$188**	**$162**	**$217**	**$262**

Source: Navigant analysis

The TRC test is a benefit-cost metric that measures the net benefits of energy efficiency measures from the combined stakeholder viewpoint of the program administrator (utility) and program participants. The TRC benefit-cost ratio is calculated in the model using Equation 3-1.

Equation 3-1. Benefit-Cost Ratio for the TRC Test

$$TRC = \frac{PV(Avoided\ Costs + Externalties)}{PV(Technology\ Cost + Admin\ Costs)}$$

[38] The values in this table are rounded to the nearest million and may result in rounding errors.

Where:

- *PV( )* is the present value calculation that discounts cost streams over time.
- *Avoided Costs* are the monetary benefits that result from electric energy and capacity savings—e.g., avoided costs of infrastructure investments and avoided fuel (commodity costs) due to electric energy conserved by efficient measures.
- *Externalities* are the monetary or quantifiable benefits associated to greenhouse gas (GHG) gas reductions (i.e., the market cost of carbon).
- *Technology Cost* is the incremental equipment cost to the customer to purchase and install a measure.
- *Admin* are the costs incurred by the program administrator to deliver services (excluding incentive costs paid to participants).

Navigant calculated TRC ratios for each measure based on the present value of benefits and costs (as defined by the numerator and denominator, respectively) over each measure's life. Avoided costs, discount rates, and other key data inputs used in the TRC calculation are presented in Appendix B. Effects of free ridership are not present in the results from this study, so the team did not apply a NTG factor. Providing gross savings results will allow the utility to easily apply updated NTG assumptions in the future and allow for variations in NTG assumptions by reviewers.

The TRC ratios for these cases are provided by year in Table 3-4. Even with the large increases in incentives for the high and 2% cases, all cases are cost-effective. Increasing incentives does not necessarily translate to a lower TRC because incentives are considered a transfer cost. However, higher incentives may make higher cost measures more attractive to end users and spur their adoption. Thus, where incentives increase as a percentage of measure cost, TRC scores can be lower even though incentives are not part of the TRC calculation.

Table 3-4. Portfolio TRC Benefit-Cost Ratios for Achievable Potential (Ratio)

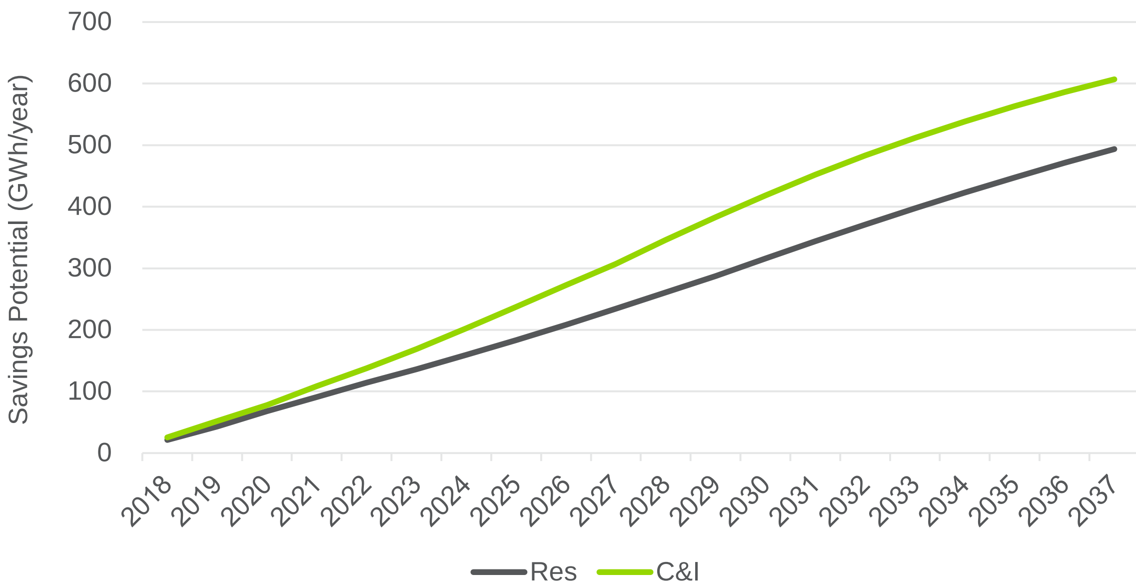
Year	Base	Low	High	2%
2018	1.5	1.6	1.4	1.5
2019	1.5	1.7	1.4	1.5
2020	1.6	1.7	1.5	1.4
2021	1.7	1.8	1.5	1.4
2022	1.8	1.9	1.6	1.4
2023	1.9	2.1	1.7	1.3
2024	1.8	2.0	1.7	1.3
2025	1.8	2.0	1.7	1.3
2026	1.9	2.1	1.7	1.3
2027	1.9	2.1	1.7	1.4
2028	1.7	1.9	1.6	1.4
2029	1.8	1.9	1.6	1.4
2030	1.7	1.9	1.6	1.4
2031	1.7	1.9	1.6	1.4
2032	1.7	1.9	1.6	1.5
2033	1.8	1.9	1.6	1.5
2034	1.8	1.9	1.6	1.5
2035	1.8	1.9	1.6	1.6
2036	1.8	1.9	1.7	1.6
2037	1.8	2.0	1.7	1.7
2018-2037	**1.7**	**1.9**	**1.6**	**1.4**

Source: Navigant analysis

3.2.2 Achievable Potential Results by Sector

Figure 3-3 shows the cumulative electric achievable savings potential for all analysis years by sector for the base case.

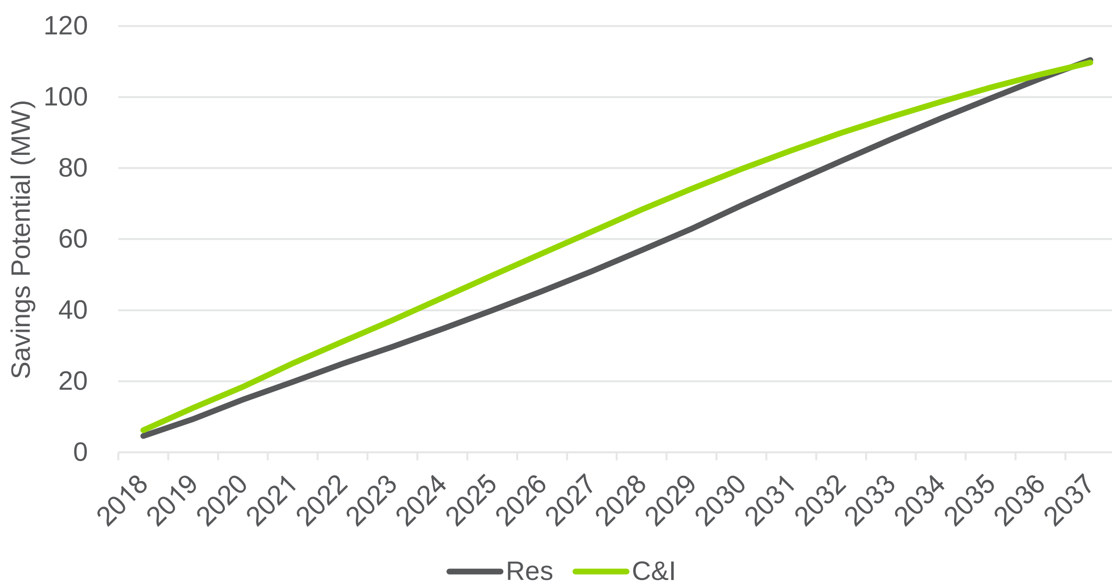
Figure 3-3. Electric Energy Cumulative Base Case Achievable Savings Potential by Sector (GWh/year)



Source: Navigant analysis

Figure 3-4 shows the cumulative demand achievable savings potential for all analysis years by sector for the base case.

Figure 3-4. Electric Demand Cumulative Base Case Achievable Savings by Sector (MW)



Source: Navigant analysis

Table 3-5 shows the cumulative electric energy achievable savings as a percentage of ENO's total sales for each sector. The residential sector accounts for a larger percentage than the C&I sector.

Table 3-5. Cumulative Electric Energy Base Case Achievable Savings Potential by Sector as a Percentage of Sales (%, GWh)

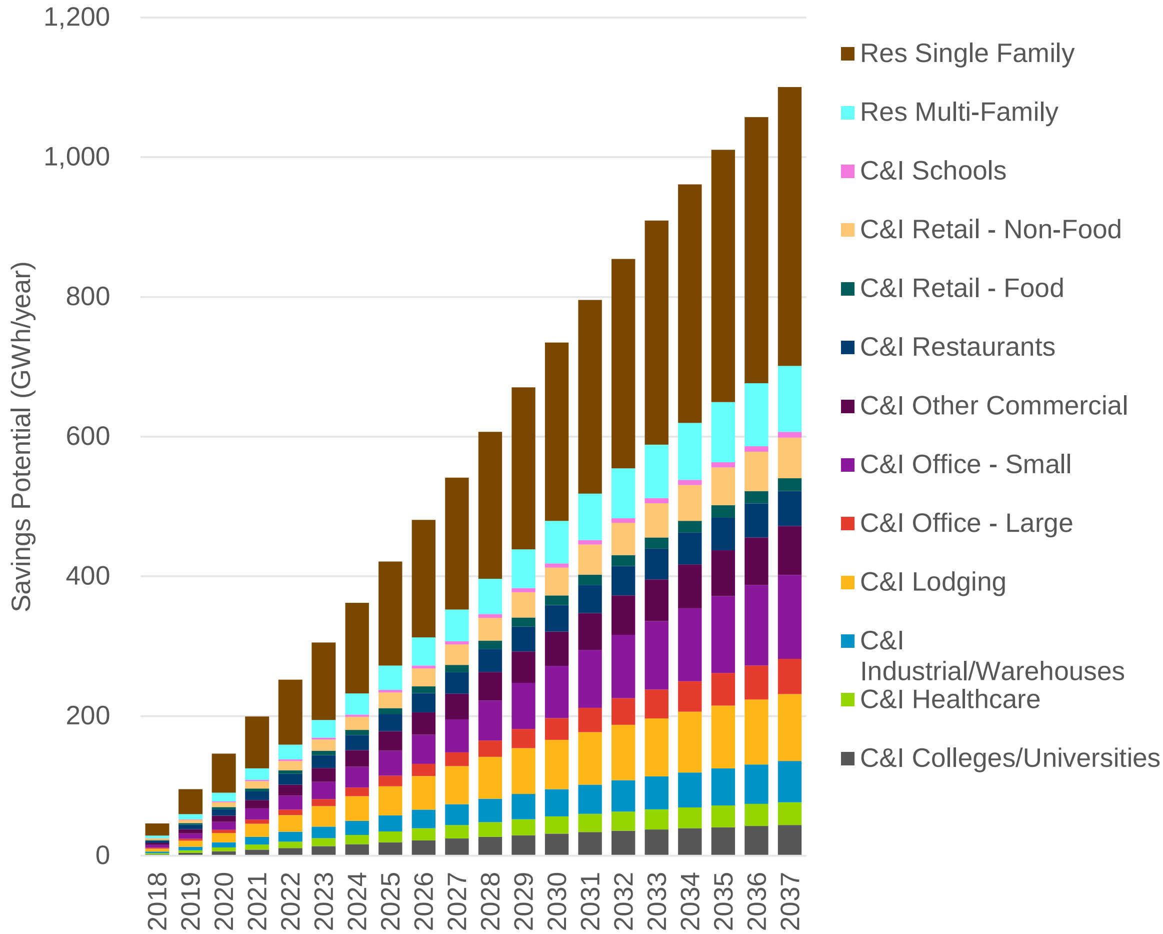
Year	All	C&I	Residential
2018	0.8%	0.7%	0.9%
2019	1.6%	1.4%	1.9%
2020	2.4%	2.1%	3.0%
2021	3.3%	2.8%	4.0%
2022	4.1%	3.6%	5.1%
2023	5.0%	4.4%	6.1%
2024	5.9%	5.2%	7.1%
2025	6.8%	6.1%	8.2%
2026	7.8%	6.9%	9.3%
2027	8.8%	7.8%	10.4%
2028	9.8%	8.8%	11.5%
2029	10.8%	9.7%	12.6%
2030	11.8%	10.6%	13.9%
2031	12.7%	11.4%	15.0%
2032	13.6%	12.2%	16.2%
2033	14.5%	12.9%	17.3%
2034	15.3%	13.5%	18.3%
2035	16.0%	14.1%	19.2%
2036	16.7%	14.7%	20.1%
2037	17.3%	15.2%	20.9%

Source: Navigant analysis

3.2.3 Results by Customer Segment

Figure 3-5 shows the cumulative electric energy achievable potential by customer segment. Residential single family is the largest segment. Small office and lodging contribute the most savings for the C&I sector.

Figure 3-5. Segment Electric Energy Base Case Achievable Potential Customer Segment Breakdown

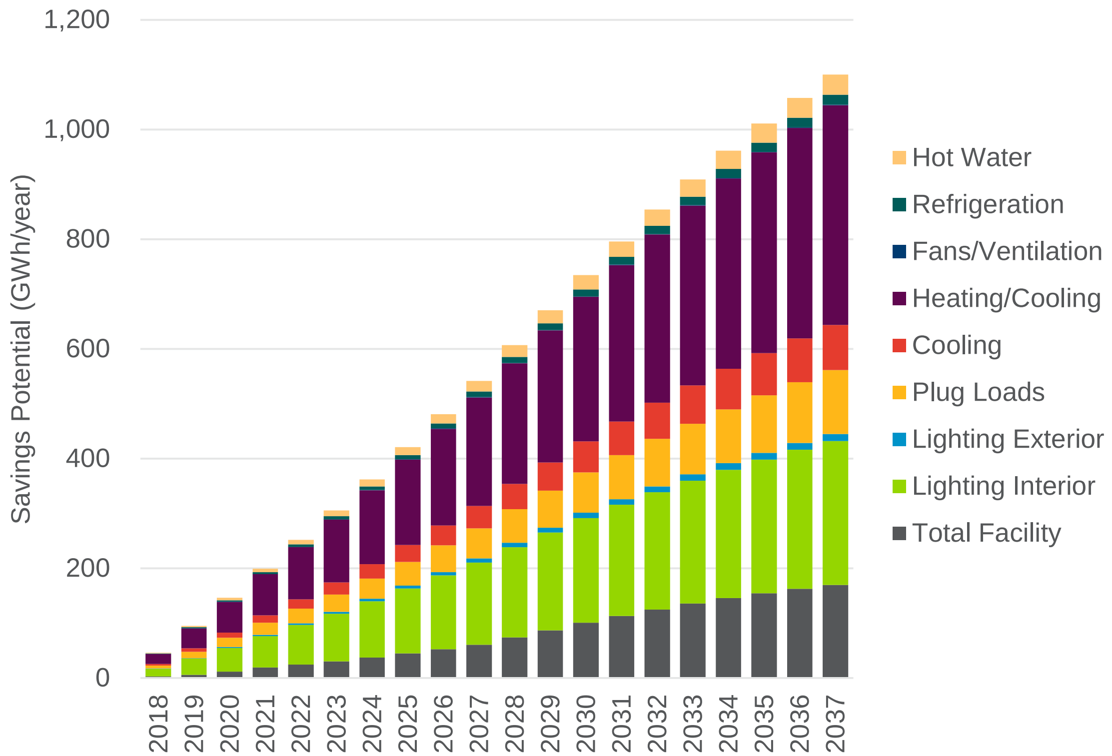


Source: Navigant analysis

3.2.4 Results by End Use

Figure 3-6 shows the electric energy cumulative achievable potential by end use. Figure 3-7 and Figure 3-8 show the percentage of each end use for each sector. The heating/cooling end use has the largest potential, with lighting interior also making a significant contribution. The heating and cooling end uses are high relative to cooling because this end use includes the sales associated with envelope and systems that affect both end uses. ENO has a relatively high penetration of electric heating, which contributes to this factor even though New Orleans experiences rather low heating degree days and high cooling degree days.

Figure 3-6. Electric Energy Base Case Achievable Potential End Use Breakdown



Source: Navigant analysis

Figure 3-7. Residential Electric Energy Achievable Potential End-Use Breakdown (%, GWh)

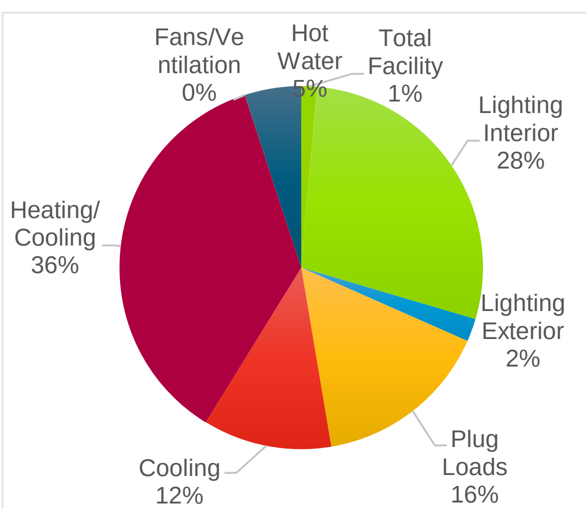
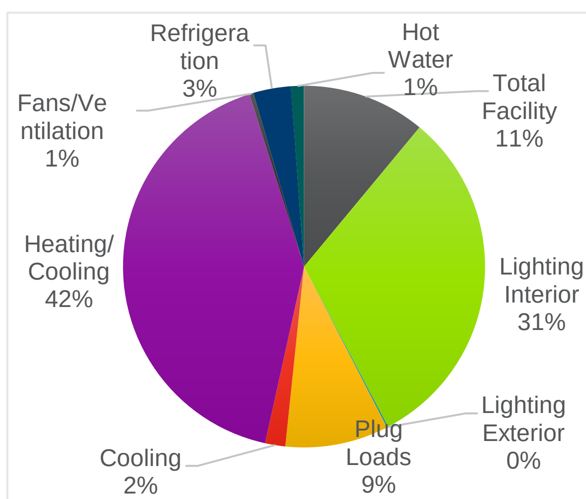


Figure 3-8. C&I Electric Energy Achievable Potential End-Use Breakdown (%, GWh)

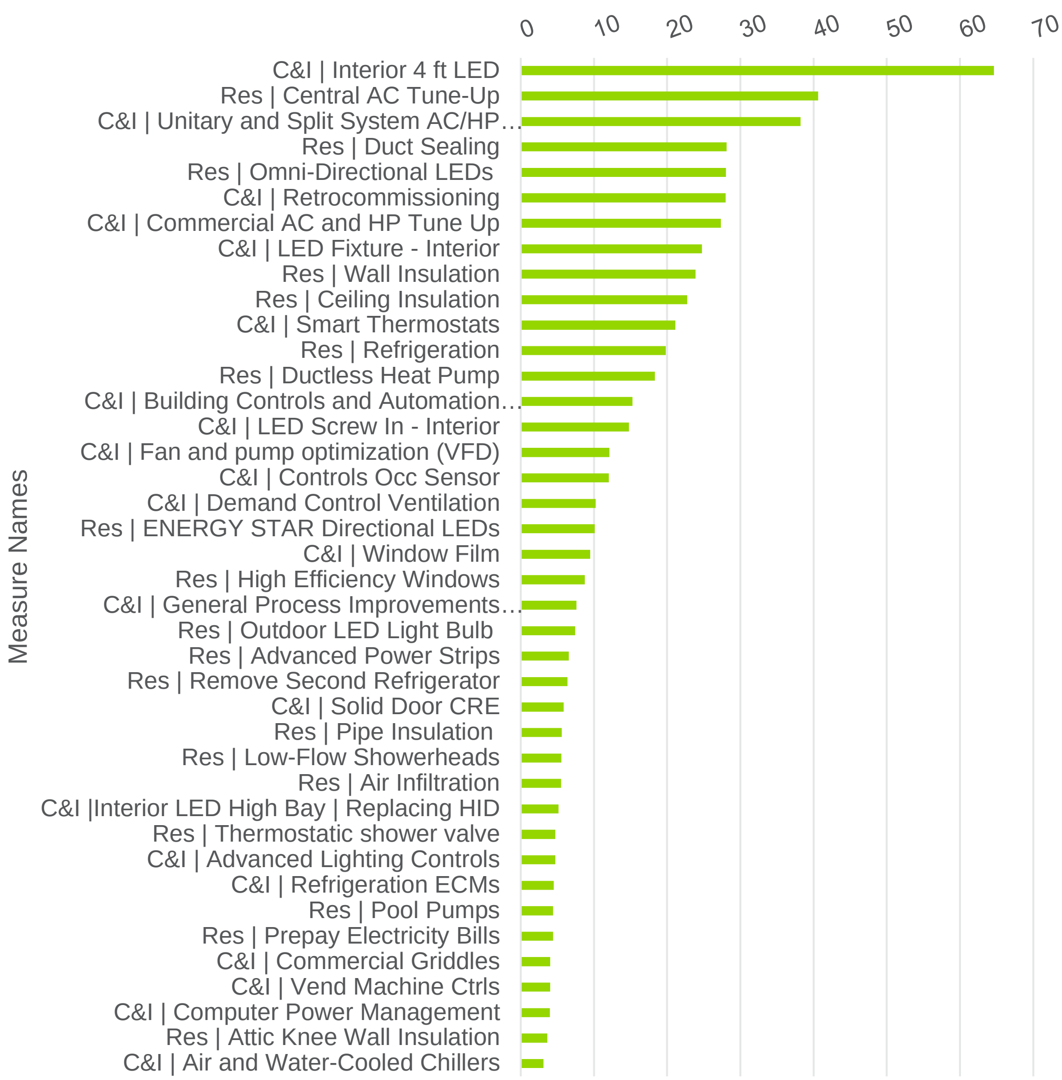


Source: Navigant analysis

3.2.5 Achievable Potential Results by Measure

Figure 3-9 shows the top 40 measures contributing to the electric energy achievable potential in 2028 (the middle of the study period and representative of the 20-year results). Interior 4 ft. LEDs in the C&I sector provide the most potential, followed by residential central air conditioning tune-up and commercial unitary and split system air conditioning/heat pump equipment.

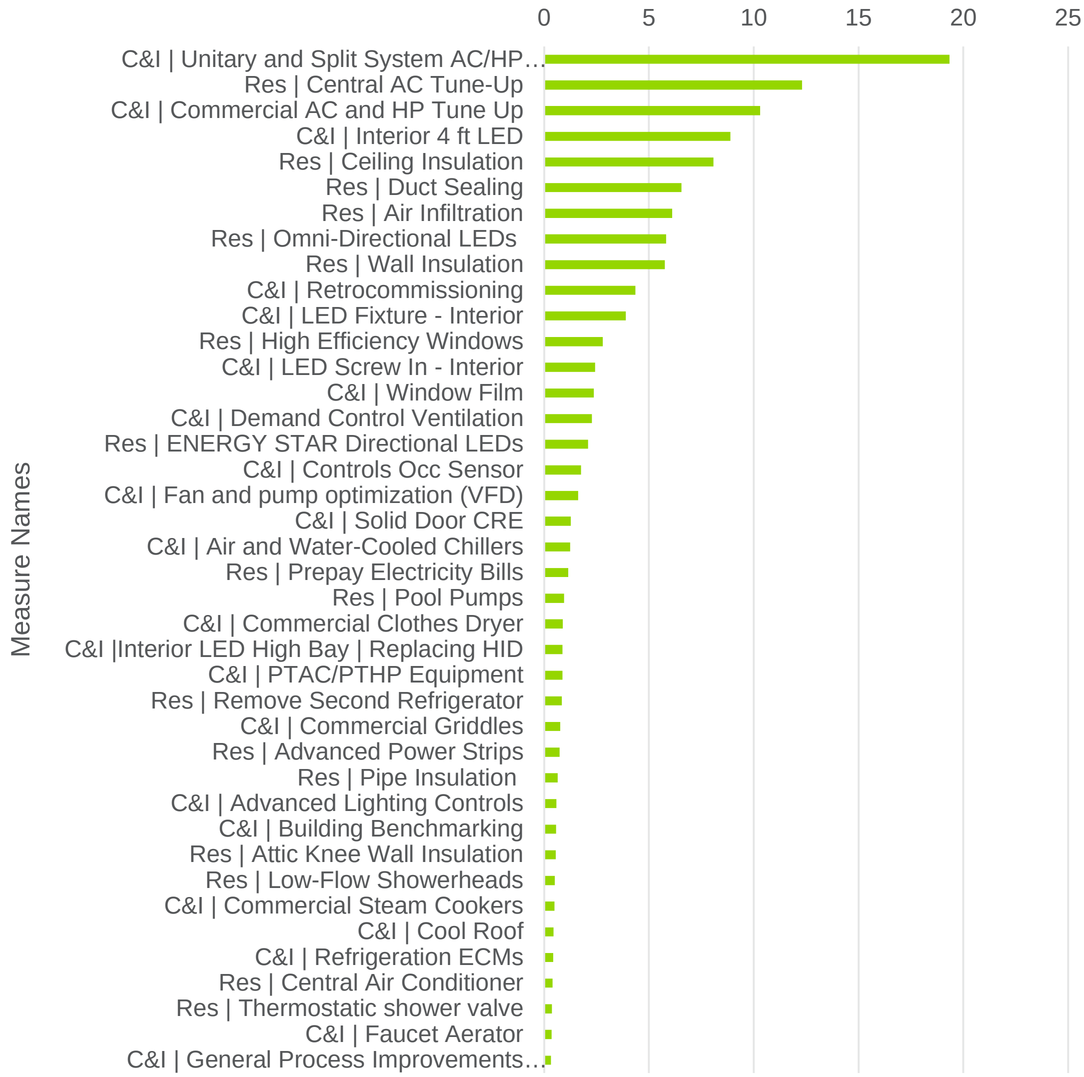
Figure 3-9. Top 40 Measures for Electric Energy Base Case Achievable Savings Potential: 2028 (GWh/year)



Source: Navigant analysis

Figure 3-10 shows the top 40 measures contributing to the demand achievable potential in 2028. The top measures are similar to those listed for electric energy.

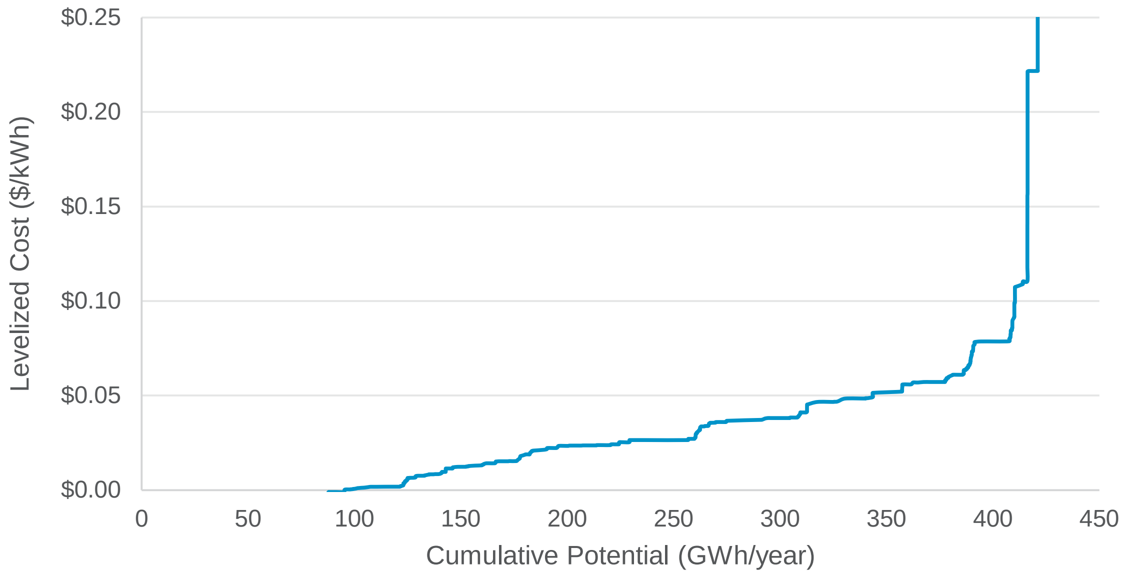
Figure 3-10. Top 40 Measures for Electric Demand Base Case Savings Potential: 2028 (MW)



Source: Navigant analysis

Figure 3-11 provides a supply curve of savings potential versus the levelized cost of savings in $/kWh for all measures considered in the study. The achievable potential levels out at about $0.08/kWh; incremental savings above this level become costlier.

Figure 3-11. Supply Curve of Electric Energy Achievable Potential (GWh/year) vs. Levelized Cost ($/kWh): 2028

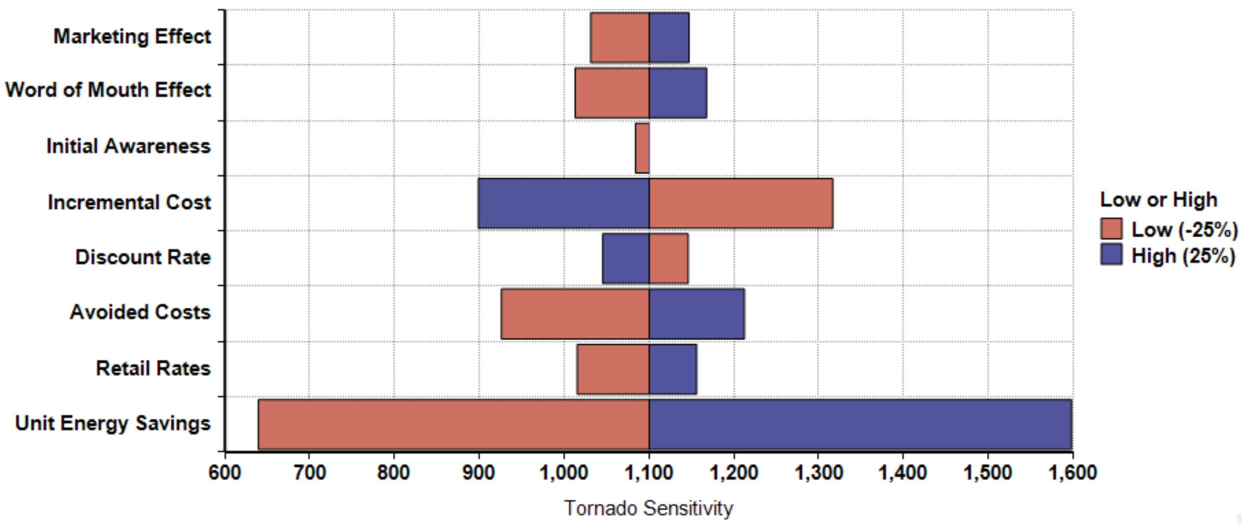


Source: Navigant analysis

3.2.6 Sensitivity Analysis

Figure 3-12 shows a sensitivity analysis of the effect on energy savings potential that results from varying the most influential factors by +/- 25%. Table 3-6 shows the percent change to the cumulative energy savings potential for each sensitivity parameter in 2037. Unit energy savings have the largest impact, followed by incremental costs, avoided costs, and retail rates. Such understandings are critical to evaluating related policy decisions and informing effective program design.

Figure 3-12. Cumulative Achievable GWh Savings in 2037 Sensitivity to Key Variables



Source: Navigant analysis

Table 3-6. Percent Change to Cumulative Potential in 2037 with 25% Parameter Change

Parameter	Low (-25%)	High (25%)
Marketing Effect	-6%	4%
Word-of-Mouth Effect	-8%	6%
Initial Awareness	-1%	0%
Incremental Cost	20%	-18%
Discount Rate	4%	-5%
Avoided Costs	-16%	10%
Retail Rates	-8%	5%
Unit Energy Savings[39]	-42%	45%

Source: Navigant analysis

[39] Unit energy savings are the same as deemed savings and sourced from the New Orleans TRM to the extent possible.

4. Demand Response Achievable Potential and Cost Results

This chapter presents the DR achievable potential and cost results based on the approach described in Section 2.2.

4.1 Cost-Effectiveness Results

This section presents cost-effectiveness results by DR option and sub-option based on the TRC test. Navigant also calculated the cost-effectiveness results based on three additional tests: the utility cost test (UCT), RIM test, and the Participant Cost Test (PCT).

4.1.1 Cost-Effectiveness Assessment Results

Table 4-1 shows benefit-cost ratios calculated for each DR sub-option based on the TRC test over the forecast period. Only the following programs are cost-effective:

- **Residential:** Dynamic pricing sub-options.
- **Small C&I customers:** HVAC DLC and dynamic pricing with enabling technology sub-options
- **Large C&I customers:** Manual curtailment of HVAC loads and dynamic pricing with enabling technology

Based on data made available by ENO, the only benefit stream captured by the TRC test is the avoided cost of generation capacity. ENO does not currently have a way to value avoided T&D capacity. These cost-effectiveness results would improve if avoided T&D capacity benefits were also included in the cost-effectiveness assessment. Only cost-effective sub-options are shown in the achievable potential results in subsequent sections.

Table 4-1. Base Case Benefit-Cost Ratios by DR Options and Sub-Options

Customer Class	DR Option	DR Sub-Option	TRC Ratio
Residential	DLC	DLC-Switch-Water Heating	0.21
		DLC-Thermostat-Heat Pump	0.95
		DLC-Thermostat-Central Air Conditioning	0.95
		DLC-Switch-Heat Pump	0.56
		DLC-Switch-Central Air Conditioning	0.56
	Dynamic Pricing	Dynamic pricing without enabling tech	1.38
		Dynamic pricing with enabling tech	1.89
Small C&I	BTMS	BTMS-Battery Storage	0.18

Customer Class	DR Option	DR Sub-Option	TRC Ratio
	DLC	DLC-Switch-Water Heating	0.17
		DLC-Thermostat-HVAC	6.53
		DLC-Switch-HVAC	2.96
	Dynamic Pricing	Dynamic pricing without enabling tech	0.24
		Dynamic pricing with enabling tech	2.90
Large C&I	BTMS	BTMS-Battery Storage	0.16
	C&I Curtailment	C&I Curtailment-Advanced Lighting Control	0.53
		C&I Curtailment-Auto-DR HVAC Control	0.57
		C&I Curtailment-Industrial	0.66
		C&I Curtailment-Manual HVAC Control	1.02
		C&I Curtailment-Other	0.61
		C&I Curtailment-Refrigeration Control	0.68
		C&I Curtailment-Standard Lighting Control	0.36
		C&I Curtailment-Water Heating Control	0.72
	Dynamic Pricing	Dynamic pricing without enabling tech	3.18
		Dynamic pricing with enabling tech	0.90

Source: Navigant

4.1.2 Comparison of Cost-Effectiveness Results by Cases

As described in Section 2.2.5, in addition to the base case, Navigant modeled potential results for low and high cases. For these cases, the team adjusted assumed participation levels and incentive amounts to determine the impacts on the DR achievable potential. Table 4-2 shows cost-effective results across the three cases for the DR sub-options that pass the cost-effectiveness screen for the base case. The C&I curtailment-manual HVAC control sub-option for large C&I participants under the low case is not cost-effective. All other base case cost-effective measures remain cost-effective under the low and high cases.

Table 4-2. Benefit-Cost Ratio Comparisons by Cases by DR Options and Sub-Options

Customer Class	DR Option	DR Sub-Option	Base TRC Ratio	Low TRC Ratio	High TRC Ratio
Residential	Dynamic	Dynamic pricing without enabling tech	1.38	1.39	1.38

Customer Class	DR Option	DR Sub-Option	Base TRC Ratio	Low TRC Ratio	High TRC Ratio
	Pricing[40]	Dynamic pricing with enabling tech	1.89	1.90	1.89
Small C&I	DLC	DLC-Thermostat-HVAC	6.53	6.09	6.76
		DLC-Switch-HVAC	2.96	2.84	3.02
	Dynamic Pricing	Dynamic pricing with enabling tech	2.90	2.91	2.89
Large C&I	C&I Curtailment	C&I Curtailment-Manual HVAC Control	1.02	0.96	1.05
	Dynamic Pricing	Dynamic pricing without enabling tech	3.18	3.21	3.17

Source: Navigant

4.2 Achievable Potential Results

This section presents cost-effective achievable potential results by DR option, sub-option, customer class and segment.

4.2.1 Achievable Potential by DR Option

Figure 4-1 summarizes the cost-effective achievable potential by DR option for the base case. Figure 4-2 shows the cost-effective achievable potential as a percentage of ENO's peak demand. Achievable potential is estimated to grow from 0.7 MW in 2018 to 34.6 MW in 2037. Cost-effective achievable potential makes up approximately 3.3% of ENO's peak demand in 2037. The team made several key observations:

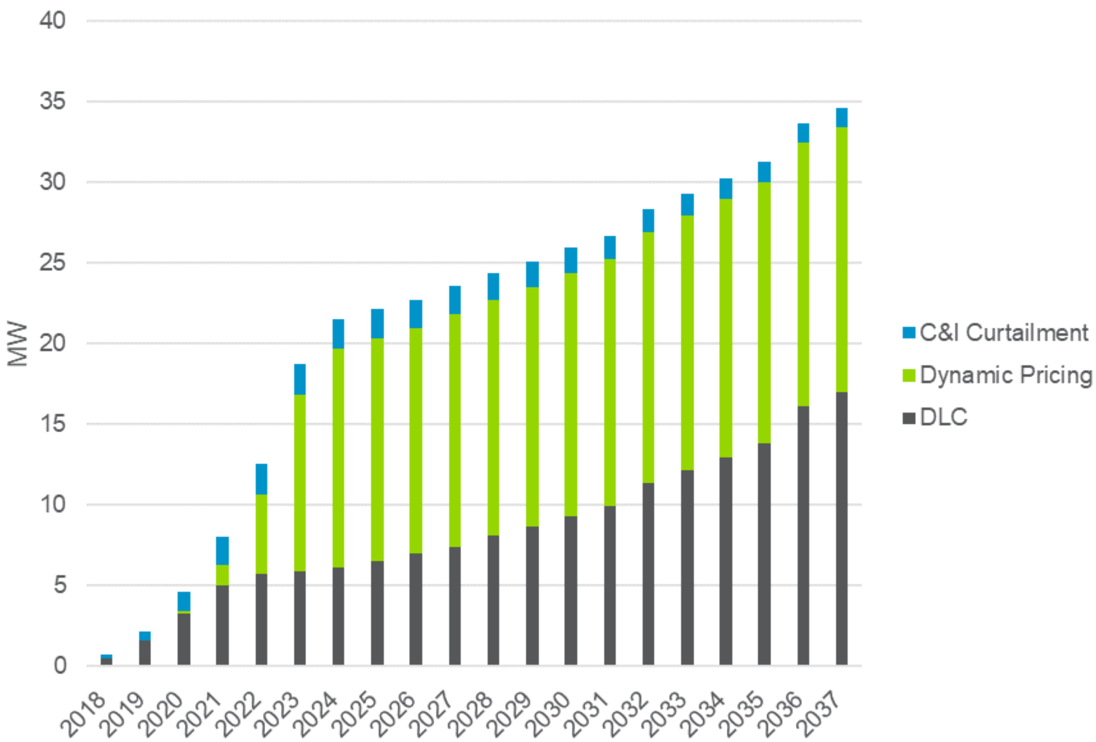
- DLC has the largest achievable potential: a 49% share of total potential in 2037. DLC potential grows from 0.5 MW in 2018 to 17.0 MW in 2037.
- This is followed by dynamic pricing with a 47% share of the total potential in 2037. As previously mentioned, the dynamic pricing offer begins in 2020 because it is tied to ENO's smart meter rollout plan. The program ramps up over a 5-year period (2020-2024) until it reaches a value of 14 MW. From then on, potential slowly increases until it reaches a value of 16 MW in 2037.
- C&I curtailment makes up the remainder of the cost-effective achievable potential with a 4% share of the total potential in 2037. C&I curtailment potential grows

[40] There are no incentives provided to customers for participating in dynamic pricing. Hence, participation, corresponding potential, costs and cost-effectiveness stay the same across scenarios. The low case ratio is slightly higher than the base and high case ratios due to lower interactive/competing effects with other programs.

rapidly from 0.2 MW in 2018 to 1.9 MW in 2022. This growth follows the S-shaped ramp assumed for the program over a 5-year period. Beyond 2022, the program attains a steady participation level and its potential slightly decreases over the remainder of the forecast period, ending at 1.2 MW in 2037.

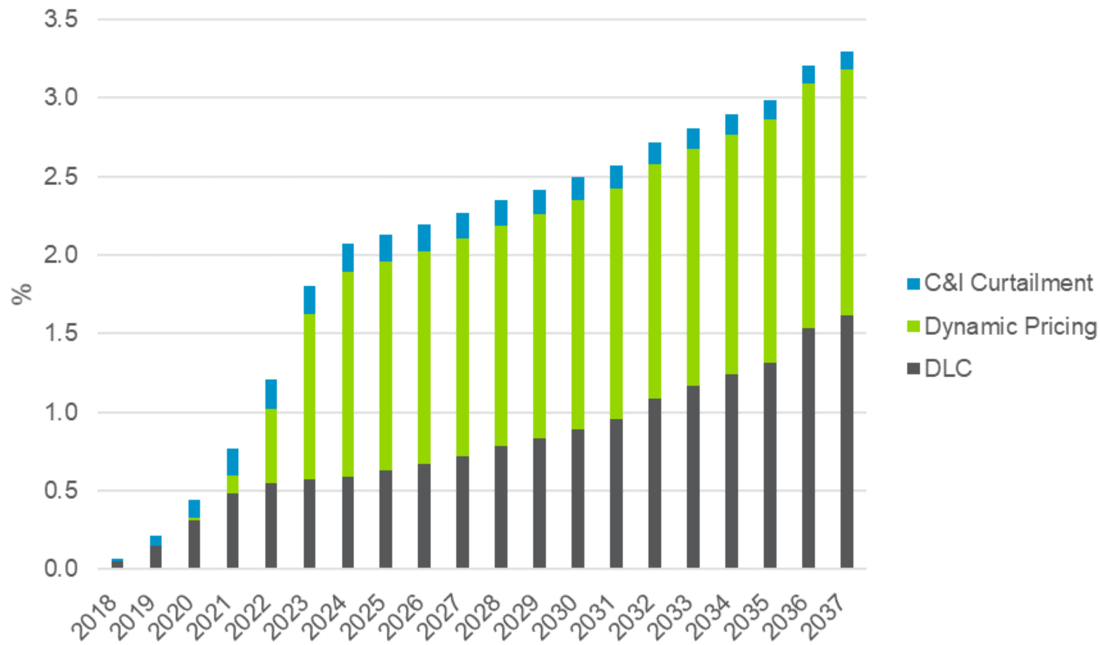
- BTMS, as described in this report, is not cost-effective; thus, it contributes 0 MW to the DR achievable potential.

Figure 4-1. Summer DR Achievable Potential by DR Option (MW)



Source: Navigant analysis

Figure 4-2. Summer DR Achievable Potential by DR Option (% of Peak Demand)



Source: Navigant analysis

4.2.2 Case Analysis Results

Navigant developed DR potential estimates for three different cases. These cases are based on the DR program incentive levels:

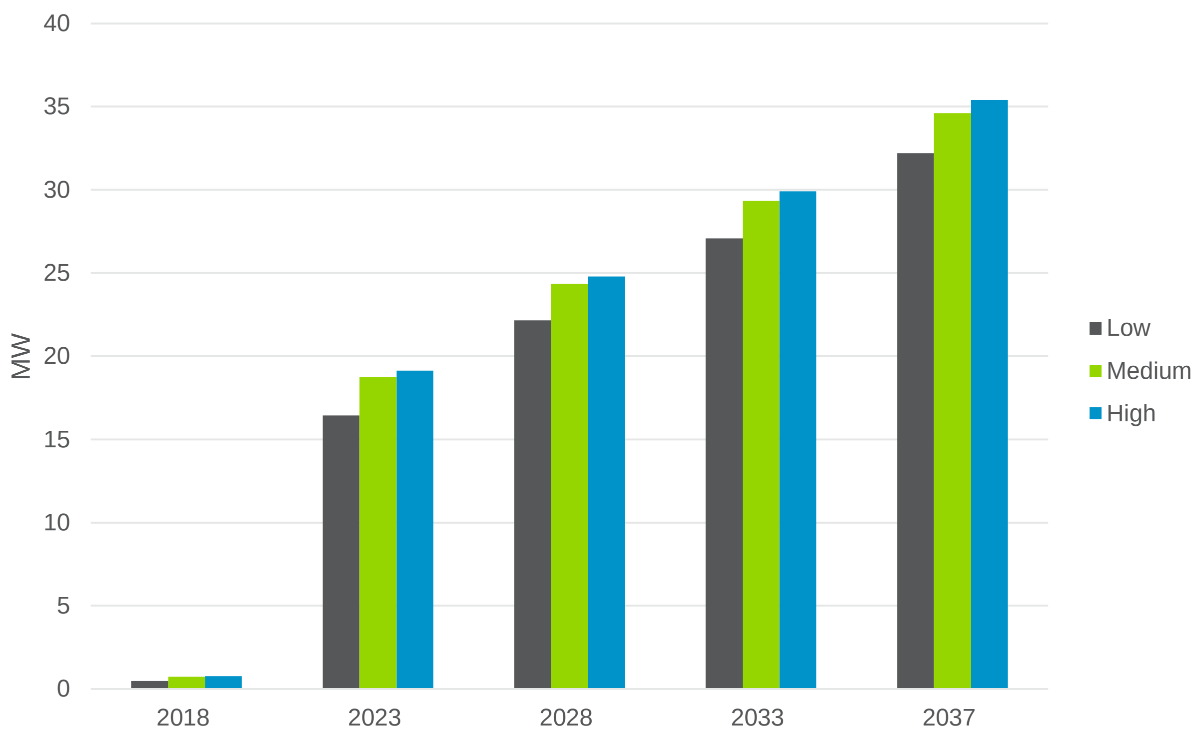
- **Base case:** Reflects DR program participation based on incentives at levels that match current programs (e.g., ENO's Smart Easy Cool program) and industry best practice.
- **Low case:** Assumes incentives are 50% lower than in the base case. This drives program participation down and results in lower implementation costs.
- **High case:** Assumes incentives are 50% higher than in the base case. This drives program participation up and results in higher implementation costs.

The low and high cases do not apply to the dynamic pricing program, as participation is strictly based on customer response to real-time price signals. The change in participation levels due to changes in incentives is based on price response curves developed by the Lawrence Berkeley National Laboratory (Berkeley Lab) for the *2025*

California Demand Response Potential Study.[41, 42]

Figure 4-3 and Figure 4-4 show the achievable potential results in terms of MW and percentage of peak demand, respectively. Under the base case, the achievable potential makes up approximately 3.3% of ENO's peak load in 2037. Under the low and high cases, the achievable potential represents approximately 3.1% and 3.4% of ENO's peak demand in 2037, respectively.

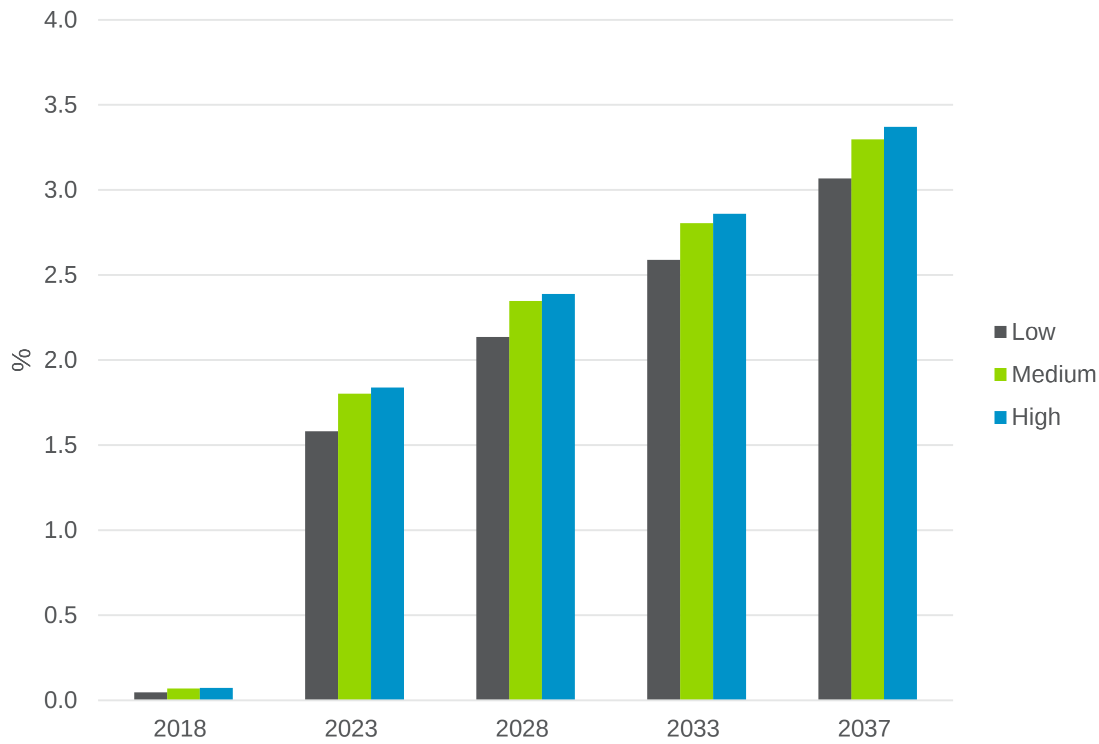
Figure 4-3. Summer DR Achievable Potential by Case (MW)



Source: Navigant

[41] Lawrence Berkeley National Laboratory. *2025 California Demand Response Potential Study: Charting California's Demand Response Future.* Appendix F. March 1, 2017.
[42] Navigant assumed medium marketing spending levels for DR programs across cases.

Figure 4-4. Summer DR Achievable Potential by Case (% of Peak Demand)



Source: Navigant analysis

4.2.3 Achievable Potential by DR Sub-Option

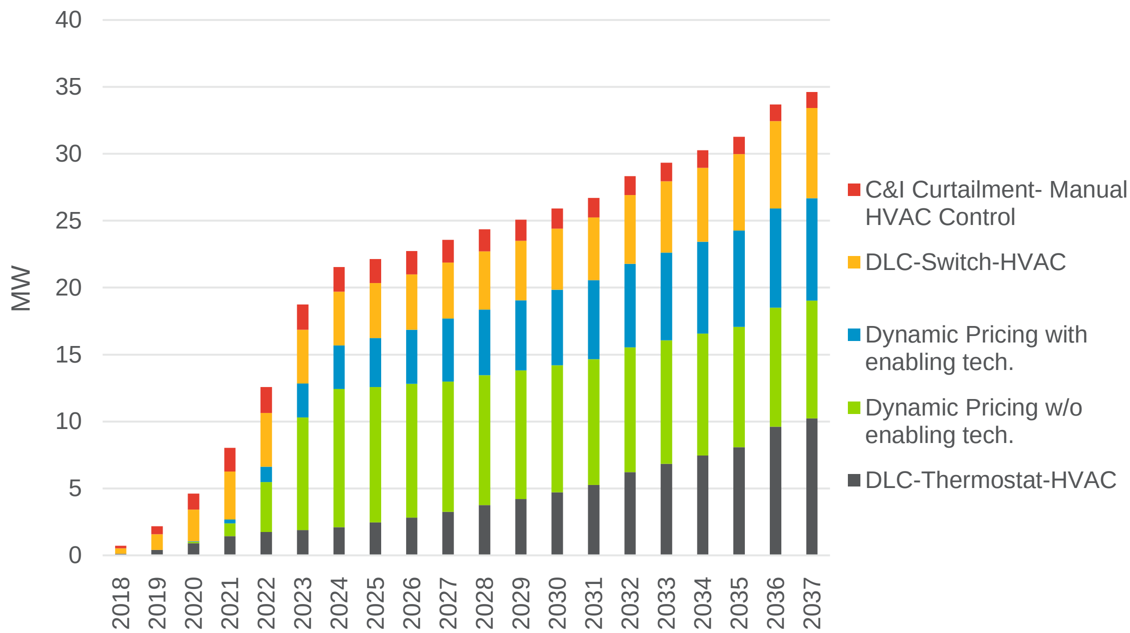
This section presents the breakdown of cost-effective potential by DR sub-option. Each sub-option is tied to a specific control technology and/or end use. Any sub-option that is tied to a control technology is tied to the penetration of that technology in the market. This penetration trajectory is informed by saturation values from the energy efficiency potential study.

Figure 4-5 summarizes the cost-effective achievable potential by DR option for the base case. Navigant had the following key observations:

- Only direct control of HVAC loads by small C&I customers is cost-effective (DLC-Switch-HVAC and DLC-Thermostat HVAC in Figure 4-5). This sub-option makes up 50% of the total cost-effective achievable potential in 2037 at 17.0 MW. Of this 17.0 MW, 10.2 MW is from thermostat-based control, while the remaining 6.7 MW is from switch-based control.
- Dynamic pricing makes up 47% of the total cost-effective achievable potential in 2037. Potential from customers with enabling technology in the form of thermostats/EMS (8.8 MW in 2037) is slightly higher than from customers without enabling technology—8.8 MW versus 7.6 MW in 2037.
- Under the C&I curtailment program, reductions associated with manual HVAC

control make up 4% of the total cost-effective potential in 2037.

Figure 4-5. Summer DR Achievable Potential by DR Sub-Option



Source: Navigant analysis

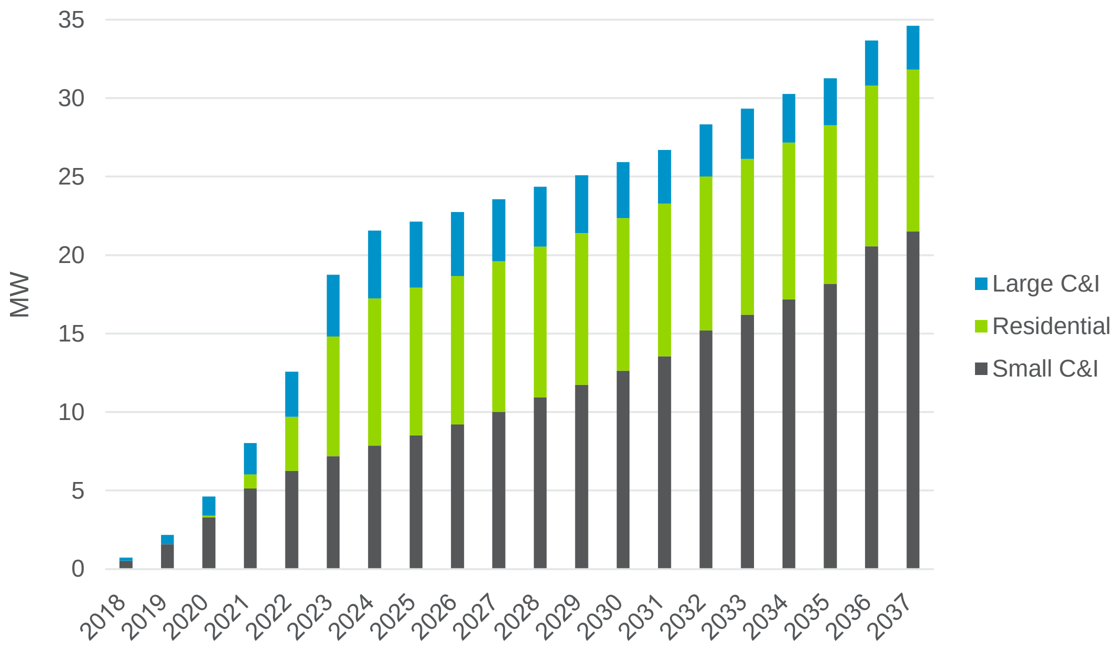
4.2.4 Achievable Potential by Customer Class

This section presents the breakdown of cost-effective potential by customer class. The three customer classes included in the study are residential, small C&I, and large C&I.

Figure 4-6 summarizes the cost-effective achievable potential by customer class for the base case. The team had the following key observations:

- Potential from residential customers makes up 30% (10.3 MW) of the total cost-effective achievable potential in 2037. C&I customers make up the remaining 70%.
- Potential from small C&I customers makes up 61% (21.5 MW) of the total cost-effective achievable potential in 2037. DLC of HVAC loads makes up 79% (48% from thermostat-based control and 31% from switch-based control) of this 21.5 MW, while dynamic pricing with enabling technology in the form of thermostats makes up the remaining 21%.
- Potential from large C&I customers makes up 8% (2.8 MW) of the total cost-effective achievable potential in 2037. Dynamic pricing with enabling technology in the form of an EMS makes up 57% of this 2.8 MW, while manual curtailment of HVAC loads makes up the remaining 43%.

Figure 4-6. Summer DR Achievable Potential by Customer Class (MW)



Source: Navigant analysis

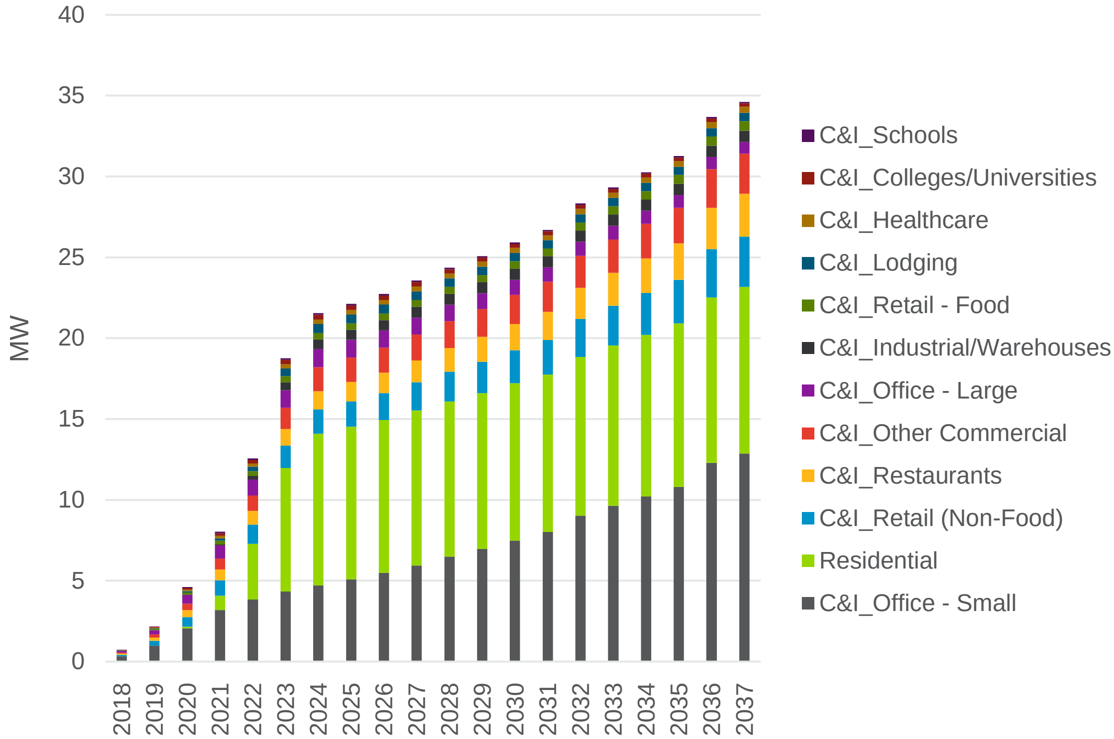
4.2.5 Achievable Potential by Customer Segment

This section presents the breakdown of cost-effective potential by customer segment. As previously discussed in the DR methodology section, these segments align with those included in the energy efficiency potential study. Navigant combined single family and multifamily customers into a single residential category because DR program and pricing offers are typically not distinguished by dwelling type. Government customers are included as part of the C&I sector. Savings potential analysis from street lighting is not included in this study.

Figure 4-6 summarizes the cost-effective achievable potential by customer segment for the base case. Navigant had the following key observations:

- Potential from C&I customers primarily comes from small offices, which make up 37% (12.9 MW) of the total cost-effective achievable potential in 2037. This is followed by retail buildings, restaurants and the other commercial building category, which each make up between 7% and 9% of the total cost-effective achievable DR potential in 2037—3.1 MW, 2.7 MW, and 2.5 MW, respectively.
- All other C&I segments make up less than 2.2% of the cost-effective achievable potential in 2037, which is less than 0.75 MW.

Figure 4-7. Summer DR Achievable Potential by Customer Segment



Source: Navigant analysis

4.3 Program Costs Results

This section presents annual program costs by case and DR option and sub-option. It also presents levelized cost estimates by DR sub-option. Annual costs and levelized costs are only shown only for cost-effective DR sub-options.

4.3.1 Annual Program Costs

4.3.1.1 Annual Costs by Case

Table 4-3 shows annual implementation costs for the entire cost-effective DR portfolio by case. These costs represent the estimated total annual costs that ENO is likely to incur to realize the potential values discussed in Section 4.2.

Relative to the base case, costs are lower and higher in the low and high cases, respectively, due to varied incentive levels paid to customers. This affects the level of participation from customers, which varies technology enablement costs, marketing costs, and O&M costs.

Table 4-3. Annual DR Portfolio Costs by Case

Year	Low	Base	High
2018	$148,508	$243,263	$250,759
2019	$112,142	$207,712	$232,074
2020	$579,445	$730,905	$778,924
2021	$655,853	$860,253	$930,087
2022	$806,604	$1,022,063	$1,095,810
2023	$813,775	$1,027,173	$1,100,283
2024	$459,268	$675,505	$751,149
2025	$295,230	$513,121	$590,823
2026	$313,916	$531,256	$609,786
2027	$331,867	$548,701	$628,218
2028	$510,256	$765,016	$847,832
2029	$431,276	$654,068	$741,000
2030	$486,591	$712,843	$803,392
2031	$511,942	$738,094	$830,734
2032	$500,861	$725,569	$820,344
2033	$455,034	$675,430	$769,963
2034	$473,555	$694,172	$791,230
2035	$497,330	$720,181	$820,580
2036	$599,336	$834,295	$945,949
2037	$557,774	$790,710	$903,719

Source: Navigant analysis

4.3.1.2 Annual Costs by DR Option and Sub-Option

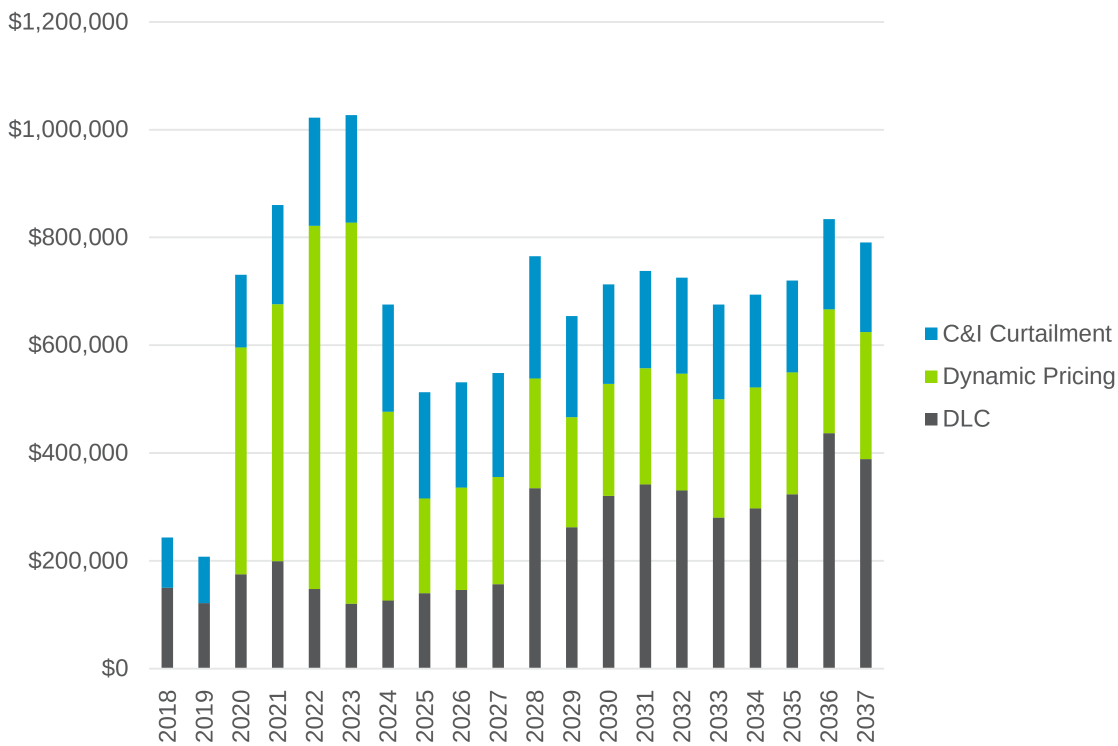
Figure 4-8 summarizes the annual program costs by DR option. Figure 4-10 summarizes the annual program costs by DR sub-option. The team observed the following:

- The program costs for DLC increase steadily from 2018 to 2021 and then drop in 2022, once the program is fully ramped up. By 2021, 90% of the program is ramped up, so the incremental cost to recruit new customers is lower in 2022. The costs remain steady and then spike back up in 2028 because the DLC program has a program life of 10 years, so technology enablement and program development costs are re-incurred at this time. From then on, costs fluctuate in accordance with program participation, which is tied in part to thermostat market penetration, until it reaches its final value of $389,000 in 2037.
- The program costs for C&I curtailment increase steadily from 2018 to 2022 until the program is fully ramped up. Because manual HVAC control is the only C&I

curtailment sub-option that is cost-effective, these costs do not include any technology enablement costs. There is a spike in costs in 2028 because, like DLC, the C&I curtailment program has a program life of 10 years, so program development costs are re-incurred at this time. From then on, costs fluctuate with program participation until it reaches its final value of $166,000 in 2037.

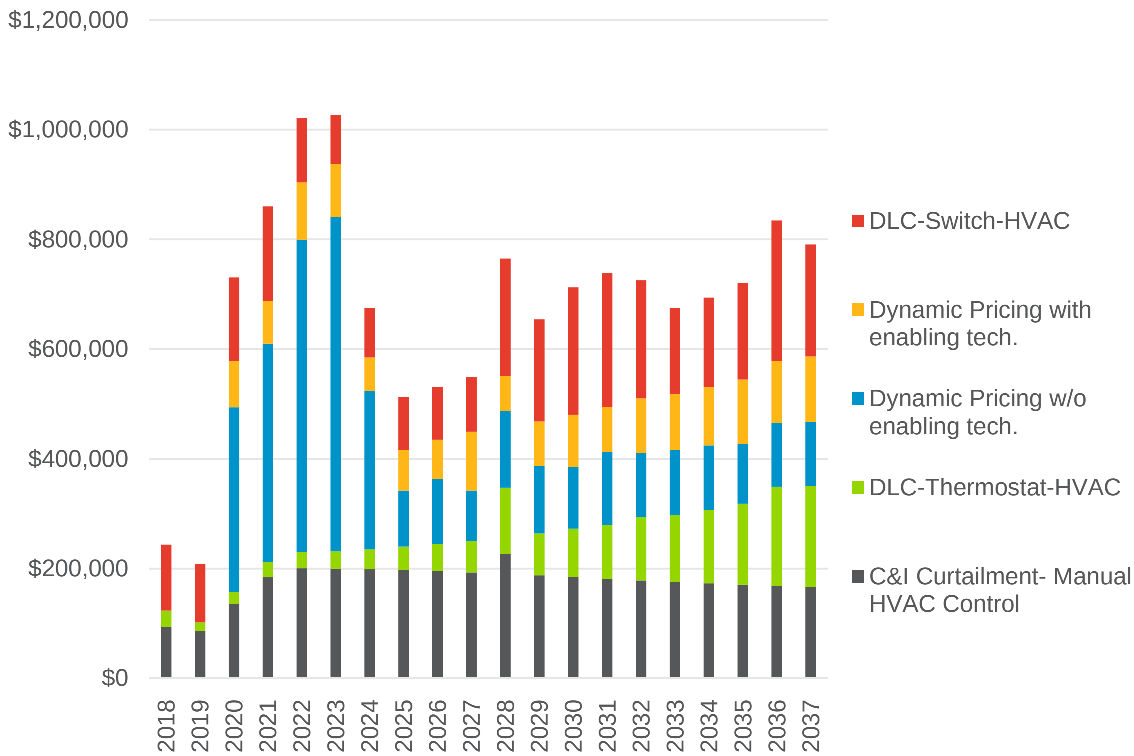
- Dynamic pricing program costs are relatively high during its initial ramp up between 2020 and 2023, and then drop in 2024 when the program is fully ramped up. By 2023, 90% of the program is ramped up, so the incremental cost to recruit new customers is lower in 2024. Beyond 2024, costs remain low and relatively steady.
- Annual BTMS program costs are zero as the program is not cost-effective.

Figure 4-8. Annual Program Costs by DR Option



Source: Navigant analysis

Figure 4-9. Annual Program Costs by DR Sub-Option

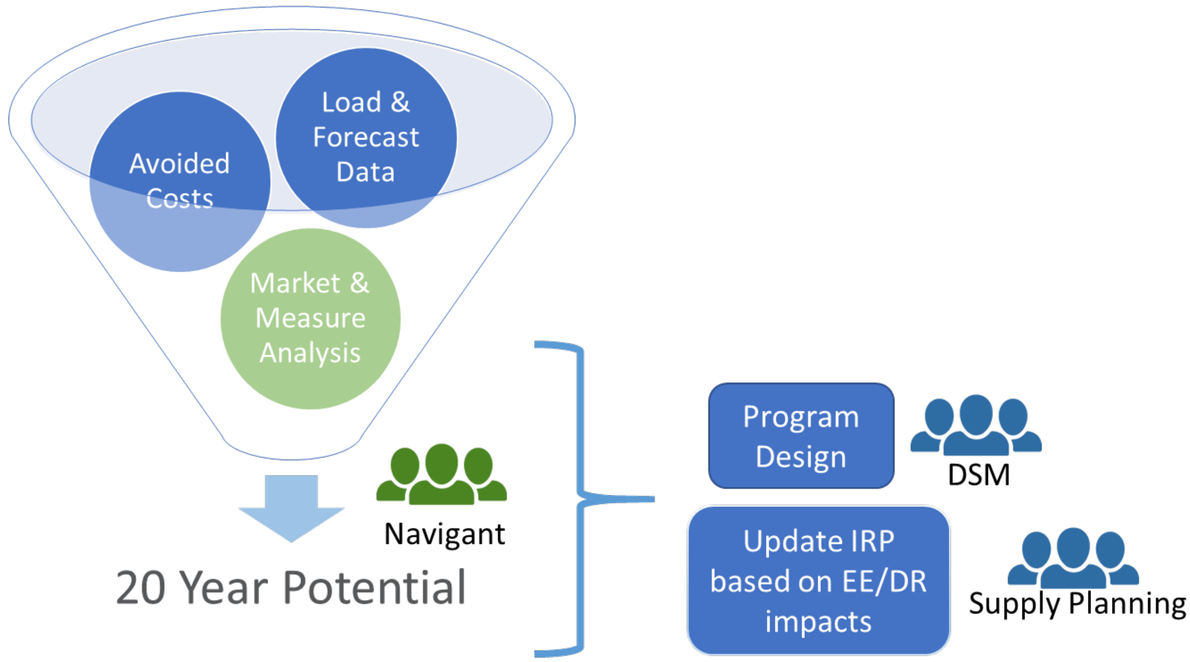


Source: Navigant analysis

5. Conclusions and Next Steps

Figure 5-1 provides an illustrative view of the data inputs and outputs of the potential study, most notably for IRP and program planning.

Figure 5-1. Integrating Potential Study Outputs to IRP and DSM Planning



Source: Navigant

5.1 Benchmarking the Results

Energy Efficiency

After completing the potential study analysis, Navigant benchmarked the energy efficiency achievable potential results against similar studies by other utilities. The goal of this exercise was to provide context for Navigant's results and to understand how various factors such as region or program spend may affect the results.

For this exercise, Navigant conducted a literature review on recent potential studies and aggregated the results. In conducting this review, the team aimed to include a mixture of utilities that had comparable electric customer counts, climate regions, regulatory requirements (e.g., publicly owned utilities), and/or locales (e.g., metropolitan centers). Based on this literature review, Navigant conducted three comparisons:

- Average annual achievable potential savings at the utility level
- Average annual potential savings at the state level
- Energy savings per dollar of program spend

Note that the sources and points of comparison differ due to data availability. The tables below list the final benchmarking pool for these comparisons and their respective data sources.

Table 5-1. EE Achievable Potential Benchmarking Pool and Sources

Utility	Data Source
Austin Energy	Austin Energy DSM Market Potential Assessment, 2012
Louisville Gas & Electric / Kentucky Utilities	Louisville Gas & Electric Company and Kentucky Utilities Company, Demand-Side Management Potential Study, 2017[43]
Commonwealth Edison (ComEd)	ComEd Energy Efficiency Potential Study, 2016[44]
Duke Energy (Indiana)	The Duke Energy Indiana 2015 Integrated Resource Plan, 2015[45]
California Public Utilities[46]	California Public Utilities Commission, 2018 Potentials & Goals Study Results Viewer[47]
Colorado Springs Utilities	Colorado Springs Utilities 2015 Demand Side Management Potential Study, 2016[48]
Seattle City Light	Seattle City Light Conservation Potential Assessment, 2016[49]

[43] CADMUS, Louisville Gas & Electric Company and Kentucky Utilities Company, *Demand-Side Management Potential Study 2019-2038*, 2017, https://lge-ku.com/sites/default/files/2017-10/LGE-KU-DSM-Potential-Study.pdf

[44] ICF, *ComEd Energy Efficiency Potential Study*, 2017-2030, May 2016, http://ilsagfiles.org/SAG_files/Potential_Studies/ComEd/ComEd_2017-2030_EE_Potential_Final_Report_5-2016.pdf

[45] Duke Energy Indiana, *The Duke Energy Indiana 2015 Integrated Resource Plan*, 2015, https://www.in.gov/iurc/files/2015_Duke_IRP_Report_Volumn_1_Public_Version.pdf

[46] CA Public Utilities are grouped together due to data availability and the study results referenced.

[47] Navigant, *California Public Utilities Commission 2018 Potentials & Goals (PG) Study Results Viewer*, 2018, http://www.cpuc.ca.gov/General.aspx?id=6442452619

[48] CADMUS, *Colorado Springs Utilities 2015 Demand Side Management Potential Study*, 2016, https://www.csu.org/CSUDocuments/dsmpotentialstudyvolume1.pdf

[49] Seattle City Light 2016 IRP “Appendix 6, Conservation Potential Assessment,” https://www.seattle.gov/light/IRP/docs/2016App-6-Conservation%20Potential%20Assessment.pdf

Table 5-2. EE Achievable Potential Savings by State Benchmarking Pool and Sources

State	Data Source
Arkansas	Arkansas Energy Efficiency Potential Study[50]
Mississippi	A Guide to Growing an Energy-Efficient Economy in Mississippi[51]
Louisiana	Louisiana's 2030 Energy Efficiency Roadmap[52]
Tennessee	Tennessee Valley Authority Potential Study[53]
Texas	Potential for Energy Efficiency, Demand Response, and Onsite Renewable Energy to Meet Texas's Growing Electricity Needs[54]

[50] Navigant, *Arkansas Energy Efficiency Potential Study*, 2015, www.apscservices.info/pdf/13/13-002-U_212_2.pdf

[51] ACEEE, *A Guide to Growing an Energy-Efficient Economy in Mississippi*, 2013, http://aceee.org/research-report/e13m

[52] ACEEE, *Louisiana's 2030 Energy Efficiency Roadmap*, 2013, http://aceee.org/research-report/e13b

[53] Global Energy Partners, *Tennessee Valley Authority Potential Study*, 2011, http://152.87.4.98/news/releases/energy_efficiency/GEP_Potential.pdf

[54] ACEEE, *Potential for Energy Efficiency, Demand Response, and Onsite Renewable Energy to Meet Texas's Growing Electricity Needs*, 2007, https://aceee.org/research-report/e073

Table 5-3. EE Actual Spending and Saving Benchmarking Pool and Sources

Utility	Data Source
Anaheim Public Utilities	Energy Efficiency in California's Public Power Sector 11th Edition[55]
Pasadena Water & Power	
Los Angeles Department of Water & Power	
Sacramento Municipal Utility District	
SWEPCO	Texas Efficiency, Energy Efficiency Accomplishments of Texas Investor-Owned Utilities 2016[56]
Entergy Texas, Inc.	
El Paso Electric	
CPS Energy (City of San Antonio)	Evaluation, Measurement & Verification of CPS Energy's DSM Programs FY 2016[57]
Louisville Gas & Electric/Kentucky Utilities	LG&E/KU DSM Advisory Group Meeting, 2017[58]

Based on the sources above, Navigant aggregated the results into the figures below.

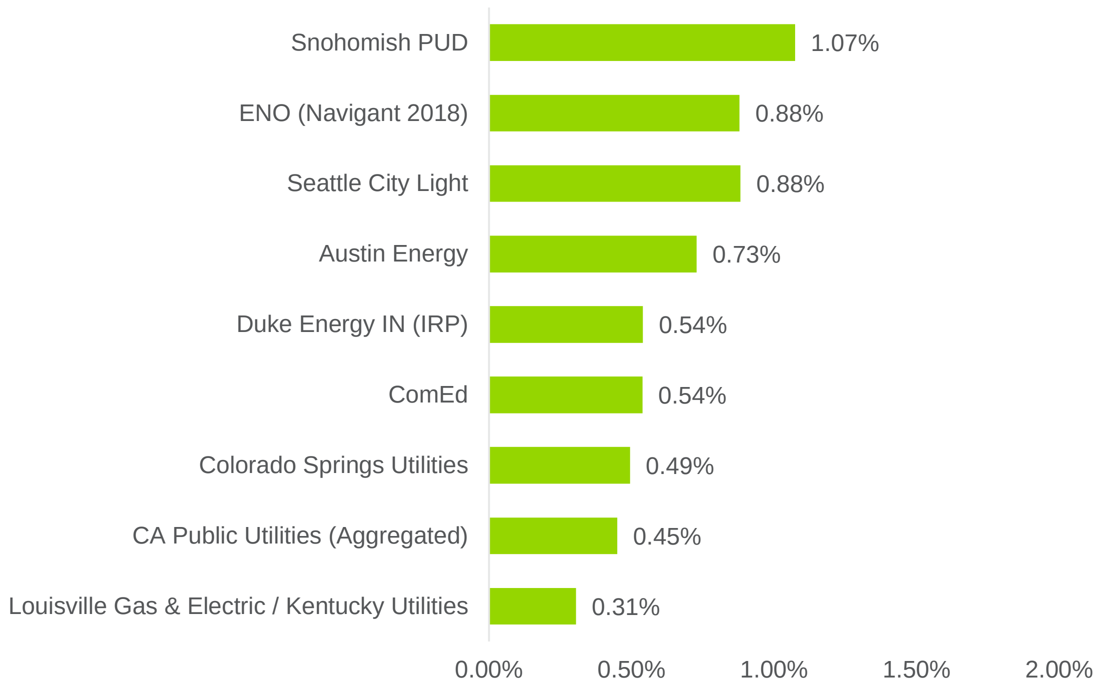
[55] California Municipal Utilities Association, Northern California Power Agency, Southern California Agency, *Energy Efficiency in California's Public Power Sector,* 11th Edition, 2017, http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-06/TN217680_20170522T124015_Energy_Efficiency_in_California's_Public_Power_Sector_11th_Edit.pdf

[56] Frontier Associates, *Energy Efficiency Accomplishments of Texas Investor-Owned Utilities 2016*, 2017, http://www.texasefficiency.com/images/documents/Publications/Reports/EnergyEfficiencyAccomplishments/EEPR2016.pdf

[57] Frontier Associates, *Evaluation Measurement & Verification of CPS Energy's FY 2016 DSM Programs*, https://www.sanantonio.gov/portals/0/files/sustainability/Environment/CPSFY2016.pdf

[58] LG&E and KU, "DSM Advisory Group Meeting," 2017, https://lge-ku.com/sites/default/files/2017-10/9-26-2017-EE-Advisory-Group-Presentation.pdf

Figure 5-2. Benchmarking Pool Average Achievable Potential Savings (% of Sales)[59]



Source: Navigant analysis

When comparing potential estimates, it is important to note that although the utilities included in the benchmarking pool may have some similar characteristics, no two utilities are the same; therefore, the results may vary based on the inputs each utility provided to its respective potential study evaluator. Study methodologies may also differ based on the potential study evaluator, providing additional room for variances across studies.

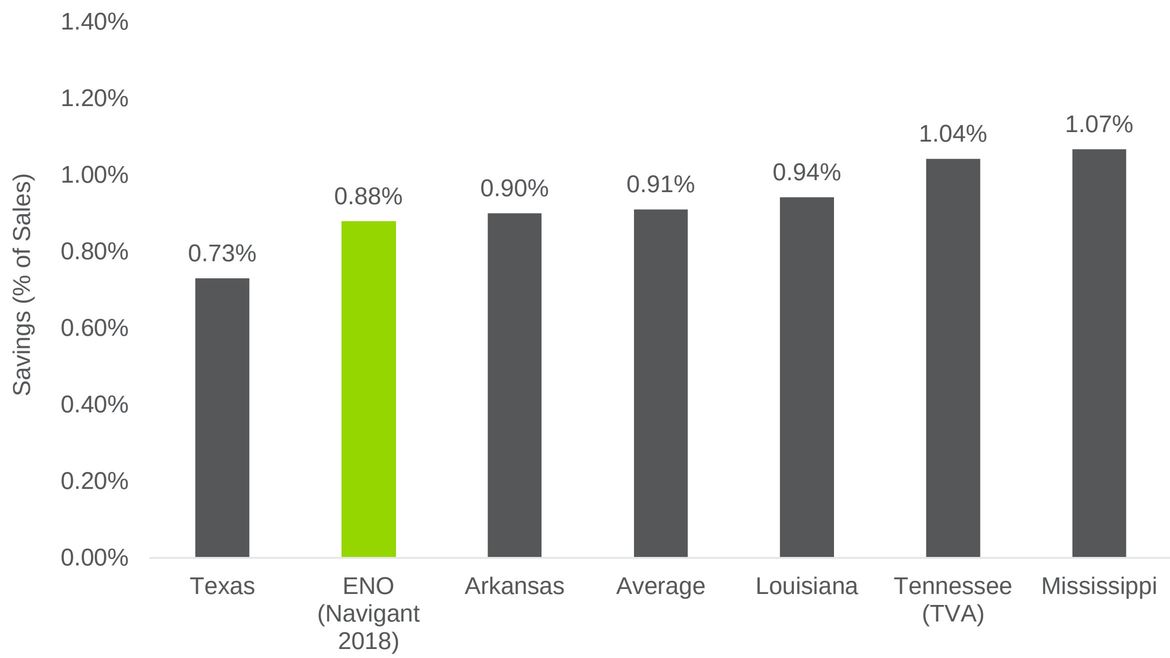
With that in mind, achievable potential savings range from 0.31% to 1.07% of sales. Snohomish Public Utility District in Washington has the highest potential and Louisville Gas & Electric/Kentucky Utilities, the lowest. As mentioned above, these differences may be driven by many factors, including measures studied, cost inputs, study years, and study methodology. ENO's achievable potential falls within the range of the benchmarking pool at an average of 0.88% savings per year over the study period (2017-2038). This is similar to Seattle City Light and slightly above Austin Energy (0.73%). Interestingly, the three all operate in large metropolitan areas and have similar

[59] These savings are shown as an annual average, which Navigant derived by dividing the cumulative study averages by the number of years in the study. The team used this approach because study years tend to differ greatly.

governance structures in that they are regulated by a city council.[60]

In addition to benchmarking the results at the utility level, Navigant created a peer pool at the state level. The goal of this analysis was to understand ENO's potential savings within the broader context of the state of Louisiana and its neighbors. Given that the states are mostly clustered within the Southeast region of the US, they have the same climate (hot-humid) and, therefore, may experience similar levels of achievable potential savings. Figure 5-3 shows how ENO's achievable potential fits into the broader state-level context.

Figure 5-3. Benchmarking Pool State Level Achievable Potential (% of Savings)



As shown in the figure above, ENO's achievable potential savings are within the range of the benchmarking pool (0.73%-1.07%), which makes sense given the similarities across the region. Its potential savings are only slightly less than the overall pool average and the state of Louisiana. The slight difference in savings of this potential study and the state may be caused by several factors, including:

- Updated inputs

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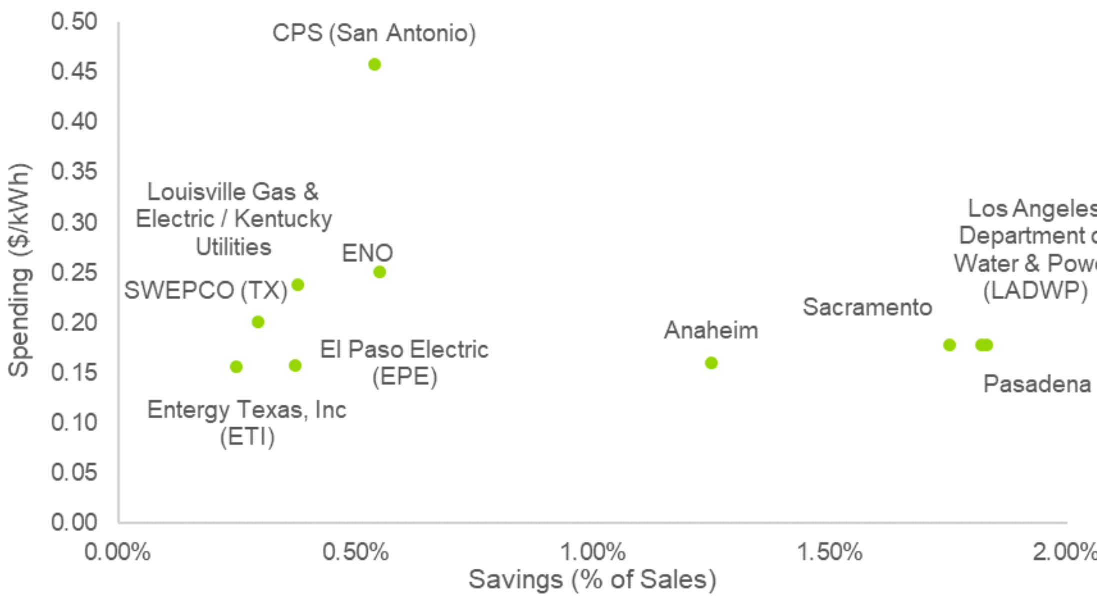
[60] It should be noted that, unlike ENO, which is an IOU, Austin Energy and Seattle City Light are both POUs that function as departments within their respective municipalities. However, all three must comply with the mandates of the local regulatory body.

- Utilities outside New Orleans had not begun implementing energy efficiency programs at the time ACEEE conducted the Louisiana study in 2013
- Broader region covered (some areas may have more or less potential savings based on stock type and other utilities' energy efficiency spending)

Figure 5-4. Benchmarking Pool Actual Savings (% of Sales) vs. Spending ($/kWh)



Source: Navigant analysis

Like achievable potential estimations, actual savings and spending may vary greatly among utilities based on inputs. In this case, inputs may include how the study is administered, what measures are offered, how the program is designed, and the number of years the program has been in place. The figure above shows that CPS Energy in San Antonio spends the most ($0.46/kWh) for less savings (0.54%), while the larger California public utilities (Sacramento Municipal Utilities District, Los Angeles Department of Water & Power, and Pasadena Water & Power) spend the least ($0.16/kWh-$0.18/kWh) but achieve the most (1.25%+). ENO falls in between these two, spending $0.24/kWh and saving 0.55% in 2016. Looking at its Southern peers, ENO's most recent spending and savings align closely, suggesting regional program administration and design variances. Additionally, California programs have been around for significantly longer, which may account for additional cost/savings differentials.

Demand Response

In addition to EE potential, the team also benchmarked DR potential, following a similar process. The process included creating a peer pool based on ENO's characteristics and data availability. This particular effort included both individual utilities and two nearby Independent System Operators (ISOs) or Regional Transmission Authorities (RTOs). The table below includes the sources used for this analysis.

Utility or ISO/RTO	Data Source
Ameren Union Electric (AmerenUE)	AmerenUE DSM Market Potential Study[61]
Con Edison (Con Ed)	DER Potential Study[62]
Commonwealth Edison (ComEd)	Comprehensive Assessment of Demand-Side Resource Potentials[63]
Electric Reliability Council of TX (ERCOT)	Assessment of Demand Response and Advanced Metering[64]
Hawaii Electric Company (HECO)	Fast DR Pilot Program Evaluation[65]
Puget Sound Energy (PSE)	2017 IRP Demand-Side Resource Conservation Potential Assessment Report[66]
Southwest Power Pool (SPP)	Assessment of Demand Response and Advanced Metering[67]

The results of this analysis are shown in the graphic below.

[61] Global Energy Partners, AmerenUE Demand Side Management (DSM) Market Potential Study Volume 1: Executive Summary, January 2010, https://www.ameren.com/-/media/missouri-site/Files/Environment/Renewables/AmerenUEVolume1ExecutiveSummary.pdf.

[62] Navigant, DER Potential Study, 2016.

[63] Cadmus Group, Comprehensive Assessment of Demand-Side Resource Potentials, February 2009, https://www.illinois.gov/sites/ipa/Documents/Appendix%20C-1%20-%20ComEd%20Potential%20Study.pdf

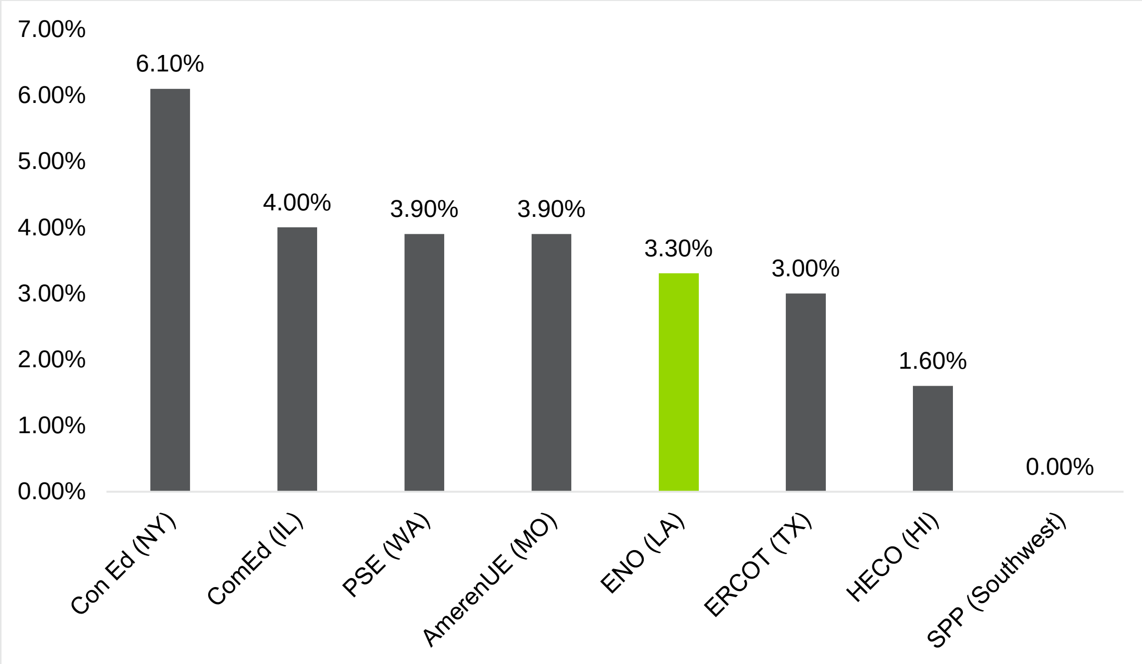
[64] Federal Energy Regulatory Commission (FERC) Assessment of Demand Response and Advanced Metering, 2016, https://www.ferc.gov/legal/staff-reports/2016/DR-AM-Report2016.pdf

[65] Navigant, Fast DR Pilot Program Evaluation, May 2015, http://media.navigantconsulting.com/emarketing/Documents/Energy/HawaiianElectricFastDREvaluationReport_Sept302014NavigantRevisedMay192015v2.pdf

[66] Navigant, 2017 IRP Demand-Side Resource Conservation Potential Assessment Report, June 2017, https://pse.com/aboutpse/EnergySupply/Documents/DSR-Conservation-Potential-Assessment.pdf

[67] FERC, Assessment of Demand Response and Metering.

Figure 5-5. Benchmarking Pool DR Potential (% of Savings)



As shown above, ENO falls in the middle of the benchmarking pool, only slightly higher than ERCOT and slightly below Ameren in Missouri. Given that DR, like EE, varies based on program administration and geographic location, amongst other factors, ENO's DR potential aligns closely to its peers.

5.2 IRP

The IRP is typically an iterative process to optimize the mix of supply- and demand-side resources to meet the utility's demand. The mix of supply-side resources dictates the costs to be used as avoided costs, but if energy efficiency programs can vary the supply-side mix (i.e., reduce the need of costlier resources), the avoided costs will vary. The IRP outputs feed into the projected cost and goals used to formulate the near-term DSM program implementation portfolio.

The potential study provides forecasted savings inputs for use in the IRP modeling. These inputs are provided by sector, segment, and end use because each combination of these items is mapped to a load shape (see Appendix C). Each measure is mapped to one or more DSM programs. Navigant then developed a load shape representative of each DSM program. The DSM program load shape represents the aggregate hourly energy savings for the group of measures included in the program over the 20-year planning period. These load shapes are what define the hourly usage profiles for the DSM program portfolio. The data provided is aligned with the Council's IRP rulemaking, R-17-429 which requests that the data supplied should include: a description of each demand-side resource considered, including a description of resource expected penetration levels by year; hourly load reduction profiles for each DSM program; and results of all 4 standard cost-effectiveness tests.

5.3 Program Planning

It is important to recognize that DSM potential studies like this one are inherently different from DSM program portfolio designs. The long-term achievable potential identified for a 20-year period through this study is different from the short-term savings potential that would be identified though a DSM program portfolio design effort targeting a 3-year period. However, it is important to note that programmatic design (such as delivery methods and marketing strategies) will have implications for the overall savings goals and projected cost. As mentioned above, **near-term savings potential, actual achievable goals, and program costs for a measure-level implementation will vary from the savings potential and costs estimated in this long-term study**. This potential study is one element to be considered in program design, along with historical program participation and current market conditions (with the team members on the ground).

Some observations on the potential study results that can provide input to program planning are:

- There is strong potential with promoting advanced lighting, which includes networked lighting technology and controls in all sectors.
- There is high potential in O&M and behavior-type programs such as retrocommissioning if they are cost-effective.
- HVAC unitary equipment has high potential in both sectors.

5.4 Further Research

Finally, the potential study identified data gaps in characterizing ENO's market and measures. This is common for most utilities; however, for ENO to have more accurate potential estimates and information to support DSM planning, there is ENO-specific data that could support this end goal:

- Baseline and saturation studies for each sector
- Updated residential end-use survey
- C&I end-use survey
- Customer payback acceptance analysis specific to the ENO service area (in particular due to the high penetration of renters)

Appendix A. Energy Efficiency Detailed Methodology

A.1 End-Use Definitions

Table A-1. Description of End Uses

Segment	End Use	Definition
Residential	Total Facility	Consumption of all electric end uses in aggregate
	Lighting Interior	Overhead lights, lamps, etc.
	Lighting Exterior	Spotlighting, security lights, holiday/seasonal lighting, etc.
	Plug Loads	Large/small appliances including ovens, refrigerators, freezers, clothes washers, etc. Televisions, computers and related peripherals, and other electronic systems
	Cooling	All cooling, including both central air conditioning and room or portable air conditioning
	Heating	All heating, including both primary heating and supplementary heating
	Fans/Ventilation	Motor drives associated with heating and cooling
	Water Heating	Heating of water for domestic hot water use
	Other	Miscellaneous loads
C&I	Total Facility	Consumption of all electric end uses in aggregate
	Lighting Interior	Overhead lights, lamps, etc. (main building and secondary buildings)
	Lighting Exterior	Spotlighting, security lights, holiday/seasonal lighting, etc. (main building and secondary buildings)
	Plug Loads	Computers, monitors, servers, printers, copiers, and related peripherals
	Cooling	All cooling equipment, including chillers and direct expansion cooling
	Heating	All heating equipment, including boilers, furnaces, unit heaters, and baseboard units
	Fans/Ventilation	Motor drives associated with heating and cooling
	Refrigeration	Refrigeration equipment including fridges, coolers, and display cases
	Water Heating	Hot water boilers, tank heaters, and others
	Other	Miscellaneous loads including elevators, gym equipment, and other plug loads

Source: Navigant

A.2 Residential Sector

The following sections describe the detailed approach used to determine electricity consumption by segment, the approach used to estimate end-use intensities (EUIs), and the resulting residential household stock. To do this, Navigant needed to determine four pieces of information:

1. Base year stock
2. Base year consumption
3. Base year EUIs
4. Reference case forecast for all values

1. Base Year Residential Stock and 2. Base Year Electricity

To estimate the residential stock, Navigant proposed an approach that leveraged ENO's billing data. The challenge with this approach was that ENO's billing data identifies residential accounts using a customer name rather than a billing address. This can overstate the residential stock, as multiple tenants may occupy a single billing address over time. For example, a home with two different tenants (e.g., tenant A from January to June, and tenant B from July to December) are reported as two separate accounts and thus imply two separate residential households. This approach can also underestimate the average electricity usage by account. In fact, the team compared the billing and consumption data against historical sales and found that the data did not align. Navigant overcame these challenges by:

- Determining residential electricity sales (GWh) with a full year of data (e.g., an account with 12 consecutive months of sales) by segment and calibrating these values to ENO's sales forecast to ensure alignment with ENO's sales planning assumptions moving forward.
- Determining stock (#) from accounts with a full year of data (e.g., an account with 12 consecutive months of sales) by segment and calibrating these to ENO's account forecast to ensure alignment with ENO's account planning assumptions moving forward.

The team applied this approach to the two residential segments to ensure that all datasets provided by ENO aligned to their internal planning assumptions. Table A-2 provides an example of the base year residential stock and sales calculations.[68]

[68] Note these do not represent actual values provided by ENO. All values are meant to illustrate the methodology.

Table A-2. Example Base Year Residential Stock and Sales Equations

Step	Value	Calculation
(1) Aggregate sales from residential sector billing data to get a sector-level sales value (1,000 GWh for single family and 900 GWh for multifamily)	1,900 GWh	
(2) Determine sales for residential sector from billing data	1,700 GWh	Provided by ENO
(3) Compare (1) to (2) to get a calibration factor	0.89	(2) / (1)
(4) Calibrate segment-level sales by calibration factor from (3)	895 GWh for single family; 805 GWh for multifamily	Segment-level sales from (1)*(3)

Note: Navigant used this process for both the residential stock (accounts) and sales (load). As mentioned above, the team used ENO's billing data as a starting point and the account forecast as the basis for calibration.
Source: Navigant analysis

Table A-3 shows the segment-level stock and base year sales derived from the calibration analysis outlined above.

Table A-3. ENO Residential Base Year Results

Segment	Sales (GWh)	Stock (Households)	kWh/ Household
Single Family	749	132,901	11,144
Multifamily	1,481	45,048	16,632
Total	**2,230**	**177,949**	**12,533**[69]

Source: Navigant analysis

3. Base Year EUIs

To determine residential EUIs at the segment level, Navigant leveraged the calibrated sales and stock derived above. The team then divided the load per segment by the stock per segment to get the EUIs. After calculating the segment-level EUIs, Navigant further disaggregated the values to get EUIs, a key model input. This process consisted of multiplying the segment-level EUIs by end-use allocations, or the proportion of energy used by a certain end use (e.g., this proportion of the EUI is X% of the total EUI). Navigant derived these proportions using the DOE's EnergyPLUS model in

[69] This figure represents the total consumption divided by the total number of households and not the addition of the single family and multifamily kWh/household EUI values.

conjunction with an internal model.

Table A-4 provides the derived end-use allocations by residential segment.

Table A-4. Base Year Residential EUIs (kWh per Acct.)

Building Segment	Cooling	Fans/ Ventilation	Heating	Hot Water	Lighting Exterior	Lighting Interior	Plug Loads	Heating/ Cooling	Total Facility
Single Family	3,229	1,790	304	493	345	2,158	2,824	3,533	11,144
Multifamily	4,819	2,672	454	736	515	3,221	4,215	5,273	16,632

Source: Navigant analysis

4. Reference Case Stock and EUIs

To develop the residential stock forecast through 2037, ENO provided Navigant with its residential account and sales forecasts. Based on these forecasts, the team derived the annual growth rates by dividing the difference of the new and old stock by the old stock (e.g., (2017 stock – 2016 stock) / 2016 stock). Navigant used the same approach to determine the annual sales forecast growth. After deriving the growth rates, the team applied them directly from the account forecast to determine the growth in stock across all segments over the forecast period. Likewise, the team applied the annual growth rates directly from the sales forecast to determine the growth in sales across all segments over time.

Table A-5 shows the growth in stock from 2016 to 2037 used in the reference case by segment.

Table A-5. Reference Case Residential Stock Forecast (Accounts)

Segment	2016	2037
Single Family	132,901	144,972
Multifamily	45,048	49,139
Total	**177,949**	**194,111**

Source: Navigant analysis

Because the EUI formula leverages the stock and load directly, the EUI growth trends follow both the stock and load trends. More specifically, the team divided the load by the stock to get the base year's EUIs. Therefore, the overall growth rate is 0.4% from 2016 to 2037 for both segments and all end uses. Table A-6 shows the change in EUI from 2016 to 2037.

Table A-6. Reference Case EUI Forecast (Accounts)

Segment	2016	2037
Single Family	11,144	10,829
Multifamily	16,632	16,161

A.3 C&I Sector

To determine the total C&I floor space stock in ENO's service area, Navigant needed to determine four key pieces of information:

1. Base EUI for ENO's climate region in kWh/thousands SF
2. ENO's base year sales by segment in kWh
3. Base year C&I stock in thousands SF
4. Reference case forecast based on the base year numbers

The approach used to determine each of these pieces of information and the methodology for deriving the floor space stock is described below.

1. Base EUIs for ENO's Climate Region

As a starting point for the analysis, Navigant needed to determine a base EUI value by segment that the team could calibrate to ENO's stock and climate. Navigant first began with the US Energy Information Administration's (EIA's) electricity energy (use) intensity in kWh/SF by EIA principal building activity for ENO's climate category, the hot-humid region.[70] The team then mapped the principal building activities to the study's segments as a basis for the EUI. Table A-7 shows the mappings.

Table A-7. C&I EIA EUI Segments to Study Segment Mappings

EIA Principal Building Activity	Study Segment
Education	Colleges/Universities
Health care	Healthcare
All Buildings	Industrial/Warehouses
Lodging	Lodging

[70] Source: CBECS, Table C20. Electricity consumption and conditional energy intensity by climate region, 2012, May 2016, https://www.eia.gov/consumption/commercial/data/2012/c&e/cfm/c20.php

EIA Principal Building Activity	Study Segment
Office	Office – Large
Office	Office – Small
Public Assembly	Other Commercial
Food Service	Restaurants
Food Sales	Retail – Food
Mercantile	Retail – Non-Food
Education	Schools

Source: Navigant analysis

After deriving the calibrated segment-level EUIs, Navigant further disaggregated by end use to obtain EUIs. The team disaggregated the values by first determining the end-use allocations for each segment, leveraging the US Department of Energy's (DOE's) EnergyPLUS model in conjunction with proprietary internal models. Like residential, these values represented a proportion of each segment and were applied by multiplying the proportion by the segment-level EUIs.

As noted above, Navigant used a top-down approach rather than bottom-up for this particular analysis due to data availability. The team wanted to leverage as many ENO-specific sources as possible to ensure consistency with ENO's planning. In this case, ENO had not conducted any recent commercial end-use saturation studies, and Navigant could not find any reliable secondary studies specifically for the New Orleans area. For this reason, the team used the best data available at the time of modeling, which was ENO's internal forecasts and Navigant's end-use allocation estimates.

2. Base Year Electricity Sales

To determine the base year electricity sales of each C&I segment, ENO provided SIC account data, which the team used to create a breakdown of electricity sales by SIC. Navigant and ENO then worked together to develop a mapping of SIC data to C&I segments. It is generally recognized that SIC assignment to account data may have errors. The team developed this mapping through various reviews of the data to minimize electricity sales allocated to the other commercial segment. The mapping yielded a breakdown of accounts by segments (e.g., 5.6% of accounts are colleges/universities). Navigant used this breakdown to disaggregate the 2016 sales into segments (e.g., 5.6% of accounts are colleges/universities; therefore, 5.6% of the load belongs to that segment).

One exception to the account and sales mapping process was the industrial/warehouses segment. For this specific segment, Navigant noticed that the proportion of accounts mapped to this segment was greater than ENO's industrial load forecast by roughly 3%. To ensure complete alignment with ENO's internal planning assumptions, the team moved the excess 3% sales into the other commercial segment after discussions with the utility. Navigant then added in the industrial proportion, which was negligible (0%). This resulted in industrial/warehouses having 13.0% of the sales and other commercial having 13.9% of the sales.

Table A-8 shows the breakdown of C&I sales resulting from this analysis.

Table A-8. ENO C&I Base Year Results (GWh)

Segment	Stock (thousands SF)	Total Sales (GWh)	Percentage of Total
Colleges/Universities	15,388	196	5.6%
Healthcare	8,318	237	6.8%
Industrial/Warehouses	27,863	457	13.0%
Lodging	34,693	523	14.9%
Office – Large	15,875	270	7.7%
Office – Small	36,365	619	17.7%
Other Commercial	22,504	485	13.9%
Restaurants	4,720	218	6.2%
Retail – Food	2,574	125	3.6%
Retail – Non-Food	16,548	327	9.3%
Schools	3,494	45	1.3%
Total	**188,340**	**3,503**	**100%**

Source: Navigant analysis

3. Base Year Stock Calibration Approach

After determining the base EUIs from EIA data and disaggregating ENO's sales data, Navigant calculated the base year C&I stock using the formula in Figure A-1.

Figure A-1. C&I Base Year Stock Formula

ENO Stock by Segment [ft^2] = *ENO Sales by Segment [kWh]* / *EUI by Segment [kWh/ft^2]*

Derived from Step 2 | Derived from Step 1

Source: Navigant analysis

The calculation yielded the base year stock by segment, which the team then used to determine the reference case stock and EUI.

4. Reference Case Stock and EUI Approach

The team used the base year values to create the reference case stock and EUI forecasts. To do this, Navigant used the growth rates directly from ENO's sales and account forecast, applying the C&I sector forecasts to all segments except for industrial/warehouses.[71] For that specific segment, Navigant applied the industrial sector forecast to ensure consistency with ENO's data. The team then applied these growth rates to each of the base year values to obtain the reference case.

Table A-9 shows the results of these analyses.

Table A-9. Reference Case C&I EUI, Sales, and Stock

Data Point	2016	2037
Sales (GWh)	3,503	3,999
EUI (kWh/thousands SF)	255,744	272,412
Stock (thousands SF)	188,340	200,648

Source: Navigant analysis

[71] Note that the growth rates for the forecasts aligned at 0.4% for commercial and 0.0% for industrial/warehouses over the study period. These rates represent the compound annual growth rate (CAGR) across the entire study period. Actual growth rates fluctuate from year to year following the load forecast provided by ENO. The load forecasts are largely driven by industry indices.

Appendix B. Energy Efficiency Input Assumptions

B.1 Measure List and Characterization Assumptions

Navigant developed the measure list and characterizations based on internal expertise, ENO-specific data, the New Orleans TRM, and secondary sources where necessary.

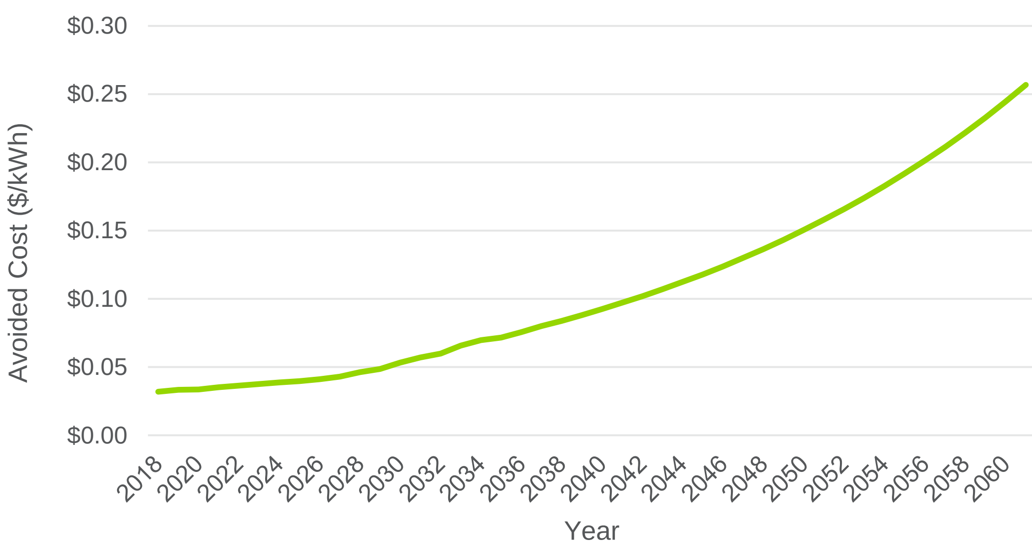
B.2 Avoided Costs and Cost-Effectiveness

In addition to the reference case and measure characterization assumptions, Navigant input several cost-related inputs to determine the cost-effectiveness of measures over the study period. This section details those inputs.

Avoided Energy Costs

ENO provided the BP18U[72] avoided costs over the study period plus the longest measure life (2037 + 25 years) to Navigant to input into the model. Figure B-1 shows the avoided energy cost projections, or forecasted locational marginal prices (LMPs).

Figure B-1. ENO BP18U Avoided Cost Projections

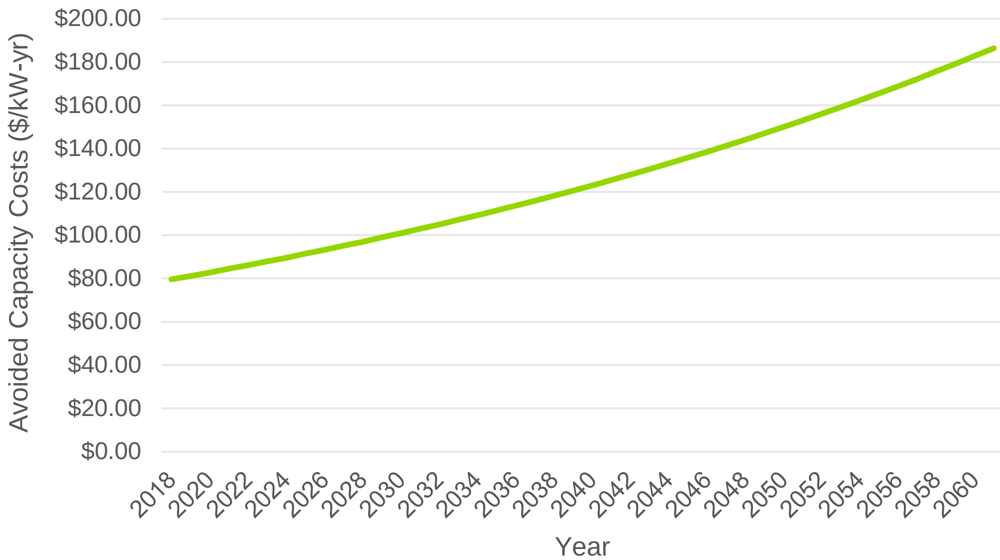


[72] BP18U refers to the vintage of a set of planning and modeling assumptions. At the time of this study, BP18U was the latest assumption set available.

Avoided Capacity Cost

ENO also gave Navigant avoided capacity costs to input into the model for costs over the study period plus the longest measure life (2037 + 25 years). Like the avoided energy costs, the capacity costs align with ENO's BP18U and its internal planning. Figure B-2 shows these costs over the study period.

Figure B-2. ENO BP18U Avoided Capacity Projections

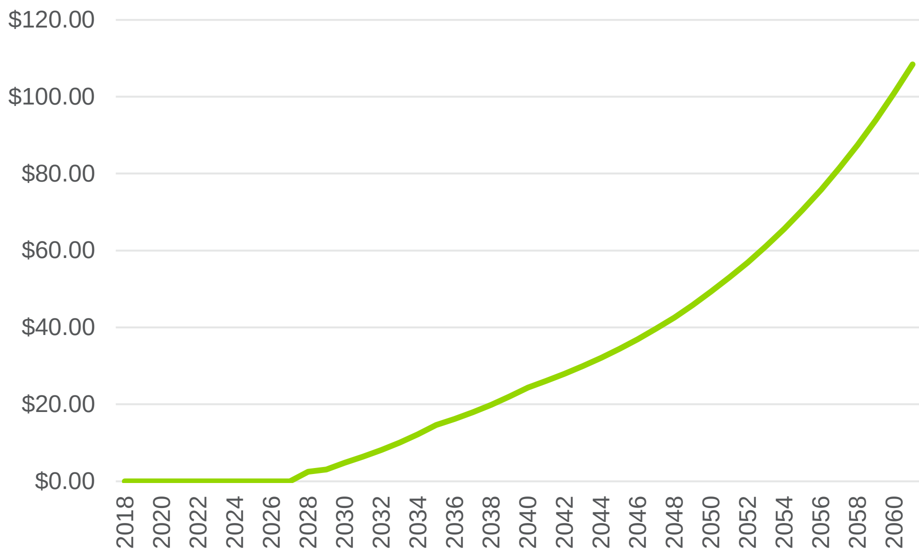


Carbon Pricing

In addition to avoided costs, ENO provided carbon pricing estimates through 2050 for the potential model. However, the carbon pricing inputs needed to extend further out than the study period to accurately model measure costs over their lifetime. More specifically, Navigant needed to model carbon prices up until the end of the study period plus the longest measure life (25 years). The team extrapolated these last years by taking the average growth (8%) for the last 5 years of the forecast (2045-2050) and applying it to the remaining 11 years.[73] Figure B-3 shows the carbon pricing estimates provided and extrapolated.

[73] Note that the growth rate was flat for the remaining 5 years provided.

Figure B-3. ENO Carbon Pricing Projections[74]



B.3 Cost-Effectiveness Calculations

The potential analysis uses two forms of cost-effectiveness calculations. The total resource cost (TRC) test is for utility cost-effectiveness. There is also the participant cost test (PCT), which is mostly addressed by calculating the participant payback period instead of the benefit-cost ratio for the PCT. This section describes these tests, the inputs, and how they are used for the potential study.

TRC Test

The TRC test is a benefit-cost metric that measures the net benefits of energy efficiency measures from the combined stakeholder viewpoint of the utility (or program administrator) and the customers. The TRC benefit-cost ratio is calculated in the model using Equation B-1.

Equation B-1. Benefit-Cost Ratio for TRC Test

$$TRC = \frac{PV(Avoided\ Costs)}{PV(Technology\ Cost + Admin\ Costs)}$$

[74] Note that the forecast extends until 2061, although the label for year 2061 is not visible. This is because the chart shows years in increments of two for aesthetic purposes.

Where:

- *PV( )* is the present value calculation that discounts cost streams over time.
- *Avoided Costs* are the monetary benefits resulting from electric energy and capacity savings—e.g., avoided costs of infrastructure investments and avoided fuel (commodity costs) due to electric energy conserved by efficient measures.
- *Technology Cost* is the incremental equipment cost to the customer.
- *Admin Costs* are the administrative costs incurred by the utility or program administrator.

Navigant calculated TRC ratios for each measure based on the present value of benefits and costs (as defined above) over each measure's life. Effects of free ridership are not present in the results from this study, so the team did not apply a NTG factor. Providing gross savings results will allow ENO to easily apply updated NTG assumptions in the future and allow for variations in NTG assumptions.

The administrative costs are included when reporting sector-specific or portfolio-wide cost-effectiveness. However, they are not included at the measure level for economic potential screening. For this screening, it is important to identify measures that are cost-effective on the margin prior to assessing effects for the achievable potential where administrative costs are considered depending on the amount and level of programmatic spend.

Participant Payback Period

Navigant calculates the customer payback period to assess customer potential to implement the energy-saving action. The payback period is used to assess customer acceptance and adoption of the measure. Additional details are described in the achievable potential methodology section 2.1.4.3. The payback period is calculated after the incentive is applied to the measure cost. Equation B-2 demonstrates the calculation.

Equation B-2. Participant Payback Period

$$Payback = \frac{Annual\ kWh\ Saved\ \times Annualized\ Retail\ Rate\ \left(\$/_{kWh}\right)}{Incremental\ Measure\ Cost - Incentive}$$

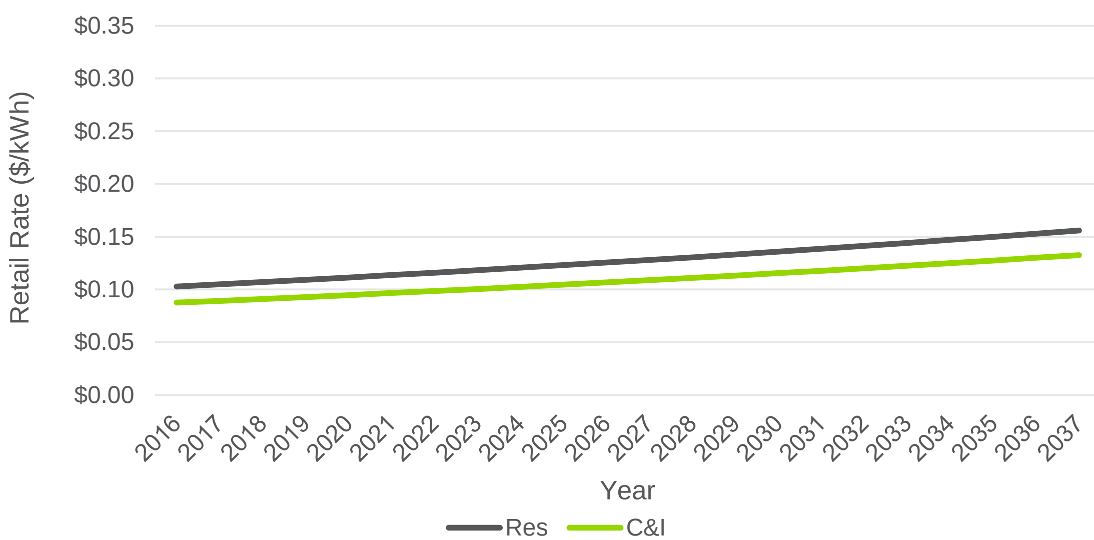
Where:

- *Annual kWh Saved* is calculated for each measure and segment (as appropriate).
- *Annualized Retail Rate* is the overall cost a customer pays per kWh consumed (see Appendix B.4).
- *Incremental Measure Costs* are the costs the participant would pay (without an incentive) to implement the measure. In replace-on-burnout (ROB) and new construction (NEW), depending on the measure, the difference in the cost of the efficiency and standard equipment is used instead of the full cost of installation (material and labor costs).
- *Incentives* are the incentive costs paid for a customer's out of pocket costs to be reduced.

B.4 Retail Rates

Because customer economics is a primary driver of energy efficiency measure adoption, Navigant used a forecast of electric retail rates for each sector to estimate achievable energy and demand potential. Because ENO did not have a forecast of retail rates readily available, the team calculated the retail rates by dividing the historic revenue ($) by the historic sales (kWh) to yield an approximation of retail rates ($/kWh) by sector for the base year (2016). Navigant then assumed that the rates would increase with inflation, or 2% per year.

Figure B-4. Electricity Retail Rate Forecast: 2016-2037



Source: Navigant analysis

B.5 Other Key Input Assumptions

As shown in Table B-1 below, Navigant used ENO's financial WACC as the discount rate[75] and an inflation rate consistent with the utility's planning.

Table B-1. Potential Study Assumptions

Variable Name	Percentage
Discount Rate	7.72%
Inflation Rate	2.00%

Source: ENO

[75] *See*, Docket UD-08-02, Technical Advisors' Evaluation of Energy Smart Program Years 7-9 Proposed Program Budget, dated July 6, 2017, for discussion of appropriate use of utility WACC as discount rate in evaluating cost effectiveness of DSM programs.

Appendix C. Hourly 8,760 Analysis and Measure/Program Mapping

Navigant developed an 8,760 hourly normalized end-use load shape library to support case-specific assessments of specific energy efficiency, demand response (DR), and other technologies assessed as part of this study. For this task, the team created representative end-use load shapes for each customer segment identified by ENO. Navigant also used these load shapes to calculate the peak savings for energy efficiency measures.

In the absence of end-use metered consumption, the US Department of Energy (DOE) prototype reference building models, simulated with local weather files, provide reasonable end-use load shapes to use in the potential model. The end-use load profiles are sensitive to several of the building model inputs (temperature setpoints, operation schedules, etc.); however, Navigant put considerable thought into adjusting these inputs to model typical consumption profiles for each building segment.

End-use metering provides load shapes with a higher degree of certainty, but the costs far exceed those of using prototypical building models. The resulting end-use load shape estimates may have high uncertainty. Additional rigor of the end-use load shape estimate becomes critical when the valuation of energy efficiency and understanding of each electric using equipment load profile must match each kW as tracked by supply-side resource planning. In these instances, end-use metering may be warranted.

C.1 End-Use Load Shape Development

Navigant's load profile development followed these steps:

1. **Assess measures and identify load profiles.** Following ENO approval of the final list of measures to be characterized and included in the analysis, Navigant staff identified a set of end use/sector/segment combinations of load profiles such that each conservation measure and base technology has an assigned load profile.
2. **Present load profile mapping for ENO feedback and approval.** Once Navigant staff mapped a load profile type to each measure, ENO reviewed the list of load profiles and the measures to which they map.
3. **Identify appropriate base load shapes.** To maximize value for ENO, Navigant leveraged its existing database of end-use sectoral load profiles for this analysis.
4. **Adapt load shapes to New Orleans.** Navigant include New Orleans-specific weather and residential sector consumption data to adapt load shapes to be ENO-specific. The next section describes the approach used for this step.
5. **Apply load profiles to DSMSim outputs.** Navigant applied the final load shapes to the aggregated DSMSim outputs to deliver the 8,760 profile of conservation impacts required by ENO.

Load Shape Development Approach

Navigant used the EnergyPlus building simulation software to run prototypical building energy models for residential and C&I customer segments. The team used updated versions of the US DOE commercial and residential reference building models to complete the simulations; these are representative of typical building constructions and represent typical energy and demand for buildings within the building stock. Navigant maintains this model set for extracting end-use load shapes for potential studies. The team leveraged EnergyPLUS prototype models that include several updates made during a previous study to more accurately reflect typical hourly energy consumption of buildings. These updates include smoothing HVAC operation schedules and ramping HVAC setpoint changes over many hours instead of a step-change in setpoint between two adjacent hours. Navigant also leveraged various end-use load shape metering studies to make informed model updates to more accurately reflect real-world operation of these equipment types:

- Navigant updated the lighting profiles contained in the DOE commercial reference building models with Northeast Energy Efficiency Partnerships (NEEP) lighting profiles.[76] The NEEP lighting profiles are weather-normalized lighting profiles that were developed for the Northeast and Mid-Atlantic regions of the US using data from integral lighting meters. The metered data was collected for energy efficiency project evaluations ranging from 2000 to 2011. It is important to note that non-weather dependent end uses can be transferable from one region to another, such as lighting and appliances.[77]
- Navigant updated the lighting profiles for the residential reference building with the residential lighting load shapes from a metering study in the Northeast. The metered data was collected in 2015.

Navigant used typical meteorological year (TMY) weather data for New Orleans in the EnergyPLUS modeling environment.

Residential Load Shapes

ENO provided Navigant with 2015 distribution-level data containing hourly energy consumption for residential buildings across the ENO service area. The team used the consumption data for the residential sector to visually calibrate the load shape outputs

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[76] Lighting hourly load profiles were taken from the July 19, 2011 C&I Lighting Load Shape Project for NEEP (associated spreadsheet - Profiles v2.6_4_18-KIC.xls).

[77] End-Use Load Data Update Project Final Report, www.neep.org/file/2693/download?token=aOWk8oud. Tables 3 and 4 in the report identify the load shapes that are highly transferrable across regions.

from the residential building models for the 2015 model year. To do this, Navigant processed the consumption data and the hourly building energy model output data to visually compare average daily profiles (weekday and weekend) for each month of the year. The team adjusted building model inputs to calibrate the total building load to the ENO distribution data.

For the residential building model, Navigant used the average daily load shapes from the ENO residential distribution data to adjust various inputs in the building model. The team adjusted building model input parameters to match the on-peak and off-peak energy consumption shapes and to ensure that the total facility energy peaks developed with the building model lined up temporally with the system peaks represented within the distribution data. Navigant made slight adjustments to lighting, equipment, and heating and cooling schedules to calibrate the residential model to the ENO distribution data.

Load profiles were then developed using the calibrated building models and a TMY3 New Orleans weather file. Table D-1 and Table D-2 list the residential customer segment building types and end uses modeled, respectively.

C&I Load Shapes

The Navigant team used the commercial building models from its model library and simulated typical load shapes using the TMY3 New Orleans weather files. Navigant inputted these load shapes into the ENO potential model. Table C-1 and Table C-2 list the C&I customer segment building types and end uses modeled, respectively.

Table C-1. Modeled Customer Segments by Sector

Residential	Commercial and Industrial
Multifamily	Colleges/Universities
Single Family	Healthcare
	Industrial/Warehouses
	Lodging
	Office-Large
	Office-Small
	Schools
	Restaurants
	Retail - Food
	Retail (Non-Food)
	Other Commercial

Table C-2. Modeled End Uses by Sector

Residential	Commercial & Industrial
Total Facility (Electric)	Total Facility (Electric)
Lighting Interior (Electric)	Lighting Interior (Electric)
Lighting Exterior (Electric)	Lighting Exterior (Electric)
Plug Loads (Electric)	Plug Loads (Electric)
Cooling (Electric)	Cooling (Electric)
Heating (Electric)	Heating (Electric)
Heating/Cooling (Electric)	Heating/Cooling (Electric)
Hot Water (Electric)	Fans/Ventilation (Electric)
Other	Refrigeration (Electric)
	Hot Water (Electric)
	Other

C.2 Hourly IRP Model Inputs Development

The Navigant team used the 8,760 loadshapes developed using the approach described in the previous section to convert the annual potential estimates into hourly potential estimates. In doing so, Navigant created program categories (Table C-3) to aggregate these hourly potential estimates to the program level and develop the input files necessary to support the IRP modeling. Navigant performed this aggregation using the mapping in Table C-4, below. The table shows a many-to-one mapping between measures and programs because some measures belong to more than one program. Navigant used the verified savings breakdown by program in ENO's PY6 Energy Smart EM&V report to weight the savings allocation of these measures to programs.

Table C-3. Program Categories

Sector	Program Name	Program Abbreviation
C&I	Commercial Behavior	Com Behavior
	Large Commercial & Industrial	Large C&I
	Small Commercial & Industrial	Small C&I
Res	Consumer Products	Consumer Products
	Home Performance with Energy Star	HPwES
	Heating, Ventilation, Air Conditioning	HVAC
	Low Income_ Multi-Family	LI_MF
	Residential Behavior	Res Behavior

School Kits	School Kits

Table C-4. Measure and Program Mapping for IRP Modeling Inputs

Sector	Program	Measure
C&I	Com Behavior	C&I | Building Benchmarking
C&I	Com Behavior	C&I | Retro commissioning
C&I	Large C&I	C&I | Advanced Lighting Controls
C&I	Large C&I	C&I | Advanced Roof Top Unit (RTU) Controls
C&I	Large C&I	C&I | Air and Water-Cooled Chillers
C&I	Large C&I	C&I | Air Compressor Improvements
C&I	Large C&I	C&I | Building Controls and Automation Systems (applicable to central/RTU systems)
C&I	Large C&I	C&I | Combination Ovens
C&I	Large C&I	C&I | Commercial Clothes Dryer
C&I	Large C&I	C&I | Commercial Clothes Washer
C&I	Large C&I	C&I | Commercial Fryers
C&I	Large C&I	C&I | Commercial Griddles
C&I	Large C&I	C&I | Commercial Steam Cookers
C&I	Large C&I	C&I | Computer Power Management
C&I	Large C&I	C&I | Controls Continuous Dimming
C&I	Large C&I	C&I | Controls Occupancy Sensor
C&I	Large C&I	C&I | Convection Ovens
C&I	Large C&I	C&I | Cool Roof
C&I	Large C&I	C&I | Demand Control Ventilation
C&I	Large C&I	C&I | Demand Controlled Ventilation (DCV) Exhaust Hood
C&I	Large C&I	C&I | Door LEDs
C&I	Large C&I	C&I | Ductless Mini-Split Heat Pump
C&I	Large C&I	C&I | Electric Storage Water Heater
C&I	Large C&I	C&I | Electric tankless water heater
C&I	Large C&I	C&I | ENERGY STAR Clothes Washers
C&I	Large C&I	C&I | ENERGY STAR Residential-size Refrigerator in Commercial Buildings
C&I	Large C&I	C&I | Evap Fan Controls
C&I	Large C&I	C&I | Fan and pump optimization (variable frequency drive)
C&I	Large C&I	C&I | Faucet Aerator
C&I	Large C&I	C&I | General Process Improvements (Strategic Energy management)
C&I	Large C&I	C&I | Heat Pump Water Heater
C&I	Large C&I	C&I | High Efficiency Fans and energy management

Sector	Program	Measure
C&I	Large C&I	C&I | Interior 4 ft LED
C&I	Large C&I	C&I | Interior LED High Bay | Replacing HID
C&I	Large C&I	C&I | Interior LED High Bay | Replacing T8HO HB
C&I	Large C&I	C&I | LED Fixture - Interior
C&I	Large C&I	C&I | LED Screw In - Interior
C&I	Large C&I	C&I | LED Traffic Signals
C&I	Large C&I	C&I | Low-Flow Showerheads
C&I	Large C&I	C&I | Plug Load Occupancy Sensors
C&I	Large C&I	C&I | Pre-rinse spray valve
C&I	Large C&I	C&I | PTAC/PTHP Equipment
C&I	Large C&I	C&I | Smart Thermostats
C&I	Large C&I	C&I | Unitary and Split System AC/HP Equipment
C&I	Large C&I	C&I | Variable Air Volume HVAC
C&I	Large C&I	C&I | Water Heater Pipe Insulation
C&I	Large C&I	C&I | Window Film
C&I	Large C&I	C&I | Zero Energy Doors
C&I	Small C&I	C&I | Advanced Lighting Controls
C&I	Small C&I	C&I | Advanced Power Strips
C&I	Small C&I	C&I | Advanced Roof Top Unit (RTU) Controls
C&I	Small C&I	C&I | Building Controls and Automation Systems (applicable to central/RTU systems)
C&I	Small C&I	C&I | Combination Ovens
C&I	Small C&I	C&I | Commercial AC and HP Tune Up
C&I	Small C&I	C&I | Commercial Clothes Dryer
C&I	Small C&I	C&I | Commercial Clothes Washer
C&I	Small C&I	C&I | Commercial Fryers
C&I	Small C&I	C&I | Commercial Griddles
C&I	Small C&I	C&I | Commercial Steam Cookers
C&I	Small C&I	C&I | Computer Power Management
C&I	Small C&I	C&I | Controls Continuous Dimming
C&I	Small C&I	C&I | Controls Occupancy Sensor
C&I	Small C&I	C&I | Convection Ovens
C&I	Small C&I	C&I | Cool Roof
C&I	Small C&I	C&I | Demand Control Ventilation
C&I	Small C&I	C&I | Demand Controlled Ventilation (DCV) Exhaust Hood
C&I	Small C&I	C&I | Door Heater Controls
C&I	Small C&I	C&I | Door LEDs
C&I	Small C&I	C&I | Ductless Mini-Split HP
C&I	Small C&I	C&I | Electric Storage Water Heater

Sector	Program	Measure
C&I	Small C&I	C&I | Electric tankless water heater
C&I	Small C&I	C&I | Electronically Commutated Motors (ECMs) for Refrigeration and HVAC Applications
C&I	Small C&I	C&I | ENERGY STAR Clothes Washers
C&I	Small C&I	C&I | ENERGY STAR Residential-size Refrigerator in Commercial Buildings
C&I	Small C&I	C&I | Evap Fan Controls
C&I	Small C&I	C&I | Fan and pump optimization (variable frequency drive)
C&I	Small C&I	C&I | Faucet Aerator
C&I	Small C&I	C&I | Heat Pump Water Heater
C&I	Small C&I	C&I | Interior 4 ft LED
C&I	Small C&I	C&I | Interior LED High Bay | Replacing HID
C&I	Small C&I	C&I | Interior LED High Bay | Replacing T8HO HB
C&I	Small C&I	C&I | LED Fixture - Interior
C&I	Small C&I	C&I | LED Screw In - Interior
C&I	Small C&I	C&I | Low-Flow Showerheads
C&I	Small C&I	C&I | Plug Load Occupancy Sensors
C&I	Small C&I	C&I | Package terminal air conditioner/Package terminal heat pump Equipment
C&I	Small C&I	C&I | Refrigeration electronically commutated motor
C&I	Small C&I	C&I | Smart Thermostats
C&I	Small C&I	C&I | Solid Door commercial refrigerator
C&I	Small C&I	C&I | Strip Curtain
C&I	Small C&I	C&I | Variable Air Volume HVAC
C&I	Small C&I	C&I | Vend Machine Controls
C&I	Small C&I	C&I | Water Heater Pipe Insulation
C&I	Small C&I	C&I | Window Film
C&I	Small C&I	C&I | Zero Energy Doors
Res	Consumer Products	Res | Dehumidifiers
Res	Consumer Products	Res | Dryers
Res	Consumer Products	Res | ENERGY STAR Directional LEDs
Res	Consumer Products	Res | Omni-Directional LEDs
Res	Consumer Products	Res | Outdoor LED Light Bulb
Res	Consumer Products	Res | Pool Pumps
Res	Consumer Products	Res | Refrigeration
Res	Consumer Products	Res | Remove Second Refrigerator
Res	Consumer Products	Res | Window AC
Res	HPwES	Res | Advanced Networked Lighting Controls with Directional LEDs

Sector	Program	Measure
Res	HPwES	Res | Advanced Networked Lighting Controls with Omni-Directional LEDs
Res	HPwES	Res | Advanced Power Strips
Res	HPwES	Res | Air Infiltration
Res	HPwES	Res | Attic Knee Wall Insulation
Res	HPwES	Res | Ceiling Insulation
Res	HPwES	Res | Central AC Tune-Up
Res	HPwES	Res | Duct Sealing
Res	HPwES	Res | ENERGY STAR Directional LEDs
Res	HPwES	Res | Faucet Aerators
Res	HPwES	Res | Furnace Filter Whistle
Res	HPwES	Res | High Efficiency Windows
Res	HPwES	Res | Low-Flow Showerheads
Res	HPwES	Res | Omni-Directional LEDs
Res	HPwES	Res | Outdoor Dusk-Til-Dawn LED Light Bulb
Res	HPwES	Res | Outdoor LED Light Bulb
Res	HPwES	Res | Pipe Insulation
Res	HPwES	Res | Smart Thermostats
Res	HPwES	Res | Thermostatic shower valve
Res	HPwES	Res | Wall Insulation
Res	HPwES	Res | Window Film
Res	HVAC	Res | Air Source Heat Pump
Res	HVAC	Res | Central AC Tune-Up
Res	HVAC	Res | Central Air Conditioner
Res	HVAC	Res | Duct Sealing
Res	HVAC	Res | Ductless Heat Pump
Res	LI_MF	Res | Air Infiltration
Res	LI_MF	Res | Attic Knee Wall Insulation
Res	LI_MF	Res | Ceiling Insulation
Res	LI_MF	Res | Central AC Tune-Up
Res	LI_MF	Res | Duct Sealing
Res	LI_MF	Res | ENERGY STAR Directional LEDs
Res	LI_MF	Res | Faucet Aerators
Res	LI_MF	Res | Furnace Filter Whistle
Res	LI_MF	Res | High Efficiency Windows
Res	LI_MF	Res | Low-Flow Showerheads
Res	LI_MF	Res | Omni-Directional LEDs
Res	LI_MF	Res | Outdoor Dusk-Til-Dawn LED Light Bulb
Res	LI_MF	Res | Outdoor LED Light Bulb

Sector	Program	Measure
Res	LI_MF	Res | Pipe Insulation
Res	LI_MF	Res | Smart Thermostats
Res	LI_MF	Res | Thermostatic shower valve
Res	LI_MF	Res | Wall Insulation
Res	LI_MF	Res | Window Film
Res	Res Behavior	Res | Home Energy Report
Res	Res Behavior	Res | Large Residential Competitions
Res	Res Behavior	Res | Prepay Electricity Bills
Res	Res Behavior	Res | Web-based Real-time Feedback
Res	School Kits	Res | ENERGY STAR Directional LEDs
Res	School Kits	Res | Faucet Aerators
Res	School Kits	Res | Low-Flow Showerheads
Res	School Kits	Res | Outdoor LED Light Bulb

Note that the following programs that appear in the PY6 Energy Smart EM&V report have been rolled up to broader program categories in Table C-3, as follows:

- Low Income/Multi-Family—includes the Low Income and Multi-Family programs from the EM&V report
- Consumer Products—includes the GreenLight, Residential Lighting, and Other programs from the EM&V report

Appendix D. Achievable Potential Modeling Methodology Details

D.1 Calculating Achievable Potential

This section demonstrates Navigant's approach to calculating achievable potential, which is fundamentally more complex than calculating technical or economic potential.

The critical first step in the process to accurately estimate achievable potential is to simulate market adoption of energy efficient measures. The team's approach to simulating the adoption of energy efficient technologies for purposes of calculating achievable potential can be broken down into the following two strata:

1. Calculation of the dynamic approach to equilibrium market share
2. Calculation of the equilibrium market share

D.2 Calculation of Dynamic Equilibrium Market Share

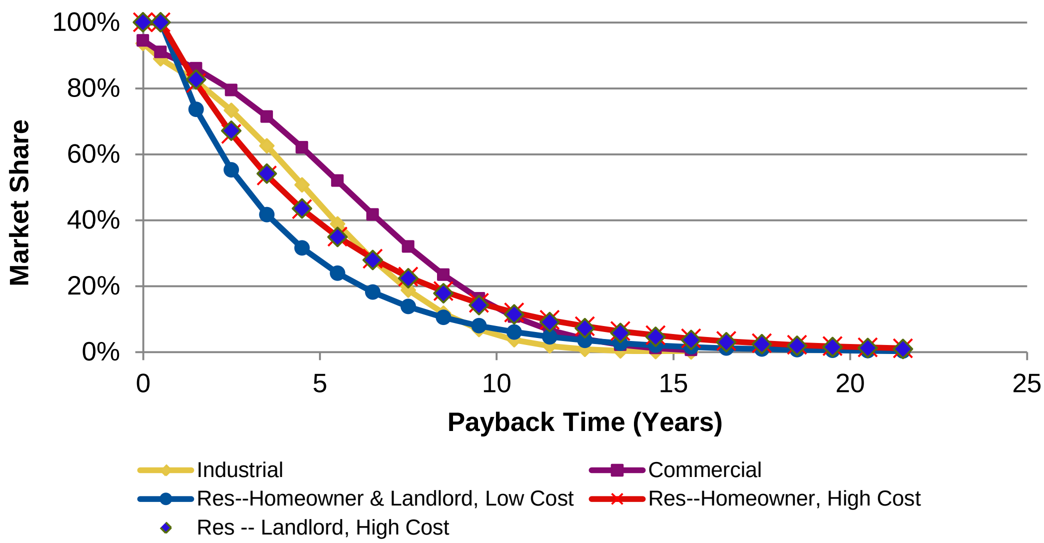
The equilibrium market share can be thought of as the percentage of individuals choosing to purchase a technology, provided those individuals are fully aware of the technology and its relative merits (e.g., the energy- and cost-saving features of the technology). For energy efficient technologies, a key differentiating factor between the base technology and the efficient technology is the energy and cost savings associated with the efficient technology. That additional efficiency often comes at a premium in initial cost. Thus, in efficiency potential studies, equilibrium market share is often calculated as a function of the payback time of the efficient technology relative to the inefficient technology. While such approaches have limitations, they are nonetheless directionally reasonable and simple enough to permit estimation of market share for the dozens or even hundreds of technologies that are often considered in potential studies.

Navigant uses equilibrium payback acceptance curves that were developed using primary research conducted by Navigant in the Midwest US in 2012.[78] To develop these curves, Navigant conducted surveys of 400 residential, 400 commercial, and 150 industrial customers. These surveys presented decision makers with numerous choices between technologies with low upfront costs but high annual energy costs and measures with higher upfront costs but lower annual energy costs. Navigant conducted statistical analysis to develop the set of curves shown in Figure D-1, which were leveraged in this study. Though ENO-specific data is not currently available to estimate these curves, Navigant considers that the nature of the decision-making process is such

[78] A detailed discussion of the methodology and findings of this research is contained in the *Demand Side Resource Potential Study*, prepared for Kansas City Power and Light, August 2013.

that the data developed using these surveyed customers represents the best data available for this study at this time.

Figure D-1. Payback Acceptance Curves



Source: Navigant, 2015

Because the payback time of a technology can change over time, as technology costs and/or energy costs change over time, the equilibrium market share can also change over time. The equilibrium market share is, thus, recalculated for every time-step within the market simulation to ensure the dynamics of technology adoption considers this effect. As such, the term equilibrium market share is a bit of an oversimplification and a misnomer, as it can itself change over time and is, therefore, never truly in equilibrium. It is used nonetheless to facilitate understanding of the approach.

D.3 Calculation of the Approach to Equilibrium Market Share

The team used two approaches to calculate the approach to equilibrium market share (i.e., how quickly a technology reaches final market saturation): one for new technologies or those being modeled as a retrofit (a.k.a. discretionary) measures, and one for technologies simulated as replace-on-burnout (ROB, a.k.a. lost opportunity) measures.[79] A high level overview of each approach is provided in the following sections.

[79] Each of these approaches can be better understood by visiting Navigant's technology diffusion simulator, available at: http://forio.com/simulate/navigantsimulations/technology-diffusion-simulation.

Retrofit/New Technology Adoption Approach

Retrofit and new technologies employ an enhanced version of the classic Bass diffusion model[80,81] to simulate the S-shaped approach to equilibrium that is commonly observed for technology adoption. Figure E-2 provides a stock/flow diagram illustrating the causal influences underlying the Bass model. In this model, achievable potential flows to adopters through two primary mechanisms: adoption from external influences such as program marketing/advertising, and adoption from internal influences including word of mouth. The fraction of the population willing to adopt is estimated using the payback acceptance curves illustrated in Figure D-1.

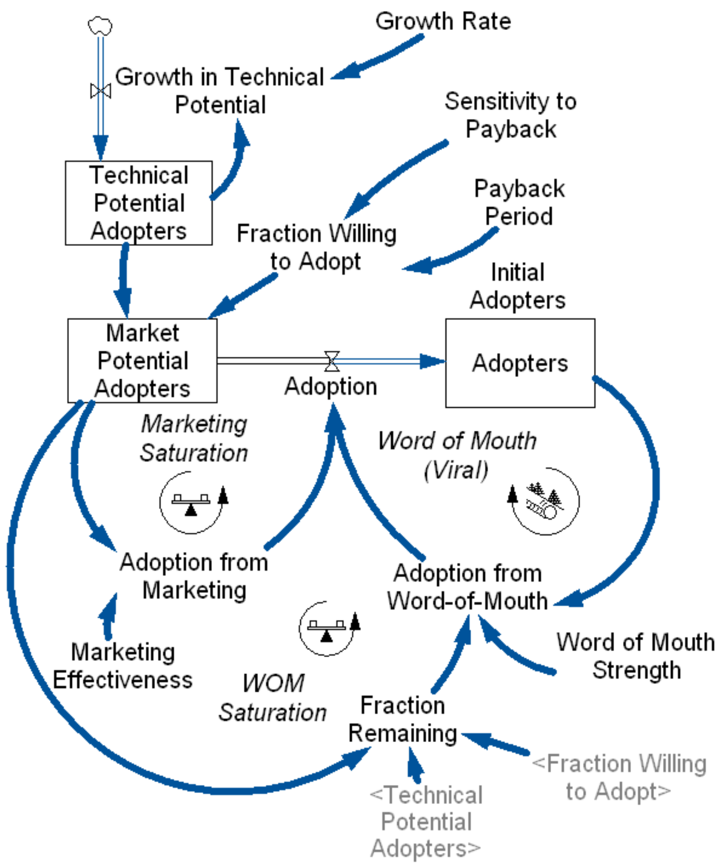
The marketing effectiveness and external influence parameters for this diffusion model are typically estimated upon the results of case studies where these parameters were estimated for dozens of technologies.[82] Additionally, the calibration process permits adjusting these parameters as warranted (e.g., to better align with historic adoption patterns within the ENO market). Recognition of the positive or self-reinforcing feedback generated by the word of mouth mechanism is evidenced by increasing discussion of concepts like social marketing and the term viral, which has been popularized and strengthened by social networking sites such as Facebook and YouTube. However, the underlying positive feedback associated with this mechanism has always been part of the Bass diffusion model of product adoption since its inception in 1969.

[80] Bass, Frank (1969). "A new product growth model for consumer durables." *Management Science* 15 (5): p215–227.

[81] See Sterman, John D. *Business Dynamics: Systems Thinking and Modeling for a Complex World*. Irwin McGraw-Hill. 2000. p. 332.

[82] See Mahajan, V., Muller, E., and Wind, Y. (2000). *New Product Diffusion Models.* Springer. Chapter 12 for estimation of the Bass diffusion parameters for dozens of technologies. This model uses the median value of 0.365 for the word of mouth strength in the base case. The Marketing Effectiveness parameter was assumed to be 0.04, representing a somewhat aggressive value that exceeds the most likely value of 0.021 (75th percentile value is 0.055) per Mahajan 2000.

Figure D-2. Stock/Flow Diagram of Diffusion Model for New Products and Retrofits

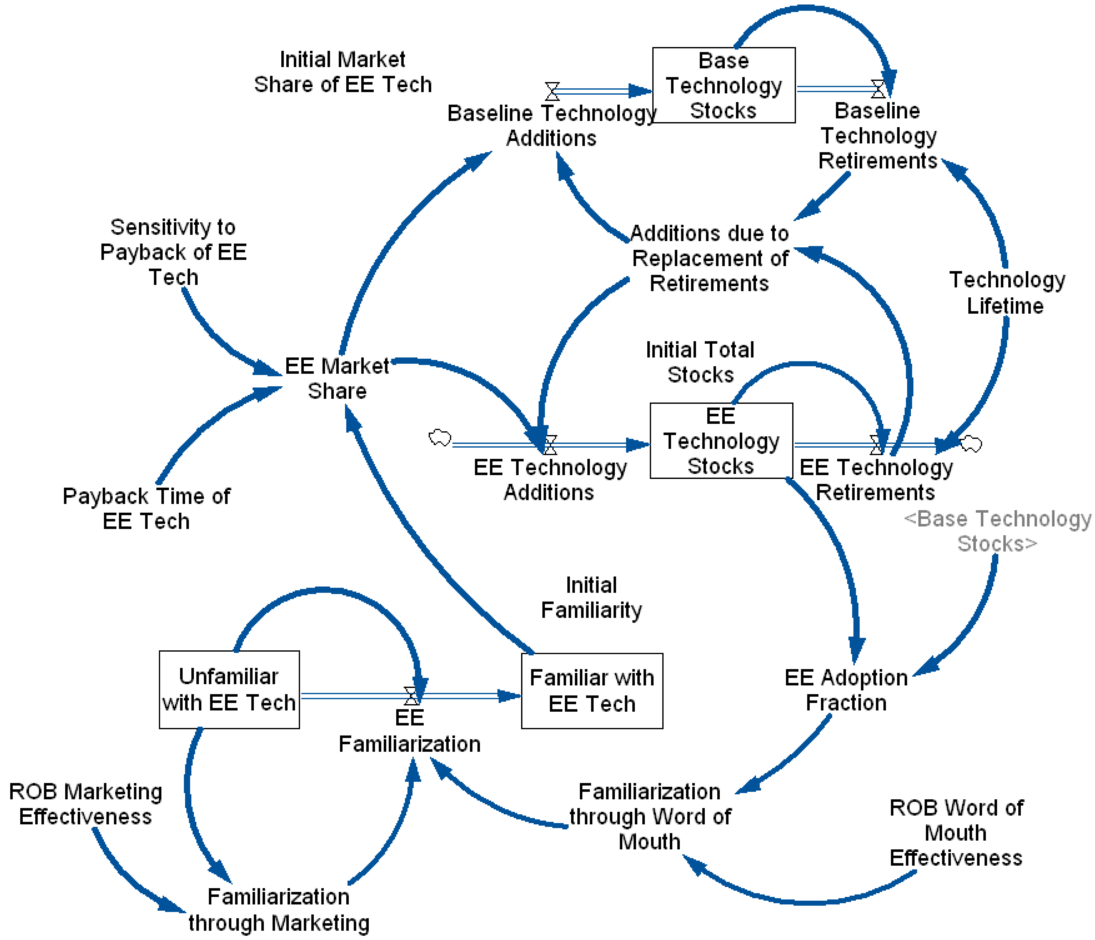


Source: Navigant, 2015

ROB Technology Adoption Approach

The dynamics of adoption for ROB technologies are somewhat more complicated than for new/retrofit technologies because it requires simulating the turnover of long-lived technology stocks. To account for this, the DSMSim model tracks the stock of all technologies, both base and efficient, and explicitly calculates technology retirements and additions consistent with the lifetime of the technologies. Such an approach ensures that technology churn is considered in the estimation of achievable potential, as only a fraction of the total stock of technologies are replaced each year, which affects how quickly technologies can be replaced. A model that endogenously generates growth in the familiarity of a technology, analogous to the Bass approach described above, is overlaid on the stock tracking model to capture the dynamics associated with the diffusion of technology familiarity. A simplified version of the model employed in DSMSim is illustrated graphically in Figure D-3.

Figure D-3. Stock/Flow Diagram of Diffusion Model for ROB Measures



Source: Navigant, 2015

Appendix E. Interactive Effects of Efficiency Stacking

The report's results assume that all measures are implemented in isolation from one another and that the measures do not include adjustments for interactive effects from efficiency stacking. Interactive effects from efficiency stacking are different from cross end-use interactive effects (e.g., efficient lighting affects heating/cooling loads), which are present regardless of stacking assumptions and are included in the reported savings estimates. This appendix describes the challenges related to accurately determining the effects of efficiency stacking, and why Navigant has modeled savings as though measures are implemented independently from one another.

E.1 Background on Efficiency Stacking

When a home or business installs two or more measures that affect the same end-use energy consumption in the same building, the total achievable savings is less than the sum of the savings from those measures independently. For example, in isolation, the installation of light-emitting diode (LED) lighting might save 40% of electric consumption relative to baseline linear fluorescent fixtures, while occupancy sensors might save 25% of electric consumption relative to fixtures without occupancy sensors. However, if both LED fixtures and occupancy sensors are installed in the same facility, the savings from the LED lighting decrease due to the reduced lighting operating hours caused by the occupancy sensors.

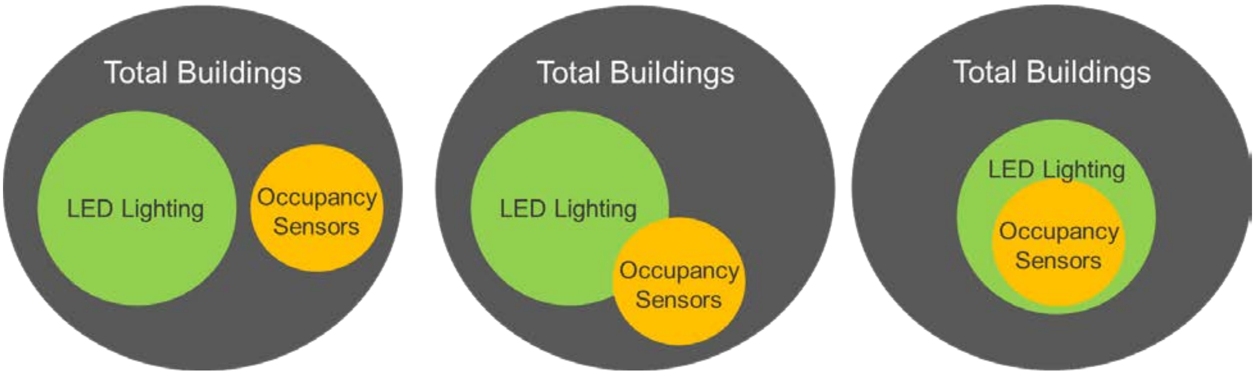
Navigant generalizes this concept by referring to measures that convert energy as engines (boilers, light bulbs, motors, etc.) and measures that affect the amount of energy an engine must convert as drivers (insulation, thermostats, lighting controls, etc.). Any time an engine and driver are implemented in the same building, the expectation is savings from the engine measure will decrease.[83]

Figure E-1 provides an illustration of three different efficiency stacking approaches. The modeled approach assumes no overlap in measure implementation and no efficiency stacking, which leads to an upper bound on savings potential. The opposite of the modeled approach is to assume all measures are stacked wherever possible, which provides a lower bound on savings. Lastly, there is the real-world approach where some measures are implemented in isolation and others are stacked. However, the data is simply not available to accurately estimate the savings from the real-world approach.

[83] In practice, it does not matter whether one assumes the engine's savings decrease or the driver's savings decrease, as the final savings result is the same. In this discussion, Navigant chose to always reduce the savings from the engine measures, while holding the savings from the driver measures fixed.

Figure E-1. Venn Diagrams for Various Efficiency Stacking Situations

Upper Bound (Modeled)	Real World	Lower Bound
Savings are independent	Uncertain mix of independent and stacked savings	Savings are stacked wherever possible



Source: Navigant

The area of the colored circle represents the number of buildings with a given savings opportunity. Overlapping circles indicate a building has implemented both measures.

E.2 Illustrative Calculation of Savings after Efficiency Stacking

For a simplistic scenario looking at only two measures it is possible to determine the stacked savings from the lower bound approach, which assumes efficiencies are stacked wherever possible. To find the LED lighting savings relative to the baseline after stacking:

1. **Find the complement of the occupancy sensor savings percentage.**

Occupancy Sensor Savings Complement = 100% - Occupancy Sensor Savings

Occupancy Sensor Savings Complement = 100% - 25% = 75%

2. **Reduce the LED lighting unstacked savings by the complement of the occupancy sensor savings.**

Stacked LED Lighting Savings = Unstacked LED Lighting Savings x Occupancy Sensor

Savings Complement Stacked LED Lighting Savings = 40% x 75% = 30%

3. **Find the greatest percentage of buildings where LED lighting and occupancy sensor stacking is possible.**

% of Buildings with Stacking = Buildings with Occupancy Sensors / Buildings with LED lighting x 100%

% of Buildings with Stacking = 145,300 / 720,200 x 100% = 20.2%

4. **Calculate the LED lighting weighted average savings across all buildings with occupancy sensors.**

Weighted LED Lighting Savings = Stacked LED Lighting Savings x % of Buildings with Stacking + Unstacked LED Lighting Savings x (100% - % of Buildings with Stacking)

Weighted LED Lighting Savings = 30% x 20.2% + 40% x (100% - 20.2%) = 38%

Table E-1 summarizes the example for the LED lighting and occupancy sensors before and after stacking. As expected, when treated independently the combined savings from the measures exceeds the combined savings after stacking.

Table E-1. Comparison of Savings Before and After Stacking

	LED Lighting	Occupancy Sensors
Applicable Buildings	720,200	145,300
Savings Treated Independently (No Stacking)		
Savings Relative to Baseline (%)	40%	25%
Savings Treated Interactively (Stacking)		
Savings Relative to Baseline (%)	38%	25%

Source: Navigant analysis

E.3 Impetus for Treating Measure Savings Independently

Although it is possible to find the lower bound on savings with just one driver and one engine measure, the process becomes intractable when multiple drivers and engines can be installed in the same facility. Table E-2 lists all the engine and driver measures included in this study that could have interactive effects within the commercial lighting end use, which is just one of many end uses across multiple sectors where stacking could occur.

Table E-2. Measures with Opportunity for Stacking in Commercial Lighting End Use

Engine Measures	Driver Measures
Exterior LED	Photocell
Interior LED Tube	Interior Daylighting Controls
Interior LED MR/PAR Lamps	Fixture or Wall-Mounted Occupancy Sensors
Interior Recessed LED Downlighting (Troffer LEDs)	-
Interior High Bay LED	-
LED Luminaire	-

Source: Navigant

Determining the appropriate stacking and correctly weighting the savings percentages from each of the engine measures requires the following:

- Case-by-case expert judgment about the combinations of driver and engine measures that might realistically be found in the same building given historic and future construction practices
- The conditional probability that a building has an inefficient driver A and an inefficient engine B for all drivers and engines relevant to a given end use
- In-depth knowledge of program design and how managers are considering pursuing participants and bundling measure offerings

Lastly, at low levels of customer participation, assuming savings are independent is the best representation of what the actual measure stacking would be. When customer participation is high, the real-world scenario is the best representation of actual measure stacking. Thus, under the plausible ranges of customer participation, the modeled (upper bound) scenario is likely to be a better representation of actual measure stacking than the lower bound scenario.

Although this report does not rigorously attempt to quantify the impact from efficiency stacking within the ENO service area, Navigant's experience indicates stacking can lead to a 5%-10% reduction in savings potential at high levels of technology adoption. This estimate is applicable to the residential and C&I sectors but is less applicable for the industrial sector because of reduced opportunity for stacking among the industrial measures considered in this study. Additionally, the 5%-10% reduction is highly uncertain and dependent upon the characteristics of any given building and grouping of measures.

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	)	**DOCKET NO. UD-17-03**

APPENDIX E

Study of Potential for Energy Savings in New Orleans
prepared by
Optimal Energy

JULY 2019

Study of Potential for Energy Savings in New Orleans

Final: August 31, 2018

Prepared for

by

with

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EXECUTIVE SUMMARY

STUDY CONTEXT AND OBJECTIVES

This study provides an estimate of the potential for energy savings and peak demand reduction through utility run energy efficiency, peak demand, and rate design programs in Entergy New Orleans' (ENO or "Entergy") service territory. Energy efficiency is typically a less expensive way to meet customer load requirements than traditional supply side investments. Furthermore, energy efficiency produces significant additional benefits, such as lower electric bills for ratepayers, lower carbon emissions, and healthier buildings. For these reasons, efficiency has increasingly been used by utilized as an alternative to supply side investments on the electric grid.

This study will be used to inform ENO's future Energy Smart programs; it will also produce inputs for ENO's upcoming Integrated Resource Plan (IRP). An IRP is an analysis that seeks to optimize a utility's supply portfolio to meet its load requirements at lowest cost, subject to fulfilling criteria related to reliability, risk, and other metrics. To this end, Optimal Energy, Inc. (Optimal) will provide ENO with a 20-year forecast of potential energy and demand savings as a demand-side resource in the IRP modeling, which will "compete" with other resources for inclusion in an overall strategy for least-cost planning.

SUMMARY OF RESULTS

High-level results for the three components of this study (i.e., energy efficiency, demand response, and rate design) are presented separately in the sections below. Further detail is provided in the full report that follows.

Energy Efficiency

As discussed in detail in the methodology section, the energy efficiency potential analysis included three levels of potential.

- Economic – All measures that are cost-effective and technically feasible, assuming no market barriers to adoption.
- Maximum Achievable – All cost-effective measures are promoted by aggressive programs, including incentives covering 100% of the total incremental costs of the measure, with the intent of securing the maximum amount of efficiency savings possible given real-world constraints of customer behavior.
- Program Achievable – The amount of available potential assuming "best practice" program design, with incentives covering, on average, 50% of the incremental costs of the measures. An exception is made for income-eligible customers, who still receive 100% incentives, as with ENO's current Energy Smart programs.

Our energy efficiency analysis begins by characterizing hundreds of possible energy efficiency measures as to their costs and energy savings. Savings are expressed as percentage reduction in energy use for the relevant "end-use" (e.g., lighting, cooling, refrigeration). An overall estimate of efficiency potential is generated by first dividing all energy use by ENO's customers into end-uses and then applying relevant measures and their respective savings percentages to these "buckets" of energy use. This "top-down" approach ensures that energy savings are appropriately scaled to the actual energy consumption of ENO's customers, and will be described in greater detail later in the report. Overall, we examined 173 different measures over 3 different market types (new construction/renovation, market opportunity, and retrofit/early retirement) and 14 different building types, for 1,491 permutations of unique measures.

Comparisons across potential types are useful for understanding the bounds of achievement. Following the portfolio level results we present more detailed results for the program potential, including disaggregated results for each sector (Residential, Low-Income, and Commercial/Industrial).

Table 1 provides a summary of the economic, maximum achievable, and program potential for electric energy savings relative to the sales forecast after 10 and 20 years. Savings as a percentage of forecast sales is a common metric for comparing efficiency programs and potential estimates, as it provides an understandable scale for those not familiar with energy measurements such as megawatt-hours (MWh). Overall, program potential for electricity is 21% of the forecasted load in 2038. This means that the cumulative result after 20 years of energy efficiency programs with incentives covering 50% of the incremental cost is that New Orleans electric load is 21% lower than it would be with no efficiency programs. The maximum achievable potential for electricity is 30% by 2038, roughly 40% greater than the program potential.

Potential after 20 years is not much greater than after 10 years, particularly for economic and max achievable scenarios, because the majority of equipment has been upgraded after the initial 10 year period. Over the course of the next 10 years, equipment that reaches the end of its useful life provides further opportunities for efficient measures, but savings from measures installed in the earlier years are expiring.

Table 1 shows the cumulative savings in year 10 and year 20. In other words, it represents the total reduction in the given year from all the efficiency measures installed in prior years that have not reached the end of their useful life. However, due to variations in measure lives and baseline adjustments for retrofit, the sum of incremental annual savings (the "new" savings achieved in each year of an efficiency program, independent of what has been achieved in other years) is typically higher than the cumulative savings totals. It is therefore instructive to see the incremental annual savings for each year of the study horizon. This is shown in Table 2.

Table 1 | Cumulative Energy Efficiency Potential as Percent of Sales Forecast

Year	Scenario	Residential Savings	Low Income Savings	C&I Savings	Total
2027	Economic	49%	49%	43%	45%
	Max Achievable	27%	27%	25%	25%
	Program	9%	27%	18%	18%
2037	Economic	49%	49%	45%	46%
	Max Achievable	33%	33%	29%	30%
	Program	9%	33%	21%	21%

Table 2 | Incremental Annual Savings by Year as Percent of Sales Forecast

	Economic Potential			Max Achievable Potential			Program Potential		
Year	Total	Res	C&I	Total	Res	C&I	Total	Res	C&I
2018	5.7%	7.5%	4.6%	0.7%	0.7%	0.6%	0.5%	0.5%	0.5%
2019	5.5%	7.3%	4.4%	1.3%	1.4%	1.2%	1.0%	1.0%	0.9%
2020	5.2%	6.7%	4.4%	2.0%	2.0%	1.9%	1.4%	1.4%	1.4%
2021	4.4%	4.6%	4.3%	2.6%	2.5%	2.7%	1.9%	1.7%	2.0%
2022	4.2%	4.3%	4.2%	2.8%	2.7%	2.8%	2.0%	1.8%	2.1%
2023	4.4%	4.5%	4.3%	3.0%	3.1%	3.0%	2.2%	2.1%	2.2%
2024	4.5%	4.7%	4.4%	3.1%	3.3%	3.0%	2.3%	2.3%	2.3%
2025	4.5%	4.6%	4.4%	3.2%	3.5%	3.1%	2.3%	2.4%	2.3%
2026	4.6%	4.7%	4.5%	3.3%	3.7%	3.1%	2.4%	2.5%	2.3%
2027	4.7%	5.0%	4.5%	3.4%	3.8%	3.1%	2.4%	2.6%	2.3%
2028	2.7%	2.5%	2.8%	1.3%	1.7%	1.1%	0.9%	1.2%	0.8%
2029	3.0%	2.8%	3.1%	1.6%	1.9%	1.5%	1.2%	1.3%	1.1%
2030	3.0%	2.9%	3.1%	1.9%	2.0%	1.8%	1.4%	1.4%	1.4%
2031	3.3%	3.0%	3.6%	2.3%	2.2%	2.4%	1.7%	1.5%	1.8%
2032	3.4%	3.0%	3.6%	2.3%	2.2%	2.4%	1.7%	1.5%	1.8%
2033	3.6%	3.1%	3.9%	2.5%	2.2%	2.6%	1.8%	1.6%	2.0%
2034	3.6%	3.1%	3.9%	2.5%	2.2%	2.6%	1.8%	1.6%	2.0%
2035	3.6%	3.1%	3.9%	2.5%	2.2%	2.6%	1.8%	1.6%	2.0%
2036	3.7%	3.4%	3.9%	2.6%	2.4%	2.6%	1.9%	1.7%	2.0%
2037	3.7%	3.4%	3.9%	2.6%	2.4%	2.6%	1.9%	1.7%	2.0%

Figure 1 shows the historic and forecasted sales of electric energy. As seen, the forecast is expected to be relatively flat over the next 20 years.[1] Total sales could be reduced significantly, however, through energy efficiency.

Figure 1 | Electric Energy Savings Relative to Sales Forecast

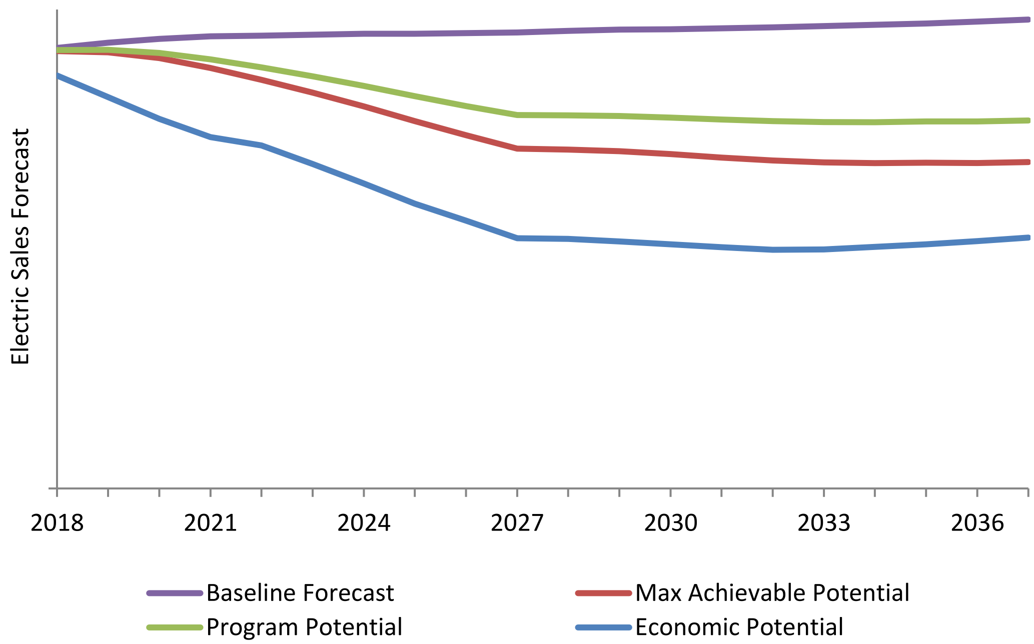


Table 3 shows the peak demand reduction in 2027 and 2037 for the different potential scenarios. These represent the savings associated with efficiency programs only. Savings from demand response programs are discussed separately below. In contrast to the energy savings estimates, these are given in megawatts (MW) instead of percent of total load. This allows for an easier comparison to traditional generation assets, such as the recently approved 150 MW gas turbine plant.

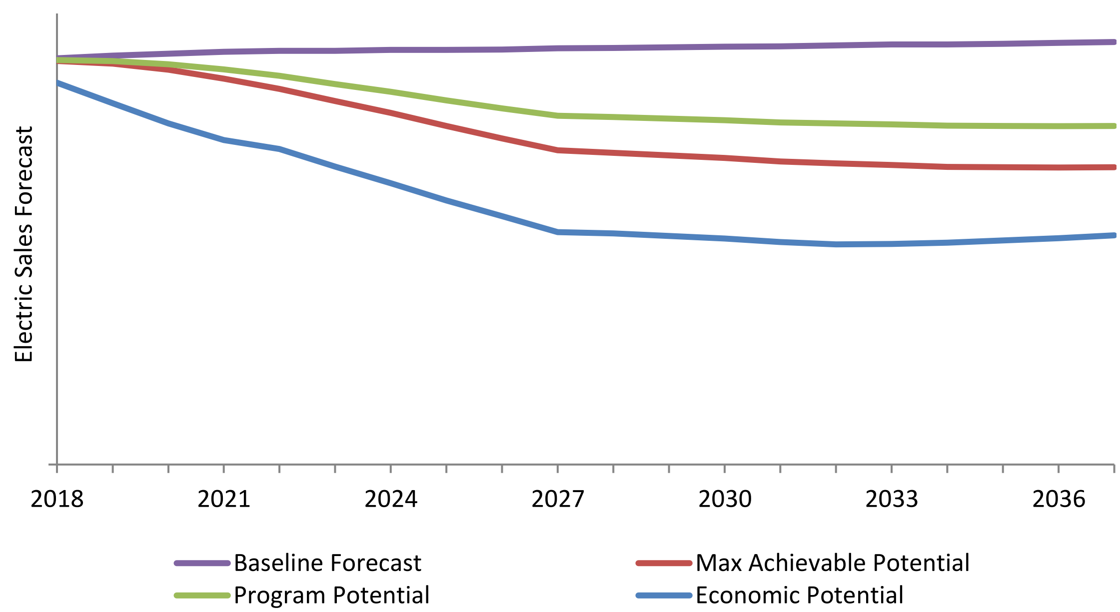
Figure 2 shows the historic and forecasted sales of electric peak demand. The other lines show the reduction in peak demand from each scenario. This graph only shows peak demand reduction from efficiency. Demand response impacts are discussed separately in the next section.

[1] The scale for the y-axis of this figure is omitted to avoid disclosing data considered by ENO as Highly Sensitive Protected Material (HSPM).

Table 3 | Cumulative Demand Savings Potential by Sector and Scenario (MW)

Year	Scenario	Residential Savings	LI Savings	C&I Savings	Total
2027	Economic Potential	137	133	260	530
	Max Achievable Potential	73	71	150	294
	Program Potential	17	71	106	194
2037	Economic Potential	137	134	286	557
	Max Achievable Potential	89	86	186	361
	Program Potential	24	86	133	243

Figure 2 | Electric Peak Demand Savings From Efficiency Relative to Sales Forecast



The next table shows the Total Resource Cost Effectiveness Test results for each scenario. The costs and benefits below represent the net present value of running 20 years of programs. As seen, while the scenarios incur significant costs (i.e., utility administrative costs, incentive costs, and customer contributions), the total benefits are two to four times larger than the costs.

Table 4 | Scenario TRC Cost-Effectiveness by Sector – Full 20 Years

Sector	Scenario	Costs ($MM)	Benefits ($MM)	Net Benefits ($MM)	BCR
Residential	Economic	461	1,216	754	2.6
	Max Achievable	310	716	406	2.3
	Program	207	467	260	2.3
C&I	Economic	516	2,486	1,970	4.8
	Max Achievable	304	1,129	825	3.7
	Program	202	823	621	4.1
Total	Economic	978	3,702	2,724	3.8
	Max Achievable	614	1,845	1,231	3.0
	Program	409	1,290	880	3.2

Table 5 shows the same information, but for the 2018-2027 time frame instead of the full 20-years. As seen, BCRs are very similar, but slightly lower. This is because of a higher share of retrofit measures which, on average, have lower BCRs than market driven measures.

Table 5 | Scenario TRC Cost-Effectiveness by Sector – First 10 Years

Sector	Scenario	Costs ($MM)	Benefits ($MM)	Net Benefits ($MM)	BCR
Residential	Economic	$335	792	$457	2.37
	Max Achievable	$203	$409	$207	2.02
	Program	$134	$267	$133	1.99
C&I	Economic	$333	1,445	$1,112	4.33
	Max Achievable	$185	597	$412	3.23
	Program	$118	$427	$309	3.62
Total	Economic	$668	$ 2,237	$1,569	3.35
	Max Achievable	$388	$ 1,006	$619	2.60
	Program	$252	$694	$442	2.75

The costs presented in the tables above represent the net present value of the total costs of energy efficiency programs and the resulting investment in efficient measures. This includes the administrative costs of running the programs and the full incremental costs of installing the measures, regardless of the amount paid for by the utility vs. paid for by the customer. In the program potential scenario, the utility only covers a portion of the measure costs; the table below shows the utility program budget needed to achieve the savings in the program potential scenario.

Table 6 | Nominal Program Potential Budgets by Year (Millions$)

Year	Non-Incentive	Incentive	Total	Year	Non-Incentive	Incentive	Total
2018	$1.6	$4.8	$6.5	2028	$2.6	$9.9	$12.5
2019	$3.2	$9.7	$12.9	2029	$3.1	$11.2	$14.3
2020	$4.7	$14.4	$19.2	2030	$3.5	$12.4	$15.9
2021	$6.4	$19.4	$25.8	2031	$4.2	$14.3	$18.5
2022	$6.7	$20.6	$27.3	2032	$4.2	$14.3	$18.5
2023	$7.2	$22.4	$29.7	2033	$4.6	$15.4	$20.1
2024	$7.6	$23.6	$31.2	2034	$4.6	$15.5	$20.2
2025	$7.8	$24.4	$32.2	2035	$4.7	$15.6	$20.2
2026	$8.0	$25.2	$33.2	2036	$4.8	$16.0	$20.7
2027	$8.1	$25.8	$34.0	2037	$4.8	$16.0	$20.8

Demand Response

While energy efficiency investments result in "permanent" load reductions (i.e., throughout the useful life of the measure), demand response (DR) strategies aim to reduce usage during peak load conditions. This may mean shifting consumption to off-peak periods or simply reducing consumption without replacing it at another time. Because energy prices are typically highest during peak load conditions, this can substantially reduce total system costs. Furthermore, in areas with constrained generation, transmission, or distribution capacity, it can avoid the need to invest in additional capacity, again typically at lower cost. The DR analysis in this study is based on the demonstrated performance of DR programs in other utility-implemented programs and extrapolating to the ENO service territory.

The DR analysis considered two scenarios, which roughly align with the max achievable and program potential scenarios from the energy efficiency analysis. Scenario One assumes participation on the lower end of the range of what is being achieved in other jurisdictions for residential and large customer direct load control (DLC), residential automated demand response (ADR), and large customer standard offer program (SOP). Scenario Two assumes participation on the upper end for these programs. In addition, Scenario One assumes a residential peak time rebate program (in which customers can receive an incentive payment for reducing usage during times of highest load, e.g., "peak time event"), while Scenario Two assumes residential critical peak pricing (in which customers must pay a much higher rate for usage during peak time events). Studies have been shown that because consumers tend to be more averse to losing money than to missing out on a similar windfall, critical peak pricing can have a somewhat bigger impact on behavior than peak time rebates.

Results for each of the scenarios are presented in the Figures and Tables below.

Table 7 | Demand Response Peak Load Reductions (MW) – Scenario One

Program	2018	2027	2037
Residential DLC and ADR	2.0	16.0	20.2
Residential PTR pricing	4.9	12.6	15.5
Large Customer SOP	1.1	10.9	16.9
Total	**8.0**	**39.5**	**52.5**

Table 8 | Demand Response Peak Load Reductions (MW) – Scenario Two

Program	2018	2027	2037
Residential DLC and ADR	3.9	31.9	40.3
Residential PTR pricing	5.6	14.2	17.5
Large Customer SOP	1.9	13.4	23.2
Total	**11.5**	**59.6**	**81.1**

Figure 3 | Electric Demand Savings—Scenario One

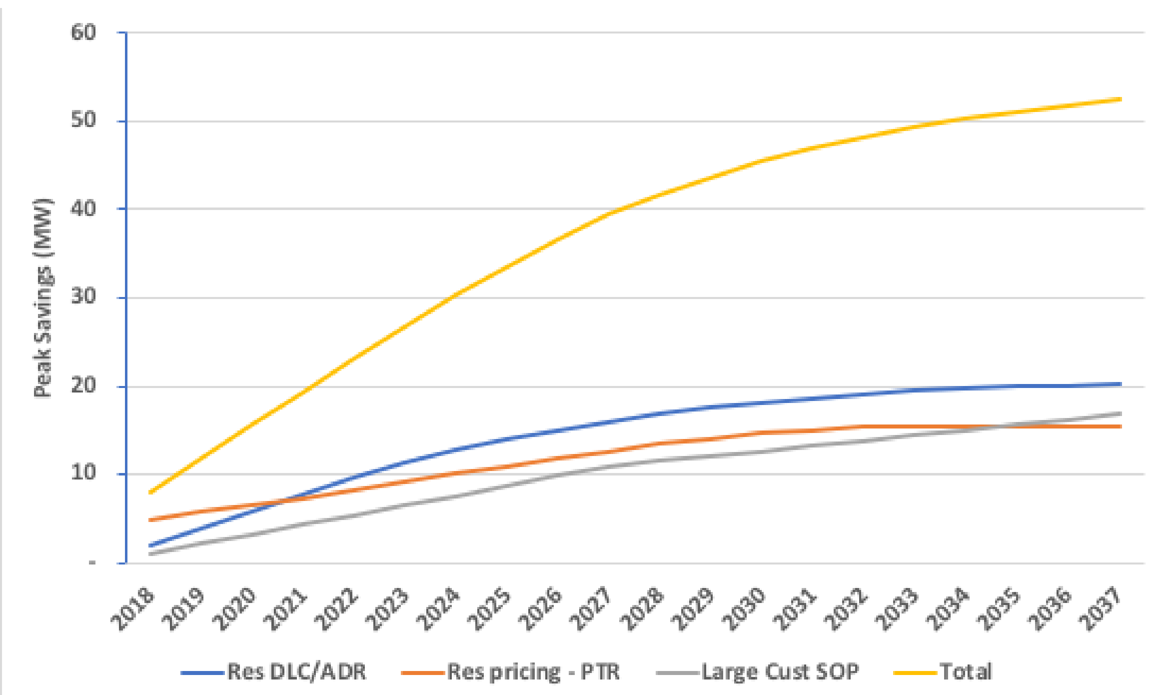
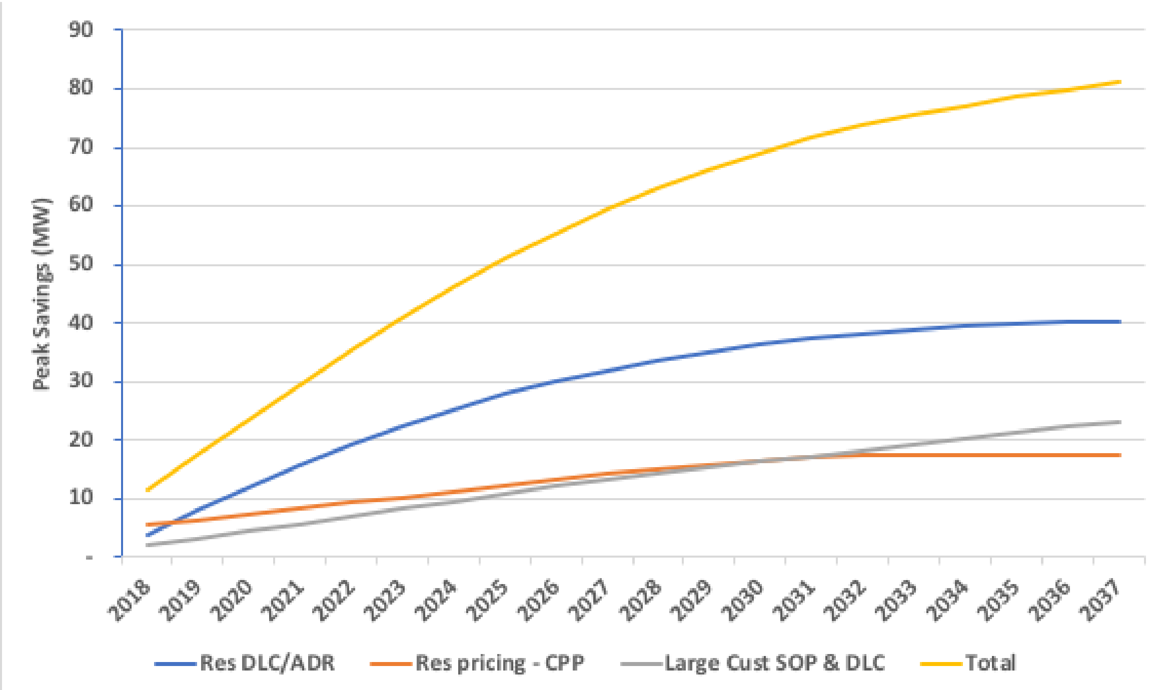


Figure 4 | Electric Demand Savings Relative to Sales Forecast--Scenario Two



Rate Design

The design of rate tariffs can have a significant impact on patterns of electric consumption. For example, inclining block rates (in which the price per unit of energy increases as consumption increases) tend to discourage energy use as the marginal cost of consumption exceeds the average. Declining block rates and large monthly fixed costs may encourage additional electric use for the opposite reason; lower marginal energy costs increase consumption. Now that advanced metering infrastructure (AMI) enables more sophisticated tariffs such as time-of-use (TOU) rates, utilities can better correlate prices with the costs of energy at different times. This can shift usage to off-peak periods, resulting in benefits similar to demand response efforts. Importantly, all of these rate options can be implemented in a way that does not change the total revenue collected from customers, which means neither the customers as a whole or the utility are disadvantaged.

For this study, we use recently published estimates of the price elasticity of electricity to calculate the impact of various revenue neutral rate designs for the residential sector. We considered the following rate structures.

- Higher monthly customer charges – this will decrease the marginal price of electricity, and thus increase the total usage
- Time-of-use rates – we examined both “opt-in” and “opt-out” scenarios
- Seasonal inclining block rate – the cost per unit of electricity increases as consumption increases, thus increasing the incentive to use less electricity at the margin

The table below shows the results from the analysis. Increased customer charges would increase the total electric load, while the inclining block rate would decrease total load. The time-of-use rate would produce a small decrease in total load, but create a fairly significant shift from on-peak to off-peak periods. Note that these impacts are one-time events – they do not accumulate from year-to-year as efficiency savings do.

Table 9 | Cumulative Rate Design Potential Relative to Sales Forecast

Rate Scenario	Change in energy consumption	Change in peak demand
Optional time of use	-0.5%	-4.4%
Default time of use	-0.9%	-7.9%
Inclining block rate	-2.1%	N/A
Seasonal ($25/mo. customer charge)	3.6%	N/A
Seasonal ($50/mo. customer charge)	8.9%	N/A

Total Peak Demand Savings, all DSM

Although this analysis mainly treats the demand response, energy efficiency, and rate design portions as independent and separate, we do provide a high level analysis of the likely total peak demand reduction from all three DSM types (efficiency, demand response, and rate design). The table below shows project total demand reduction by year. We derived these values by assuming a simple "loading order" of the categories: first rate design first, then energy efficiency, and then demand response. In other words, if in a given year the three categories would each produce a 10% reduction in peak separately, we assume that the rate design reduces the forecast by 10%, then the efficiency reduces the new forecast by 10%, and then demand response reduces the remaining peak by another 10%. This way, total demand is reduced by around 27%, instead of the 30% that would result if you simply added the reductions together. Table 10 presents the results of this analysis, assuming an optional time of use rate design, the program potential energy efficiency savings, and scenario two for demand response.

Table 10 | Cumulative Peak Demand Reduction from EE, DR, and Rate Design

Year	Peak Reduction (MW)	Year	Peak Reduction (MW)
2018	67	2028	297
2019	83	2029	305
2020	104	2030	313
2021	129	2031	321
2022	154	2032	329
2023	181	2033	335
2024	209	2034	340
2025	236	2035	343
2026	262	2036	347
2027	288	2037	350

INTRODUCTION

STUDY OVERVIEW AND SCOPE

This section provides a brief overview of the study scope and approaches, with more detail provided in the sections below. This study was conducted to provide a set of inputs for use in Entergy New Orleans' (ENO or "Entergy") upcoming Integrated Resource Plan (IRP), as well as to inform spending and savings targets for future Energy Smart program years. The study looked at savings opportunities from energy efficiency, demand response, and rate designs independently over a 20-year horizon. Each can serve as a resource for meeting some of ENO's forecast load requirements in the IRP modeling. The study scope was limited in several important respects:

- Except for input from the Delphi panel, no primary data were collected; the study thus relies primarily on existing available data, in some cases from outside of ENO's service territory or Louisiana
- Does not include combined heat and power (CHP) opportunities
- Did not attempt to project future changes in code that are not currently planned, nor changes in costs and savings from current technologies over time

The Methodology section later in this report describes the methods and assumptions used in the analysis in detail. The efficiency, demand response, and rate design analyses are each present in their own section that includes the methodology, data sources, and results.

SUMMARY OF STUDY PROCESS AND TIMELINE

The study was initiated in late March, followed by a kick-off meeting in New Orleans on April 4, attended by Entergy New Orleans, several stakeholders, and representatives of the City Council, the client for the project. At this meeting, the Optimal Energy team (Optimal) presented a preliminary measure list and described the study methodology. Analytical work began in earnest after the stakeholder meeting, including the creation of two Delphi panels to provide key input to the efficiency potential study. Draft results for a "maximum achievable" scenario were distributed to stakeholders on July 9, followed by another stakeholder meeting on July 13. Stakeholders submitted comments and questions on the draft results on July 23, and responses were provided on August 6. A draft final report was circulated on August 16, followed by the receipt of comments from stakeholders and the release of this report on August 31.

DEFINITION OF SCENARIOS

This study evaluated energy efficiency potential for three separate scenarios:

- Economic – Everything that is cost-effective and technically feasible, assuming no market barriers. A measure is considered to be cost-effective if the net present value of the avoided energy and capacity costs over its effective useful life is equal to or greater than the net present value of the measure cost.

- Maximum Achievable – The maximum level of program activity and savings that is possible given the market barriers to adoption of energy efficient technologies, with no limits on incentive payments, but including administrative costs necessary to implement programs.
- Program Achievable – A feasible and practical level of achievable savings given a specific set of programs targeting specific markets, with realistic estimates of incentive payments. Administrative costs are again included.

The analyses of demand response and rate design opportunities proceeded using slightly different methodologies, so the scenario definitions for efficiency are not directly applicable to these resources. The demand response analysis includes two scenarios of greater or lesser "aggressiveness" in assumed customer response and a key programmatic difference. The rate design analysis included five different scenarios with a range of impacts.

ENERGY EFFICIENCY

This section presents the methodology for and detailed results from our analysis of the energy efficiency potential.

SUMMARY OF APPROACH & MAJOR ASSUMPTIONS

The major steps in conducting the energy efficiency potential study were as follows:

- Develop energy use forecasts
- Disaggregate energy forecasts by sector (e.g., residential vs. commercial), and end uses (e.g., lighting, cooling, refrigeration)
- Characterize efficiency measures
- Screen measures and programs for cost-effectiveness
- Develop measure penetrations for "achievable" scenarios
- Determine scenario potential and develop outputs

A key characteristic of our approach to efficiency potential studies is that it proceeds using a "top-down" methodology. This involves beginning with the entirety of ENO's electric sales, then "disaggregating" those sales into many smaller quantities of electricity that represent consumption by various customer types and several building types. From there, energy efficiency measures—in the form of percentage reductions in consumption—are applied to the portion of each quantity of electricity to which they are applicable. This is in contrast to a "bottom-up" methodology that seeks to build up the efficiency potential by estimating the quantity of measures that could be installed and the per-unit energy savings of that measure. The top-down method insures that the energy savings are calibrated to actual energy sales.

METHODOLOGY OVERVIEW

This section gives a short summary of the overall methodology used to perform the efficiency analysis. For much more detail see the later section on methodology.

Energy Use Forecast and Disaggregation

For consistency with the IRP process, we started from Entergy's sales forecast, and adjusted to add back savings from current levels of savings from existing Energy Smart Programs. Energy use was disaggregated using multiple sources. In the commercial sector, data provided by Entergy was used to segment sales by building type based on customer SIC code. In both the residential and commercial sectors, disaggregation by end-use relied on data from the Energy Information Administration[2,3].

Measure Selection and Characterizations

The measure list for the study was initially developed from several sources in combination, including the NOLA TRM and previous potential studies conducted by Optimal Energy. Each measure included in the study must be characterized, which is a process of specifying the costs, savings, effective useful life, and other impacts of the measure. This is at the core of any potential study. To characterize the measures for this study we used data from the NOLA TRM where applicable and practical. This information was supplemented with other regional TRMs and Optimal's existing measure characterization database. In addition, we drew on data from a Residential Appliance Saturation Survey conducted by Entergy, as well as other similar studies conducted more in nearby states. All told, we examined 173 different measures over 3 different market types (New Construction/Renovation, market opportunity, and retrofit) and 14 different building types for 1,491 permutations of unique measure types. See the section on methodology details for more information.

Assessing Economic Potential & Cost-Effectiveness

Once the measure list is complete and fully characterized, we can develop an initial estimate of potential that assumes all cost-effective measures are fully implemented where technically feasible. Although this "economic" potential does not represent an outcome that could reasonably be expected under any conditions, it helps to calibrate the remaining scenarios that take into account customer behavior and the many barriers to efficiency investment.

This study uses a "Total Resource Cost" (TRC) test to evaluate cost-effectiveness, by comparing the economic benefits resulting from the program activity to the costs of efficiency investments. The TRC test is the most commonly used cost-effectiveness test for evaluating energy efficiency programs and measures, and attempts to consider a total, economy-wide vision of the costs and benefits of the program. On the cost side, program administration costs and the full incremental costs of the efficiency measures are included. The precise incentive amount does not impact the TRC, as the total incremental cost is incurred by the economy, regardless of whether it is paid for by the participant or the program administrator. Efficiency measures and programs are considered to be cost-effective if the net present value of benefits exceeds the net present value of costs.

Assessing the cost-effectiveness of efficiency measures means comparing the costs of investing in the measure with the economic benefits realized from that investment. With most efficiency measures, the vast majority of economic benefits are derived from the value of avoiding

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[2] US Energy Information Administration. Commercial Building Energy Consumption Survey. https://www.eia.gov/consumption/commercial/reports.php. Used data from 2012 survey in West South Central Census Division.

[3] US Energy Information Administration. Residential Energy Consumption Survey. https://www.eia.gov/consumption/residential/. Used data from 2009 survey in West South Central Census Division

the energy consumption that would otherwise other in the absence of the efficiency measure. These "avoided costs" are therefore a key input to the potential model. The benefits listed below are included. For more detailed descriptions, please refer to the Methodology Section

- Avoided Energy Costs: These represent the variable costs associated with producing the marginal unit of electricity. For this study, we used forecasts of location marginal prices (LMPs) for the relevant zone within the Midcontinent Independent System Operator (MISO) footprint.
- Avoided Capacity Costs: This is the value of avoiding new generation equipment. For this study, we use ENO's forecast cost of a new combustion turbine plant.
- Avoided Fuel Costs: Some measures, such as insulation, result in fossil fuel savings in addition to electric savings. These savings are included in a TRC test.
- Avoided Non-Energy Costs: Some measures produce quantifiable non-energy benefits, such as operation and maintenance savings and water savings. These have been included in the measure TRCs to the extent feasible given current estimates of their magnitude and value.

For this study, we developed avoided energy costs from ENO's forecast of annual energy prices[4] and historical hourly Locational Marginal Price (LMP) data.[5] We simplified these thousands of data points into average costs during four energy periods. The year was first divided in "summer" months (April through October) and "winter" months (November through March) based on observed patterns of energy consumption revealed in. Figure 5, below, shows the average hourly price for each summer month. In each season, on-peak and off-peak periods were determined, again using hourly LMP data. For summer, on-peak hours are weekdays between 11 AM and 9 PM; winter on-peak hours are weekdays between 7 and 10 AM and between 6 and 10 PM. At the beginning of the study period, 2018, avoided energy costs ranged from 2.7 cents/kWh winter off-peak hours to 4.6 cents/kWh for summer on-peak hours.

We also developed loadshapes for each sector and end use. These loadshapes determine what portion of the total annual energy savings coincides with each peak period. This means that cooling measures, for example, will have larger benefits than outdoor lighting measures, where the savings general fall on off-peak hours. As indicated earlier, if the net present value of the future stream of benefits (energy and demand, but also other societal benefits such as gas, water, or maintenance savings) exceeds the costs, then the measure is considered cost-effective.

Avoided costs for peak demand reduction were based on ENO's forecast cost of a new combustion turbine plant. No value was placed on avoided transmission and distribution (T&D) costs; ENO did not provide an estimate of these values and we wished to use assumptions consistent with the other aspects of the IRP modeling. Our cost-effectiveness results are therefore likely to be conservative. Line losses were calculated by using ENO's estimates of average losses

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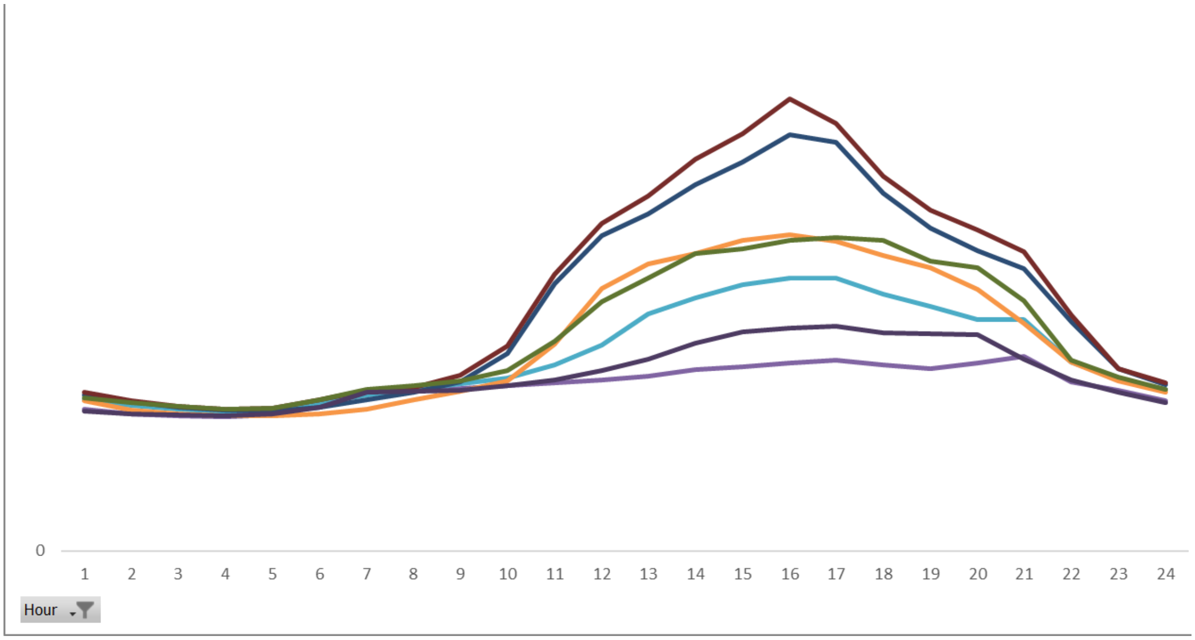
[4] Forecast annual LMPs for Zone ENOI were provided by Entergy, and are Highly Sensitive Protected Material (HSPM)

[5] Historical hourly real-time LMP for 2015 for zone EES.NOPLD from MISO

adjusted for the fact that efficiency reduces consumption on the margin and therefore should result in marginal line loss savings, which are higher than average losses. Finally, we use a discount rate of three percent to better reflect the public policy nature of energy efficiency programs. We also include a sensitivity analysis using ENO's weighted average cost of capital (WACC), again for consistency with the IRP.

Figure 5 | Average Hourly Forecast Energy Price – Summer Months



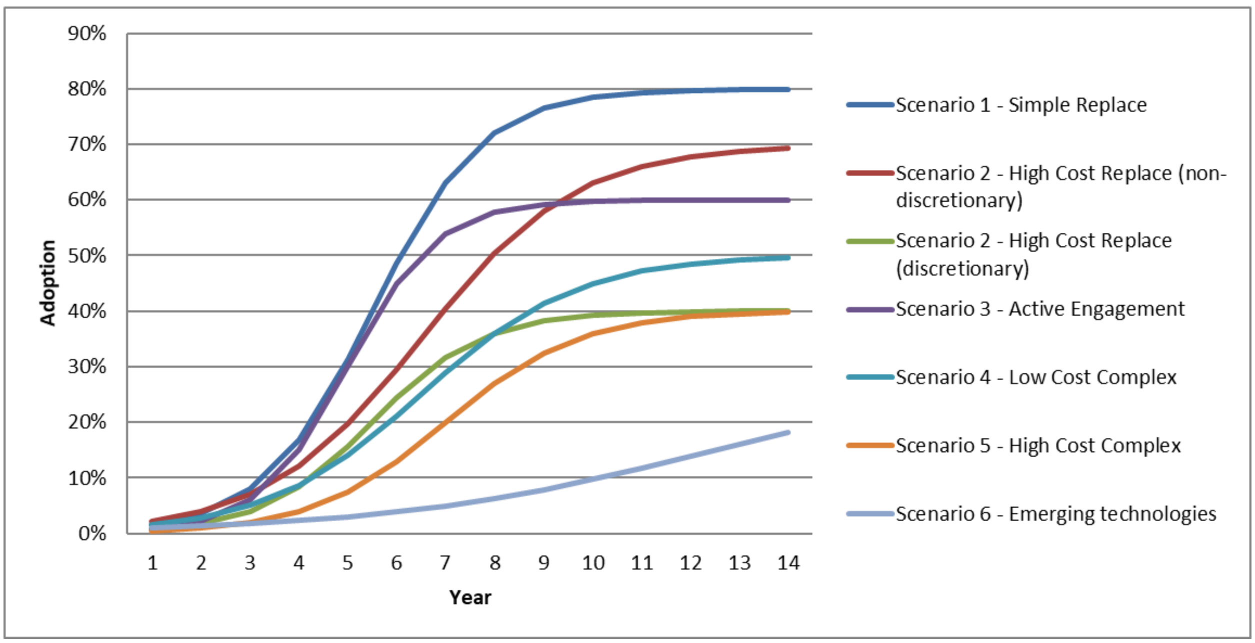
The avoided costs and loadshapes allow us to calculate the net present value of each measure's energy and capacity savings. A measure is considered cost-effective if this value exceeds the measure's cost. For the economic potential estimate, we generally assumed that all cost-effective measures would be immediately installed for market-driven measures such as for new construction, major renovation, and natural replacement ("replace on failure"). For retrofit measures we generally assumed that resource constraints (primarily contractor availability) would limit the rate at which retrofit measures could be installed, depending on the measure, but that all or nearly all efficiency retrofit opportunities would be realized over the 10-year study period. Spreading out the retrofit opportunities results in a more realistic distribution of efficiency investment over time, providing a better basis for the later achievable scenarios.

Estimating Achievable Potential using a Delphi Panel

As noted earlier, one of the key objectives of this study is to provide inputs to ENO's Integrated Resource Plan (IRP). To properly define the efficiency resource that is available as part of the IRP analysis, there must be a high level of confidence that the resource can be "built" in the required timeframe using tested programmatic and policy approaches. In short, the level of efficiency must be "achievable." From an analytical perspective, this means that we developed a set of assumptions about the rate at which efficiency measures will be adopted by customers if promoted by an energy efficiency program. Typically, this means that the utility provides a monetary incentive to offset the increased capital cost of high efficiency equipment or retrofit activity (e.g., adding insulation). An achievable efficiency scenario therefore assumes some level of incentive and attempts to model customer response. This can be done either quantitatively or qualitatively. The former models customers' willingness to participate as a function of the financial impacts of each measure, usually in terms of a measure called simple payback. Simple payback is the ratio of the required investment to the annual cost savings from the investment. It is a measure of the length of time required for the savings to repay the initial investment. A qualitative approach relies on data from existing programs to estimate program participation as function of incentive levels and various program approaches. That is, if a particular program type succeeded in convincing 10% of customers to invest in an efficiency measure, this value could be used as an estimate for the participation of a similar measure under similar conditions.

We developed two estimates of achievable potential using a combination of these methods. First, we developed an estimate of "maximum achievable" potential. Maximum achievable potential assumes that efficiency programs cover 100% of the incremental cost of efficiency measures. As a result, the simple payback is undefined, because there is no investment to repay from bill savings. Therefore, we used a set of qualitative estimates developed by a panel of experts. Please refer to Appendix A for more information on the Delphi panel process. These estimates indicate, for several prototypical efficiency measures, the likely maximum adoption rate by customers and the time required to reach that maximum. See the figure below for the residential adoption curves that resulted from the Delphi Panel.

Figure 6 | Delphi Panel Adoption Curves – Residential Sector



Although the maximum achievable potential is theoretical possible, it is usually considered an extreme upper-bound. As with any product, at any given price there are those who will purchase the product and those who will not. But within those who would purchase the product, some would have purchased it at an even higher cost. With energy efficiency programs, it is difficult to provide different incentive levels for the same product to different customers.

Therefore, if incentives are raised to increase participation, all participants must receive the higher payment, even those who would have participated at the lower incentive lever. As a result, increasing incentive levels results in diminishing returns, and programs rarely provide full or nearly full coverage of measure costs (with the exception of low-income programs). Therefore, we developed a "program achievable" potential that is based on incentive levels that are more in keeping with actual program practice.

For this study, we assumed an average incentive of 50% of measure costs for the program achievable potential. The Delphi panel provided estimates of how measure adoption would change based on changes in customer simple payback. Therefore, this step in the process used a quantitative approach that adjusted the maximum achievable potential based on the calculated simple payback for measure. The Delphi Panel developed consensus on the amount by which the maximum adoption curve would be reduced given certain simple paybacks in the residential and C&I sectors. See Appendix A for more details.

Hourly Efficiency Savings ("8760" Outputs)

Because the results of this report will be used as inputs for ENO's IRP, we will provide an efficiency savings potential estimate for each hour of the year for the next 20-years. In order to produce this "8760" output (so-called because there are 8,760 hours in a non-leap year), we use the same efficiency loadshapes provided by ENO in their 2015 potential study. Note that since these loadshapes are not identical to those we use to model cost-effectiveness, the resulting peak demand impacts implied by the 8760 output may be slightly different than those reported in our study.

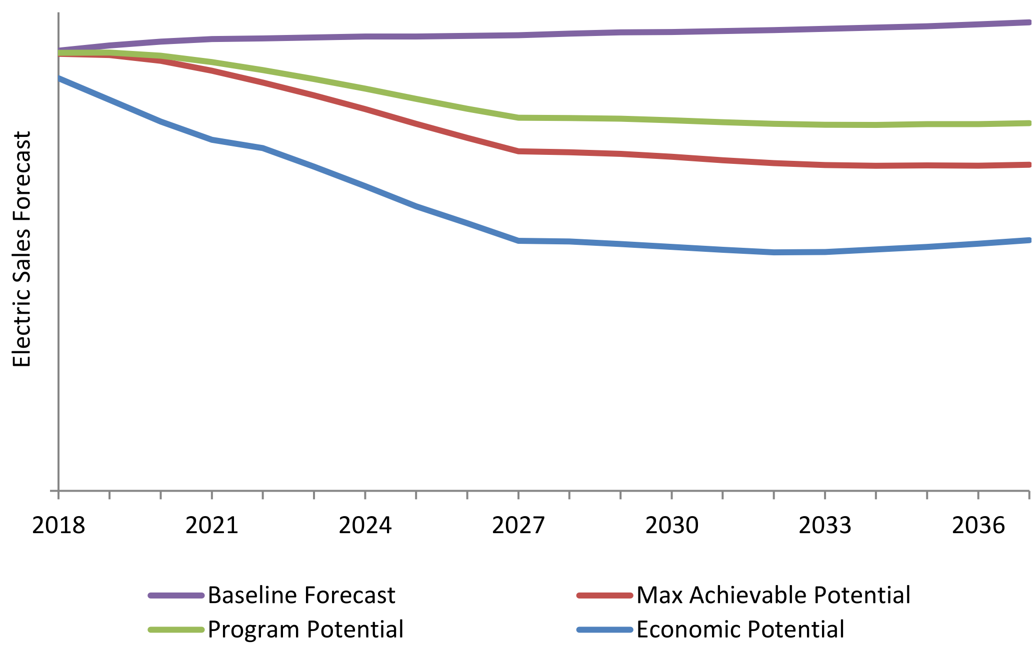
RESULTS

Overall Results

This section presents the overall results of the three scenarios examined. The results are given at the sector level – residential and C&I. Low-income results, where measures with a TRC above 0.8 were counted as economic, are separated from residential further below. Further, note that the cumulative potential does not significantly change between year 10 and year 20. This is because all the adoption curves, as defined by the Delphi Panels, reach full or nearly-full adoption by year 10. Thus most of the market is addressed in the first 10 years, and the additional potential in the last 10 years is largely due to equipment turnover. We also want to emphasize that, due to inherent uncertainties in predicting the future, the results get less and less certain the further out in time. We therefore would recommend placing a focus on the first 10 years when evaluating the results of this study.

The figure below shows the baseline forecasted electric usage (purple line) over the 20-year study horizon, and compares to what sales would be under the three scenarios examined for the study. As expected, sales decline significantly under the efficiency scenarios. This represents electricity that will not be sold if the given scenario is followed.

Figure 7 | Electric Energy Savings Relative to Sales Forecast



The table below gives the specific figures. There is economic potential of 49% in the residential sector, and 45% in the C&I sector. This drops of to 22% and 21% in the program potential scenario.

Table 11 | Cumulative Energy Savings As Percent of Sales by Sector and Scenario (MWh)

Year	Scenario	Residential Savings	Low Income Savings	C&I Savings	Total
	Economic Potential	49%	49%	43%	45%
2027	Max Achievable Potential	27%	27%	25%	25%
	Program Potential	9%	27%	18%	18%
	Economic Potential	49%	49%	45%	46%
2037	Max Achievable Potential	33%	33%	29%	30%
	Program Potential	9%	33%	21%	21%

Note that the above values represent cumulative savings. Due to many measures having a useful life of less than 20 years, a cumulative savings value of, for example, 20% in year 20 does not mean that incremental annual savings will be 1% in each year (i.e., 20% / 20 years). Our modeling tool provides the incremental savings in each year, from which we calculate the average incremental annual savings for the first and second 10 years show in the table below.

Table 12 | Average Incremental Annual Savings

Scenario	2018-2027	2028-2037
Economic	4.8%	3.4%
Max Achievable	2.5%	2.2%
Program	1.8%	1.6%

The average savings above still masks some granularity, for example in the early years while the program is ramping up. The table below shows the incremental annual savings for every year of the analysis period.

Table 33 | Incremental Annual Savings by Year as Percent of Sales

	Economic Potential			Max Achievable Potential			Program Potential		
Year	Total	Res	C&I	Total	Res	C&I	Total	Res	C&I
2018	5.7%	7.5%	4.6%	0.7%	0.7%	0.6%	0.5%	0.5%	0.5%
2019	5.5%	7.3%	4.4%	1.3%	1.4%	1.2%	1.0%	1.0%	0.9%
2020	5.2%	6.7%	4.4%	2.0%	2.0%	1.9%	1.4%	1.4%	1.4%
2021	4.4%	4.6%	4.3%	2.6%	2.5%	2.7%	1.9%	1.7%	2.0%
2022	4.2%	4.3%	4.2%	2.8%	2.7%	2.8%	2.0%	1.8%	2.1%
2023	4.4%	4.5%	4.3%	3.0%	3.1%	3.0%	2.2%	2.1%	2.2%
2024	4.5%	4.7%	4.4%	3.1%	3.3%	3.0%	2.3%	2.3%	2.3%
2025	4.5%	4.6%	4.4%	3.2%	3.5%	3.1%	2.3%	2.4%	2.3%
2026	4.6%	4.7%	4.5%	3.3%	3.7%	3.1%	2.4%	2.5%	2.3%
2027	4.7%	5.0%	4.5%	3.4%	3.8%	3.1%	2.4%	2.6%	2.3%
2028	2.7%	2.5%	2.8%	1.3%	1.7%	1.1%	0.9%	1.2%	0.8%
2029	3.0%	2.8%	3.1%	1.6%	1.9%	1.5%	1.2%	1.3%	1.1%
2030	3.0%	2.9%	3.1%	1.9%	2.0%	1.8%	1.4%	1.4%	1.4%
2031	3.3%	3.0%	3.6%	2.3%	2.2%	2.4%	1.7%	1.5%	1.8%
2032	3.4%	3.0%	3.6%	2.3%	2.2%	2.4%	1.7%	1.5%	1.8%

Peak demand reduction for each scenario in 2027 and 2037 are reported in megawatts, rather than percent of forecast peak load, in order to make it more easily comparable to power generation that may be avoided through efficiency. See Table 14.

Table 14 | Cumulative Demand Savings Potential by Sector and Scenario (MW)

Year	Scenario	Residential Savings	LI Savings	C&I Savings	Total
2027	Economic Potential	137	133	260	530
	Max Achievable Potential	73	71	150	294
	Program Potential	17	71	106	194
2037	Economic Potential	137	134	286	557
	Max Achievable Potential	89	86	186	361
	Program Potential	24	86	133	243

Figure 8 shows the demand under each scenario compared to the baseline peak demand forecast. As seen, similar to the chart for energy, peak demand quickly starts to diverge from the forecast. Note that this figure includes peak demand reduction from efficiency only. Demand response programs will provide additional savings and are discussed fully below.

Figure 9 shows the cumulative avoided CO_2 emissions achieved through the efficiency programs. By the end of the study horizon, the program potential scenario would avoid almost 800 thousand metric tons of CO_2, the equivalent to the emissions from over 160,000 cars. This represents a reduction of emissions of over 26% compared to the baseline forecast.

Figure 8 | Electric Peak Demand Savings From Efficiency Relative to Sales Forecast

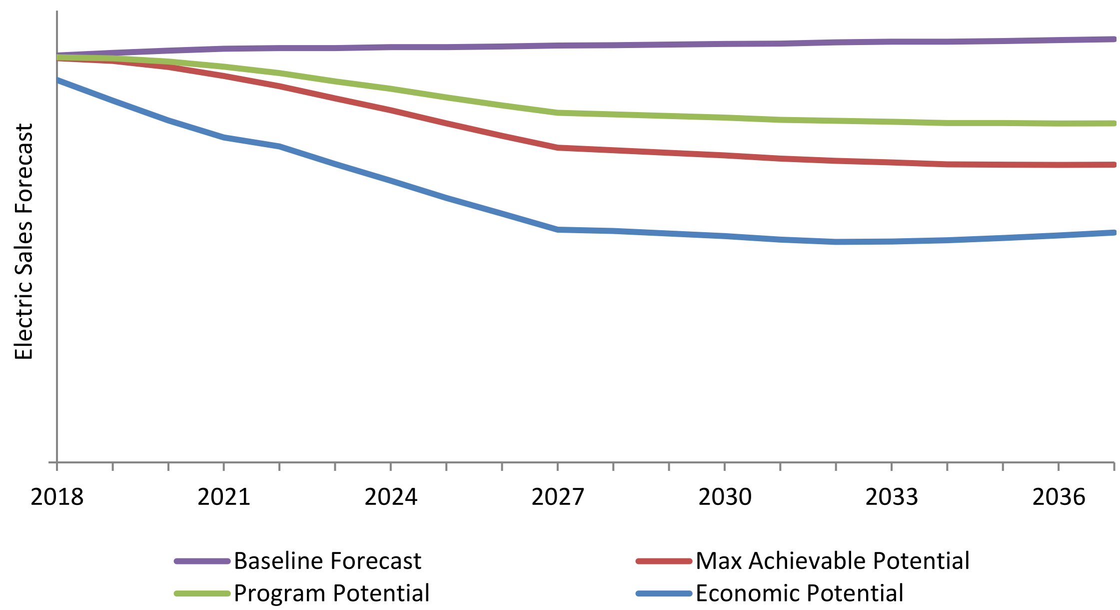
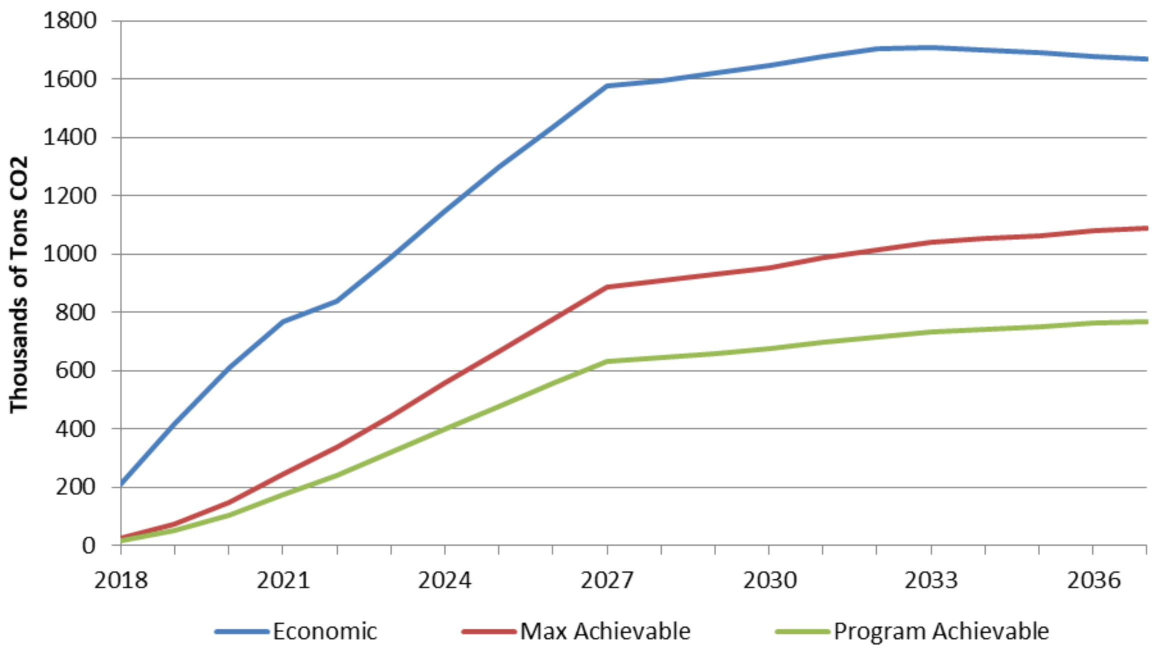


Figure 9 | Cumulative Avoided CO_2 Emissions (Thousands of Metric Tons)



The next table shows the Total Resource Cost Effectiveness Test results in each scenario. The costs and benefits below represent the net present value of running 20 years of programs. As seen, while the scenarios incur significant costs (i.e., utility administrative costs, incentive costs, and customer contributions), there societal benefits are 2-4 times larger.

Table 15 | Scenario TRC Cost-Effectiveness by Sector – Full 20 Years

Sector	Scenario	Costs ($MM)	Benefits ($MM)	Net Benefits ($MM)	BCR
Residential	Economic	461	1,216	754	2.6
	Max Achievable	310	716	406	2.3
	Program	207	467	260	2.3
C&I	Economic	516	2,486	1,970	4.8
	Max Achievable	304	1,129	825	3.7
	Program	202	823	621	4.1
Total	Economic	978	3,702	2,724	3.8
	Max Achievable	614	1,845	1,231	3.0
	Program	409	1,290	880	3.2

Table 16 shows the same information, but for the 2018-2027 time frame instead of the full 20 years. As seen, BCRs are very similar, but slightly lower. This is because of a higher share of retrofit measures during this period which, on average, have lower BCRs than market driven measures.

Finally, tables 17 and 18 show the utility budgets, by year, for the max achievable and program potential scenarios. As seen, the year 1 budget would be $6.5 million, a slight increase from the current Energy Smart Program budgets of $6.2 million.[6] From there, budgets would continue to increase until reaching $58.5 million in 2027. After 2027, budgets begin to decline as retrofit opportunities decline. Achieving the program potential would represent a significant investment. However, it would also avoid significant electricity generation need and produce benefits of three to four times greater than the cost (as seen in the TRC ratios above)..

[6] Entergy New Orleans. Program Year Six Annual Report.

Table 16 | Scenario TRC Cost-Effectiveness by Sector – First 10 years

Sector	Scenario	Costs ($MM)	Benefits ($MM)	Net Benefits ($MM)	BCR
	Economic	$335	792	$457	2.37
Residential	Max Achievable	$203	$409	$207	2.02
	Program	$134	$267	$133	1.99
	Economic	$333	1,445	$1,112	4.33
C&I	Max Achievable	$185	597	$412	3.23
	Program	$118	$427	$309	3.62
	Economic	$668	$ 2,237	$1,569	3.35
Total	Max Achievable	$388	$ 1,006	$619	2.60
	Program	$252	$694	$442	2.75

Table 17 | Program Potential Nominal Budgets ($MM)

Year	Non-Incentive	Incentive	Total	Year	Non-Incentive	Incentive	Total
2018	$1.6	$4.8	$6.5	2028	$2.6	$9.9	$12.5
2019	$3.2	$9.7	$12.9	2029	$3.1	$11.2	$14.3
2020	$4.7	$14.4	$19.2	2030	$3.5	$12.4	$15.9
2021	$6.4	$19.4	$25.8	2031	$4.2	$14.3	$18.5
2022	$6.7	$20.6	$27.3	2032	$4.2	$14.3	$18.5
2023	$7.2	$22.4	$29.7	2033	$4.6	$15.4	$20.1
2024	$7.6	$23.6	$31.2	2034	$4.6	$15.5	$20.2
2025	$7.8	$24.4	$32.2	2035	$4.7	$15.6	$20.2
2026	$8.0	$25.2	$33.2	2036	$4.8	$16.0	$20.7
2027	$8.1	$25.8	$34.0	2037	$4.8	$16.0	$20.8

Table 18 | Maximum Achievable Potential Nominal Budgets ($MM)

Year	Non-Incentive	Incentive	Total	Year	Non-Incentive	Incentive	Total
2018	$1.9	$10.8	$12.8	2028	$2.7	$21.2	$23.9
2019	$3.7	$21.7	$25.5	2029	$3.2	$24.3	$27.5
2020	$5.6	$33.0	$38.5	2030	$3.6	$26.9	$30.5
2021	$7.5	$44.9	$52.4	2031	$4.5	$32.2	$36.7
2022	$7.8	$47.5	$55.3	2032	$4.5	$32.3	$36.8
2023	$8.3	$51.4	$59.8	2033	$5.0	$35.3	$40.2
2024	$8.7	$53.7	$62.4	2034	$5.0	$35.4	$40.4
2025	$8.9	$55.4	$64.3	2035	$5.0	$35.5	$40.5
2026	$9.1	$57.1	$66.2	2036	$5.1	$36.2	$41.3
2027	$9.3	$58.5	$67.9	2037	$5.1	$36.3	$41.4

Detailed Results

Overview

This section drills down into the results in more detail. We focus on the Program Potential Scenario, since that is the scenario most likely to be implemented in New Orleans. For each sector (Residential, Low-Income, and Commercial and Industrial), we show the savings by end use, as well as the top 10 saving measures. Note that the percentages in the tables showing the top savings measures represent the portion of total 2037 savings by that measure. A few items to note:

- There are very little residential lighting savings remaining in 2037. This is due to federal regulations that essentially eliminate the opportunity in that sector.
- The "ElecTotal" end-use represents measures that reduce full building electric use. This includes measures such as Conservation Voltage Reduction, Commissioning, and integrated New Construction.
- There are significant space heating savings in the residential sector. This is due to a high saturation of electric resistance heat – a prime candidate for significant savings from replacing with an air source heat pump.
- Residential demand savings are dominated by cooling, while C&I demand reduction is due to a broader combination of measures.

Residential Non Low-Income

Figure 10 | Residential Electric Energy Savings by End Use (2037)

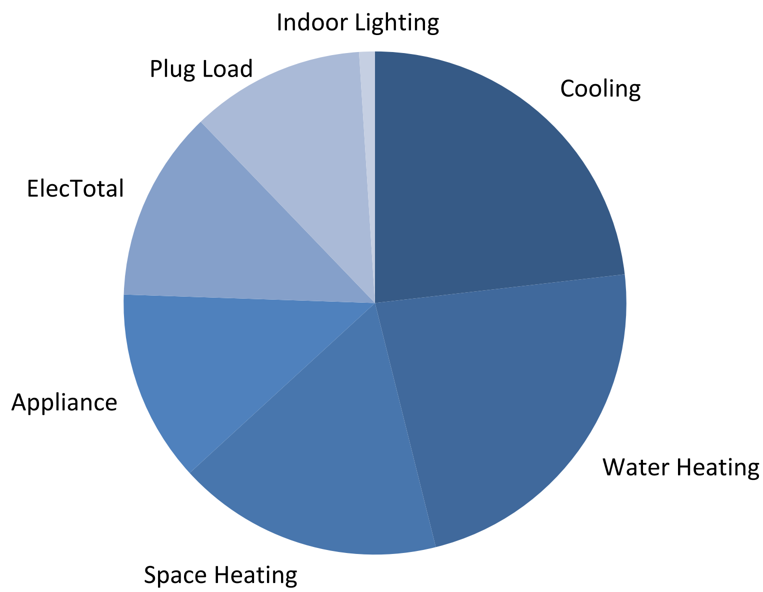


Table 19 | Residential Electric Energy Top Saving Measures (2037)

Measure Name	Percent of Total Savings
Low Flow Showerhead	14.2%
Conservation Voltage Reduction	8.0%
Duct Sealing	7.0%
Ductless Mini-split Heat Pump	5.5%
Faucet Aerator	4.9%
Quality Install Air Source Heat Pump	4.1%
Air Source Heat Pump	3.5%
Learning Thermostat	3.5%
Desktop Computer	2.9%
Fridge and Freezer Removal	2.9%
SubTotal	*56.5%*

Figure 11 | Residential Electric Demand Savings by End Use (2037)

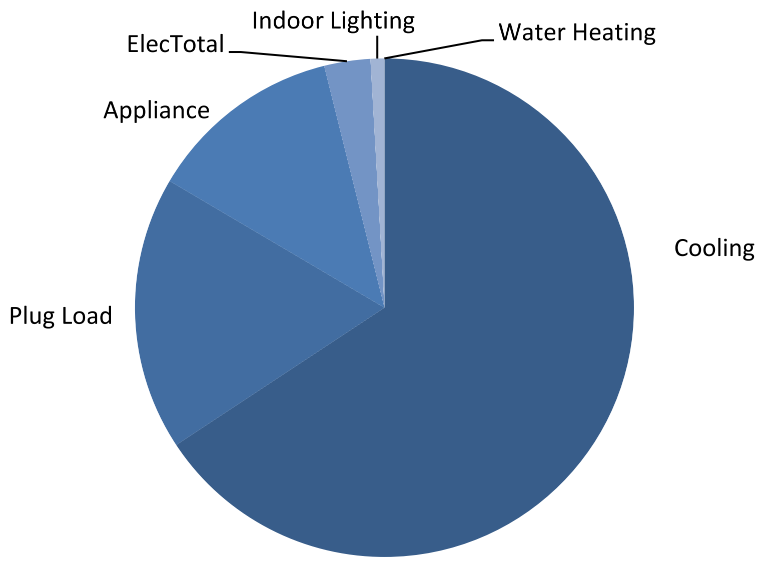


Table 20 | Residential Electric Demand Top Saving Measures (2037)

Measure Name	Cumulative MW
Duct Sealing, Electric Heat	1.56
Duct Sealing, Gas Heat	1.56
Learning Thermostat, Gas Heat	1.48
Learning Thermostat, Electric Heat	1.48
Central AC	1.44
Energy Star Ceiling Fan	1.37
Energy Star Room AC	1.33
Ductless Mini-Split HP	1.30
Quality Install ASHP	1.20
Tier 2 Power Strip	0.97
SubTotal	*13.68*
Total	**24**

Residential Low-Income

Figure 12 | LI Residential Electric Energy Savings by End Use (2037)

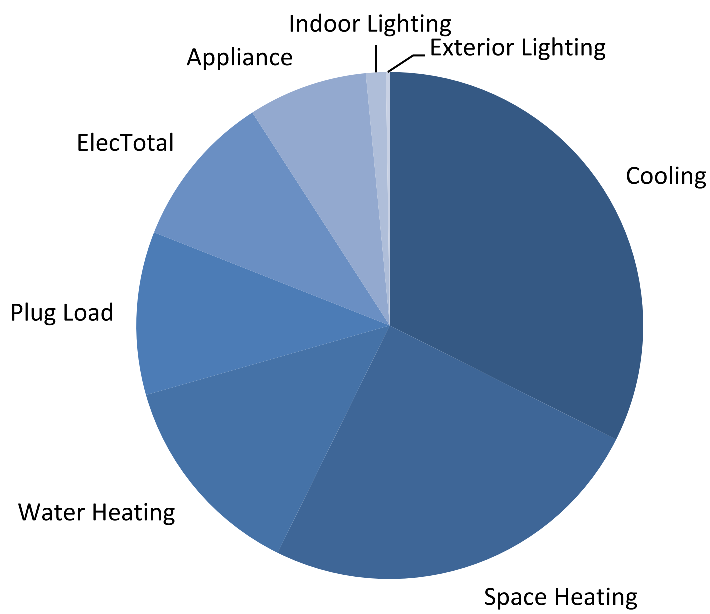


Table 21 | LI Residential Electric Energy Top Saving Measures (2037)

Measure Name	Percent of Total Savings
Air Source Heat Pump	9.6%
Ductless Mini-split Heat Pump	7.3%
Low Flow Showerhead	6.6%
Quality Install Air Source Heat Pump	5.9%
Learning Thermostat	5.8%
Attic Insulation	4.1%
Central AC	3.8%
Duct Sealing	3.8%
ES Ceiling Fan	3.8%
Conservation Voltage Reduction	3.8%
SubTotal	54.5%

Figure 13 | LI Residential Electric Demand Savings by End Use (2037)

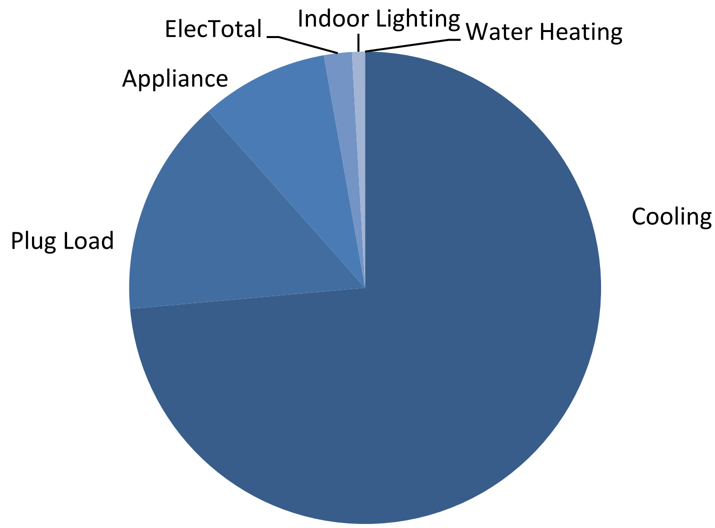


Table 22 | LI Residential Electric Demand Top Saving Measures (2037)

Measure Name	Cumulative MW
Air Source Heat Pump	7.43
Learning Thermostat, Elec Heat	7.16
Learning Thermostat, Gas Heat	7.16
Central AC	6.97
ES Ceiling Fan	6.65
Quality Install Air Source Heat Pump	5.20
Ductless Mini Split Heat Pump	5.09
Quality Install Central AC	3.33
Efficient Windows	3.32
Window Attachments	2.78
SubTotal	55.08
Total	**86.36**

Commercial and Industrial

Figure 14 | C&I Electric Energy Savings by End Use (2037)

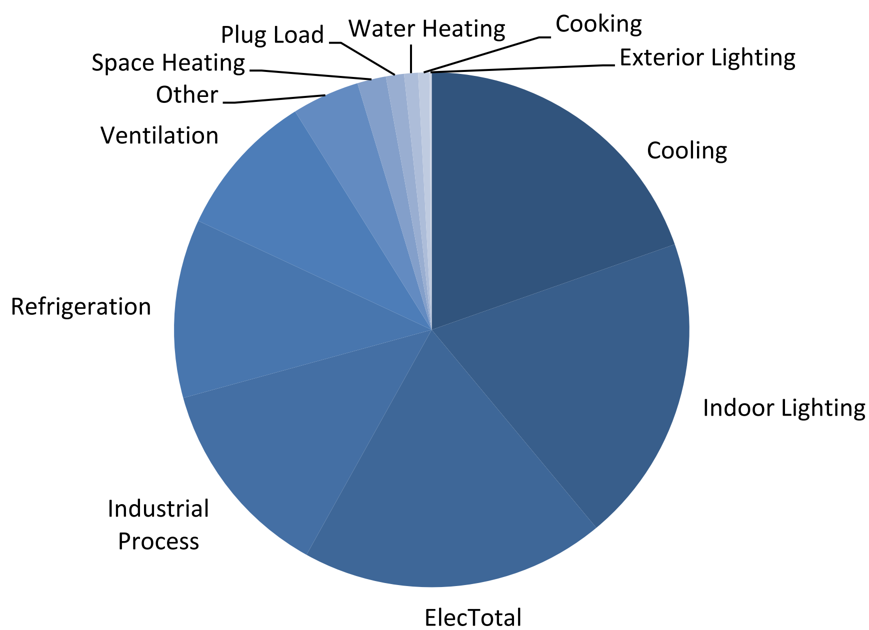


Table 234 | C&I Electric Energy Top Saving Measures (2037)

Measure Name	Percent of Total Savings
Retrocommissioning/Calibrate Sensors - Elec Heat	10.5%
Com LED Tube Replacement Lamps	8.9%
Interior Lighting Controls	7.9%
Compressed Air	6.9%
Industrial Process	5.8%
VSD, HVAC Fan	5.0%
Conservation Voltage Reduction	4.6%
Heat Pump Tune Up	4.5%
Refrigeration Retrofit	3.9%
High Efficiency Heat Pump	3.6%
SubTotal	*61.5%*

Figure 15 | C&I Electric Demand Savings by End Use (2037)

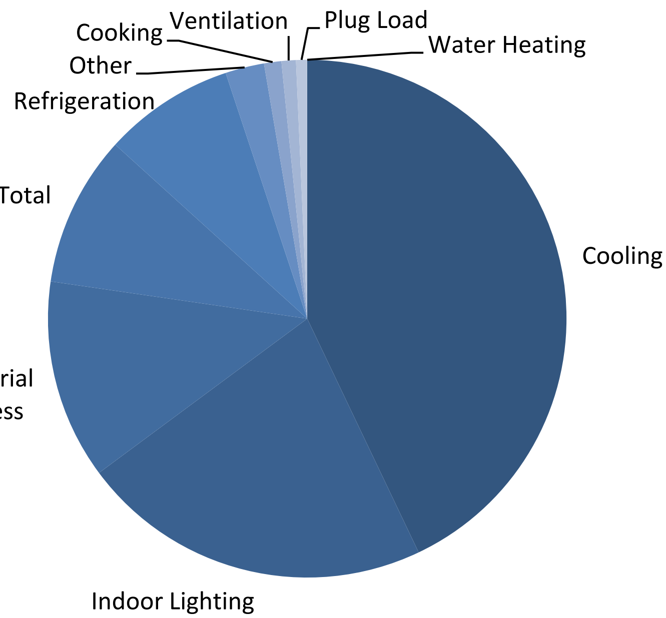


Table 24 | C&I Electric Demand Top Saving Measures (2037)

Measure Name	Cumulative MW
Com LED Tube Replacement Lamps	13
HP Tune Up	13
Int Lighting Controls	12
Mini Split Ductless HP-Cool	10
High Efficiency AC	9
Compressed Air	9
High Efficiency HP	8
Industrial Process	8
Retrocommissioning/Calibrate Sensors - Electric Heat	6
Cool Roof	4
SubTotal	92
Total	**133**

Rate and Bill Impacts

Although cost-effective energy efficiency lowers overall utility bills and the utility's revenue requirement, it also affects customer rates. A utility that promotes efficiency will see a reduction in revenue from the reduced sales volume. Because a portion of the variable rate that customers pay compensates the utility for their fixed costs, the utility will under-recover their fixed costs as a result. In the absence of a rate case that resets rates to meet the revenue requirement with the new, lower volume of sales, the utility will suffer lost fixed cost revenues (sometime referred to as lost base revenues). When rates are reset, they will be higher than they were in absence of energy efficiency, but total customer bills will still be reduced, because the variable costs of efficiency are lower than the variable costs of traditional supply.

Some jurisdictions rely on the Ratepayer Impact Measure (RIM) test to assess whether or not rates will increase as a result of efficiency. The RIM test is a poor measure of this, though, as it provides no information about the magnitude of the rate increase, nor how changes in total utility bills will be distributed among the customer population. Furthermore, nearly every efficiency program will fail the RIM test, precisely because it reduces consumption. It is not a sign that an efficiency measure or program is a bad investment for the utility or their customers.

Not surprisingly, the program achievable scenario fails the RIM test, with a benefit-cost ratio of 0.6. More relevant information can be gleaned from assessing the size of the rate increase and the change in overall utility revenue requirement from efficiency programs. For the program potential scenario, the rate impacts in the short term are minor. Through the first five years of the program, the cumulative reduction of roughly 7% of sales results in a 4% increase in rates. The utility's revenue requirement decreases by nearly $16 million, which indicates that overall customer bills are also reduced by this amount. As efficiency savings accumulate, the rate impacts and the customer bill savings both grow. In 2027, the cumulative sales reduction is approximately 18%, while rates will have increased by approximately 13%. The results in total annual bill savings of over $41 million.

Sensitivity Analysis

As discussed earlier, we used a discount rate of three percent to evaluate the measures for cost-effectiveness. However, Entergy has normally used a higher discount rate reflecting their weighted average cost of capital (WACC) of seven to eight percent in screening measures for cost-effectiveness. A higher discount rate has the effect of placing a lower value on future costs and benefits. The costs of efficiency measures are generally incurred at the time of installation while the benefits of energy savings occur over the life of the measure. A higher discount rate thus lowers the value of the future energy savings relative to the costs, which lowers the cost-effectiveness of measures and programs. In this case, it is possible that some measures that pass the TRC with a three percent discount rate would not be cost-effective using a higher rate such as WACC. In order to estimate how large an impact this may have, we performed a sensitivity analysis looking at the TRCs of each measure using both the societal discount rate and the WACC.

The table below shows the measures that passed the TRC using the societal discount rate but not with the WACC. Only 12 measures of the over 190 examined in the study meet this criterion.

The table also shows the Year 2037 savings from each of these measures in the Max Achievable Scenario. The cumulative savings from these 12 measures represents 8% of the total potential. Looking at program potential, these measures also consist of about 8% of the total. However, this does not necessarily mean that the potential would be 8% lower using the WACC; some measures could be replaced with similar measures with the same or higher savings. For example, even though air source heat pumps do not pass using the WACC, air source heat pumps with quality install still do pass, as do ductless mini-split heat pumps. In a scenario where air source heat pumps do not pass the TRC, these other measures could be promoted in their place.

Table 255 | Measures not Cost-Effective with Higher WACC Discount Rate

Measure Name	Sector	TRC (3%)	TRC (WACC)	Savings in Max Achievable Scenario (MWh, 2037)
Central AC RET	Res	1.09	0.72	8,441
Quality Install Central AC RET	Res	1.30	0.84	6,357
Air Source Heat Pump	Res	1.38	0.99	60,992
Water Heater Jacket RET	Res	1.06	0.80	1,121
Window Attachments RET	Res	1.14	0.92	22,040
LED DI (2018) RET*	Res	1.01	0.92	-
Occupancy Sensors RET	Res	1.00	0.82	10,006
Energy Efficient New Home - Multi Family MD	Res	1.59	0.87	16,661
Retrofit duct sealing	C&I	1.16	0.85	16,356
Integrated bldg design -Elec MD	C&I	1.76	0.98	10,107
Advanced RTU Control - Gas Heat MD	C&I	1.15	0.84	7,458
Integrated bldg design -Gas MD	C&I	1.59	0.88	2,074

BENCHMARKING THE RESULTS

In addition to conducting this New Orleans-specific potential study, we examined how our results compare to the results from other recent potential studies in the region. Table 26 shows the results of both economic and achievable potential scenarios from these studies.

Our New Orleans study generated results that are higher than these other studies, sometimes by a substantial amount. While it is hard to know the specific reasons other studies generated lower results, some of the reasons may include the following.

- Lower penetration rate assumptions, based solely on customer “willingness-to-accept” studies
- Fewer measures included
- Failure to include early retirement measures
- Lower avoided costs and/or higher discount rates
- Different assumptions regarding free-ridership and spillover

- Limited inclusion of potential savings from "custom" projects (i.e., projects involving efforts beyond narrowly-defined "prescriptive" measures)

Table 26 | Potential Study Benchmarking

State	Study Year	Study Period	Analysis Period	Economic Potential	Achievable Potential	Scenario Description
Arkansas	2015	2016-2025	10	17%	8%	Funding set at levels comparable to levels in the past
Georgia (Georgia Power)	2015	2015-2026	12	19%	14%	Max achievable
Mississippi	2013	2014-2025	12	N/A	13%	Reflects other programs in the region, does not attempt to examine maximum
Missouri (Ameren)	2013	2016-2030	15	23%	16%	Max achievable
Austin, Texas	2012	2011-2020	10	26%		Economic only
Tennessee	2011	2012-2030	20	25%	20%	Incentives cover "a substantial portion of the incremental cost"
Oklahoma	2015	2015-2024	10	15%		Economic only
Penn.	2015	2016-2024	10		13%	Max achievable
New Orleans	**2018**	**2018-2037**	**20**	**46%**	**21%/30%**	**Program/Max achievable**

It is also instructive to consider actual program experience in leading efficiency states. The program potential scenario in this study indicates average incremental annual savings of 1.7%. Table 27 shows the 10 states with the highest actual achieved savings in 2016. The average savings is 1.82% of sales, slightly higher than our result. We also note that these top states represent a wide variety of climates and demographics; they are not limited to a particular set of circumstances that are not applicable to Louisiana or New Orleans. In fact, there are many good reasons to believe that New Orleans can at least match the performance of these other jurisdictions with high levels of savings. For example:

- New Orleans does not have a long a history of aggressive efficiency programs, and the existing stock of equipment and buildings is likely of lower efficiency than in areas where efficiency savings have been pursued for many years
- New Orleans has a high cooling load, due to its hot, humid climate
- New Orleans has a high heating load, due to a preponderance of electric resistance heating in the residential sector and relatively low levels of insulation and air sealing.

Table 27 | Efficiency 2016 Top Savers

State	% of 2016 retail sales
Massachusetts	3.0%
Rhode Island	2.8%
Vermont	2.5%
Washington	1.5%
California	1.5%
Connecticut	1.5%
Arizona	1.4%
Maine	1.4%
Hawaii	1.3%
Minnesota	1.1%
Average	**1.82%**

OTHER BENEFITS OF EFFICIENCY

Our assessment of the efficiency potential assessed cost-effectiveness using a set of benefits limited largely to directly avoided supply costs and readily quantifiable resource impacts. Yet efficiency produces many other benefits that are difficult to quantify and often excluded from benefit-cost analysis. This can result in an underestimate of efficiency potential, the net benefits of efficiency, or both. This section briefly describes several benefit categories not quantified in our analysis.

Risk Reduction

Because the largest portion of the marginal costs of producing electricity are related to fuel expenses, electric prices are highly correlated to the underyling commodity. Commodity prices can be highly volatile and cyclical, and thus leave ratepayers exposed to the risk of price shocks. The costs related to energy efficiency, by contrast, are largely related to local labor and expenses, can be ramped up and down much more easily, and are thus much less exposed to the ups and downs of the global commodity markets.

Another type of risk relates to the construction of new generation facilities. These facilities may take 10 years or longer to begin producing power, while demand side investments start saving energy right away. Generation facilities are therefore far more exposed to unexpected capital cost overruns (such as from rising labor and/or material costs), as well as lower than projected load requirements. Some states have begun to quantify the value of reduced risk from efficiency and include it as a benefit in the TRC test. Vermont, for example, adds 10% to the benefits of avoided energy and capacity as a proxy for this risk reduction. However, this practice is still fairly rare.

Transmission and Distribution Avoidance

In addition to peak demand savings from avoided generation, there is often additional savings from lowering the load on the Transmission and Distribution System. These savings can be significant, but they are highly variable from jurisdiction to jurisdiction and difficult to estimate without a dedicated study. We do include these benefits in the analysis of this study due to lack of ENO specific data, but they likely do exist and are possibly significant.

Demand Reduction Induced Price Effects

Many states, especially in New England, are beginning to recognize Demand Reduction Induced Price Effects (DRIPE) as a quantifiable benefit of energy efficiency and demand response. DRIPE is a measurement of the value of efficiency provides by reducing the wholesale energy prices borne by all retail customers. The reduced energy demand due to efficiency programs removes the most expensive marginal generating resources and lowers the overall costs of energy. This reduces the wholesale prices of energy and demand, and this reduction, in a relatively deregulated market, is in theory passed on to retail customers. The effects on energy prices are small in terms of percentages, but the absolute dollar impacts are significant because the price reduction applies to all energy usage on the system.

Originally, it was thought that DRIPE would only be significant in the short-term. In the long run, market actors would react to lower energy consumption and peak demand by retiring inefficient generators. With lower available supply, wholesale prices would begin to increase again, assuming no other changes in demand. However, the most recent study on avoided costs in New England concluded that DRIPE impacts persist far longer than had been assumed. DRIPE effects in New England are now estimated to last 11 years for peak capacity reductions and 13 years for energy reductions. The value of DRIPE varies based on energy period and region, but for New England range from $0.001/kWh to $0.032/kWh and from $2.23/kW to $59.07/kW for peak demand.

Economic Benefits

There is a large and growing body of evidence that money spent on energy efficiency creates more jobs and provides a greater stimulus to local economies than equivalent money spent on supply-side resources. Efficiency investments are far more labor intensive than supply-side resources and require significant effort from contractors, design professionals, and suppliers/distributors. Academic research and interviews with business owners from process evaluations both confirm that utility-run efficiency programs can be an enormous boon for small businesses. According to 2009 study done by the University of Massachusetts, Amherst, a $1 million investment in supply-side resources will create 5.3 jobs, while an equivalent investment in efficiency can be expected to create 16.7 jobs.[7] The table below shows estimates of the jobs effect of efficiency spending.[8] The multipliers are based on modeling by ACEEE, with multipliers adapted from a regional economic modeling tool. Typically, studies have found that around 10-20 net jobs are created per million dollars spent on efficiency.

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[7] Throughout the report, one "job" represents one full time job for one year.

[8] ACEEE. *Potential for Energy Efficiency, Demand Response, And Onsite Solar Energy in Pennsylvania. April, 2009.*

Table 28 | Effect of Efficiency Spending on Jobs[9]

Spending Category	Impact	Amount (Millions)	Job Multiplier	Job Impact (job-years)
Installation	Upfront payment for efficiency measures	$100	13	1,300
Consumer Spending	Because of efficiency spending, consumers spend less in the short term	-$100	12	-1,200
Consumer Savings	Because of energy savings, consumers spend more in the long term	$200	12	2,400
Lost Utility Revenues	Utility revenues decrease because of energy savings	-$200	5	-1,000
Net effect of a $100 million investment in efficiency measures				**1,500**

In addition to direct job benefits, one dollar of efficiency spending creates more than one dollar of economic activity. In economics, this is known as the multiplier effect. While every economic activity has some multiplier, the multiplier for efficiency spending is larger than that of many other activities, particularly compared with supply-side spending. The efficiency multiplier occurs as 1) people who are employed due to the efficiency program re-spend their new income into the economy; 2) increased demand for efficient products causes increased demand for upstream suppliers; and, 3) money saved by ratepayers from lower energy bills is spent on other goods and services.

These estimates have been validated by economic studies of specific investment decisions. For example, a 2009 study in East Kentucky found that efficiency investment of $634.2 million would create $1.2 billion of local economic activity and over 5,400 jobs, not including the effect of energy savings being reinvested into the local economy. A coal plant to produce the equivalent amount of energy would not only be more expensive, but would create only 700 jobs during the 3-year construction phase and 60 positions once operational.[10]

Health Benefits

Air pollution such as sulfur dioxide, nitrogen oxides, and particulate matter emitted during electricity generation causes health effects that damage both public well-being and the economy. Additionally, there is mounting evidence that weatherization programs can have significant health benefits in low-income households. Adverse effects include increased incidences of asthma, respiratory, and cardiac diseases; higher mortality rates, and increased medical and hospitalization spending. In fact, there is reason to believe that increased health costs due to air emissions effectively double the price of coal-fired electricity. For example, a recent study from Harvard University finds that adverse health impacts from coal generation cost the public an

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[9] This study uses the same job multiplier as was found in the PA ACEEE study, or 15 jobs per million dollars spent. This number is actually on the low side of multipliers found in the economic literature. When this paper references jobs created, it is referring to a job as one full time job for one year.

[10] http://www.ochscenter.org/documents/EKPC_report.pdf

average of 9.3 cents per kWh of power generated.[11,12] A study for the European Union estimates direct externalities at between 4 and 15 euro cents per kWh for coal generation, between 3 and 11 euro cents per kWh for oil, and between 1 and 3 cents per kWh for gas, consistent with the Harvard study.[13] Another study found that Ontario's electric generation produces 668 premature deaths, 928 extra hospital admissions, 1,100 extra emergency room visits, and 333,600 minor illnesses. The financial impact of these health effects is estimated to be over $3 billion per year. The study estimates total Ontario consumption at 26.6 TWh/year, implying health costs for Ontario of over $0.11 per kWh.

Environmental Benefits

In addition to the health effects discussed above, emissions from electricity generation carry significant environmental costs. Although environmental damage can be very difficult to quantify, they can be avoided by investing in efficiency rather than traditional supply-side resources.

- Surface water and soil acidification
- Damage to vegetation and forests
- Contributions to coastal eutrophication, causing algal blooms, depletion of dissolved oxygen, changes in biodiversity, and losses in the tourism/fishing industry
- Faster weathering of buildings
- Reduced visibility from smog and haze
- Mercury accumulation in fish

Other Benefits

Efficient buildings tend to have smaller temperature swings, better lighting levels, less glare, lower temperature gradients, and better indoor air quality than standard buildings. These additional benefits partly improve participant comfort and quality of life, but may also manifest as decreased illnesses and increased worker productivity which can translate into additional economic benefits. The links between buildings and occupant health and productivity are very complex and difficult to generalize. However, the Center for Building Performance Diagnostics at Carnegie Mellon University has created a database of studies that have attempted to quantify this link. Overall, it finds that building environments that are associated with efficiency, such as increased outside air circulation, individual control of lights, moisture control, and pollutant source controls reduce symptoms of illnesses such as flu, asthma, sick building syndrome, and headaches by an average of 43%. Other measures, such as window views, natural ventilation, and increased day-lighting reduce symptoms by an average of 36%. Further, the studies find that lighting measures in offices increase worker productivity by a median of 3.2%. These estimates

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11 This is an average. The actual value varies widely from plant to plant based on its age, type of pollution controls, and downwind population.

12 Epstein et al. Page 86. http://solar.gwu.edu/index_files/Resources_files/epstein_full%20cost%20of%20coal.pdf

13 Page 13. http://www.externe.info/externpr.pdf

are highly uncertain, and the past efforts to quantify the benefits have found a range of from less than $10 to $50 per square foot over 20 years. Since the energy savings over 20 years for a typical LEED-certified building are about $10 per square foot, even the low range of this estimate would mean that health and productivity benefits equal the energy saving benefits of green buildings.[14]

[14] Kats, Greg. *Greening Our Built World*.

DEMAND RESPONSE

SUMMARY OF APPROACH & MAJOR ASSUMPTIONS

Demand response (DR) is defined by the Federal Energy Regulatory Commission (FERC) as changes in electric usage by end-use customers from their normal consumption patterns in response to either short-term changes in the price of electricity or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized.[15]

We estimate the potential and costs for demand reductions from DR in New Orleans based on a review of DR programs by other utilities, with an emphasis on Southern states. We collected data on participation rates, average savings per participating customer, and cost of reduced demand ($/kW). We apply these representative values, adjusted to an ENO context, to estimate the savings and costs for various DR program strategies in the appropriate customer groups in the ENO service territory, and estimate benefits based on the avoided cost of capacity in New Orleans.

ENO customers have had limited experience with DR offerings, in particular those strategies that rely upon advanced metering infrastructure (AMI), which ENO is just beginning to implement in its service territory. Program marketing will be important to build customer awareness and encourage participation. As AMI becomes available to more customers, the range of program offerings can diversify to take advantage of these new technology opportunities.

METHODOLOGY

This section provides an overview of our approach to the DR portion of the potential study analysis. The subsequent sections provide more detailed descriptions of the analysis methodology and assumptions for each program area.

The DR potential analysis involved several steps. We began by conducting a literature review of previous DR potential studies, including at the national, state, and utility-territory levels. We reviewed DR program evaluations from utilities and their evaluators, as well as available meta-studies of demand response. We reviewed relevant literature throughout the study and used previous studies and program results to compare and check the general scale and validity of our own data.

Following the initial literature review, we compiled a database of utility demand response program evaluations and results. These evaluations are typically publicly available on utility websites and public utility commission docketing systems. We spoke with evaluators and program administrators to collect further documentation or to clarify methodology and results where necessary. We collected program evaluations from programs run in the same or similar climate regions to Entergy New Orleans in order to have data that would be comparative. To supplement the somewhat limited in-region data, we also collected data for programs run in

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15 https://www.ferc.gov/industries/electric/indus-act/demand-response/dr-potential.asp

different climate zones in order to build out a more robust data set. For each program, we collected data points including:

- Program title and utility administrator
- Year of program
- Location or state of program
- Program description
- Target sector including customer demand level cutoffs when applicable
- Key demand response technique(s) used
- Measures, appliances, or technologies targeted, including use of AMI
- Season and time period of demand response events called
- Participation rates
- Number of events called
- Incentive amount
- Program spending
- Demand savings
- Energy savings

In order to build the savings models, we used data from Entergy New Orleans as well as other publicly available data sources. The latter included assessments of peak demand, penetration of central air conditioning, and load growth projections. Entergy New Orleans provided data including number of customers in each class and avoided capacity costs. To calculate cost-effectiveness, we assume a discount rate of 3%.

Subsequent to our analysis we were able to obtain monthly peak demand for 2017 disaggregated by residential, small commercial, and large commercial customers. Annual peaks occurred during the three summer months (June, July, and August) with residential and non-residential each contributing about half of the total peak. This distribution of the annual peak confirms our assumptions based on power sales to these customers used in our analysis. The review of the monthly peaks also revealed a winter peak primarily driven by residential load, assumed to result from resistance heating load. While our residential demand response measures will also ameliorate these peaks, an increased use of heat pumps in residential sector would also provide an important contribution to managing this peak in the future, as is mentioned in the residential energy efficiency discussion.

From the data points we collected, we created a taxonomy of major demand response program types.[16] We determined major programs to be based on sector (residential, small, medium, and large commercial and industrial), program type (e.g., direct control, automated response, or use of rates), and the targeted energy end-use (e.g., lighting, heating, air conditioning). For each program, we developed two achievable scenarios, as described below.

Data on demand by disaggregated customer types was not available from ENO. We therefore use various strategies to estimate the share of demand attributable to these customers.

[16] We relied upon Peters and Cappers 2017 to inform the general taxonomy of DR programs.

Availability of Data

With limited current presence of DR programs from Louisiana utilities, we have had to rely upon data from a larger geographic area. For some program models the available data are limited or incomplete, creating uncertainty in our estimates of performance, costs and participation, particularly for large customers. The available program data limits our ability to project the likely participation by specific target audiences, limiting our ability to reflect unique demographic characteristics for ENO with a greater share of some customer classes such as hospitality and healthcare. Additionally, residential rate demand response programs vary widely in design, including number and magnitude of peak prices or rebates. This creates variability in program costs and achieved savings. We used estimates for costs and savings consistent with levels we observed in the programs we reviewed, although the utility could choose to spend more to achieve deeper savings, such as through increased recruitment and marketing efforts.

MEASURE CHARATERIZATIONS

Residential Direct Load Control (DLC) and Automated Demand Response (ADR)

The objective of both residential direct load control (DLC) and automated demand response (ADR) programs is to reduce residential peak demand (as measured in kW) during load control events, which typically occur during the summer months. In the case of DLC programs, for example program participants have a load control receiver installed typically on their central air conditioners (CAC) that allows the program administrator to remotely shut down or reduce the amount of time the unit is running. Water heaters and pool pumps are other common technology applications. Participants typically have an option of 50% or 75% cycling of their CAC during the events and receive an incentive based on the level of cycling. Participants may also receive a one-time bill credit for installation and successful testing of the load control device.

An example of an ADR program is the Bring Your Own Thermostat (BYOT) program, which has recently emerged as a residential demand response program opportunity. Through the program, consumers purchase Wi-Fi-enabled smart thermostats and participate in this cloud-based demand response programs. The DR implementer provides a software solution to coordinate and communicate with the thermostat to cycle air conditioning use during called-upon event days.

To estimate demand reductions and costs for residential DLC and ADR programs, we first estimated local penetration of residential central air conditioning (CAC) from the American Housing Survey (Census 2015). We assume that the presence of CAC would determine the households that would be the target of such a program. The Census survey identified that an estimated 89% of housing units in the NOLA metro area have CAC. We use this estimate because it is more recent than the Residential Appliance Saturation Survey (RASS) data from Entergy, which found that 83% of customers had CAC in 2006 (Entergy 2006)[17]. Next, we estimated participation levels based on data from other utility demand response programs in the region.

[17] Full citations for this and other in-text references are forthcoming.

For example, Entergy Arkansas' DLC program reached a participation rate of about 6.5% of eligible customers after about six years.[18] Participants in that program received an installation incentive of $25 or $40 as well as an annual incentive of up to $25 or $40 (depending on the cycling level with higher incentives for the higher level of cycling). Another example is Duke Energy, which had achieved 13% customer participation over five years. Yet another example is PNM in New Mexico, which has reached an estimated 22% of eligible customers.[19]

Similarly, we estimated energy and demand savings and costs assumptions based on DLC and ADR program data from other programs in the region. Savings are based on portfolio results from programs in our review, which may include multiple measures such as HVAC, hotwater, and pool pumps. In addition to Entergy Arkansas, Duke Energy Carolinas and PNM New Mexico, we also used DR program data from utilities in Texas, including Centerpoint Energy Houston, AEP Texas Central, and Oncor.

Table 29 | Residential DLC/ADR Model Inputs

Program Measure	Peak Reduction per Participant (kW)	Participation Rate (% residential customers)[1]	Cost per kW Saved[2]
Residential DLC/ADR (Scenario 1)	1.25 (DLC) and 1.2 (ADR)	1%-9%	$48-$160
Residential DLC/ADR (Scenario 2)	1.25 (DLC) and 1.2 (ADR)	2%-18%	$48-$160

[1]Assumes total starting participation of 1% for both DLC and ADR programs combined ramping up to total participation of 9% by 2037 in scenario one.In scenario two, participation starts at 2% combined for DLC and ADR programs ramping up to total participation of 18% by 2037.

[2]Assumes costs range from $48/kW for ADR to $160/kW for new DLC customers.

Residential Time-Varying Rates Demand Response Programs

The objective of residential time-varying rates in demand response portfolios is to use price signals to reduce residential peak loads during load control events. Residential demand response rate programs vary in design. Some offer customers a rebate for reducing load during peak times, while others increase prices during peak load events. Programs vary in the number of pricing blocks used throughout the day and in the magnitude of the rebate or price increase. These price blocks can range from "real-time pricing" where prices may vary by the hour or even smaller intervals, to programs with a few or even just two different price blocks (off-peak and peak/critical peak). Peak times typically cover a span of a few hours in the afternoon/evening and are also influenced by the weather. The magnitude of the price signal influences the savings achieved. Time-varying rates are "carrot and stick" approaches. Rewards can include very low

[18] This assumes 55% saturation of CAC in Arkansas per FERC 2009 and a total number of residential customers in the service area in 2016 per EIA 2017.

[19] This estimate again uses statewide penetration of CAC per FERC 2009 and total number of residential customers in the service area per EIA 2017.

prices for energy usage in off-peak periods or rebates for demand reductions in peak periods. Penalties can include very high prices for usage in on-peak times.

For this analysis, we consider two common residential rate options: Residential Peak Time Rebates (PTR) and Residential Critical Peak Pricing (CPP). We consider these two programs because they aim to specifically reduce demand during peak times (load control events), rather than during multiple time periods throughout the day. Additionally, these programs are commonly included in utility demand response portfolios, meaning that there are adequate data available for conducting analysis. We explain each program in further detail below. The use of advanced metering technology (such as programmable communicating thermostats or Wi-Fi thermostats) in conjunction with these programs influences the level of savings achieved. For that reason, we model savings potential with and without these technologies for both program types ("without tech." or "with tech.").

Rate programs can be designed as "opt-in" or "opt-out" programs. For opt-out programs, the time-varying rate is the default, and customers can decide not to participate, and for opt-in programs, customers must actively sign up for the time-varying rate. We consider only opt-in programs in this analysis, as these are typically pursued prior to implementing opt-out or default time-varying rates. For opt-in programs, spending on marketing and outreach to recruit customers influences participation and savings rates. Some utilities administer these programs as they would any other rate option, meaning that their only costs are program evaluations. Other utilities invest in marketing and outreach to increase rate subscriptions. Programs that use high on-peak prices to penalize energy use during certain times attract customers by focusing on low off-peak prices that they can take advantage of.

There are limited data available to determine a direct ratio between spending and savings for time-varying rate programs, and utility spending on time-varying rate programs varies widely. For this reason, we use a median cost estimate of $50/kW-saved based on utility evaluations we reviewed and keep this estimate consistent over time. We use the same cost estimate for both rate programs in this analysis because utilities often market their time-varying rate options together and evaluation or other costs are similar for both types of programs. For example, in 2015 Arizona Public Service reports spending $2.24/kW-saved on marketing and outreach for their time-varying rates with low participation, while BGE reports spending $154.58/kW-saved in total for their opt-out program, which achieved high participation (APS 2016; BG&E 2016).

In coordination with the mid-range spending value used, we also used conservative estimates for participation rates. For the PTR program, we assume participation rates begin at 5% based on utility evaluations and recruitment rates, and end with just over 15% participation in 2037. We use similar estimates for the CPP program, starting at 4% participation based on utility evaluations and recruitment rates, and end with just over 12.5% participation in 2037. These are reasonable estimates using a mid-range spending value over time, as other utilities have achieved similar or higher participation for opt-in time-varying rates. For example the Salt River Project achieved over 30% participation in the opt-in time-of-use rate program in 2015, and OG&E achieved about 15% participation in their time-varying rate program in 2016 (Relf, Baatz, and Nowak 2017; OG&E 2017). We split participation rates between those with and without technology, based on technology adoption rates of past utility programs. For example, OG&E has achieved between 45% and 65% technology adoption rates in past program years. This is consistent with other utility technology adoption rates.

Residential Peak Time Rebates (PTR)

Peak time rebates (PTR) are pay-for-performance incentive programs that pay participants to reduce energy use during certain hours of selected days when a peak event is called. The number of events called varies by year based on weather and system needs. Our methodology does not attempt to assume a certain number of events, but rather uses the percent of peak energy saved based on the median data point from a meta-analysis of PTR programs with and without AMI technologies. The incentive payment is calculated based on the difference between actual metered electricity use and estimated participant use in the absence of a called event (i.e. baseline electricity use). PTR programs provide only "carrots," or rewards, for reducing energy during peak times, rather than using a "stick," or penalties, in the rate structure. Examples of PTR programs include Baltimore Gas & Electric's (BG&E) PTR program and Oklahoma Gas & Electric's (OG&E) PeakTime Rewards program. PTR has also been offered as a default rate with the option to opt-out in Southern California, Maryland, and Washington, D.C. (Brattle 2014).

The price ratio for a peak rebate to off peak price typically falls in a range of about 4 to 9, meaning that the peak rebate is 4 to 9 times the off-peak price. Examples include (Fenrick et. al 2014):

- SDG&E's PTR program that provides incentives of $0.75/kWh for manual reduction and $1.25/kWh for automated demand response
- AEP Central Power and Light's PTR program that provided incentives ranging from $0.65-$1.60/kWh
- Pepco's PTR that provided an incentive of $0.75/kWh

Residential PTR Model Inputs

For the PTR potential savings model, we used residential customer and peak demand load forecast data from ENO. We used ENO 2017 residential peak demand data and estimated savings using the median data point of percent of peak energy saved from a meta-analysis of PTR programs with and without AMI technologies. These estimates are consistent with peak savings percentage data from additional utility program evaluations we reviewed. Participation rates and costs per kW saved data are based on utility program evaluations. Table 30 shows the major assumptions and inputs to the PTR models.

Table 30 | Residential PTR Model Inputs

Program Measure	Baseline Demand (average peak kW per customer)[1]	Peak Reduction per Participant	Participation Rate (% residential customers)[2]	Cost per kW Saved
Residential PTR w/o tech.	3.35	12%	2.3%	$50
Residential PTR with tech.	3.35	20%	2.7%	$50

[2]Asummes total starting participation of 5% for both programs combined (without tech at 2.3% and with tech at 2.7%). Analysis assumes an annual participation growth rate of 15% that declines by 1% annually. We assume no growth in participation after 2032 to be conservative. . Total participation reaches a maximum of 15.7% in 2033. [2]We use a median cost estimate of $50/kW-saved for PTR and CPP programs, based on utility evaluations we reviewed; this estimate remains constant over time.

Residential Critical Peak Pricing (CPP)

Residential Critical Peak Pricing (CPP) programs charge customers a higher peak price during certain hours of selected days when events are called. The number of events called varies by year based on weather and system needs. Our methodology does not attempt to assume a certain number of events, but rather uses the percent of peak energy saved based on the median data point from a meta-analysis of CPP programs with and without AMI technologies. CPP programs provide "carrots", or incentives of very low energy prices, for using energy during peak times. They also use a "stick", or penalty of very high prices for energy use during peak times in the rate structure. Opt-in CPP programs attract customers by focusing on the ability of participants to manage their consumption and to take advantage of very low off-peak prices. The ratio of the peak price to off-peak prices typically falls around 8 or 9, meaning that the critical peak price is 8 or 9 times the off-peak price. Examples include (Fenrick et. al 2014):

- OG&E's critical peak price of $0.42/kWh
- PSE&G's critical peak price added to the off-peak price in a range from $0.23/kWh (non-summer) to $1.37/kWh (summer)
- Pacific Gas & Electric's critical peak price adder of $0.60/kWh
- DTE's critical peak price of $1.00/kWh (DTE 2014)

Examples of CPP programs include OG&E's SmartHours program and Arizona Public Service's residential Super Peak CPP program.

Residential CPP Model Inputs

For the CPP savings potential model, we used residential customer and peak demand load forecast data from ENO. We used ENO 2017 residential peak demand data and estimated savings using the median data point of percent of peak energy saved from a meta-analysis of CPP programs with and without AMI technologies. This estimate is consistent with peak savings data from additional utility program evaluations we reviewed. Participation rates and estimated costs per kilowatt saved are based on averages of utility evaluation program data. Table 31 shows the major assumptions and inputs to the CPP models.

Table 31 | Residential CPP Model Inputs

Program Measure	Baseline Demand (average peak kW per customer)[1]	Peak Reduction per Participant	Participation Rate (% residential customers)[2]	Cost per kW Saved
Residential CPP w/o tech.	3.35	20%	1.6%	$50
Residential CPP with tech.	3.35	25%	2.4%	$50

[2]Asummes total starting participation of 4% for both programs combined (without tech at 1.6% and with tech at 2.4%). Analysis assumes an annual participation growth rate of 15% that declines by 1% annually. We assume no growth in participation after 2032 to be conservative. Total participation reaches a maximum of 12.5% in 2033. [2]We use a median cost estimate of $50/kW-saved for PTR and CPP programs, based on utility evaluations we reviewed; this estimate remains constant over time.

Large Customer Programs

The only current large customer demand response offering from ENO is a curtailment tariff that is used by Air Products for their air separation plant. Expanded participation will likely come with the implementation of advanced metering infrastructure (AMI) that would enable bidirectional communications between the customer and the utility, which should be available for large customers in the early to mid-2020s.

Reviewing the literature, we chose to research three program models for the large customers:

- Standard offer program (SOP), where the customer is paid to allow the utility to curtail load for a maximum number of times during a set period, usually with 24 hours advance notice.
- Direct load control (DLC), where the utility installs equipment on large energy using equipment, predominately HVAC, that allows the utility to remotely control the equipment during certain prescribed periods of time.
- Automated demand response (ADR), which makes use of AMI system bi-directional communications to provide information to the customer that allows their intelligent building management system to take steps, such as precooling of the facility, to anticipate future grid needs that would allow the facility to reduce energy consumption during peak periods. In exchange, the customer is compensated for their reductions. In some cases, the customer is also incented to install necessary equipment to participate in the program.

In general, these programs are made available to all larger customers.

Looking at the examples of these programs from across the country for which data was available, with a particular focus on programs in the south, we found multiple examples of SOP that showed a consistent pattern of cost and performance. Data on large customer DLC and ADR programs are more limited, with significant variation in cost of avoided capacity despite similarities in the programs. In particular, the data for ADR showed a wide variation in cost and in many cases lacked other performance indicators.

Because of this limited data for the large customer ADR, and its dependence on availability of AMI, we opted to collapse these two categories (i.e., DLC and ADR) into a single load control measure. We anticipate that initially the load control would make use of DLC technologies, but as the technologies continue evolve and AMI becomes available that the program would likely transition to next generation ADR in those applications where it is more cost effective than traditional DLC. We would anticipate that the cost per kW would likely remain the same, but that the reductions per customer would increase. Because there is significant uncertainty in projecting this results into future years, we elected to make a conservative assumption of holding per-customer savings and costs constant for the study period.

We propose two large customer DR program bundles: 1) a standard offer that would be available initially to about half of the commercial, industrial, and government load, with modest participation increases during the study period, and 2) the standard offer combined with a direct load control offering that would initially be available to about 20% of the load, increasing to 40% of load by the end of the study period as the program transitions from DLC to next generation ADR system that can control a larger range of loads. In the second scenario we assume that the SOP and DLC/ADR programs are complementary and additive.

As noted above, ENO does not have a history of DR programs for the majority of their C&I customers, which means that it will take several years of marketing and customer experience to build participation in the program. As a result, we project a relatively modest trajectory of increasing program participation. In addition, the ENO commercial base has a higher share of hospitality customers than we see in most customer bases. The large national chains are likely to participate in DR programs, but we might anticipate that locally-owned customers would be less likely to participate in DR programs because they have limited familiarity with DR programs and concerned about customer comfort in a hot and humid climate, and therefore less willing to participate in any program that might interrupt cooling and negatively affect customer comfort. For both of these reasons we feel that a lower ultimate participation of the large customer DR program is reasonable.

We estimate that the non-residential customers account for about half of the peak for the study period, as reflected in data from 2017.

Table 32 | Large Customer Program Assumptions

Program Measure	Savings per Customer (kW)	Spending per kW Saved
Standard Offer Program (SOP)[1]	5.1	$37.26
Large Customer Direct Load Control (DLC)[2]	1.7	$33.50

Notes: 1) Assumes an average 10% reduction for participating customers; 2) assumes an average 3% reduction for participating custom

RESULTS

This section presents results including total costs, peak demand savings, and cost-effectiveness for the demand response programs evaluated. We present findings from two scenarios for years 2018-2037. Both scenarios are achievable and are based on participation rates that have been achieved in other jurisdictions. In Scenario One, we assume participation rates at the lower end the range that we see from other jurisdictions. In Scenario Two, we assume participation rates at the upper end of the range that we see from other jurisdictions. Scenario Two therefore assumes more aggressive program participation and marketing and as a result higher levels of demand reduction. Another important distinction between the two scenarios is for the residential pricing programs. In Scenario One we model a residential PTR program and in Scenario Two we model a residential CPP program that would achieve higher levels of demand reduction.

Scenario One includes the following measures:

- Residential DLC and ADR
- Residential PTR pricing with and without AMI technology
- Large customer standard offer program (SOP)

Scenario Two includes the following measures:

- Residential DLC and ADR
- Residential CPP pricing with and without AMI technology
- Large customer SOP plus a DLC/ADR offering

Peak Demand Savings

Results for each of the scenarios are presented in the Figures and Tables below.

Figure 16 | Electric Demand Savings - Scenario One

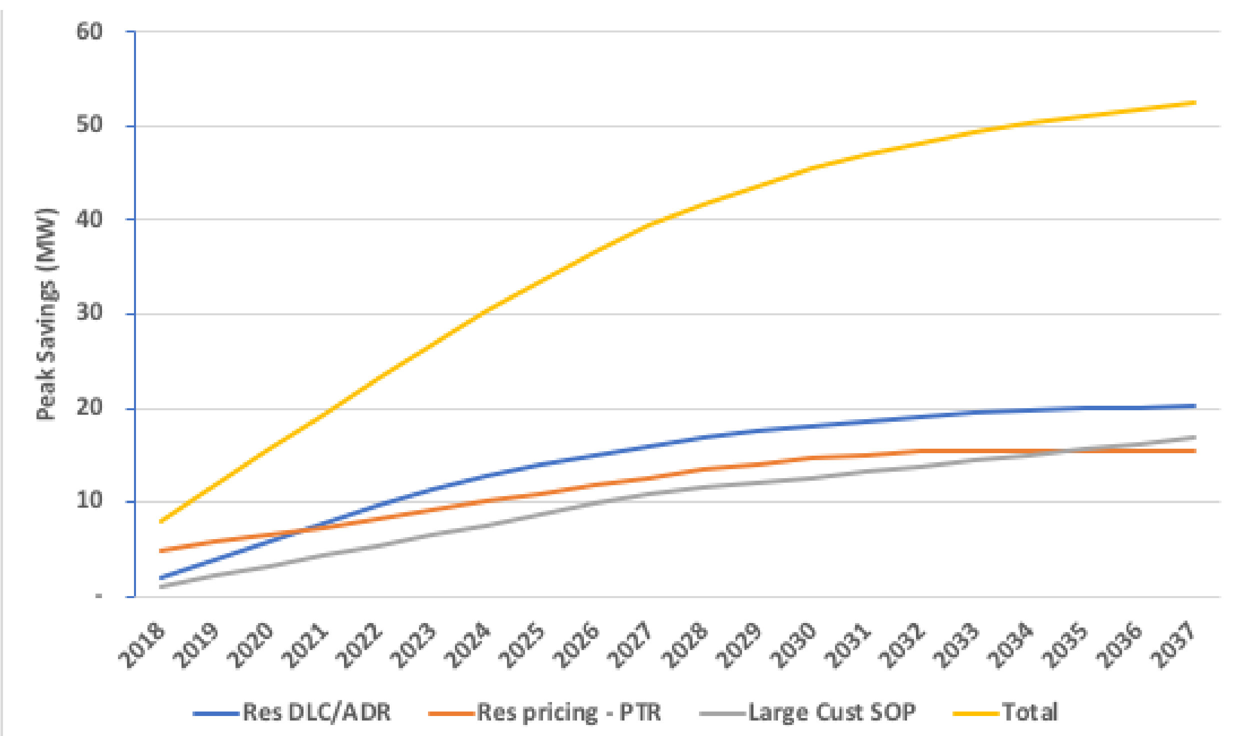

Figure 17 | Electric Demand Savings - Scenario Two

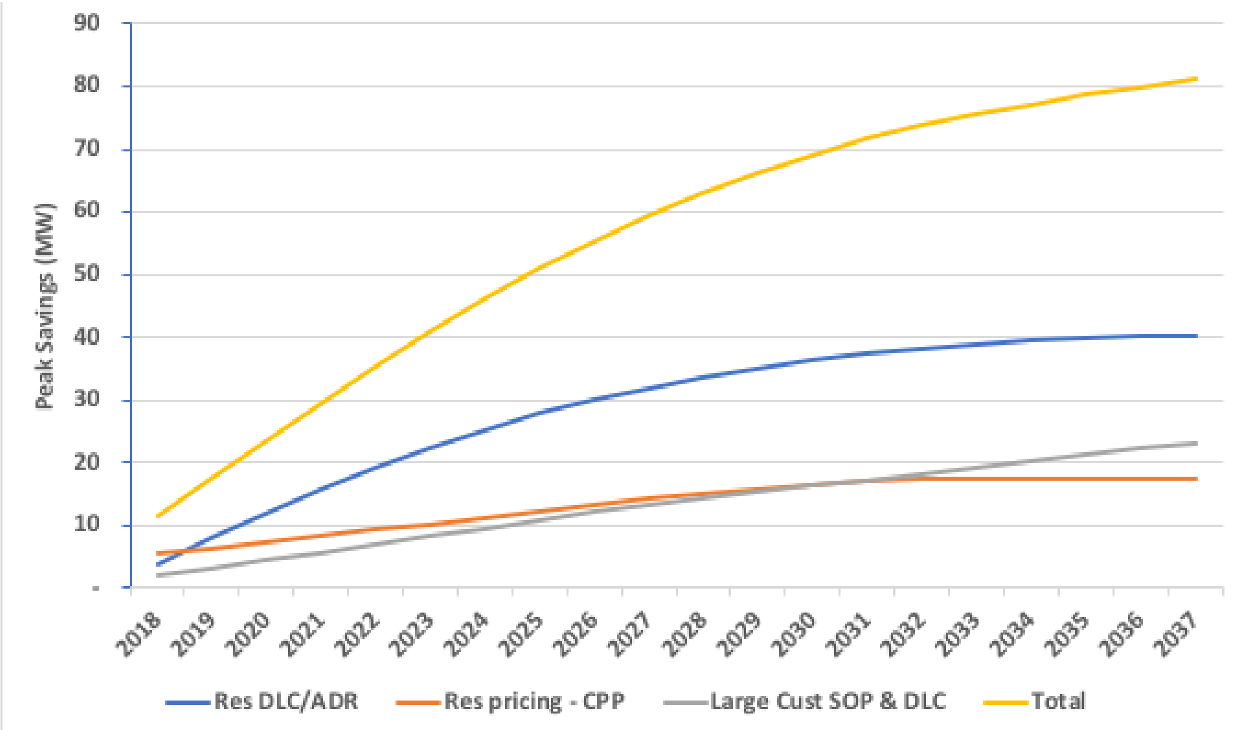

Table 33 | Demand Response Peak Load Reductions Summary – Scenario One

Program	2018	2027	2037
Residential DLC and ADR	2.0	16.0	20.2
Residential PTR pricing	4.9	12.6	15.5
Large Customer SOP	1.1	10.9	16.9
Total	8.0	39.5	52.5

Table 34 | Demand Response Peak Load Reductions Summary– Scenario Two

Program	2018	2027	2037
Residential DLC and ADR	3.9	31.9	40.3
Residential CPP pricing	5.6	14.2	17.5
Large Customer SOP	1.9	13.4	23.2
Total	11.5	59.6	81.1

Scenario One reached peak reductions from these programs equivalent to 2.7% of total system forecast peak in 2027 and 3.6% in 2037. In Scenario Two, peak reductions from these programs are equivalent to 4.5% of forecasted system peak in 2027 and 5.9% in 2037. The tables below gives a more detailed breakout of savings by year for every year of the study horizon for each scenario.

Table 35 | Demand Response Peak Load Reductions By Year – Scenario One

	Res DLC/ADR	Res Pricing - PTR	Large Cust SOP	Total
2018	2	5	1	**8**
2019	4	6	2	**12**
2020	6	6	3	**16**
2021	8	7	4	**19**
2022	10	8	5	**23**
2023	11	9	6	**27**
2024	13	10	8	**30**
2025	14	11	9	**34**
2026	15	12	10	**37**
2027	16	13	11	**39**
2028	17	13	11	**42**
2029	18	14	12	**44**
2030	18	15	13	**45**
2031	19	15	13	**47**
2032	19	15	14	**48**
2033	19	16	14	**49**
2034	20	16	15	**50**
2035	20	16	16	**51**
2036	20	16	16	**52**
2037	20	16	17	**53**

Table 36 | Demand Response Peak Load Reductions By Year – Scenario Two

	Res DLC/ADR	Res Pricing - PTR	Large Cust SOP	Total
2018	4	6	2	**11**
2019	8	6	3	**18**
2020	12	7	4	**24**
2021	16	8	6	**30**
2022	19	9	7	**35**
2023	23	10	8	**41**
2024	25	11	10	**46**
2025	28	12	11	**51**
2026	30	13	12	**55**
2027	32	14	13	**60**
2028	34	15	14	**63**
2029	35	16	15	**66**
2030	36	16	16	**69**
2031	37	17	17	**72**
2032	38	17	18	**74**
2033	39	17	19	**76**
2034	39	17	20	**77**
2035	40	17	21	**79**
2036	40	17	22	**80**
2037	40	17	23	**81**

Budgets and Cost-Effectiveness

Program budgets are presented in the figures below and overall cost-effectiveness results for each program, scenario, and the overall DR portfolio are presented in the table below.

Figure 18 | Annual Program Costs—Scenario One

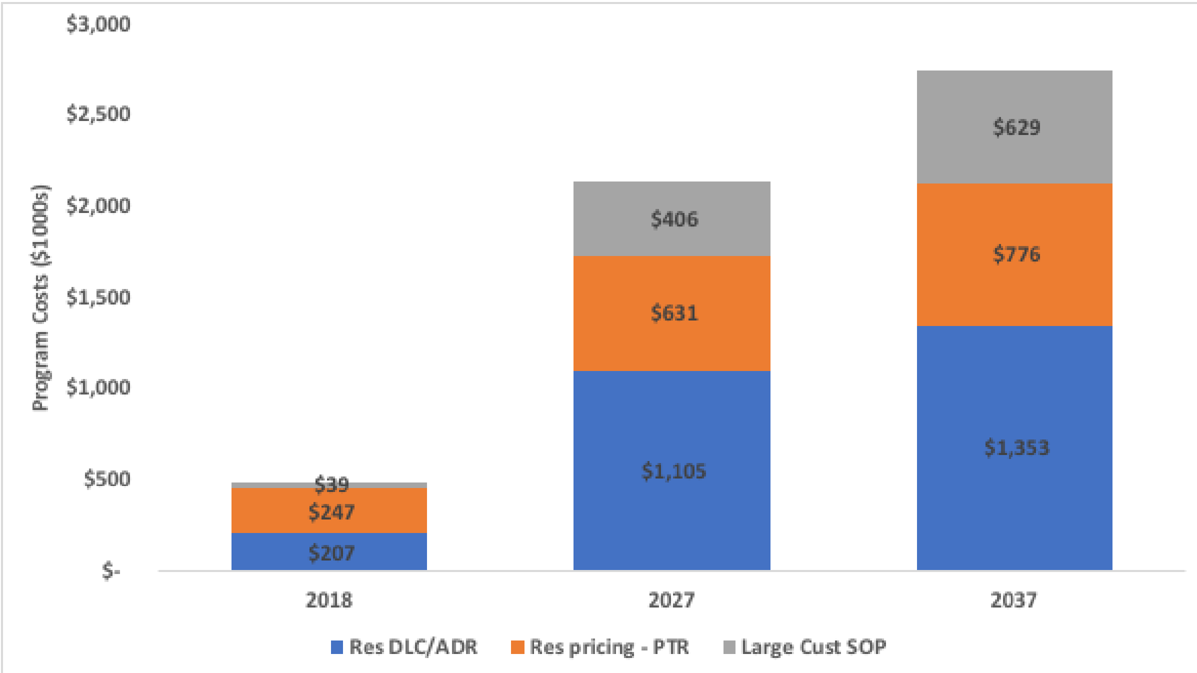

Figure 19 | Annual Program Costs—Scenario Two

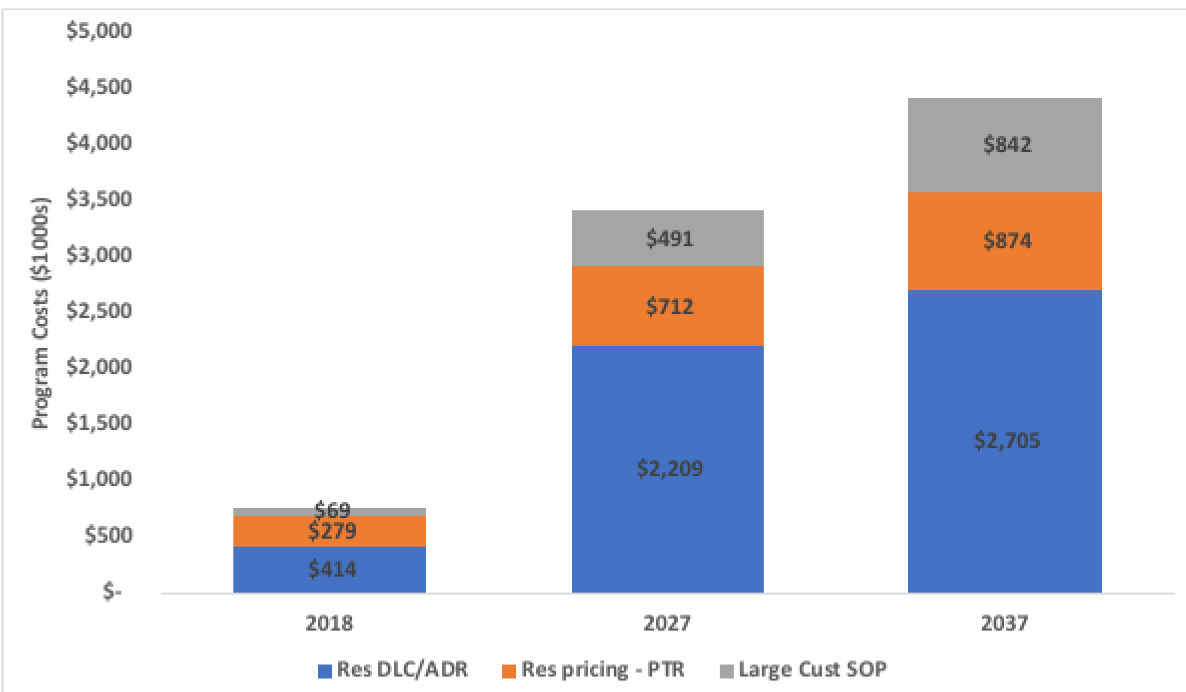

Table 376 | Net Costs and Benefits of DR Potential in Scenarios One and Two

Program	Scenario One			Scenario Two		
	Costs (Million$)	**Benefits (Million$)**	**BCR**	**Costs (Million$)**	**Benefits (Million$)**	**BCR**
Residential DLC and ADR	$14.0	$19.8	1.4	$18.3	$25.2	1.4
Residential pricing	$8.4	$16.4	2.0	$9.4	$18.5	2.0
Large Customer SOP	$1.87	$4.99	2.7	$6.6	$18.1	2.8
Total	$27.5	$50.1	1.8	$34.3	$61.9	1.8

COMBINED RESULTS

Total Peak Demand Savings, all DSM

Although this analysis mainly treats the demand response, energy efficiency, and rate design portions as independent and separate, we do provide a high level analysis of the likely total peak demand reduction from all three DSM types (efficiency, demand response, and rate design). The table below shows project total demand reduction by year. We derived these values by assuming a simple "loading order" of the categories: first rate design first, then energy efficiency, and then demand response. In other words, if in a given year the three categories would each produce a 10% reduction in peak separately, we assume that the rate design reduces the forecast by 10%, then the efficiency reduces the new forecast by 10%, and then demand response reduces the remaining peak by another 10%. This way, total demand is reduced by around 27%, instead of the 30% that would result if you simply added the reductions together. Table 10 presents the results of this analysis, assuming an optional time of use rate design, the program potential energy efficiency savings, and scenario two for demand response.

Table 38 | Cumulative Peak Demand Reduction from EE, DR, and Rate Design

Year	Peak Reduction (MW)	Year	Peak Reduction (MW)
2018	67	2028	297
2019	83	2029	305
2020	104	2030	313
2021	129	2031	321
2022	154	2032	329
2023	181	2033	335
2024	209	2034	340
2025	236	2035	343
2026	262	2036	347
2027	288	2037	350

RATE DESIGN

SUMMARY OF APPROACH & MAJOR ASSUMPTIONS

Electric rate design holds promise as a tool to incent specific behavior or consumption pattern changes from customers. In the assessment of demand response potential, we considered rate design approaches that focus on short-duration price signals for specific events (i.e., critical peak pricing and peak time rebates). This section of the analysis describes other rate design options (such as a time of use rates) that apply to all hours of the year and therefore can result in larger shifts in customer energy consumption patterns. Decades of study has demonstrated positive customer response to changes in marginal prices or electric rates.[20] In this section we present results of our analysis of how Entergy New Orleans residential customers may respond to different rate design alternatives.

Rate design refers to the process of translating utility revenue requirements into the prices paid by customers.[21] Rates for residential customers are typically composed of two parts, a fixed customer charge and a volumetric energy rate. The fixed customer charge is a flat fee paid by customers regardless of how much energy they use in a given month. This is often intended to recover specific costs of utility service, including billing, metering, and customer service. The volumetric energy component bills customers for each unit of energy consumed. While the majority of residential customers in the United States are subject to a flat energy charge, meaning they pay the same price for each unit of energy regardless of what time of day it is used or the total level of consumption, many utilities also offer time varying volumetric energy rates, charging customers different prices for energy consumed based on the time of day or year. Finally, some utilities also offer tiered rates, charging customers a higher or lower rate for each unit of consumption based on the total usage for the month. Entergy New Orleans currently relies on a rate structure with a flat energy charge in the summer and a declining block rate in the winter. Table 39 shows the current residential rate design.

Table 39 | ENO Existing Residential Rates

Component	Summer	Winter
Customer charge (monthly)	$8.07	$8.07
Energy Charge per kWh		
Tier 1 (0-800 kWh)	$0.06002	$0.06002
Tier 2 (over 800 kWh)	$0.06002	$0.04766

To estimate potential changes in consumption for the Entergy New Orleans service territory we relied on existing evidence from prior pricing studies regarding customer price response and participation. We developed five revenue neutral rate design scenarios to understand consumer

[20] Electric Power Research Institute. 2008. *Price Elasticity of Demand for Electricity: A Primer and Synthesis.* epri.com/#/pages/product/1016264/?lang=en.

[21] National Association of Regulatory Utility Commissioners. 2016. *Distributed Energy Resources Rate Design and Compensation.* pubs.naruc.org/pub/19FDF48B-AA57-5160-DBA1-BE2E9C2F7EA0.

price response using the current rate structure as a baseline. Revenue neutral rate approaches are designed to recover the same level of revenue in the analysis period, which is one year for this analysis. The various rate design scenarios are based on commonly used and industry-accepted approaches to residential rate design. Table 40 shows the five rate scenarios, with customer charge and volumetric rate values for each scenario. The table also shows the participation assumption for the analysis, which is described in greater detail below.

Table 40 | Summary of Rate Design Scenarios

Description	Customer charge ($/month)	Season	Period or block	Volumetric rate ($/kWh)	Participation Assumption
Seasonal with higher customer charge	$25	Summer	all	$0.0508	100% (mandatory)
		Winter	all	$0.0351	
Seasonal with higher customer charge	$50	Summer	all	$0.0278	100% (mandatory)
		Winter	all	$0.0168	
Time of use (opt in)	$8.07	summer	on peak	$0.1231	25% (opt in)
		summer	off peak	$0.0424	
		winter	on peak	$0.0925	
		winter	off peak	$0.0463	
Time of use (opt-out)	$8.07	summer	on peak	$0.1231	90% (opt-out)
		summer	off peak	$0.0424	
		winter	on peak	$0.0925	
		winter	off peak	$0.0463	
Seasonal inclining block rate	$8.07	summer	tier 1	$0.0550	100% (mandatory)
		summer	tier 2	$0.0850	
		winter	tier 1	$0.0343	
		winter	tier 2	$0.0548	

The first two scenarios are both seasonal rates with higher customer charges. The volumetric price varies from summer to winter to reflect the higher cost of energy production in the summer. The customer charge for the first scenario is $25 per month and $50 per month for the second scenario. The time of use rate relies on the same customer charge as the current residential offering, but uses on- and off-peak periods in both summer and winter for the volumetric charge. This structure more accurately reflects the cost to serve residential customers throughout the day.

Finally, the seasonal inclining block rate relies on the existing customer charge and an inclining block structure for volumetric prices. As with the other scenarios, the seasonal price varies to reflect the higher cost to serve customers in the summer months. The inclining tier structure assesses a higher cost per unit of energy consumed based on higher levels of consumption. In this analysis, the first tier includes consumption from 0-500 kWh per month. The second tier captures all consumption in excess of 500 kWh per month. The current ENO residential rate uses a declining block rate in the winter months, meaning customers are billed a lower cost per unit of energy in the second tier (800 kWh or greater).

For all seasonal rates we assumed a summer period of May through October and a winter period of November through April. For the time of use rate, we assume a peak period between 3 and 8 pm in summer and 6 to 9 am in the winter. These periods are based on consumption patterns presented in the load research sample data from Entergy.

These scenarios represent a range of potential rate designs for Entergy New Orleans. The time-of-use scenario relies on an on-peak to off-peak ratio of 3:1 in the summer. Prior research demonstrates that this ratio is a critical factor in how customers respond and modify their energy consumption.[22]

METHODOLOGY

We took several steps to estimate changes in consumption and peak demand for various rate designs. First, we created revenue neutral rate designs using a load research sample provided by Entergy New Orleans. We determined revenue targets using revenues per customer provided in the most recent Federal Energy Regulatory Commission (FERC) Form 1, an industry data reporting form required for all investor-owned utilities. We then applied applicable price elasticities from relevant, recent pricing studies to usage in specific periods to measure changes in consumption.

According to EPRI, the price elasticity of demand is a measure of how price changes influence electricity use.[23] Price elasticities for electricity, as with nearly all consumer products and services, are generally negative, meaning that as prices increase, consumption declines. The EPRI study surveyed prior literature on price elasticity and concluded that residential short-run price elasticity ranges between -0.2 and -0.6, with a mean value of -0.3. The long-run elasticities were estimated between -0.7 and -1.4, with a mean value of -0.9. Short run is considered 1-5 years, while long run is anything beyond five years. The value represents the ratio of a percentage change in quantity demanded and the percentage change in price. For example, a 10% increase in residential electricity prices would result in a 3% decline in short term consumption, relying on the mean estimate from the EPRI study. These values allow us to estimate how residential customers may adjust their electric consumption in responses to changes in prices.

Entergy New Orleans has not conducted any recent pricing studies which would offer primary data for this purpose. Instead, we reviewed several recent pricing studies to source applicable elasticities for the Entergy New Orleans service territory. Table 29 shows the elasticities used for this analysis. For the seasonal two-part rate, we relied on the first tier elasticity for the summer period consumption. All elasticities are short run, meaning they only capture changes in consumption in the near term. . We did not estimate customer response in the long

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[22] Faruqui, A. et al. 2017. *Arcturus 2.0: A Meta-Analysis Of Time Varying Rates For Electricity.* The Electricity Journal. Vol 30, Issue 10, December 2017, pages 64-72.

[23] Electric Power Research Institute. 2008. *Price Elasticity of Demand for Electricity: A Primer and Synthesis.* *epri.com/#/pages/product/1016264/?lang=en*.

run because the results are less certain than the short run customer response. However, we would expect greater price response in the long run as customers have more options to reduce or shift consumption over time..

Table 41 | Price Elasticity Assumptions[24]

Rate	Elasticity
IBR first tier	-0.130
IBR second tier	-0.260
TOU on peak	-0.083
TOU off peak	-0.0265

Our analysis applies these elasticities to consumption data for a sample population of 319 residential ENO customers. The sample is intended to represent the larger population of residential customers. However, Entergy New Orleans has approximately 178,000 residential customers. The sample, if properly drawn, should represent the larger population of residential customers.[25] To estimate changes for the entire customer class, we extrapolate the results from the price response analysis of the sample population to the entire residential customer class. This allows us to understand the potential impacts of implementation of a given rate design to all residential customers.

For this exercise, we must also make assumptions on uptake or participation of specific rates by the customer class. This is primarily important because customers have demonstrated greater changes in consumption when opting-in or subscribing to a specific rate on a voluntary basis.[26] Customers as a whole show a lower response when placed on a rate on a nonvoluntary basis. For the optional time-of-use (TOU) rate, we assumed 25% of customers would enroll, with the remaining customers staying on the existing rate. Under the default TOU rate, we assumed 90% of customers stayed on the rate, while the other 10% opted back to the existing two part seasonal rate. The inclining block and seasonal two part iterations were assumed to be mandatory, with 100% of customers subject to the rate.

RESULTS

High-level results include:

- Under an optional time-of-use rate with on and off-peak pricing for both summer and winter periods, overall consumption declined by 0.5% for the entire class, with a summer peak period reduction of 4.4%.

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[24] The tier rate elasticities are sourced from Faruqui, A. 2008. *Inclining Towards Efficiency.* Public Utilities Fortnightly. August. The time-of-use rate elasticities are sourced from Faruqui et al. 2016. *Analysis of Ontario's Full Scale Roll-out of TOU Rates.*

[25] We did not conduct a review of the accuracy of the sample of residential customers and assume it accurately matches the rest of the customer class.

[26] George, S. et al. 2014. SMUD SmartPricing Options Pilot Evaluation. August 6. smartgrid.gov/files/SMUD-CBS_Final_Evaluation_Submitted_DOE_9_9_2014.pdf.

- If the time-of-use rate were default instead of optional, we estimate a decrease in overall consumption of 0.9%, with a summer peak period reduction of 7.9%.
- If all customers were moved to an inclining block rate, we estimate a decrease in overall consumption of 2.1%.
- If the customer charge was increased to $25 a month (from the current $8.07 per month) and the second tier in the winter rate were eliminated, we estimate overall consumption would increase by 3.6%. If it were increased to $50, we estimate overall consumption could increase by 8.9%.

Table 42 presents a summary of these results.

Table 42 | Summary of Results

Rate Scenario	Change in Energy Consumption	Change in Peak Demand
Optional time of use	-0.5%	-4.4%
Default time of use	-0.9%	-7.9%
Inclining block rate	-2.1%	N/A
Seasonal ($25/mo. customer charge)	3.6%	N/A
Seasonal ($50/mo. customer charge)	8.9%	N/A

Our analysis shows that time-of-use and inclining block rates would marginally reduce consumption, while also providing a price signal to customers to engage in energy efficiency programs and behavior. The reductions of peak demand are driven by higher rates in those time periods. These results also suggest not all consumption in the peak period is reduced, but some is shifted to off peak periods. The seasonal rate options with higher customer charges would lead to higher consumption overall and provide a poor price signal to conserve electricity and engage in energy efficiency programs.

Peak Demand Savings

The analysis showed a summer peak period demand savings of 7.9% under the default time-of-use rate, but only a 4.4% reduction under an optional time-of-use rate. The inclining and seasonal rate options with higher customer charge are not intended to drive changes in the timing of consumption or reductions in peak demand.

Effect on System Costs

There are several categories of utility system costs that may be affected through the changes in overall consumption and peak demand presented in table 4. Reducing peak demand allows a utility to reduce production during peak periods, which lowers overall energy costs and the need for increased peaking production capacity. Energy and other variable costs are also avoided through consumption reductions during off peak periods. Conversely, increasing consumption and peak demand would likely increase system costs. At a minimum, variable energy and maintenance costs would increase. However, generation and distribution system capacity cost increases will depend on current system conditions and needs. Future rate increases because of investment in new assets may be avoided through the reduction in peak demand and localized demand reductions.

The cost associated with rolling out new rate design approaches varies significantly based on the level of marketing and customer outreach employed by the utility. There are also many other considerations for a utility or regulator in any new rate design approach. Not all customers will respond and some will face higher bills as a result of the new rates. Before implementing any new rate design, the effect on vulnerable customers should be assessed and attempts made to mitigate any negative outcomes they may face. Discussion of methods for doing so are beyond the scope of this study.

METHODOLOGY DETAILS

OVERVIEW

This section provides a brief overview of our approach to the study analysis. The subsequent sections provide more detailed descriptions of the analysis methodology and assumptions.

The energy efficiency potential analysis involves several steps. The first several are required regardless of the scenario being analyzed, and were first performed in order to build the base model used to run each scenario. These steps include:

- Assess and adjust energy forecast. In this case, we used the forecast from Entergy New Orleans, and added back the projected savings from current Energy Smart Programs.
- Disaggregate adjusted energy forecasts by sector (residential, low-income, commercial and industrial), by market segment (e.g., building types), and end uses (e.g., lighting, cooling, etc.)
- Characterize efficiency measures, including estimating costs, savings, lifetimes, and share of end use level forecasted usage for each market segment

To develop each scenario (economic, maximum achievable, and program potential) required additional steps specific to the assumptions in each scenario. These steps are listed below.

- Build up savings by measure/segment based on measure characterizations calibrated to total energy usage
- Account for interactions between measures, including savings adjustments based on other measures as well as ranking and allocating measures when more than one measure can apply to a particular situation
- Run the stock adjustment model to track existing stock and new equipment purchases to capture the eligible market for each measure in each year
- Run the efficiency potential model to estimate the total potential for each measure/segment/market combination to produce potential results
- Screen each measure/segment/market combination for cost-effectiveness. Remove failing measures from the analysis and rerun the model to re-adjust for measure interactions

Annual energy sales forecasts were for each sector (residential, low income, commercial/industrial), for the 20-year study period. The electric forecasts was provided by Entergy, and adjusted to add back in the Energy Smart savings. The sales forecasts was then disaggregated by end use and building type in order to apply each efficiency measure to the appropriate segment of energy use. This study applied a top-down analysis of efficiency potential relative to the energy sales disaggregation for each sector, merged with a bottom-up measure level analysis of costs and savings for each applicable technology.

The study applied a Total Resource Cost (TRC) Test to determine measure cost-effectiveness. The TRC test considers the costs and benefits of efficiency measures from the perspective of society as a whole. Efficiency measure costs for market-driven measures represent the incremental cost from a standard baseline (non-efficient) piece of equipment or practice to the high efficiency measure. For retrofit markets the full cost of equipment and labor was used because the base case assumes no action on the part of the building owner. Measure benefits are driven primarily by energy savings over the measure lifetime, but also may include other easily quantifiable benefits associated with the measures, including water savings, and operation and maintenance savings. The energy impacts may include multiple fuels and end uses. For example, efficient lighting reduces waste heat, which in turn reduces the cooling load, but increases the heating load. All of these impacts are accounted for in the estimation of the measure's costs and benefits over its lifetime.

There are two aspects of electric efficiency savings: annual energy and coincident peak demand. The former refers to the reductions in actual energy usage, which typically drive the greatest share of electric economic benefits as well as emissions reductions. However, because it is difficult to store electricity the total reduction in the system peak load is also an important impact. Power producers need to ensure adequate capacity to meet system peak demand, even if that peak is only reached a few hours each year. As a result, substantial economic benefits can accrue from reducing the system peak demand, even if little energy and emissions are saved during other hours. The electric benefits reported in this study reflect both electric energy savings (MWh) and peak demand reductions (MW) from efficiency measures.

The primary scenario for the study was the program potential, which best reflects what could actually be accomplished by efficiency programs given real-world constraints, and assumes incentive amounts of 50% of the incremental cost for residential and C&I sectors, and 100% for the low-income sector. We have also estimated the economic and maximum achievable potentials. The general approach for these three scenarios differed as follows:

- **Economic potential scenario:** We generally assumed that all cost-effective measures would be immediately installed for market-driven measures such as for new construction, major renovation, and natural replacement ("replace on failure"). For retrofit measures we generally assumed that resource constraints (primarily contractor availability) would limit the rate at which retrofit measures could be installed, depending on the measure, but that all or nearly all efficiency retrofit opportunities would be realized over the 10-year study period. Spreading out the retrofit opportunities results in a more realistic ramp up, providing a better basis of comparison for the achievable scenarios. In years 11-20 the retrofit activity significantly declines as the entire market has been reached, and any new retrofits are just replacing another technology that has failed (such as re-commissioning a building that was commissioned 10 years earlier).
- **Maximum achievable scenario:** This scenario is based on the economic potential but accounts for real-world market barriers. We assumed that efficiency programs would provide incentives to cover 100% of the incremental costs of efficiency measures, so that program participants would have no out-of-pocket costs relative to standard baseline equipment. Measure

participation was estimated using the Delphi Process, described earlier in the report.

- **Program potential scenario:** For this scenario, we assume that most incentives are set to 50% of the incremental cost. Penetration rates are based on the simple payback of the measure, as defined by the Delphi Panels. The one exception is that, for low income, we assume that programs will still provide 100% incentives. These programs therefore achieve the same participation as in the Max Achievable scenario.

ENERGY FORECASTS

Electric Forecast

The electric usage forecast was developed primarily from the information provided by Entergy New Orleans. Reported sales categories aligned with traditional utility categories, which closely mirror the three customer sectors that were analyzed. In some cases, energy loads were aggregated to the sector level using standard conventions (e.g., street lighting energy use is included in the commercial sector). Assumed savings from the Energy Smart Programs running at constant savings into the future were added back into the provided forecast. Current programs save about 0.4% of total sales, at a cost of $6.2 million. By adding these savings back to the forecast, the results of the study reflect a base case where no utility run efficiency programs exist.

Forecast Disaggregation by Segment and End Use

The commercial and residential sales disaggregations draw upon many sources. The commercial and industrial disaggregation relies on a number of sources. First, total forecasted energy sales are divided across building types using data from Entergy showing usage by SIC code, supplemented with data from EIA. Low-income buildings were separated from non-LI residential based on the statistical atlas[27]. Next, energy use was disaggregated into end use using the data from the EIA, and especially the Commercial Building Energy Consumption Survey (CBECS) and the Residential Energy Consumption Survey (RECS) .

Sales were further disaggregated into sales for new construction and renovated spaces and those for existing facilities. New construction activity was based on Entergy's projection of customer count growth, compared with EIA data on the consumption of new versus existing facilities.

MEASURE CHARACTERIZATION

The first step for developing measure characterizations is to define a list of measures to be considered. This list was developed and qualitatively screened for appropriateness in consultation with stakeholders to the study process. The final list of measures considered in the

[27] https://statisticalatlas.com/place/Louisiana/New-Orleans/Household-Income

analysis is shown with their characterizations in Appendix I, which also shows the markets for which each measure was considered.

A total of 173 measures were included and characterized for up to three applicable markets (new construction/renovation, natural replacement, and retrofit). This is important because the costs and savings of a given measure can vary depending on the market to which it is applied. For example, a retrofit or early retirement of operating but inefficient equipment entails covering the costs of entirely new equipment and the labor to install it and dispose of the old equipment. For new construction or other market-driven opportunities, installing new high efficiency equipment may entail only the incremental cost difference between a standard efficiency piece of equipment and the high efficiency one, as other labor and capital costs would be incurred in either case. Similarly, on the savings side, retrofit measures can initially save more when compared to older existing equipment, while market-driven measure savings reflect only the incremental savings over current standard efficiency purchases. For retrofit measures, often we model a baseline efficiency shift at the time when the retrofit measure being replaced is assumed to have needed to be replaced anyway.

For each measure, in addition to separately characterizing them by market, we also separately analyze each measure/market combination for each building segment (e.g., small office, large office, industrial, restaurant, etc.). The result is that we modeled 1,591 distinct measure/market/segment permutations for each year of the analysis.

The overall potential model relies on a top-down approach that begins with the forecast and disaggregates it into loads attributable to each possible measure, as described in the following section. In general, measure characterizations include defining the following characteristics for each combination of measure, market, and segment:

- Measure lifetime (both baseline and high efficiency options if different)
- Measure savings (relative to baseline equipment)
- Measure cost (incremental or full installed depending on market)
- O&M impacts (relative to baseline equipment)
- Water impacts (relative to baseline equipment).

Energy Savings

For each technology, we estimate the energy usage of baseline and high efficiency measures based primarily on engineering analysis. We rely heavily on the New Orleans Technical Resource Manual (TRM), as well as other TRMs from other jurisdictions, and Optimal's existing database of measure characteristics. For more complex measures not addressed by the TRMs engineering calculations are used based on the best available data about current baselines in New Orleans and the performance of high efficiency equipment or practices. The New Orleans Appliance Saturation Survey, done in 2006, was used to determine they type of equipment and fuel used, but was too old to use to determine the efficiencies. Due to budget and time constraints we did not include any building simulation modeling or other sophisticated engineering approaches to establishing detailed, weather normalized savings.

Costs

Measure costs were drawn from Optimal Energy's measure characterization database when no specific Louisiana costs were available. These costs have been developed over time, and are continually updated with the latest information, including a recent update for an ongoing potential study in Minnesota. Major sources include the New Orleans TRM and Mid-Atlantic TRMs, baseline studies, incremental cost studies, direct research into incremental costs, and other analyses and databases that are publicly available.

Lifetimes

As with measure costs, lifetimes are drawn from Optimal's measure characterization database. These have been developed over time, and were revised for this study based on the New Orleans TRM.

Operations and Maintenance Impacts

Operation and maintenance (O&M) impacts are those other than the energy costs of operations. They represent, for example, things like replacement lamp purchases for new high efficiency fixtures, or changes in labor for servicing high-efficiency vs. standard-efficiency measures. High efficiency equipment can often reduce O&M costs because of higher quality components that require less-frequent servicing. On the other hand, some high efficiency technologies require enhanced servicing, or have expensive components that need to be replaced prior to the end of the measure's lifetimes. For most measures, O&M impacts are very minimal, as many efficient and baseline technologies have the same O&M costs over time. Where they are significant, we estimate them based on our engineering and cost analyses, the New Orleans TRM, and other available data.

Additional aspects of measure characterization are more fully described below in the potential analysis section, along with other factors that merge the measure level engineering data with the top-down forecast of applicable loads to each measure.

TOP-DOWN METHODOLOGY

The general approach for this study, for all sectors, is "top-down" in that the starting point is the actual forecasted loads for each sector. As described above, we then break these down into loads attributable to individual building equipment. In general terms, the top-down approach starts with the energy sales forecast and disaggregation and determines the percentage of the applicable end use energy that may be offset by the installation of a given efficiency measure in each year. This contrasts with a "bottom-up" approach in which a specific number of measures are assumed installed each year.

Various measure-specific factors are applied to the forecasted building-type and end use sales by year to derive the potential for each measure for each year in the analysis period. This is shown below in the following central equation:

Measure Savings	=	Segment/ End use /year kWh Sales	x	Applicability Factor	x	Feasibility Factor	x	Turnover Factor (replace-ment only)	x	Not Complete Factor (retrofit only)	x	Savings Fraction	x	Net Penetration Rate

Where:

- **Applicability** is the fraction of the end use energy sales (from the sales disaggregation) for each building type and year that is attributable to equipment that could be replaced by the high-efficiency measure. For example, for replacing office interior linear fluorescent lighting with a higher efficiency LED technology, we would use the portion of total office building interior lighting electrical load consumed by linear fluorescent lighting.
- **Feasibility** is the fraction of end use sales for which it is technically feasible to install the efficiency measure. Numbers less than 100% reflect engineering or other technical barriers that would preclude adoption of the measure. Feasibility is not reduced for economic or behavioral barriers that would reduce penetration estimates. Rather, it reflects technical or physical constraints that would make measure adoption impossible or ill advised. An example might be an efficient lighting technology that cannot be used in certain low temperature applications.
- **Turnover** is the percentage of existing equipment that will be naturally replaced each year due to failure, remodeling, or renovation. This applies to the natural replacement ("replace on failure") and renovation markets only. In general, turnover factors are assumed to be 1 divided by the baseline equipment measure life (e.g., assuming that 5% or 1/20th of existing stock of equipment is replaced each year for a measure with a 20-year estimated life).
- **Not Complete** is the percentage of existing equipment that already represents the high-efficiency option. This only applies to retrofit markets. For example, if 30% of current single family homes already have learning thermostats, then the not complete factor for residential thermostats would be 70% (1.0-0.3), reflecting that only 70% of the total potential from thermostats remains.
- **Savings Fraction** represents the percent savings (as compared to either existing stock or new baseline equipment for retrofit and non-retrofit markets, respectively) of the high efficiency technology. Savings fractions are calculated based on individual measure data and assumptions about existing stock efficiency, standard practice for new purchases, and high efficiency options.
  - **Baseline Adjustments** adjust the savings fractions downward in future years for early-retirement retrofit measures to account for the fact that newer, standard equipment efficiencies are higher than older, existing

stock efficiencies. We assume average existing equipment being replaced for retrofit measures is at 60% of its estimated useful life. The baseline adjustment also comes with a cost credit to reflect the standard equipment that the participant would have had to install to replace the failed unit.

- **Annual Net Penetrations** are the difference between the base case measure penetrations and the measure penetrations that are assumed for an economic potential. For the economic potential, it is assumed that 100% penetration is captured for all markets, with retirement measures generally being phased in and spread out over time to reflect resource constraints such as contractor availability. The product of all these factors results in the total potential for each measure permutation. Costs are then developed by using the "cost per energy saved" for each measure applied to the total savings produced by the measure. The same approach is used for other measure impacts, e.g., operation and maintenance savings.

COST-EFFECTIVENESS ANALYSIS

Cost-Effectiveness Tests

This study applies the Total Resource Cost (TRC) Test as the basis for excluding non-cost-effective measures from the potential. The TRC test considers the costs and benefits of efficiency measures from the perspective of society as a whole. In addition, for the program potential scenario we report the cost-effectiveness of the efficiency programs using the Program Administrator Cost Test and the Participant Cost Test. The principles of these cost tests are described in the *California Standard Practice Manual*.[28]

Table 43 provides the costs and benefits from the perspective of each of the cost-effectiveness tests.

Discounting the Future Value of Money

Future costs and benefits are discounted to the present using a real discount rate of 3%. The U.S. Department of Energy recommends a real discount rate of 3% for projects related to energy conservation, renewable energy, and water conservation, which is consistent with the Federal Energy Management Program (FEMP).[29] For discounting purposes we assume that initial measure costs are incurred at the beginning of the year, whereas annual energy savings are incurred half way through the year. As described further above, we also performed a sensitivity analysis on the cost-effectiveness of each measure using a higher discount rate representing Entergy's Weighted Average Cost of Capital (WACC).

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[28] California Standard Practice Manual: Economic Analysis Of Demand-Side Programs And Projects, July 2002; Governor's Office of Planning and Research, State of California; http://www.calmac.org/events/SPM_9_20_02.pdf

[29] See page 1 in http://www1.eere.energy.gov/femp/pdfs/ashb10.pdf.

Table 43 | Overview of Cost-Effectiveness Tests

Monetized Benefits / Costs	Total Resource Cost (TRC)	Program Administrator Cost Test	Participant Cost Test
Measure cost (incremental over baseline)	Cost		Cost
Program Administrator incentive costs		Cost	Benefit
Program Administrator non-incentive program costs	Cost	Cost	
Energy & electric demand savings*	Benefit	Benefit	Benefit
Fossil fuel increased usage	Cost	Cost	Cost
Operations & Maintenance savings	Benefit		Benefit
Water savings	Benefit		Benefit
Deferred replacement credit**	Benefit		Benefit

*For the TRC and PACT, energy and electric demand savings are valued using avoided cost values that represent wholesale marginal costs, varying by time of day and season. For the Participant Cost Test, energy savings are valued at average retail costs for each customer sector.

**For early-retirement retrofit measures, the Deferred Replacement Credit is a credit for when the existing equipment would have needed replacement. The equipment's replacement cycle has been deferred due to the early replacement.

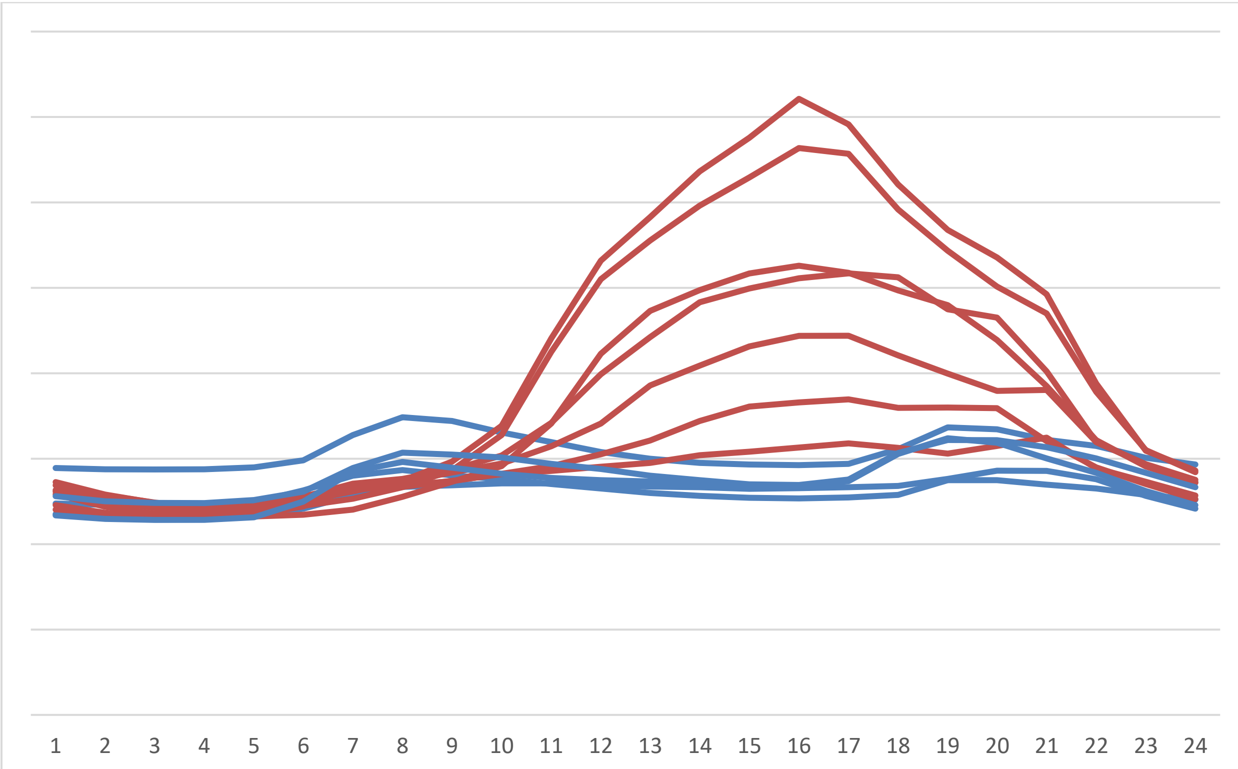
AVOIDED ENERGY SUPPLY COSTS

Avoided energy supply costs are used to assess the economic value of energy savings (or the costs of increased consumption). Developing a set of avoided costs specific to energy efficiency in New Orleans was outside the scope of the project; we relied on the best available data to prepare a set of values that represent reasonable estimates without a substantial investment of time and resources.

We developed electric energy avoided costs using a set of forecast hourly marginal energy prices in the relevant load zone operated by the Midcontinent Independent System Operator (MISO). We reduced this detailed information into forecast energy prices in four energy costing periods for use in our modeling software. We had previously determined that using four distinct energy periods would produce a more accurate estimate of avoided energy benefits than would a single annual average value, particularly for cooling measures that save energy during expensive summer on-peak hours.

To develop the energy costing periods we reviewed and plotted the daily average hourly marginal energy prices for each month. This is shown in the figure below, with summer months in orange and winter months in blue.

Figure 20 | Average Hourly Forecast Energy Price – Summer Months



As seen, there is a clear difference in price between peak and off peak periods, as well as between summer and winter periods. Based on this review, we defined four energy periods: Summer On-Peak, Summer Off-Peak, Winter On-Peak, and Winter Off-Peak.

- Summer is April through October; peak hours are 11 AM – 9 PM weekdays (1,683 hours)
- Off-peak Summer is the rest of the summer months (3,453 hours)
- Winter November through March; peak hours are 7 AM – 10 AM and 6 PM – 10PM weekdays (972 hours)
- Off-peak Winter is the rest of the winter months (2,652 hours)

In addition to avoided electric energy costs, we develop avoided capacity costs to value reductions in peak demand. For this study, these costs are based on Entergy's projected cost to build a new gas turbine plant. Gas avoided costs are based on the long-term Henry Hub price forecast. Entergy did not provide any information on the value of avoided capacity on the transmission and distribution network, the result of which is that our analysis is likely to understate the cost-effectiveness of efficiency savings.

ENERGY RETAIL RATES

Retail rates are not used in the TRC, and so do not impact the net benefits of efficiency from those perspectives. However, they were used in this study to determine the simple payback of each efficiency measure, which in turn determined the penetration rates for the program potential based on the outcome of the Delphi Panel. Retail rates were developed from Entergy New Orleans' published rate tariffs. For purposes of the simple payback analysis, only the variable portion of rates was included. For residential customers, we estimated a price of 8.5 cents/kWh. For commercial customers whose rates also depend on billing demand, we converted projected demand savings into a per kWh rate to simplify the analysis. Taking an average of both small and large commercial rates, we estimate an avoidable retail price of 9 cents/kWh.

ELECTRIC LOAD SHAPES

Electric energy load shapes are used to distribute annual efficiency measure energy savings into the energy costing periods of the avoided costs. Although previous potential studies conducted by Entergy included detailed hourly loadshapes, these were specific to particular efficiency programs (e.g., commercial new construction, residential consumer products, etc.). Our analysis applies load-shapes by energy end-use (e.g., residential lighting, commercial refrigeration, etc) and therefore could not make use of these loadshapes, because the efficiency programs each include measures of several end-uses. Instead, we relied on end-use load shapes information developed by the Electric Power Research Institute (EPRI)[30]. These end-use loadshapes are region-specific; we relied on the Southeast Reliability Council region (excluding Florida). At the level of precision in this study, any differences in the distribution of energy reductions across the four energy costing periods between this regional average and New Orleans are not expected to be significant.

For each end-use, the EPRI data include hourly loadshapes for average weekdays, peak weekdays, and average weekend days, for both summer and winter seasons. From these data, we developed a loadshape for each end-use that defines the percentage of annual energy consumption occurring in each period.

ECONOMIC POTENTIAL ANALYSIS

The top-down analysis, along with all the data inputs, produces the measure-level potential, with the economic potential being limited to installation of cost-effective measures. However, the total economic potential is less than the sum of each separate measure potential. This is because of interactions between measures and competition between measures. Interactions result from installation of multiple measures in the same facility. For example, if one insulates a building, the heating load is reduced. As a result, if one then installs a high efficiency furnace, savings from the furnace will be lower because the overall heating needs of the building have been lowered. As a result, interactions between measures should be taken into account to avoid over-estimating savings potential. Because the economic potential assumes all possible measures are adopted, interactions assume every building does all applicable measures. Interactions are accounted for by ranking each set of interacting measures by total savings, and assuming the greatest savings measure is installed first, and then the next highest savings measure.

[30] Electric Power Research Institute (EPRI). Loadshape Library. http://loadshape.epri.com/

Measures that compete also need to be adjusted for. These are two or more efficiency measures that can both be applied to the same application, but only one can be chosen. An example is choosing between installing an air source heat pump or an efficient central air conditioner, but not both. In this case, the total penetration for all competing measures is 100%, with priority given to the measures based on ranking them from highest savings to lowest savings. If the first measure is applicable in all situations, it would have 100% penetration and all other competing measures would show no potential. If on the other hand, the first measure could only be installed in 50% of opportunities, then the second measure would capture the remaining opportunities.

To estimate the economic potential we generally assumed 100% installation of market-driven measures (natural replacement, new construction/renovation) constrained by measure cost-effectiveness and other limitations as appropriate, such as to account for mutually exclusive measures.

Implementation of retrofit measures was considered to be resource-constrained, i.e., it would not be possible to install all cost-effective retrofit measures all at once. The retrofit penetrations rates are assumed to be 10% of the market for the first 10 years. After this, the entire retrofit market has been adjusted, and any additional retrofits only occur after the life of the original retrofit expires, and there is no market driven measure that addresses the same energy use. For example, since retro-commissioning has a measure life shorter than the analysis period, the same building my become eligible for a second retro-commissioning once the first one has expired.

PROGRAM POTENTIAL SCENARIO

For the achievable potential scenarios (both max achievable and program achievable), we did not attempt to develop detailed program designs to group each measure into. Instead, we make the simplifying assumption that the programs will be well designed and able to capture the amount of market adoption as determined by the local experts on the Delphi Panel. Thus, this study can help determine the amount of efficiency available, and which measures may offer the most opportunity, but is not a detailed roadmap on how to group these measures into programs or how to best promote and market the programs to customers.

Measure Incentives and Penetration Rates

Measure penetration rates, or adoption rates, are affected by a broad variety of factors depending on the measure: the market barriers that apply and to what degree, the program delivery strategy, incentive levels, marketing and outreach, technical assistance to installers, etc. While penetration rates will generally increase with increased spending, how the spending is applied can have a huge impact on actual participation rates. There is large uncertainty inherent in developing penetration rates, and self-reported surveys are often not a reliable indicator of eventual adoption. Further, these rates have an outsized impact on the final efficiency available in the max achievable and program potential scenarios. For this study, we avoided these issues by convening a group of local experts to determine the penetrations rate. We asked these panels for penetrations both at 100% incentives, and as a function of simple payback. See the Appendix on the Delphi Panel for more information.

Non-Incentive Program Budgets

The costs of implementing efficiency programs include both the cost of the efficiency measures themselves and the associated administrative costs for marketing, customer interactions, incentive and rebate processing, evaluation activities, etc. To estimate these costs for inclusion in both program budgets and cost-effectiveness testing, we relied on actual program data from a number of efficiency portfolios. We previously developed these estimates for another potential study and believe them to be reasonable for use in this study. The estimates are specific to our major program categories (e.g., residential new construction, commercial equipment replacement), because different program types and delivery models can have different administrative needs.

Data were sourced from recent program performance in New England, the Mid-Atlantic states, and Minnesota, totaling 8 individual utility or state-wide portfolios. All of these portfolios are generating savings substantially greater than Entergy New Orleans' current programs, and are likely to be a better predicted of the administrative costs needed to achieve the level of savings found by our maximum achievable and program potential analyses. The average administrative costs for the various program types range from 25 percent to 37 percent of total program costs.

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APPENDIX A: DELPHI PROCESS

As described in the report, this report used Delphi Panels in order to estimate the penetration rates for the max achievable and program potential scenarios. There were two separate panels convened – one panel for residential measures with 9 participants, and a panel for commercial and industrial measures, with 8 participants. Each participant is a local expert with appropriate knowledge to allow them to be a good judge on potential measure adoption. Each panel contained representation from each of the following categories:

- Trade Allies/Contractors
- Academics
- Program Implementers
- Program Planner/Managers
- Distributor/Manufacturing Representatives
- Government Officials
- Real Estate Developers
- Building/Facility Managers

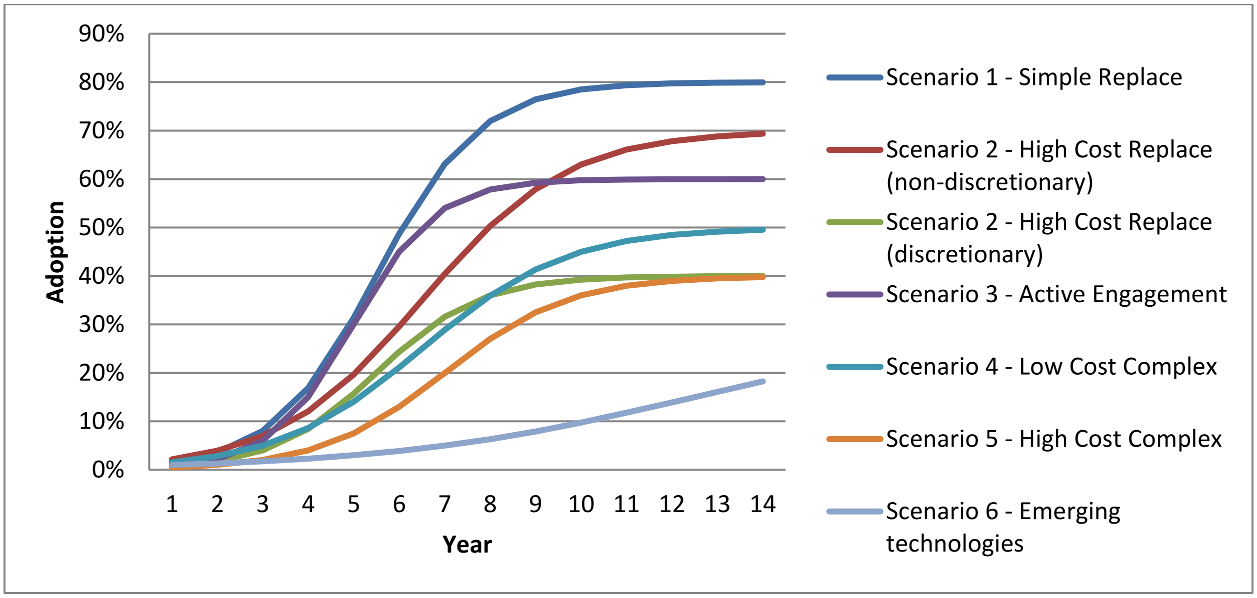
The Delphi Process is used to develop a consensus estimate for uncertain or contentious values. It involves sending the same survey to each participant on the panel. The participant then fills out their best estimates for each survey question and gives some indication of their reasoning. We then compile all answers together and send the survey back for a second round. In this round, each participant will have the opportunity to adjust their responses based on the responses and reasonings of the other participants. The survey is done anonymously, so that the loudest voices do not have disproportionate influence on the other members of the panel. The idea is that, after two or three rounds, the answers from each participant will converge on a consensus estimate. In this case, consensus was already largely achieved after two rounds.

For this study, two Delphi Panels were formed, one focusing on the residential sector and one on the C&I sector. For each sector, the survey asked for measure adoption rates assuming 100% incentives (instantaneous payback) for five different types of measures with different levels of first costs, complexities, and other market barriers. The survey asks for three different datapoints to develop this curve – the percent adoption at program maturity, the number of years to reach 10% of full adoption, and the number of years to reach 90% of full adoption. We then assume a typical "S" curve using these three datapoints, where there is fairly slow adoption until 10% adoption is reached, a steeper ramp up until 90% adoption is reached, and then slower growth until the full adoption is reached. For retrofit measures, we converted these curves to cumulative numbers, so that, for example, instead of achieving 80% penetration per year by year 12, the retrofits would reach a total of 80% market share by year 12 (in other words the sum of adoption in years 1-12 would be 80%).

In addition to the above questions, which apply to the max achievable scenario, the survey also developed estimates of adoption for the program potential scenario, which only provides incentives at 50% of the full incremental cost. In order to derive these numbers, we asked the Delphi participants by what percent the penetrations in the max achievable scenario would be reduced under numerous simple payback scenarios. This number will be applied to every year of the max achievable curve to derive the curve used for the program potential scenarios

The table below shows the curve for each scenario for the Residential sector. As seen, simple measures that are easy to install quickly achieve a fairly high adoption. Other measures types with higher market barriers tend to take longer to ramp up and achieve a lower maximum adoption.

Figure 21 | Residential Adoption Curves



The next table shows the percent that the above curve would be reduced by, if instead of paying the full incremental cost, the incentive just buys the measure down to a specified payback. For example, if an LED screw-in bulb (scenario 1) achieved a simple payback of 2-years after the incentive is applied, every datapoint in the "Scenario 1" curve from the above table would be multiplied by 0.4 to derive the new adoption curve.

Table 44 | Delphi Panel Residential Program Potential Multipliers

	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5
1-year payback	70%	70%	60%	60%	60%
2-year payback	40%	30%	30%	30%	30%
4-year payback	20%	20%	10%	10%	20%
8-year payback	5%	5%	10%	5%	10%

The next two charts give the same information for the Commercial and Industrial Sector.

Figure 22 | Delphi Panel C&I Responses

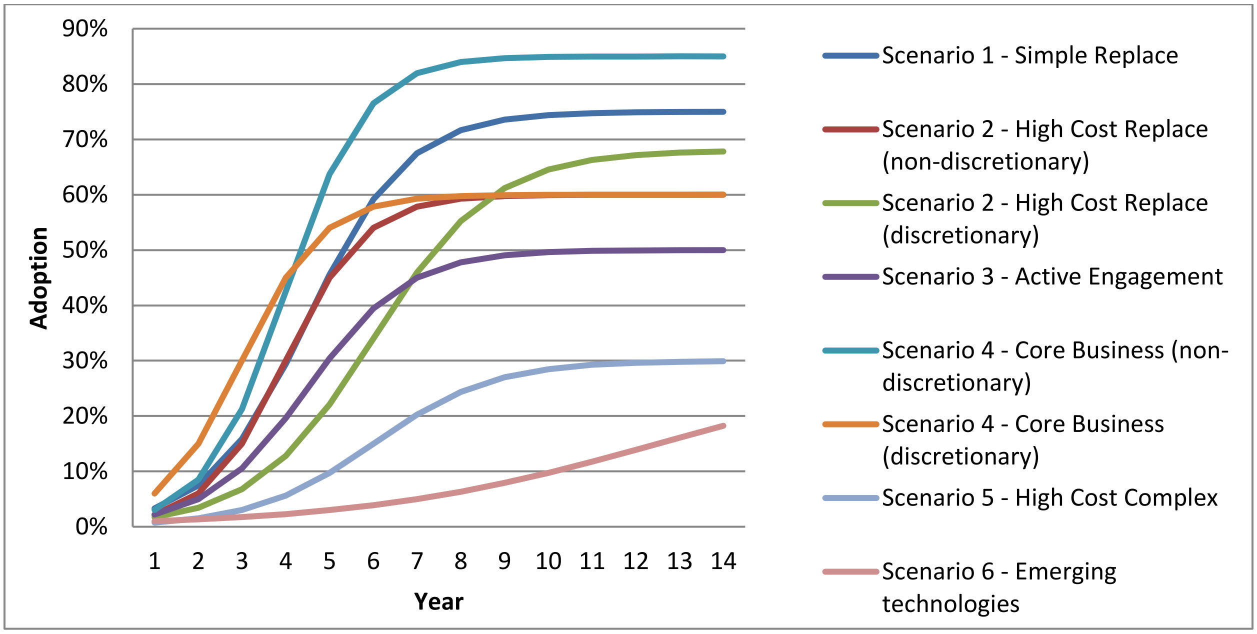


Table 45 | Delphi Panel C&I Program Potential Multipliers

	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5
1-year payback	83%	78%	78%	78%	85%
2-year payback	43%	48%	45%	65%	60%
4-year payback	23%	25%	28%	48%	38%
8-year payback	11%	10%	13%	15%	20%

Finally, we mapped each of the curves from the Delphi Panel to specific measures. The next table shows this mapping for each measure, for both market driven transactions (e.g., new construction, replace-on-failure) and retrofit transactions. If no curve number is given, that market is not applicable for that measure.

Table 46 | Delphi Panel Measure Mapping

Measure Name	Sector	Curve (market driven)	Curve (Retrofit)
ESTAR Room AC	C&I	1	1
Exterior Canopy/Soffit LED	C&I	1	1
Exterior Wall Pack LED	C&I	1	1
Improved Ext Lgt Design	C&I	1	
Heat Pump Water Heater	C&I	2	2
High Volume Low Speed Fans	C&I	2	
Mini Split Ductless HP-Cool	C&I	2	2
Mini Split Ductless HP-Heat	C&I	2	2
Optimized unitary HVAC distribution/control system	C&I	5	5
Optimized chiller distribution/control system	C&I	5	5
Int Ltg Controls	C&I		1

Exit Sign Retrofit	C&I		1
High Bay LED	C&I		1
Incand. Over 100W Ret, Fixt.	C&I		1
Incand. Over 100W Ret, Lamp	C&I		1
Incand. Up to 100W Ret, Fixt.	C&I		1
Incand. Up to 100W Ret, Lamp	C&I		1
LED Troffers	C&I		1
Com LED Tube Replacement Lamps	C&I		1
Refrigerated Case LED	C&I		2
Stairwell Occupancy Sensors	C&I		2
LED Street Lighting	C&I		1
Pre-Rinse Sprayers	C&I		1
Chiller Tune-Up	C&I		3
VSD, Chilled Water Pump	C&I		2
VSD, Heating Hot Water Pump	C&I		2
VSD, Condenser Water Pump	C&I		2
VSD, HVAC Fan	C&I		2
VSD, Cooling Tower Fan	C&I		2
Demand Control Ventilation-Cool	C&I		3
Demand Control Ventilation-Heat	C&I		3
Demand Control Ventilation-Vent	C&I		3
Screw-Based LED	C&I		1
Retrofit duct sealing fan energy	C&I		5
Retrofit duct sealing cool	C&I		5
Retrofit duct sealing HS fan	C&I		5
Retrofit duct sealing HS cool	C&I		5
Ground Source HP (Heating)	C&I	6	6
Ground Source HP (Cooling)	C&I	6	6
HE Clothes Washer, elec DHW	C&I	1	1
Ozone Laundry System	C&I		6
Office Equipment Controls	C&I		3
Window Film	C&I		3
Cool Roof	C&I	2	5
LED Ped Light (Sign Lighting)	C&I		
HE Kitchen Equipment	C&I	5	
HP Window Glaze (Cooling)	C&I	2	
HP Window Glaze (Heating)	C&I	2	
Compressed Air	C&I	4	4
Industrial Process	C&I		4
High Efficiency HP (Heating)	C&I	2	2
High Efficiency HP (Cooling)	C&I	2	2
High Efficiency AC	C&I	2	2
HP Tune Up (Heating)	C&I		1
HP Tune Up (Cooling)	C&I		1

AC Tune Up	C&I		1
Cooler Night Cover	C&I		1
Commercial Faucet Aerator (Elec WH)	C&I		1
High Efficiency Chiller	C&I	4	5
ECM Blower Motors	C&I		1
Conservation Voltage Reduction	C&I		1
Building Management System - Elec Heat	C&I		1
Control System for Hopitality	C&I	5	5
Retrocommissioning/Calibrate Sensors - Electric Heat	C&I		2
Integrated bldg design -Elec	C&I	5	
Replace Cooler and Freezer Door Gaskets	C&I		4
Reach-in Storage Refrigerator	C&I	2	
HE Small Walk-In	C&I	2	
Refrigeration Retrofit	C&I		4
Strip Curtains	C&I		4
Advanced RTU Control - Elec Heat	C&I	3	3
Advanced RTU Control - Gas Heat	C&I	3	3
Network Connected LEDs	C&I		6
High Efficiency Chiller vs DX System	C&I	5	
Replace Pneumatic contols with DDC - Elec Heat	C&I		2
Replace Pneumatic contols with DDC - Gas Heat	C&I		2
Central AC	Res	2	2
QI Central AC	Res	2	2
ASHP (Cooling)	Res	2	2
ASHP (Heating)	Res	2	2
QI ASHP (Cooling)	Res	4	2
QI ASHP (Heating)	Res	4	2
CAC Tune-Up	Res		3
ASHP Tune-Up (Cooling)	Res		3
ASHP Tune-Up (Heating)	Res		3
ES Room AC	Res	1	1
GSHP (Cooling)	Res	5	
GSHP (Heating)	Res	5	
DMSAC	Res	3	
DMSHP (Cooling)	Res	3	2
DMSHP (Heating)	Res	3	2
Duct Sealing, E (Cooling)	Res		3
Duct Sealing, E (Heating)	Res		3
Duct Sealing, G	Res		3
Smart Tstat, E (Cooling)	Res	2	1
Smart Tstat, E (Heating)	Res	2	1
Smart Tstat, G	Res	2	1
Learning Tstat, E (Cooling)	Res	2	1

Learning Tstat, E (Heating)	Res	2	1
Learning Tstat, G	Res	2	1
ES Ceiling Fan	Res	1	
ES Bathroom Ventilation Fan	Res	1	
ECM Blower Motor	Res	4	
ECM Circulators, DHW	Res		4
ECM Circulators, CW	Res		4
ECM Circulators, HW	Res		4
HEMS	Res	3	3
ES Solar Water Heater	Res	5	5
Heat Pump Water Heater	Res	2	2
Faucet Aerator	Res	1	1
Low Flow Showerhead	Res	1	1
Water Heater Pipe Insulation	Res		3
Water Heater Jacket	Res	1	1
WH Drainpipe Heat Exchange	Res	4	4
Water Heater Setback	Res		3
Therm Restriction Valve	Res	5	5
ES SF Clothes Washer (App)	Res	1	2
ES SF Clothes Washer (WH)	Res	1	2
ES MF Clothes Washer (App)	Res	1	2
ES MF Clothes Washer (WH)	Res	1	2
ES SF Clothes Dryer	Res	1	2
ES MF Clothes Dryer	Res	1	2
ES Dehumidifier	Res	1	
ES Dishwasher (App)	Res	1	
ES Dishwasher, WH	Res	1	
ES Refrigerator	Res	1	
ES Freezer	Res	1	
Fridge and Freezer Removal	Res		1
ES Air Purifier	Res	1	
ENERGY STAR Pool Pump	Res	2	2
Tier 2 Power Strip	Res		1
ES Desktop Computer	Res	1	
Efficient Windows (Cooling)	Res	2	
Efficient Windows (Heating)	Res	2	
Window Attachments (Cooling)	Res		5
Window Attachments (Heating)	Res		5
Attic Insulation, E (Cooling)	Res		3
Attic Insulation, E (Heating)	Res		3
Attic Insulation, G	Res		3
Air Sealing, E (Cooling)	Res		3
Air Sealing, E (Heating)	Res		3
Air Sealing, G	Res		3

LED Screw-in Lamp (18)	Res	1	
LED Screw-in Lamp (19)	Res	1	
LED Screw-in Lamp (20)	Res	1	
LED Screw-in Lamp (21)	Res	1	
ES LED Downlight Fixture (18)	Res	1	
ES LED Downlight Fixture (19)	Res	1	
ES LED Downlight Fixture (20)	Res	1	
ES LED Downlight Fixture (21)	Res	1	
LED DI (18)	Res		1
LED DI (19)	Res		1
LED DI (20)	Res		1
LED DI (21)	Res		1
Occupancy Sensors	Res		2
Smart LED Screw-in Lamp	Res	3	
Ext Motion Sensor	Res		2
Net Zero Energy Home	Res	5	
Energy Efficient New Home - Single Family	Res	3	
ENERGY STAR Manufactured Home	Res	3	
Energy Efficient New Home - Multi Family	Res	3	
Home Energy Reports Q3, Electric	Res		1
Conservation Voltage Reduction	Res		1
Integrated bldg design -Gas	C&I	3	
Retrocommissioning/Calibrate Sensors - Gas Heat	C&I		4
Building Management System - Gas Heat	C&I		4
HP Window Glaze Gas	C&I	2	
ES LED PAR/Flood Lamp, Ext (18)	Res		1
ES LED PAR/Flood Lamp, Ext (19)	Res		1
ES LED PAR/Flood Lamp, Ext (20)	Res		1
ES LED PAR/Flood Lamp, Ext (21)	Res		1
ENERGY STAR Pool Pump	C&I	4	4
Data Center Retrofit	C&I		5

APPENDIX B: SALES DISSAGGREGTION

Table 47 | Residential Sales Disaggregation

End Use	Non Low-Income	Low-Income
Space Heating	9%	9%
Cooling	16%	16%
Water Heating	7%	7%
Indoor Lighting	4%	4%
Exterior Lighting	1%	1%
Plug Load	6%	6%
Appliance	7%	6%
Total	**51%**	**49%**

Table 48 | Commercial and Industrial Sales Disaggregation

End Use	Small Office	Large Office	Small Retail	Large Retail	Wareh ouse	Educa-tion	Food Sales	Health	Lodg-ing	Rest-aurant	Indus-trial	Other
Space Heating	0.1%	0.1%	0.1%	0.1%	0.0%	0.1%	0.1%	0.0%	0.2%	0.1%	0.0%	0.1%
Cooling	1.7%	1.1%	1.8%	1.2%	0.4%	3.1%	0.2%	2.1%	3.0%	1.1%	0.5%	3.5%
Ventilation	1.8%	1.2%	1.4%	0.9%	0.1%	1.4%	0.2%	1.4%	2.2%	0.7%	0.5%	1.0%
Water Heating	0.1%	0.0%	0.1%	0.1%	0.0%	0.1%	0.1%	0.1%	0.2%	0.1%	0.0%	0.0%
Indoor Lighting	1.3%	0.9%	1.7%	1.1%	0.7%	1.7%	0.3%	1.1%	2.0%	0.4%	0.4%	1.9%
Exterior Lighting	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.0%	0.1%	0.2%	0.0%	0.0%	0.2%
Cooking	0.0%	0.0%	0.1%	0.1%	0.0%	0.1%	0.2%	0.1%	0.6%	1.2%	0.0%	0.0%
Refrigeration	0.2%	0.2%	2.1%	1.4%	0.3%	0.8%	2.4%	0.3%	1.6%	2.4%	0.1%	0.6%
Plug Load	1.6%	1.0%	0.4%	0.3%	0.2%	1.8%	0.1%	0.8%	2.3%	0.2%	0.5%	1.1%
Other	1.2%	0.8%	1.2%	0.8%	0.6%	1.4%	0.2%	1.3%	3.8%	0.5%	0.4%	3.0%
Industrial Process	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	10.7%	0.0%
ElecTotal	8.0%	5.4%	9.0%	6.0%	2.4%	10.5%	3.9%	7.4%	16.3%	6.8%	13.1%	11.3%

APPENDIX C: LOADSHAPES

See below for the loadshapes used to distribute the savings to the four avoided costs periods. As described above, these periods are:

- Summer on-peak is April – October, 9 AM – 9 PM Weekdays
- Summer off-peak is the rest of the time in April-October
- Winter on-peak is Nov- Mar, 7 AM – 10 AM and 6 PM – 10PM Weekdays
- Winter off-peak is the rest of the time in Nov-Mar

Table 49 | Residential Loadshapes

End Use	Summer On-Peak	Summer Off-Peak	Winter On-Peak	Winter Off-Peak
Space Heating	0.4%	0.8%	27.6%	71.2%
Cooling	44.5%	49.1%	1.9%	4.5%
Ventilation	22.4%	25.0%	14.8%	37.9%
Water Heating	18.2%	33.7%	15.3%	32.8%
Indoor Lighting	28.7%	30.6%	13.9%	26.8%
Outdoor Lighting	11.2%	47.4%	8.8%	32.6%
Refrigeration	20.2%	41.5%	10.0%	28.2%
Plug Load	24.2%	34.9%	12.8%	28.1%
Other	23.0%	32.0%	13.4%	31.6%
Appliance	22.7%	34.8%	12.2%	30.3%
Total Building	23.0%	32.0%	13.4%	31.6%

Table 50 | C&I Loadshapes

End Use	Summer On-Peak	Summer Off-Peak	Winter On-Peak	Winter Off-Peak
Space Heating	0.6%	3.5%	28.5%	67.4%
Cooling	41.8%	47.2%	3.0%	8.0%
Ventilation	19.1%	38.9%	10.6%	31.4%
Water Heating	22.7%	28.4%	13.8%	35.1%
Indoor Lighting	26.6%	32.2%	11.9%	29.2%
Outdoor Lighting	11.2%	47.4%	8.8%	32.6%
Cooking	20.8%	34.4%	12.1%	32.6%
Refrigeration	21.6%	42.0%	9.5%	27.0%
Plug Load	23.0%	35.7%	11.1%	30.2%
Other	20.8%	34.4%	12.1%	32.6%
Industrial Process	23.0%	35.9%	12.4%	28.7%
Total Building	20.8%	34.4%	12.1%	32.6%

APPENDIX D: MEASURE CHARACTERIZATIONS

This appendix shows the measure characterizations used for the study. Each measure characterization may have two different characterizations, one for market driven (MD) transactions and one for retrofit (RET) situations. Measures that show “N/A” for the TRC are one part of a linked measure. Linked measures are measures that produce savings for more than end use. For example, a heat pump produces different savings percentages for cooling and heating savings. Our analysis allocates all of the costs to just one of the end uses, but savings are kept separate because they have different loadshapes. In order to calculate TRC, costs and benefits are summed across all parts of the linked measures.

Table 51 | Residential Measure Level Information

Measure Name	Market	TRC	% Savings	$/kWh (annual)	Measure Life
Central AC	MD	2.65	26%	$0.44	19
Central AC	RET	1.09	38%	$1.39	19
QI Central AC	MD	2.12	28%	$0.55	19
QI Central AC	RET	1.30	45%	$1.25	19
ASHP (Cooling)	MD	1.38	28%	$1.18	16
ASHP (Heating)	MD	1.57	72%	$-	16
ASHP (Cooling)	RET	N/A	45%	$1.26	16
ASHP (Heating)	RET	N/A	72%	$-	16
QI ASHP (Cooling)	MD	4.51	36%	$-	16
QI ASHP (Heating)	MD	1.71	75%	$0.28	16
QI ASHP (Cooling)	RET	N/A	51%	$1.17	16
QI ASHP (Heating)	RET	N/A	75%	$-	16
CAC Tune-Up	RET	0.30	5%	$0.54	2
ASHP Tune-Up (Cooling)	RET	0.63	8%	$0.31	2
ASHP Tune-Up (Heating)	RET	N/A	8%	$-	2
ES Room AC	MD	2.96	9%	$0.20	9
ES Room AC	RET	1.58	9%	$1.23	9
GSHP (Cooling)	MD	N/A	36%	$-	18
GSHP (Heating)	MD	0.24	76%	$2.01	18
DMSAC	MD	0.43	43%	$2.61	18
DMSHP (Cooling)	MD	6.79	50%	$0.28	18
DMSHP (Heating)	MD	2.00	81%	$-	18
DMSHP (Cooling)	RET	N/A	50%	$0.95	18
DMSHP (Heating)	RET	N/A	81%	$-	18
Duct Sealing, E (Cooling)	RET	9.60	21%	$0.23	18
Duct Sealing, E (Heating)	RET	N/A	21%	$-	18
Duct Sealing, G	RET	6.84	21%	$0.23	18
Smart Tstat, E (Cooling)	RET	0.65	5%	$1.26	10
Smart Tstat, E (Heating)	RET	0.79	5%	$-	10
Smart Tstat, G	RET	N/A	5%	$1.26	10

Smart Tstat, E (Cooling)	MD	N/A	5%	$1.26	10
Smart Tstat, E (Heating)	MD	0.68	2%	$-	10
Smart Tstat, G	MD	0.68	5%	$1.26	10
Learning Tstat, E (Cooling)	RET	1.71	9%	$0.69	10
Learning Tstat, E (Heating)	RET	1.66	9%	$-	10
Learning Tstat, G	RET	N/A	9%	$0.69	10
Learning Tstat, E (Cooling)	MD	N/A	9%	$0.69	10
Learning Tstat, E (Heating)	MD	1.32	9%	$-	10
Learning Tstat, G	MD	1.46	9%	$0.76	10
ES Ceiling Fan	MD	2.09	44%	$0.62	20
ES Bathroom Ventilation Fan	MD	0.26	72%	$2.56	19
ECM Blower Motor	MD	4.64	50%	$0.22	18
ECM Circulators, DHW	RET	2.50	90%	$0.30	15
ECM Circulators, CW	RET	2.05	82%	$0.34	15
ECM Circulators, HW	RET	0.42	82%	$2.88	15
HEMS	MD	0.53	15%	$1.02	15
HEMS	RET	0.53	15%	$1.02	15
ES Solar Water Heater	RET	0.08	90%	$4.34	15
ES Solar Water Heater	MD	0.12	85%	$5.86	15
Heat Pump Water Heater	RET	0.18	64%	$7.71	10
Heat Pump Water Heater	MD	0.04	59%	$0.99	10
Faucet Aerator	RET	1.29	26%	$0.25	10
Faucet Aerator	MD	1.27	26%	$0.25	10
Low Flow Showerhead	RET	3.44	37%	$0.09	10
Low Flow Showerhead	MD	3.61	37%	$0.09	10
Water Heater Pipe Insulation	RET	2.36	60%	$0.16	12
Water Heater Jacket	RET	1.06	28%	$0.38	13
WH Drainpipe Heat Exchange	RET	0.50	25%	$1.36	20
WH Drainpipe Heat Exchange	MD	0.48	25%	$1.36	20
Water Heater Setback	RET	1.39	4%	$0.05	2
Therm Restriction Valve	RET	0.47	12%	$0.40	10
Therm Restriction Valve	MD	0.76	12%	$0.67	10
ES SF Clothes Washer (App)	MD	2.49	34%	$1.15	14
ES SF Clothes Washer (WH)	MD	0.22	37%	$-	14
ES SF Clothes Washer (App)	RET	N/A	40%	$11.48	14
ES SF Clothes Washer (WH)	RET	N/A	43%	$-	14
ES MF Clothes Washer (App)	MD	9.63	34%	$0.29	14
ES MF Clothes Washer (WH)	MD	N/A	37%	$-	14
ES SF Clothes Dryer	MD	5.07	21%	$0.26	12
ES MF Clothes Dryer	MD	18.98	21%	$0.07	12
ES Dehumidifier	MD	1.66	21%	$0.27	12
ES Dishwasher (App)	MD	N/A	12%	$-	15
ES Dishwasher, WH	MD	4.91	12%	$0.48	15
ES Refrigerator	MD	2.10	12%	$0.25	15

ES Freezer	MD	1.32	10%	$0.29	11
Fridge and Freezer Removal	RET	3.17	100%	$0.09	8
ES Air Purifier	MD	13.90	73%	$0.02	9
ENERGY STAR Pool Pump	MD	0.40	69%	$0.17	10
ENERGY STAR Pool Pump	RET	0.30	79%	$1.15	10
Tier 2 Power Strip	RET	1.68	51%	$0.32	10
ES Desktop Computer	MD	3.23	50%	$0.06	4
Efficient Windows (Cooling)	MD	4.19	10%	$0.51	25
Efficient Windows (Heating)	MD	N/A	10%	$-	25
Window Attachments (Cooling)	RET	1.14	9%	$0.81	10
Window Attachments (Heating)	RET	N/A	11%	$-	10
Attic Insulation, E (Cooling)	RET	2.48	21%	$0.95	20
Attic Insulation, E (Heating)	RET	N/A	21%	$-	20
Attic Insulation, G	RET	1.84	21%	$0.95	20
Air Sealing, E (Cooling)	RET	2.23	8%	$0.53	11
Air Sealing, E (Heating)	RET	N/A	8%	$-	11
Air Sealing, G	RET	1.87	8%	$0.53	11
LED Screw-in Lamp (18)	MD	1.88	82%	$0.10	4
LED Screw-in Lamp (19)	MD	1.42	82%	$0.10	3
LED Screw-in Lamp (20)	MD	0.96	82%	$0.10	2
LED Screw-in Lamp (21)	MD	0.48	82%	$0.10	1
ES LED Downlight Fixture (18)	MD	2.27	88%	$0.09	4
ES LED Downlight Fixture (19)	MD	1.72	88%	$0.09	3
ES LED Downlight Fixture (20)	MD	1.16	88%	$0.09	2
ES LED Downlight Fixture (21)	MD	0.58	88%	$0.09	1
LED DI (18)	RET	1.01	82%	$0.16	15
LED DI (19)	RET	0.76	82%	$0.16	15
LED DI (20)	RET	0.52	82%	$0.16	15
LED DI (21)	RET	0.26	82%	$0.16	15
Occupancy Sensors	RET	1.00	40%	$0.44	10
Smart LED Screw-in Lamp	MD	0.14	10%	$5.16	16
Ext Motion Sensor	RET	0.99	40%	$0.30	10
Net Zero Energy Home	MD	0.70	100%	$1.62	30
Energy Efficient New Home - Single Family	MD	3.37	35%	$0.34	30
ENERGY STAR Manufactured Home	MD	2.17	27%	$0.52	30
Energy Efficient New Home - Multi Family	MD	1.59	37%	$0.71	30
Home Energy Reports Q3, Electric	RET	0.98	2%	$0.04	1
Conservation Voltage Reduction	RET	56.53	2%	$0.02	30
ES LED PAR/Flood Lamp, Ext (18)	RET	1.79	82%	$0.07	4
ES LED PAR/Flood Lamp, Ext (19)	RET	1.35	82%	$0.07	3
ES LED PAR/Flood Lamp, Ext (20)	RET	0.92	82%	$0.07	2
ES LED PAR/Flood Lamp, Ext (21)	RET	0.46	82%	$0.07	1

Table 52 | Commercial Measure Level Information

Measure	Market	TRC	% Savings	$/kWh (annual)	Measure Life
ESTAR Room AC	MD	2.24	9%	$0.23	9
Exterior Canopy/Soffit LED	RET	0.64	78%	$0.34	10.2
Exterior Canopy/Soffit LED	MD	0.94	77%	$0.51	10.2
Exterior Wall Pack LED	RET	0.39	78%	$0.19	10.2
Exterior Wall Pack LED	MD	1.74	76%	$0.84	10.2
Improved Ext Lgt Design	MD	2.13	42%	$0.23	15
Heat Pump Water Heater	MD	0.22	35%	$0.86	10
Heat Pump Water Heater	RET	0.04	40%	$8.62	10
High Volume Low Speed Fans	MD	1.57	82%	$0.22	15
Mini Split Ductless HP-Cool	MD	0.93	47%	$0.24	15
Mini Split Ductless HP-Heat	MD	3.16	72%	$-	15
Mini Split Ductless HP-Cool	RET	N/A	47%	$0.83	15
Mini Split Ductless HP-Heat	RET	N/A	72%	$-	15
Optimized unitary HVAC distribution/control system	MD	0.87	30%	$1.02	15
Optimized chiller distribution/control system	MD	0.55	20%	$1.02	15
Int Ltg Controls	RET	4.55	34%	$0.06	8
Exit Sign Retrofit	RET	2.61	97%	$0.25	16
High Bay LED	RET	0.36	43%	$0.71	11.3
Incand. Over 100W Ret, Fixt.	RET	0.84	74%	$0.51	11.3
Incand. Over 100W Ret, Lamp	RET	2.50	76%	$0.04	3.4
Incand. Up to 100W Ret, Fixt.	RET	0.80	71%	$0.48	11.3
Incand. Up to 100W Ret, Lamp	RET	2.30	72%	$0.05	3.4
LED Troffers	RET	0.49	52%	$0.81	11.3
Com LED Tube Replacement Lamps	RET	3.85	58%	$0.07	11.3
Refrigerated Case LED	RET	2.03	73%	$0.22	10
Stairwell Occupancy Sensors	RET	0.81	92%	$0.77	14.4
LED Street Lighting	RET	2.25	65%	$0.20	15
VSD, Chilled Water Pump	RET	0.84	43%	$0.54	15
VSD, Heating Hot Water Pump	RET	2.14	48%	$0.21	15
VSD, Condenser Water Pump	RET	0.84	43%	$0.54	15
VSD, HVAC Fan	RET	1.86	26%	$0.24	15
VSD, Cooling Tower Fan	RET	0.35	25%	$1.27	15
Demand Control Ventilation-Cool	RET	38.02	10%	$0.18	15
Demand Control Ventilation-Heat	RET	N/A	18%	$-	15
Demand Control Ventilation-Vent	RET	N/A	10%	$-	15
Screw-Based LED	RET	1.18	13%	$0.15	3.4
Retrofit duct sealing fan energy	RET	2.53	13%	$1.49	15
Retrofit duct sealing cool	RET	N/A	7%	$-	15
Retrofit duct sealing HS fan	RET	1.16	51%	$0.89	15
Retrofit duct sealing HS cool	RET	N/A	23%	$-	15

Ground Source HP (Heating)	MD	N/A	33%	$-	20
Ground Source HP (Cooling)	MD	N/A	49%	$1.69	20
Ground Source HP (Heating)	RET	0.48	38%	$-	20
Ground Source HP (Cooling)	RET	0.06	56%	$11.23	20
HE Clothes Washer, elec DHW	MD	7.57	28%	$0.47	11
HE Clothes Washer, elec DHW	RET	1.81	20%	$3.18	11
Ozone Laundry System	RET	2.95	91%	$21.95	20
Office Equipment Controls	RET	1.11	29%	$0.11	3.2
Window Film	RET	0.80	5%	$0.46	10
Cool Roof	MD	2.37	32%	$0.31	20
Cool Roof	RET	0.22	32%	$3.50	20
HE Kitchen Equipment	MD	208.42	27%	$0.12	12
HP Window Glaze (Cooling)	MD	16.13	6%	$0.05	20
HP Window Glaze (Heating)	MD	N/A	24%	$-	20
High Efficiency HP (Heating)	MD	N/A	55%	$-	15
High Efficiency HP (Cooling)	MD	N/A	32%	$0.14	15
High Efficiency HP (Heating)	RET	6.76	59%	$-	15
High Efficiency HP (Cooling)	RET	0.81	42%	$0.87	15
High Efficiency AC	MD	4.18	30%	$0.20	15
High Efficiency AC	RET	0.50	40%	$1.25	15
HP Tune Up (Heating)	RET	N/A	18%	$-	10
HP Tune Up (Cooling)	RET	4.07	10%	$0.13	10
AC Tune Up	RET	4.16	10%	$0.14	10
Commercial Faucet Aerator (Elec WH)	RET	20.15	55%	$0.01	10
ECM Blower Motors	RET	2.31	61%	$0.50	15
Conservation Voltage Reduction	RET	57.53	2%	$0.02	30
Building Management System - Elec Heat	RET	0.39	18%	$1.27	15
Retrocommissioning/Calibrate Sensors - Electric Heat	RET	1.79	16%	$0.17	8
Integrated bldg design -Elec	MD	1.76	31%	$0.50	30
Advanced RTU Control - Elec Heat	MD	1.09	9%	$0.48	15
Advanced RTU Control - Gas Heat	MD	0.98	9%	$0.50	15
Advanced RTU Control - Elec Heat	RET	1.28	9%	$0.48	15
Advanced RTU Control - Gas Heat	RET	1.15	9%	$0.50	15
Network Connected LEDs	RET	0.44	47%	$1.31	15
High Efficiency Chiller vs DX System	MD	0.28	35%	$2.72	20
Replace Pneumatic contols with DDC - Elec Heat	RET	0.48	15%	$1.02	15
Replace Pneumatic contols with DDC - Gas Heat	RET	2.90	15%	$1.24	15
Integrated bldg design -Gas	MD	1.59	31%	$0.56	30
Retrocommissioning/Calibrate Sensors - Gas Heat	RET	1.85	16%	$0.18	8
Building Management System - Gas Heat	RET	0.35	18%	$1.34	15
HP Window Glaze Gas	MD	13.63	6%	$0.05	20
Data Center Retrofit	RET	6.17	22%	$0.12	20
Chiller Tune-Up	RET	2.00	5%	$0.11	5

Cooler Night Cover	RET	0.51	7%	$0.32	5
High Efficiency Chiller	MD	1.10	14%	$0.56	10
High Efficiency Chiller	RET	0.15	22%	$3.44	10
Replace Cooler and Freezer Door Gaskets	RET	0.76	3%	$0.18	5
Reach-in Storage Refrigerator	MD	1.55	37%	$0.31	12
HE Small Walk-In	MD	5.47	40%	$0.10	13
Refrigeration Retrofit	RET	1.36	32%	$0.36	13
Strip Curtains	RET	2.45	15%	$0.05	4
Pre-Rinse Sprayers	RET	4.80	32%	$0.12	10
Control System for Hospitality	RET	6.17	19%	$0.08	8
Control System for Hospitality	MD	5.65	19%	$0.08	8
ENERGY STAR Pool Pump	MD	2.24	69%	$0.17	10
ENERGY STAR Pool Pump	RET	0.33	69%	$0.17	10
Compressed Air	MD	1.90	22%	$0.23	10
Compressed Air	RET	1.74	22%	$0.23	10

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

***EX PARTE: IN RE*: 2018 TRIENNIAL**	**)**	
INTEGRATED RESOURCE PLAN OF	**)**	
ENTERGY NEW ORLEANS, INC.	**)**	
	)	**DOCKET NO. UD-17-03**

APPENDIX F

HIGHLY SENSITIVE
PROTECTED MATERIALS

INTENTIONALLY OMITTED

JULY 2019

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

***EX PARTE: IN RE*: 2018 TRIENNIAL INTEGRATED RESOURCE PLAN OF ENTERGY NEW ORLEANS, INC.**	**))))**	**DOCKET NO. UD-17-03**

APPENDIX G

Entergy New Orleans, LLC
Technical Meeting Presentations

JULY 2019

Entergy

ENO 2018 IRP Technical Meeting #1

January 22, 2018

Goals and Agenda of Technical Meeting #1

Goals

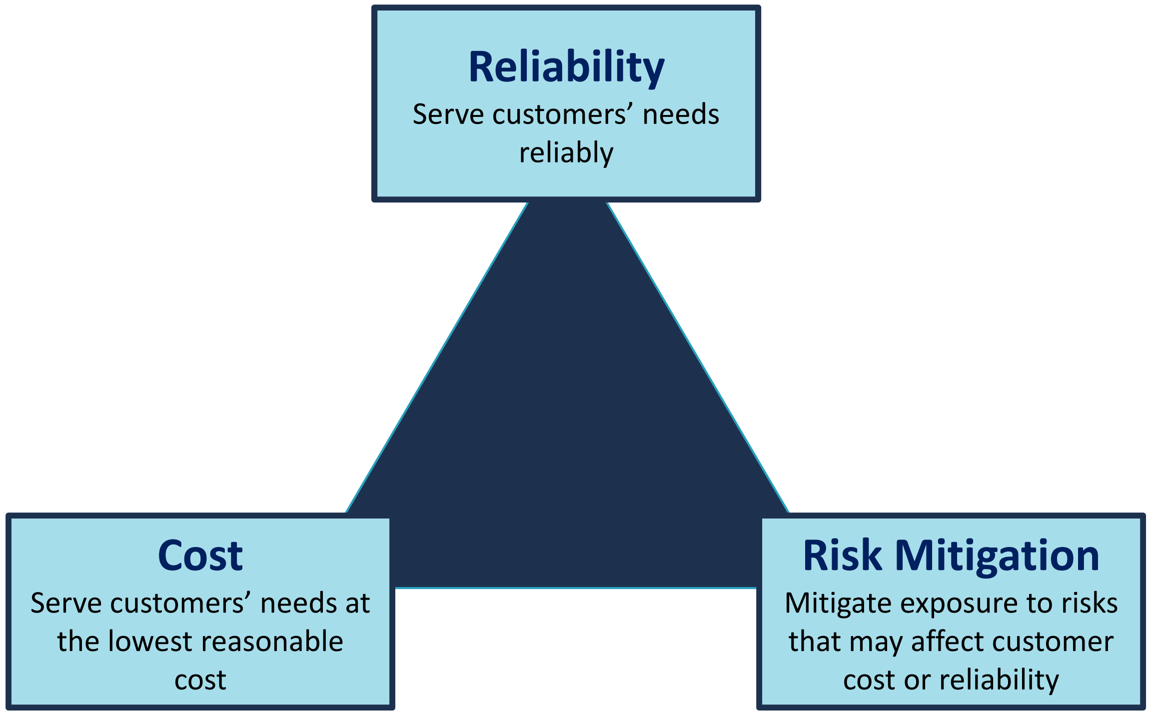
- As described in the Initiating Resolution (R-17-430), the main purpose of this meeting is for ENO, the Advisors, and Intervenors to discuss Planning Scenarios and Strategies with a view towards reaching consensus on the Scenarios and Strategies to be used in developing the 2018 IRP.
  - As such, per the Initiating Resolution, the meeting shall be treated as a settlement negotiation and subject to all applicable procedural and evidentiary protections.
- ENO will present its reference and alternative Planning Scenarios and its least-cost/reference Planning Strategy.
- Prior to the meeting, Intervenors should have discussed among themselves their priorities regarding Planning Scenarios and Strategies.
- Should the parties not agree that the proposed Scenarios and/or Strategies, or any Scenarios and/or Strategies developed during Technical Meeting #1, will adequately capture the Intervenors' point of view, the Intervenors shall prepare and submit, with the Advisors' assistance as needed, their proposed Planning Scenario and/or Strategy before Technical Meeting #2.

Agenda

1. 2018 IRP Objectives
2. Analytical Framework
3. Inputs and Assumptions
4. Resource Options
   a. Supply-Side Resources
   b. DSM Potential Study (Navigant)
5. Timeline

Section 1
2018 IRP Objectives

ENO's planning process seeks to accomplish three key objectives



Achieve these objectives while considering known utility regulatory policy goals of the Council

In the 2018 IRP, ENO will consider the ongoing evolution of the utility industry

The Changing Utility Industry

Customer Preferences

ENO's planning processes seek to address changing customer needs. Planning processes and tools will continue to evolve to help identify customer needs and wants.

Resource Alternatives

Ever advancing technology provides new opportunities to meet future customer needs reliably and affordably. Planning processes strive to understand these technological changes in order to enable us to design optimal portfolios of resources and services.

Grid Modernization

ENO's distribution planning process will need to accommodate the integration of distributed energy resources safely and securely so they can be interoperable with the grid.

Section 2
Analytical Framework

Analytic Process to Create and Value Portfolios

Development of Planning Scenarios and Strategies

Development of assumptions and inputs for Scenarios and Strategies

Market Modeling

Projection of MISO market **outside of ENO** for each Scenario

Portfolio Development

Construction of resource portfolios for each Scenario/Strategy combination

Total Relevant Supply Cost

Production costs and fixed costs are determined for each portfolio under each Scenario/Strategy combination

Action Plan

Identify action plan that balances reliability, cost, and risk

ENO Planning Scenarios--Assumptions

	Scenario 1 (Reference)	Scenario 2	Scenario 3
Peak Load & Energy Growth	Reference	Low	High
Natural Gas Prices	Reference	Low	High
Market Coal & Legacy Gas Deactivations	Reference (60 years)	Accelerated (50 years)	Accelerated (55 years)
Magnitude of Coal & Legacy Gas Deactivations	12% by 2028 54% by 2038	54% by 2028 91% by 2038	31% by 2028 88% by 2038
MISO Market Additions Renewables / Gas Mix	34% / 66%	50% / 50%	50% / 50%
CO2 Price Forecast	Reference	High	Reference

If necessary, a fourth Stakeholder Scenario will be modeled.

ENO Planning Strategies--Assumptions

	Strategy 1 (Reference)	Strategy 2	Strategy 3
Objective	Least Cost Planning	0.2/2% DSM Goal	TBD
Resource Portfolio Criteria and Constraints	Meet 12% long-term Planning Reserve Margin (PRM) target using least-cost resource portfolio of supply and DSM resources	Include a portfolio of DSM programs that meet the Council's stated 2% goal and determine remaining needs	
Description	Assess demand- and supply-side alternatives to meet projected capacity needs with a focus on total relevant supply costs	Design a portfolio that includes a set of potential DSM programs intended to meet the Council's stated 2% goal and considers additional supply-side alternatives	

If necessary, an Stakeholder Planning Strategy will be modeled.

MISO Market Modeling and Total Relevant Supply Cost Calculation

1 **Market Model Set-Up**

- Develop projection of MISO market outside ENO for each Scenario
  - 16% reserve margin target (based on MISO summer peak load and Resource Adequacy process)
  - Build out MISO resource pool to achieve target fuel mix per Scenario

2 **Initial Production Cost Simulation**

- Using AURORA production cost model, simulate MISO market to generate market price curve (i.e., LMPs) for each Scenario

3 **Development of Portfolios using either AURORA or Manual Process**

- Use AURORA capacity expansion model to select demand- and supply-side alternatives to create ENO portfolios for each Scenario/Strategy combination
  - 12% long term reserve margin (based on ENO long term planning assumption)
  - Portfolio addition decisions based on maximizing market value of supply additions
- If the capacity expansion model is unable to select resources required by a particular Strategy consistent with identified resource needs, develop manual portfolios using defined constraints and professional judgment

4 **Final Production Cost Simulations and Total Relevant Supply Cost Calculations**

- Compute variable supply costs for each portfolio in each of the Scenarios/Strategies using detailed MISO Zonal Model in AURORA
- Calculate Total Relevant Supply Cost for each portfolio
  - Includes: variable supply costs, cost of DSM programs, incremental non-fuel fixed costs, and capacity purchases

Assessment of Portfolio Performance Across Scenarios

- Portfolios developed for each Scenario/Strategy combination will be tested across all other Scenarios to assess performance in a range of possible outcomes
- The total relevant supply cost of each of the Scenario/Portfolio combinations represents the present value of fixed and variable costs to customers in 2018$

***ILLUSTRATIVE ONLY*—Actual number of Scenario/Portfolio combinations TBD**

Portfolios / Scenarios	Strategy 1 (Reference)				Strategy 2 (2% DSM Goal)				Strategy 3 (TBD)			
	Port 1	Port 2	Port 3	Port 4	Port 5	Port 6	Port 7	Port 8	Port 9	Port 10	Port 11	Port 12
Scenario 1	R_{11}	R_{12}	R_{13}	R_{14}	R_{15}	R_{16}	R_{17}	R_{18}	R_{19}	R_{110}	R_{111}	R_{112}
Scenario 2	R_{21}	R_{22}	R_{23}	R_{24}	R_{25}	R_{26}	R_{27}	R_{28}	R_{29}	R_{210}	R_{211}	R_{212}
Scenario 3	R_{31}	R_{32}	R_{33}	R_{34}	R_{35}	R_{36}	R_{37}	R_{38}	R_{39}	R_{310}	R_{311}	R_{312}
Scenario 4	R_{41}	R_{42}	R_{43}	R_{44}	R_{45}	R_{46}	R_{47}	R_{48}	R_{49}	R_{410}	R_{411}	R_{412}

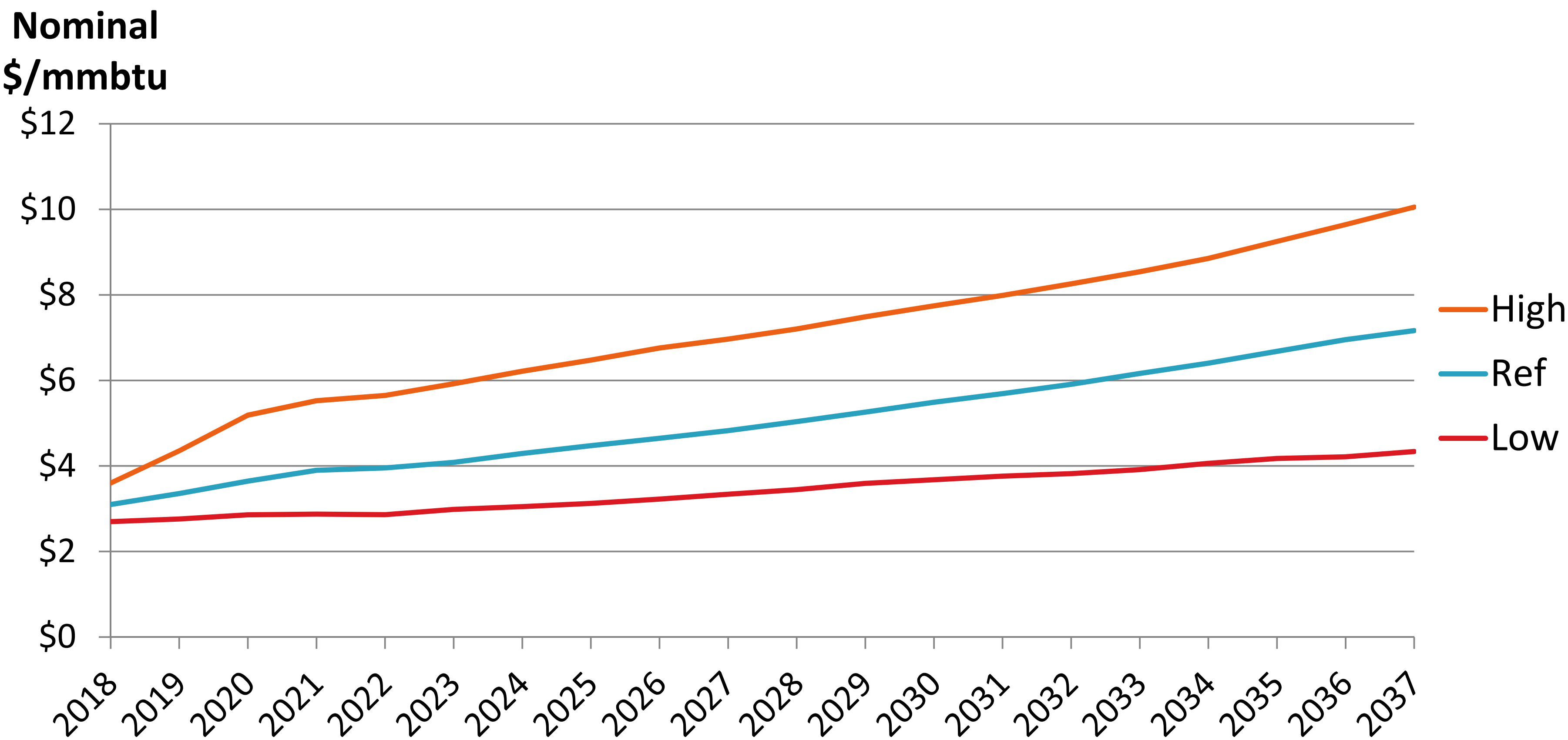
Note: “R” = resulting total relevant supply cost

Section 3
Inputs and Assumptions

2018 IRP Inputs and Assumptions

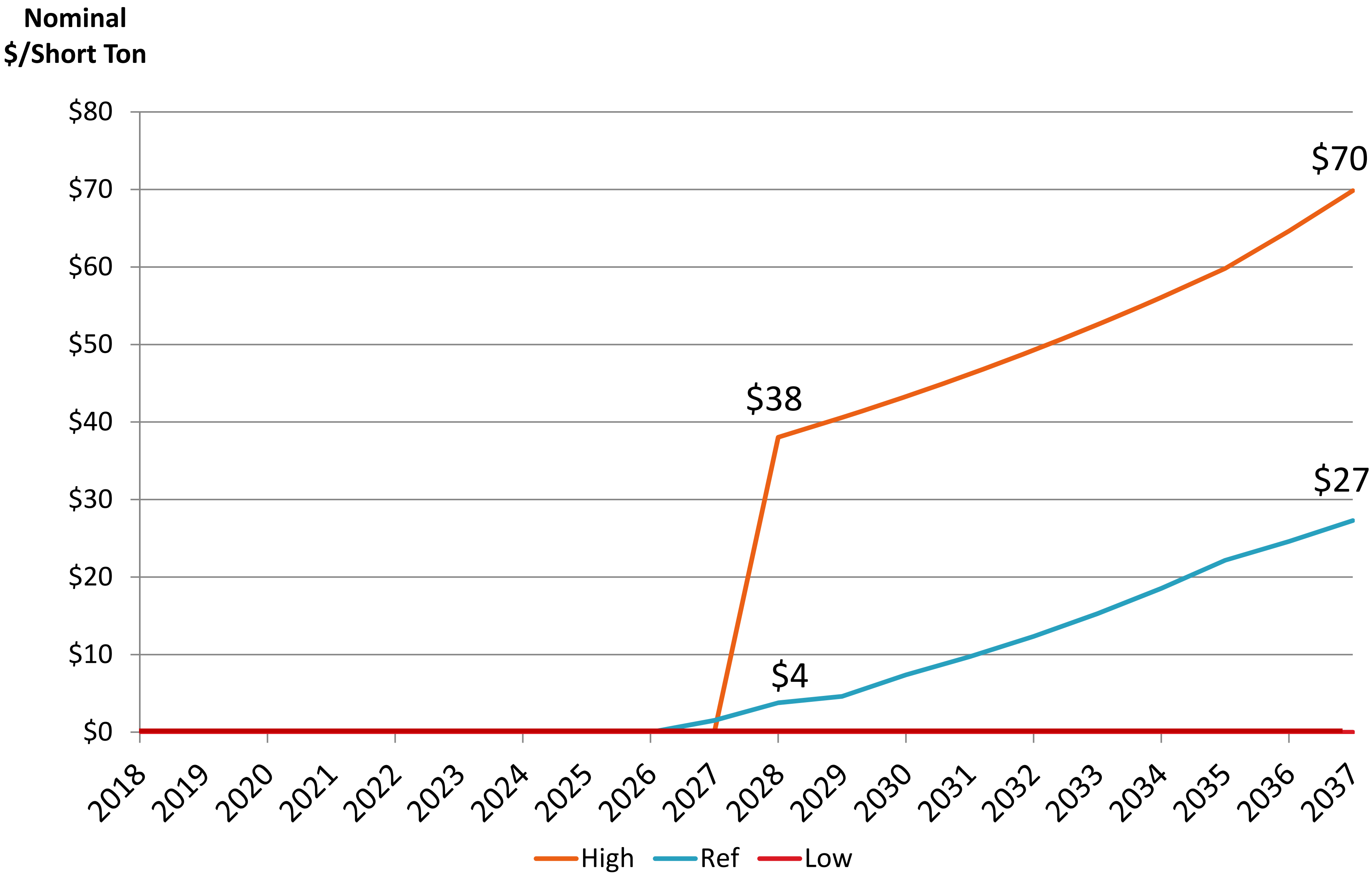
Input/Assumption	Present at Technical Meeting #	MISO Market Modeling	Portfolio Development	Total Relevant Supply Costs
Scenarios & Strategies	1	✓	✓	✓
Gas Price Forecast	1	✓	✓	✓
CO2 Price Forecast	1	✓	✓	✓
Capacity Value	1		✓	✓
Supply-Side Resource Alternative Costs	2		✓	✓
Load Forecast	2	✓	✓	
ENO's Long-Term Capacity Need	2		✓	✓
Input Sensitivities	2			✓
DSM Potential Study Results	3		✓	✓

Gas Forecast

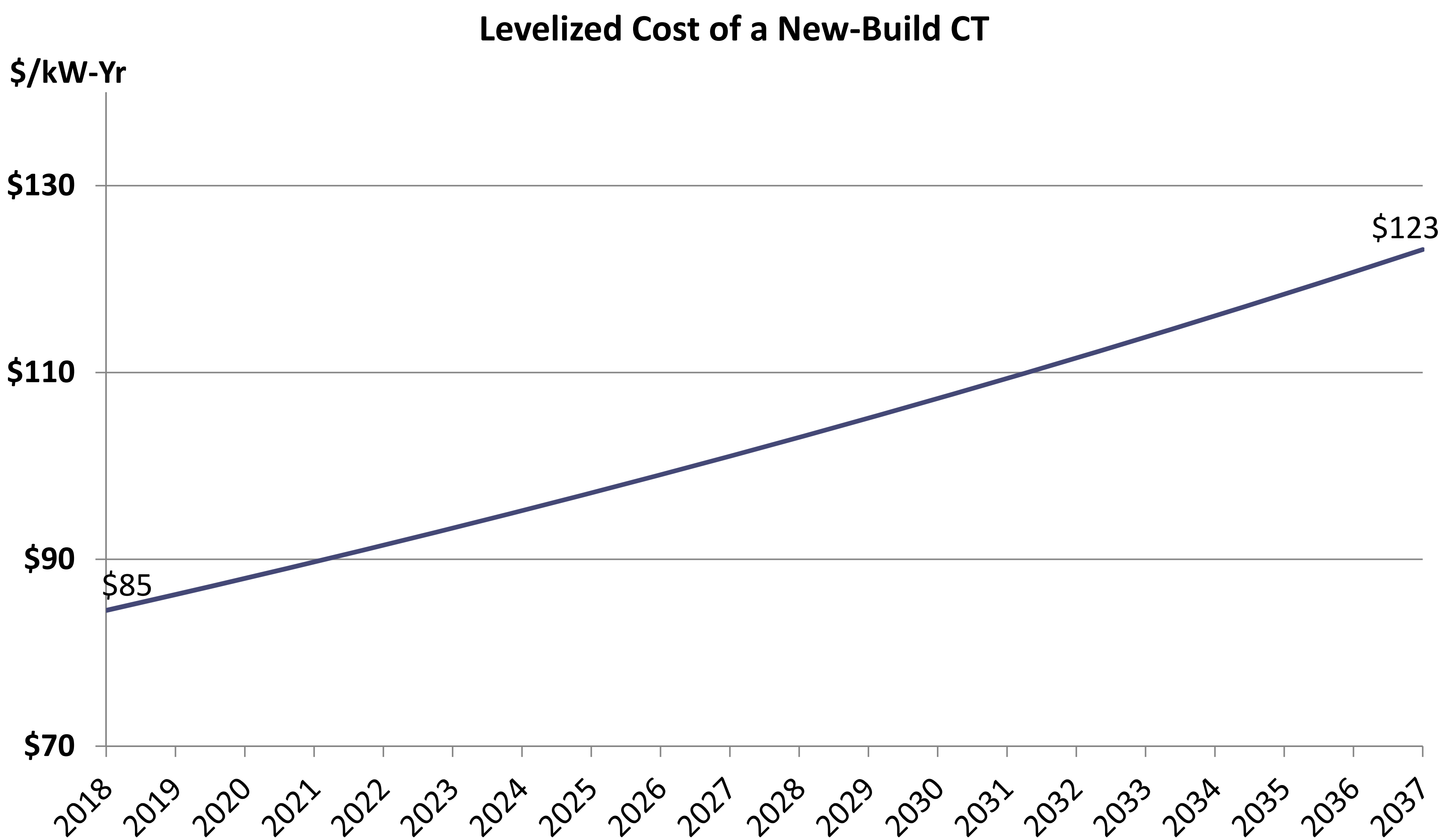


Case	2018	2025	2030	2037
Low	$2.67	$3.12	$3.68	$4.34
Reference	$3.08	$4.48	$5.49	$7.16
High	$3.55	$6.48	$7.74	$10.05

CO_2 Forecast



ENO Capacity Value

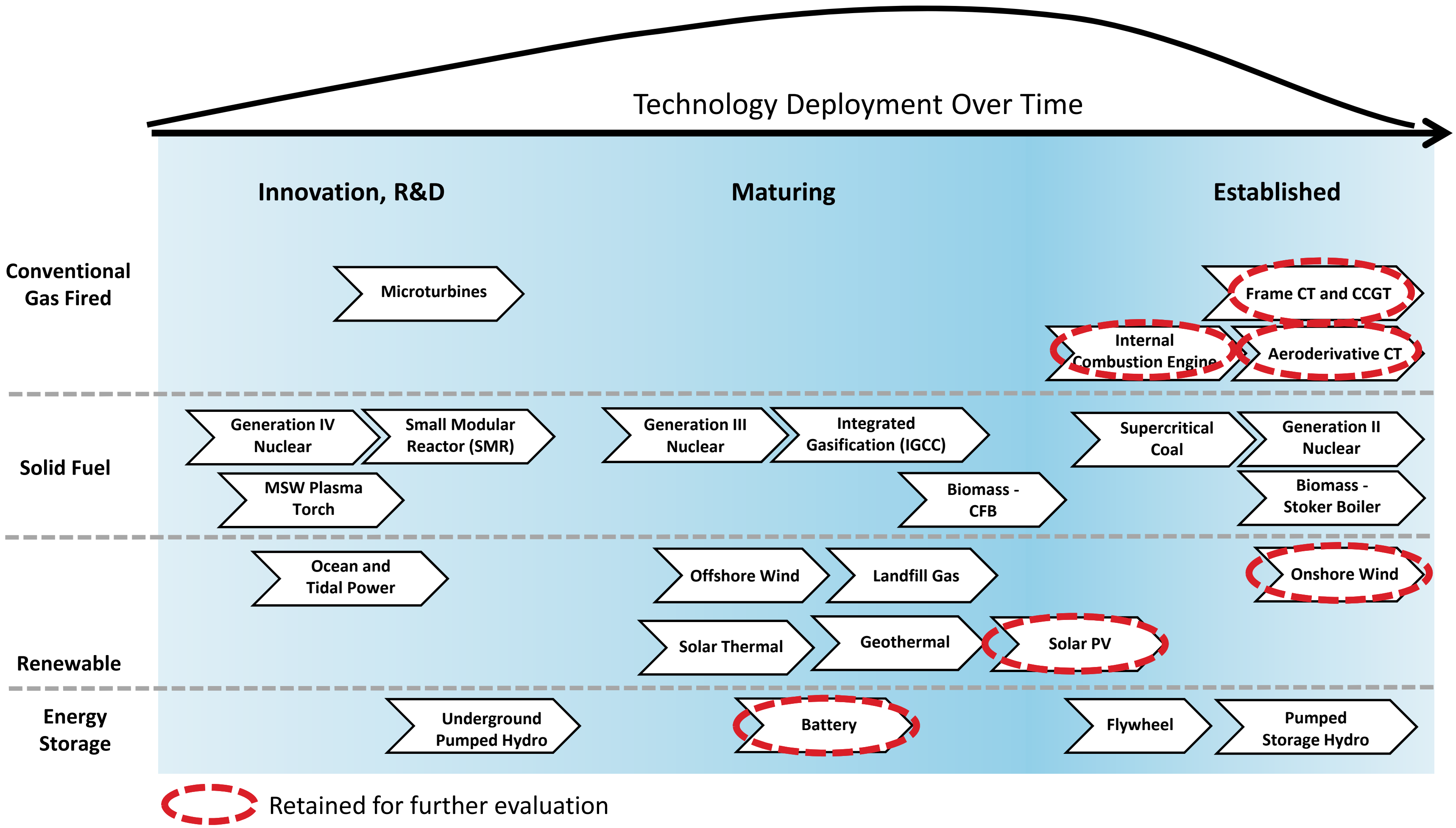


Section 4a
Supply-Side Resource Options

Technology Assessment Process and Purpose

- Generation technology cost and performance are a necessary input to resource planning and portfolio development.
- The process to evaluate generation technologies has two main steps – an initial screening level analysis and a more detailed economic analysis.
- The technology assessment includes technologically mature alternatives that are expected to be operational in or around the Entergy regulated service territory.
- In an effort to minimize operational and economic risk, ENO prefers technologies that are proven on a commercial scale. Some technologies identified lack the commercial track record to demonstrate their technical and operational feasibility.
- The technology screening analysis identifies generation technology alternatives which are expected to reasonably meet primary planning objectives of reliability, cost, and risk mitigation. Economic modeling parameters are developed for the identified technologies.
- Technologies that are eliminated as a result of the initial screen will continue to be monitored and changes in technology assessments will be incorporated in future IRPs, when appropriate.

Identified Supply-Side Resource Alternatives

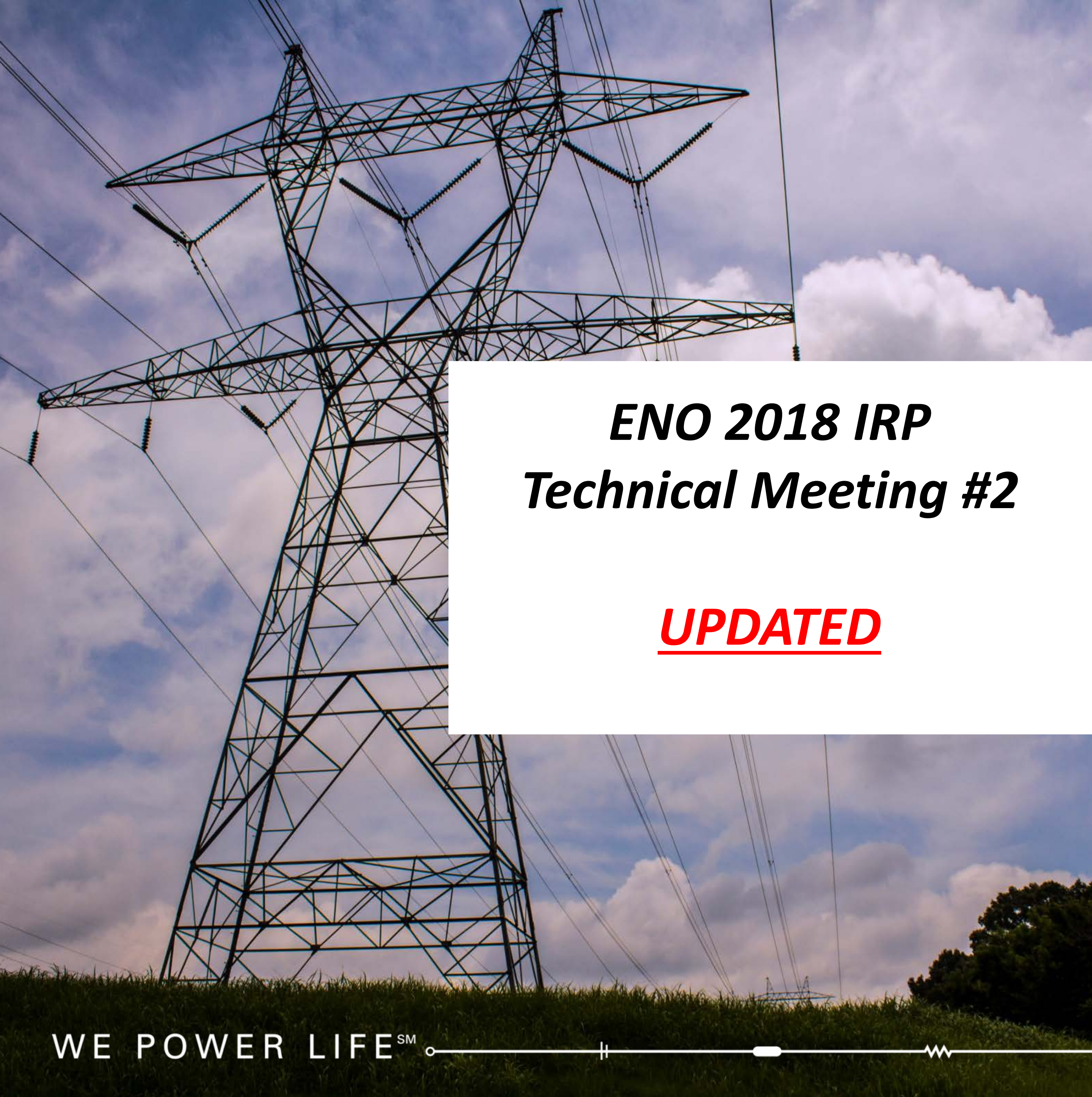


Section 4b
DSM Potential Study
(Navigant Presentation)

Section 5
Timeline

Current Timeline

Description	Target Date	Status
Public Meeting #1- Process Overview	September 2017	✓
Technical Meeting #1 Material Due	January 2018	✓
Technical Meeting #1	January 2018	✓
Technical Meeting #2 Material Due	March 2018	-
Technical Meeting #2	April 2018	-
Technical Meeting #3 Material Due	May 2018	-
Technical Meeting #3	June 2018	-
IRP Inputs Finalized	**June 2018**	-
Optimized Portfolio Results Due	October 2018	-
Technical Meeting #4 Material Due	October 2018	-
Technical Meeting #4	November 2018	-
File IRP Report	January 2019	-
Public Meeting #2 Material Due	January 2019	-
Public Meeting #2 - Present IRP Results	February 2019	-
Intervenors and Advisors Questions & Comments Due	February 2019	-
ENO Response to Questions and Comments Due	February 2019	-
Public Meeting #3 Material Due	February 2019	-
Technical Meeting #5 Material Due	February 2019	-
Public Meeting #3 - Public Response	March 2019	-
Technical Meeting #5	March 2019	-
ENO File Reply Comments	May 2019	-
Advisors File Report	June 2019	-



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ENO 2018 IRP
Technical Meeting #2

UPDATED

September 14, 2018

WE POWER LIFE℠

Goals and Agenda of Technical Meeting #2

Goals

- As described in the Initiating Resolution (R-17-430), the main purpose of this meeting is for ENO, the Advisors, and Intervenors to attempt to reach consensus on the Scenarios and Strategies that were initially discussed in Technical Meeting #1 (and which have been refined as described in this presentation), **or**
- To discuss the Planning Scenario and/or Strategies that have been prepared by the Intervenors and provided to the parties in advance of this Technical Meeting

Agenda

1. Analytical Framework and Portfolio Development
2. ENO Capacity Need and Supply Alternatives
3. IRP Inputs and Assumptions
4. Timeline and Next Steps

Technical Meeting #1—Follow Ups

- **Proposed Planning Scenarios**
  - Add narrative descriptions
  - Consider impact of 50/50 renewables-to-gas buildout on LMPs
  - Consider CO_2 pricing adjustments to create better range of macro market futures
- **Proposed Planning Strategies**
  - Propose ideas for Strategy 3 for group discussion, possible consensus building, per IRP Rules, Sec. 7 (D)2
- **IRP Modeling**
  - Further discussion of portfolio development process
- **Inputs Workbook**
  - Produce workbook with relevant IRP modeling inputs
  - Transition from BP18U to BP19

Section 1
Analytical Framework and Portfolio Development

Analytic Process to Create and Value Portfolios

Development of Planning Scenarios and Strategies

Development of assumptions and inputs for Scenarios and Strategies

Market Modeling

Projection of MISO market **outside of ENO** for each Scenario

Portfolio Development

Construction of resource portfolios for each Scenario/Strategy combination

Total Relevant Supply Cost

Production costs and fixed costs are determined for each portfolio under each Scenario/Strategy combination

Action Plan

Identify action plan that balances reliability, cost, and risk

Proposed Scenario Purpose and Drivers

IRP analytics rely on macro market Scenarios designed to allow for the assessment of the total production cost and risk of resource portfolios across a reasonable range of possible future outcomes. The three proposed Scenarios for the ENO 2018 IRP are:

Scenarios	Key Drivers
Scenario 1 (Moderate Change Over Time)	• Flat/declining usage per customer (UPC) in residential and commercial sectors due to increases in energy efficiency and other customer adopted measures • UPC declines partially offset by industrial growth and growth in residential and commercial customer counts • Renewables and gas replace retiring capacity to promote fuel diversity in long-term resource planning
Scenario 2 (Customer Driven Change)	• Low peak load growth and natural gas prices tied to slumping demand • Growth rate of residential and commercial demand and energy usage decreased due to strong customer preferences for EE and DERs • Capacity additions in the MISO market are weighted towards gas-fired generation due to low gas and CO_2 prices
Scenario 3 (Policy Driven Change)	• Growth rate of residential and commercial customer demand and energy usage increased through economic development and moderated energy efficiency gains • Political and economic pressure on coal and legacy gas plants accelerates retirements • High CO_2 pricing along with economic factors drive the replacement of retiring capacity with portfolio of equal amounts of renewables complemented with battery storage and gas-fired technology to replace retiring capacity

Development of ENO Proposed Planning Scenarios – Update

MISO Market Outside of New Orleans

- Aurora market model testing has shown negative Locational Marginal Prices (LMPs), over an extended period of time as a result of the 50/50 renewables-to-gas market additions originally proposed for the MISO market
  - These negative LMPs could result in the suppression of renewable resource additions in portfolios designed for ENO
  - Because it is not realistic to expect the MISO market to experience negative LMPs over an extended period of time, it was necessary to reconsider this assumption

- Based on this testing, two of the three Scenarios proposed at Technical Meeting #1 were modified as shown on following slide:
  - To mitigate the impact that negative LMPs would have on the results and to encourage a range of market prices, ENO:
    - Adjusted the second Scenario to reflect a 25%/75% renewables-to-gas mix for MISO Market additions, and adjusted the CO_2 pricing assumption
    - Adjusted the third Scenario to incorporate battery deployment to address the possibility of negative LMPs due to the 50/50 renewables-to-gas addition assumption
- This helps ensure that the market model doesn't preclude any resource type because of negative LMPs

ENO Proposed Planning Scenarios – Assumptions

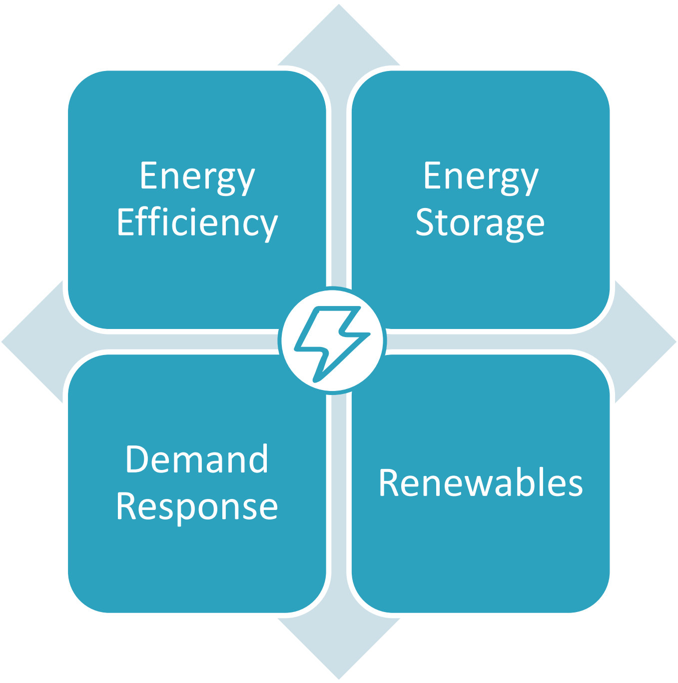
	Scenario 1 (Moderate Change)	Scenario 2 (Customer Driven)	Scenario 3 (Policy Driven)
Peak Load & Energy Growth	Medium	Low	High
Natural Gas Prices	Medium	Low	High
Market Coal & Legacy Gas Deactivations	60 years	55 years *(Modified from 50 years)*	50 years *(Modified from 55 years)*
Magnitude of Coal & Legacy Gas Deactivations[2]	12% by 2028 54% by 2038	31% by 2028 88% by 2038	54% by 2028 91% by 2038
MISO Market Additions Renewables / Gas Mix	34% / 66%	25% / 75% *(Modified from 50%/50%)*	50% / 50%
CO_2 Price Forecast	Medium	Low *(Modified from High)*	High *(Modified from Medium)*

1. Highlighted cells indicate a change since Technical Meeting #1
2. "Magnitude of Coal & Legacy Gas Deactivation" driven by "Market Coal and Legacy Gas deactivation" assumptions (e.g. 55 Years; 31%/88%) and were likewise swapped between Scenarios 2 and 3. Percentages based on BP18U for MISO South; to be adjusted for BP19

ENO Proposed Planning Strategies– Update

Proposed Strategy 3: Renewables, Storage, and DSM Alternative

- **Policy-driven, and possible consensus/reference, strategy under which incremental capacity needs are exclusively met through a diverse array of renewables, battery storage, and DSM**



ENO Proposed Planning Strategies--Assumptions

	Strategy 1[1]	Strategy 2[2]	Strategy 3[3]
Objective	Least Cost Planning	0.2/2% DSM Goal	Renewables, Storage & DSM Alternatives
Capacity Portfolio Criteria and Constraints	Meet 12% Long-term Planning Reserve Margin (PRM) target using least-cost resource portfolio	Include a portfolio of DSM programs that meet the Council's stated 2% goal	Meet peak load need + 12% PRM target using DSM, solar, and battery resources
Description	Assess demand- and supply-side alternatives to meet projected capacity needs with a focus on total relevant supply costs	Assess portfolio of DSM programs that meet Council's stated 0.2/2% goal along with consideration of additional supply-side alternatives	Assess demand- and supply-side alternatives to meet projected capacity needs with a focus on adding solar and batteries
DSM Input Case	Navigant Base	Navigant 2%	To be discussed

1 Least Cost Strategy – required by IRP Rules Sec. 7(D)1
2 Policy Goal Strategy – required by IRP Rules Sec. 7(D)3
3 Proposed Consensus/Reference Strategy – required by IRP Rules Sec. 7(D)2

Optimized Portfolio Design

- **Aurora Capacity Expansion Algorithm Portfolios**
  - Used to identify least cost portfolios for each Strategy across a range of Scenarios.

- **Aurora Production Cost Modeling**
  - Select portfolios are later tested across Scenarios in the Aurora Production Cost model in order to calculate the variable supply costs for each portfolio/Scenario combination.

	Benefits	Challenges
Aurora Capacity Expansion	• Capable of finding least cost portfolios given inputs and constraints • 3rd party model-based portfolio development • Considers multiple market and cost inputs • Simultaneously considers multiple competing constraints • Captures intermittent resource attributes • Consistent application of algorithm	• Dependent on and sensitive to changes to inputs in ways that can be unpredictable • May not account for qualitative benefits and considerations • May not account for all stakeholder preferences • Application of constraints without judgment can result in less appropriate resource selection • Lack of transparency for validation and explanation of results

Optimized Portfolio Design

Which Strategy?

Strategy Driver	Least Cost → 2% DSM → Renewables, Storage, DSM → Stakeholder
Design Process	Aurora Capacity Expansion Software
Total Fixed Costs	For each Scenario, Aurora Capacity Expansion creates the least cost portfolio of demand- and supply-side resources to meet the identified need (peak load + 12% PRM)
Total Variable Production Costs	Using Aurora's Production Cost Modeling, select portfolios are analyzed across Scenarios
Total Supply Costs	Total supply costs (fixed + variable production costs) calculated for select portfolios/scenario combinations for comparison and analysis
Sensitivity Analysis	Least cost portfolios subjected to sensitivity analysis to examine effects of differing fuel prices, CO2 costs, etc.

Optimized Portfolio Design *Illustrative*

	Strategy 1 Least Cost	**Strategy 2 2% DSM**	**Strategy 3 Renewables, Storage, DSM**	Strategy 4 (Stakeholder)
Scenario 1	Portfolio	Portfolio	Portfolio	Portfolio
Scenario 2	Portfolio	Portfolio	Portfolio	Portfolio
Scenario 3	Portfolio	Portfolio	Portfolio	Portfolio
Scenario 4 (Stakeholder)	Portfolio	Portfolio	Portfolio	Portfolio

Optimized Portfolio Design *Illustrative*

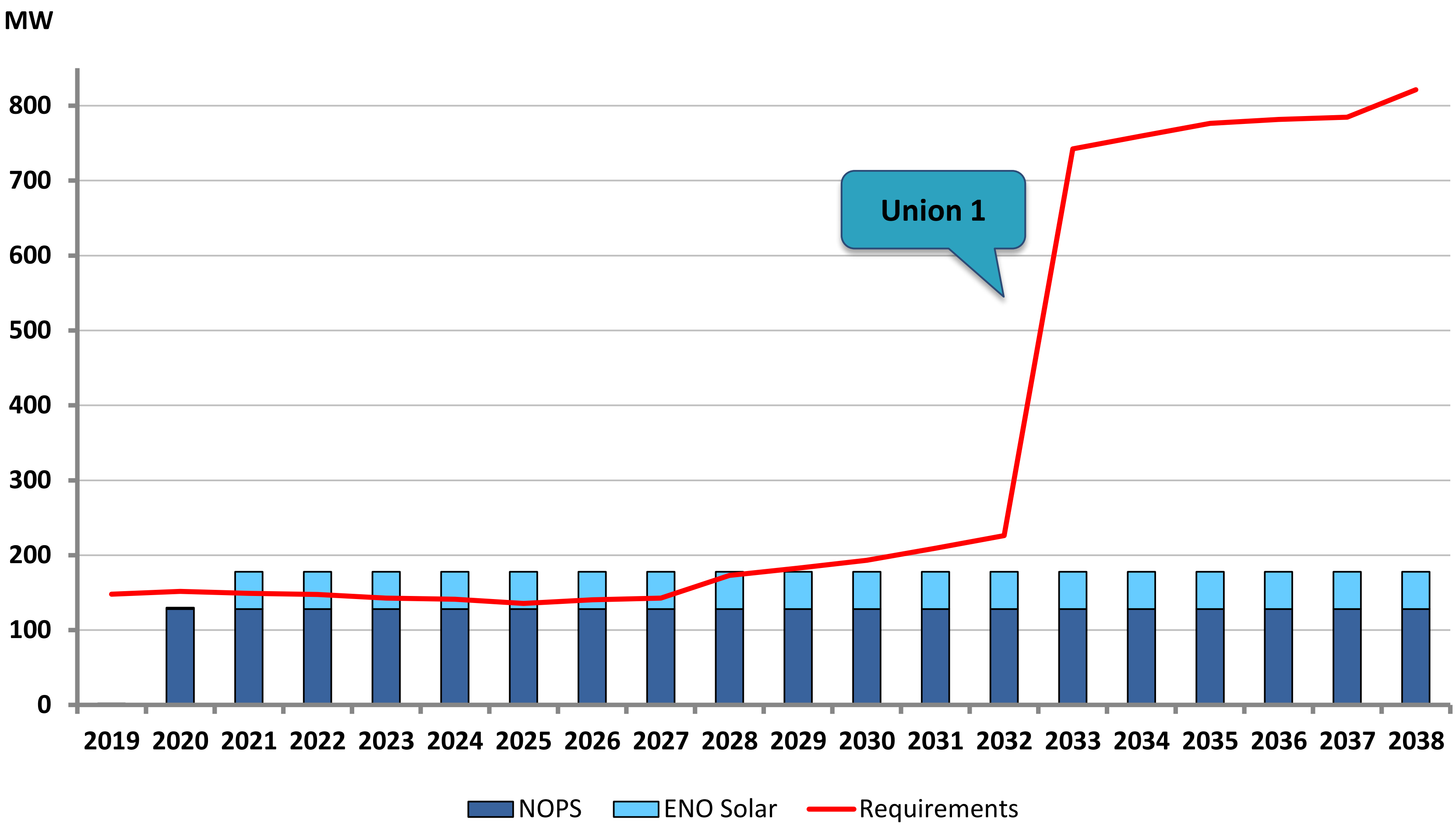
	Strategy 1 Least Cost	**Strategy 2 2% DSM**	**Strategy 3 Renewables, Storage, DSM**	Strategy 4 (Stakeholder)
Scenario 1	Portfolio	Portfolio	Portfolio	Portfolio
Scenario 2	Portfolio	Portfolio	Portfolio	Portfolio
Scenario 3	Portfolio	Portfolio	Portfolio	Portfolio
Scenario 4 (Stakeholder)	Portfolio	Portfolio	Portfolio	Portfolio

NOTE: In this example, all 7 of the select portfolios would be tested across the 4 Scenarios in the Production Cost Model, generating 28 Total Relevant Supply Cost Results

Section 2
ENO Capacity Need and Supply Alternatives

ENO's Long-Term Capacity Need

ENO's existing and planned capacity portfolio over the 20 year planning period



Assumptions:

- *Requirements based on non-coincident peak and a 12% reserve margin*
- *ENO Solar additions modeled with 50% effective capacity (100 MW nameplate)*

DSM Resources

- Same process for DSM evaluation as in 2015 IRP; including additional step to enable selection of DSM options that are cost-effective after year 1
- DSM programs will be evaluated based on the characteristics and attributes provided in the potential studies.
  - Demand Response programs described by an average annual load reduction and annual program costs will be evaluated through spreadsheet models outside of the Aurora model based on capacity value net of fixed program costs.
  - Energy Efficiency programs described by an hourly load reduction profile and annual program costs.
- Programs determined to be economic (i.e. positive net benefits) will be selected in the first year.
  - ENO's capacity position (surplus/deficit) will be adjusted to reflect the capacity contribution of selected Demand Response programs.
- Programs not considered economic in year one will be evaluated by AURORA alongside supply side resources in future years (future program inputs to be provided following initial run).
  - DSM programs with hourly load reduction profiles will be evaluated alongside supply side resources in the portfolio design in order to identify the most economic combination of DSM programs and supply side resources.

Supply-Side Technology Resources

- The supply-side technology assessment analyzes potential supply-side generation solutions that could help ENO serve customers' needs reliably and at the most reasonable cost, including renewables, energy storage, and natural gas technologies.

- ENO's technology assessment for the 2018 IRP explores in detail the challenges, opportunities, and costs of generation alternatives to be considered when designing resource portfolios to meet the capacity needs of customers.
  - Renewable energy resources, especially solar, have emerged as viable economic alternatives.
  - Trend to smaller, more modular resources (such as battery storage) provides opportunity to reduce risk and manage peak demand.
  - Deployment of intermittent generation has increased the need for flexible, diverse supply alternatives. New smaller scale supply alternatives will better address locational, site specific reliability requirements while continuing to support overall grid reliability.

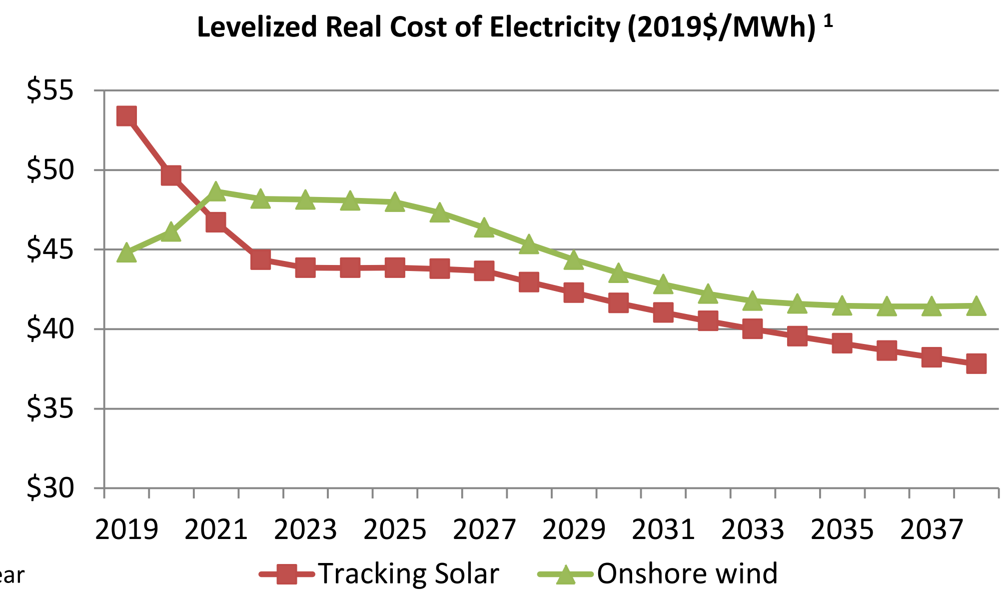
Renewable Resource Assumptions (Solar PV & Wind)

Levelized Real Cost of Electricity (2019$/MWh-AC) [1]

	2019	2020	2021	2022	2023	2026	2029	2032	2035	2038
Solar Tracking [2]	$53.39	$49.64	$46.71	$44.35	$43.86	$43.79	$42.28	$40.51	$39.10	$37.82
Onshore Wind [3]	$44.82	$46.12	$48.65	$48.19	$48.14	$47.32	$44.35	$42.21	$41.47	$41.46

Other Modeling Assumptions

	Solar	Wind
Fixed O&M (2017$/kW-yr-AC)	$16	$36.01
Useful Life (yr)	30	25
MACRS Depreciation (yr)	5	5
Capacity Factor	26%	36%
DC:AC	1.35	N/A
Hourly Profile Modeling Software	PlantPredict	NREL SAM



1. Year 1 levelized real cost for a project beginning in the given year
2. ITC normalized over useful life and steps down to 10% by 2023
3. PTC steps down to 40% by 2020 and expires thereafter

Source: The capital cost assumptions for Wind and Solar are based on a confidential IHS Markit forecast.

Grid-Scale Battery Storage Alternatives

As battery storage technology continues to improve it is important to assess the costs and benefits associated with its deployment to meet long-term needs in the proper context.

Battery storage includes a range of unique attributes that should be considered, such as:

- The ability to store energy for later commitment and dispatch (energy and capacity value)
- Ability to discharge in milliseconds and fast ramping capability (ancillary services)
- Potential deferral of transmission and distribution upgrades
- Rapid construction (on the order of months)
- Modular deployment provides potential scalability
- Portability and capability to be redeployed in different areas
- Small footprint (typically less than an acre), allowing for flexible siting
- Low round-trip losses compared to other storage technologies (such as compressed air)

These attributes should be considered in the appropriate context, not all of which is well understood at this time, including but not limited to:

- Batteries are not a source of electric generation
- Useful life can be much shorter than other grid-scale investments (replacement cost)
- Market rules not yet established to govern participation in wholesale markets
- Discharge less electricity than required to charge due to losses
- Cost of environmentally sound disposal

Battery Storage Assumptions

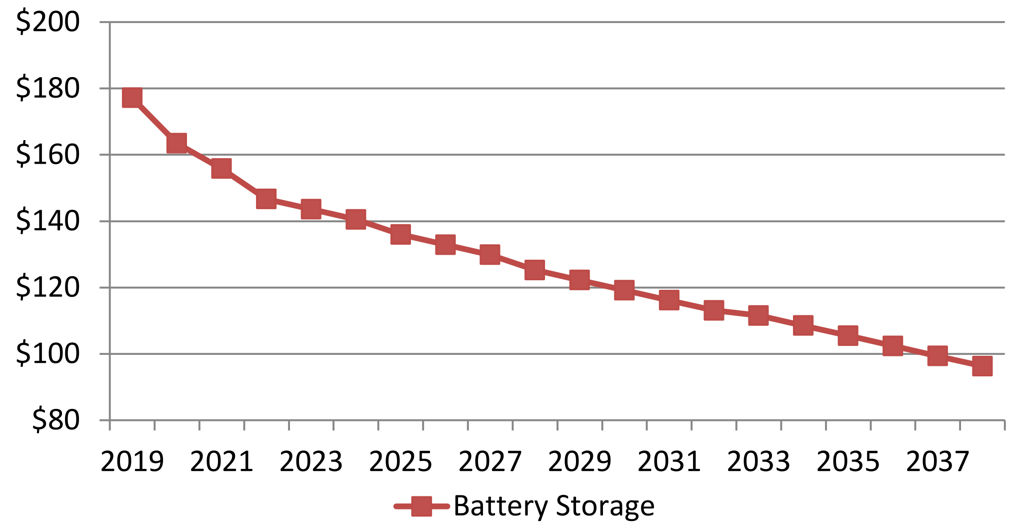
Levelized Real Fixed Cost (2019$/kW-yr) [1]

	2019	2020	2021	2022	2023	2026	2029	2032	2035	2038
Battery Storage	$177	$163	$155	$146	$143	$132	$122	$113	$105	$96

Other Modeling Assumptions

	Battery Storage
Energy Capacity : Power [2]	4:1
Fixed O&M (2017$/kW-yr)	$9.00
Useful Life (yr) [3]	10
MACRS Depreciation (yr)	7
AC-AC efficiency	90%
Hourly Profile Modeling Software	Aurora

Levelized Real Fixed Cost (2019$/kW-yr) [1]



1. Year 1 levelized real cost for a project beginning in the given year
2. Current MISO Tariff requirement for capacity credit
3. Assumes daily cycling, no module replacement cost, full depth of discharge

Source: The capital cost assumptions for Battery Storage is based on a confidential IHS Markit forecast.

Gas resource assumptions

Technology		Summer Capacity [MW]	Capital Cost [2017$/kW]	Fixed O&M [2017$/kW-yr]	Variable O&M [2017 $/MWh]	Heat Rate* [Btu/kWh]	Expected Capacity Factor [%]
Combined Cycle Gas Turbine (CCGT)	*1x1 501JAC*	605	$1,244	$16.70	$3.14	6,300	80%
Simple Cycle Combustion Turbine (CT)	*501JAC*	346	$809	$2.37	$13.35	9,400	10%
Aeroderivative Combustion Turbine (Aero CT)	*LMS100PA*	102	$1,543	$5.86	$2.90	9,400	20%
Reciprocating Internal Combustion Engine (RICE)	*7x Wartsila 18V50SG*	128	$1,545	$31.94	$7.30	8,400	30%

*Heat Rate based on full load without duct firing

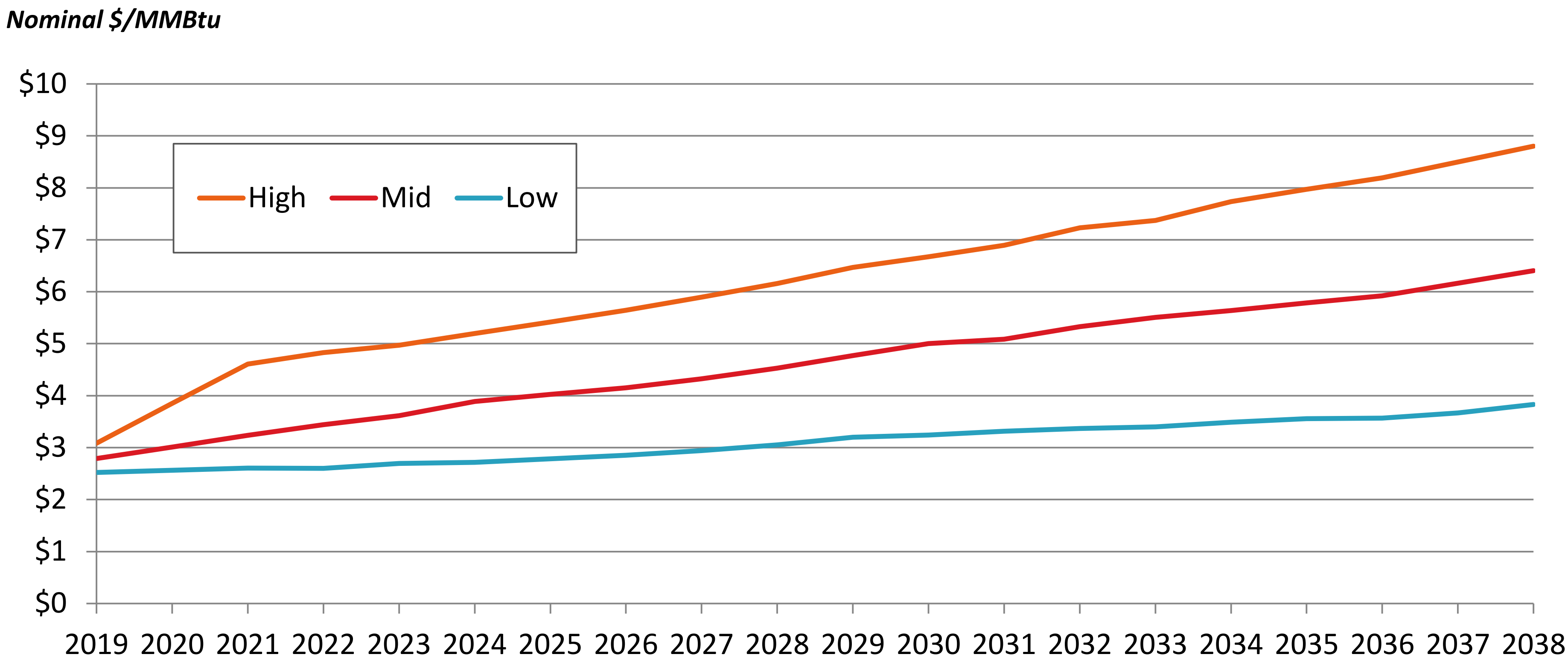
Section 3
Inputs and Assumptions

2018 IRP Inputs and Assumptions

Input/Assumption	MISO Market Modeling	Portfolio Development	Total Relevant Supply Costs
Scenarios & Strategies	✓	✓	✓
Gas Price Forecast*	✓	✓	✓
CO_2 Price Forecast*	✓	✓	✓
Capacity Value*		✓	✓
Supply-Side Resource Alternative Costs*		✓	✓
Load Forecast*	✓	✓	
ENO's Long-Term Capacity Need*		✓	✓
DSM Potential Study Results		✓	✓

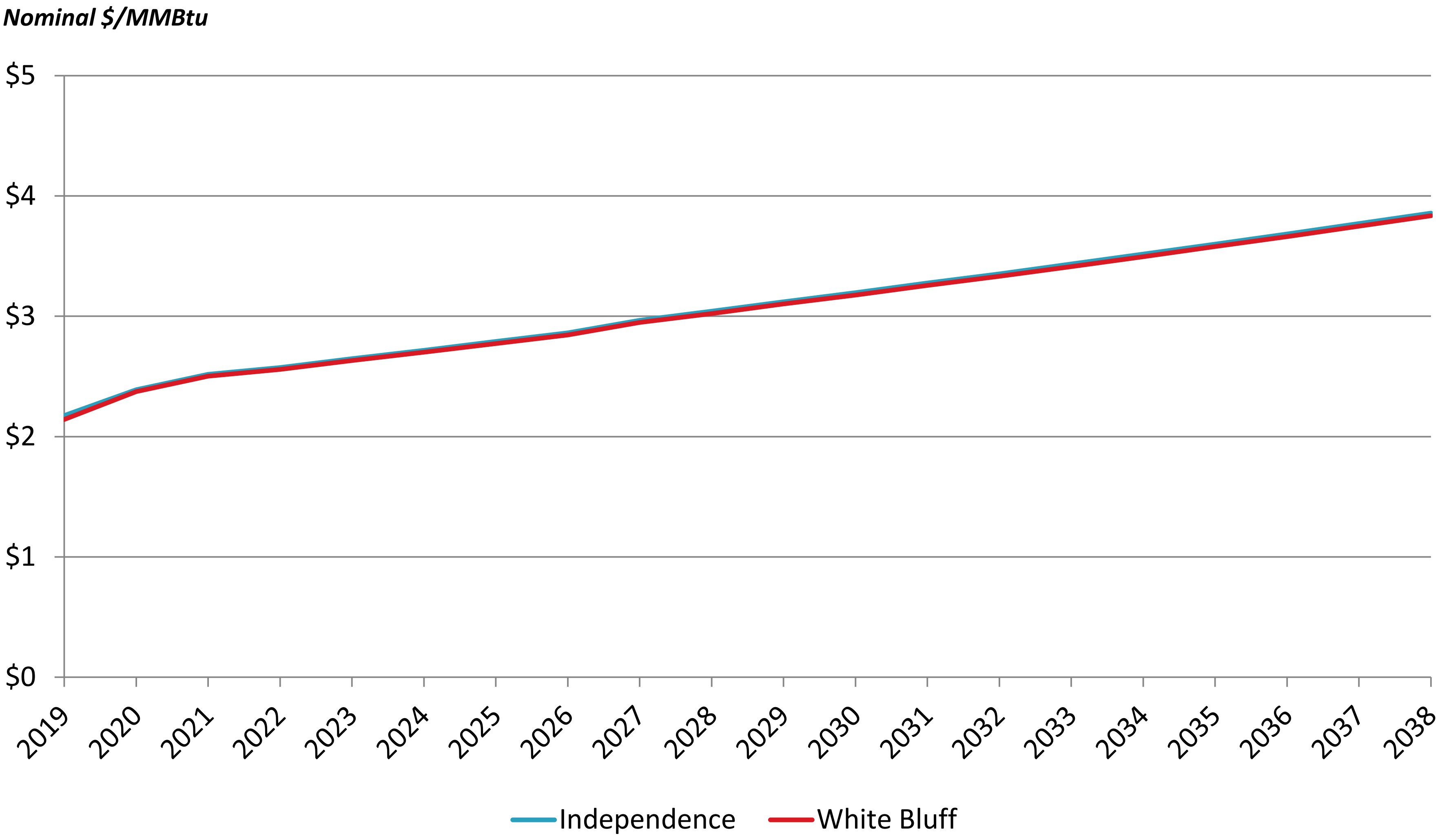
*Updated to Business Plan 19 Inputs since Technical Meeting #1

Gas Price Forecast

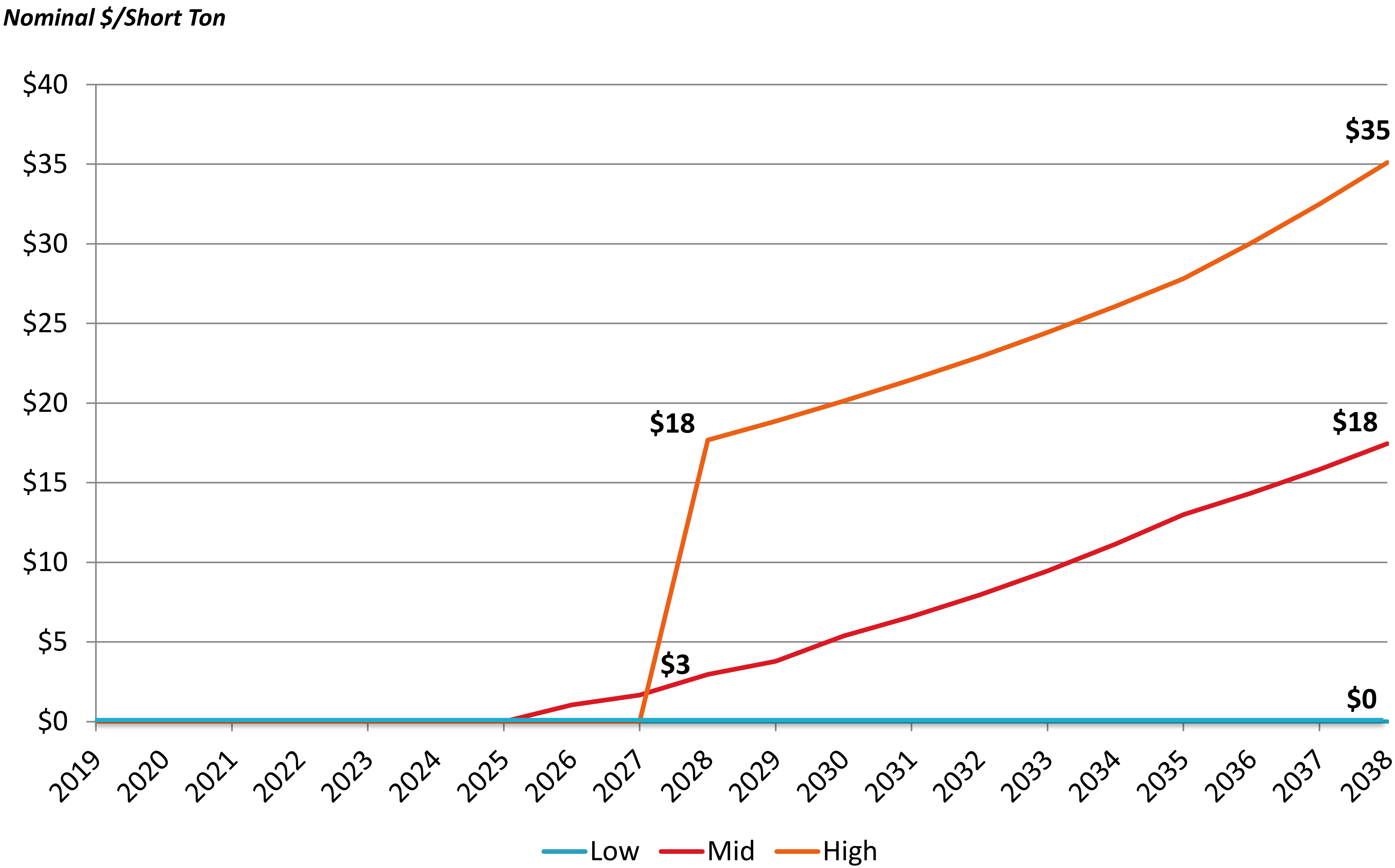


Case	2019	2026	2031	2038
Low	$2.52	$2.86	$3.32	$3.83
Medium	$2.79	$4.15	$5.09	$6.41
High	$3.09	$5.64	$6.89	$8.80

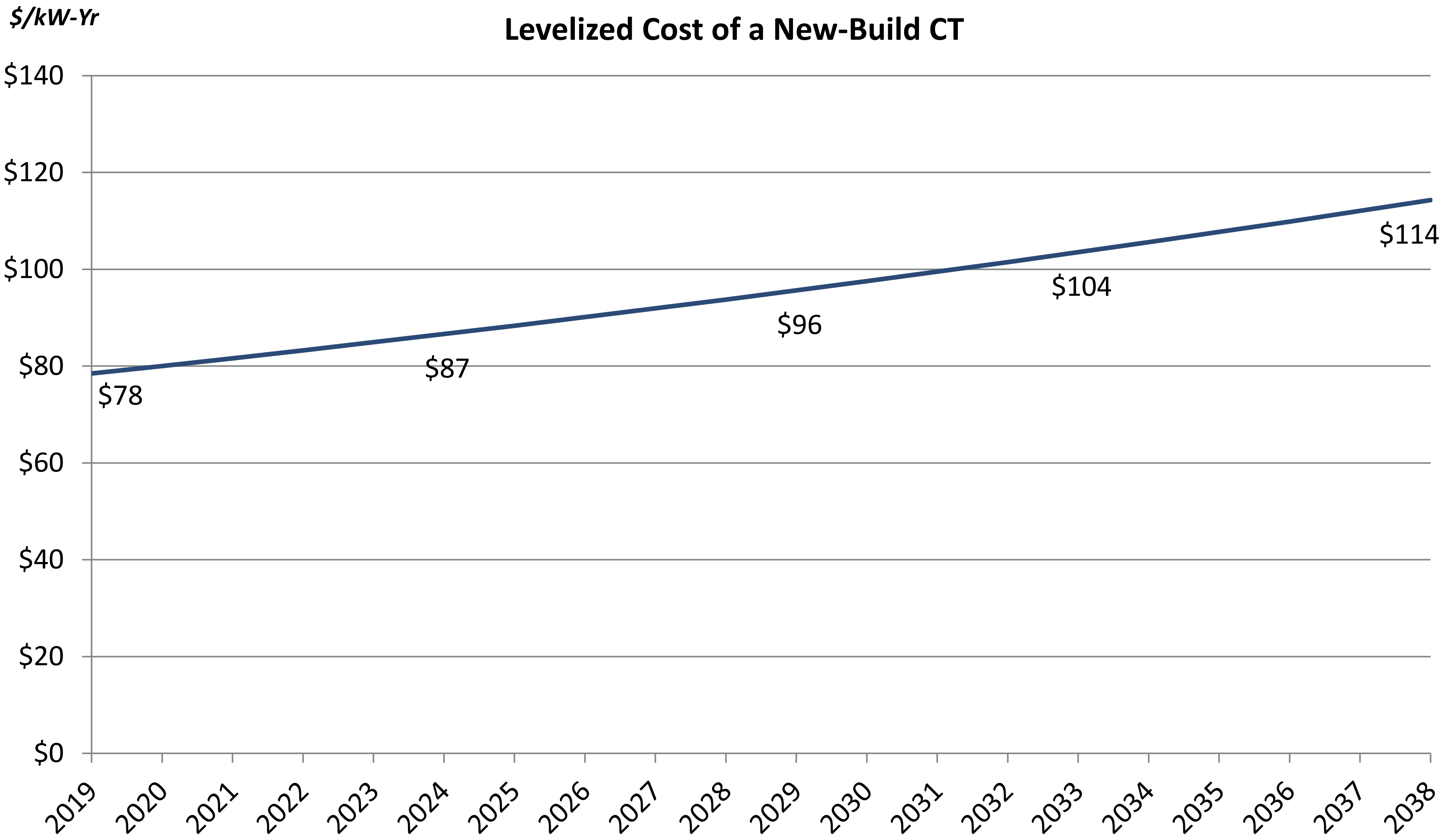
Coal Price Forecast



CO_2 Price Forecast

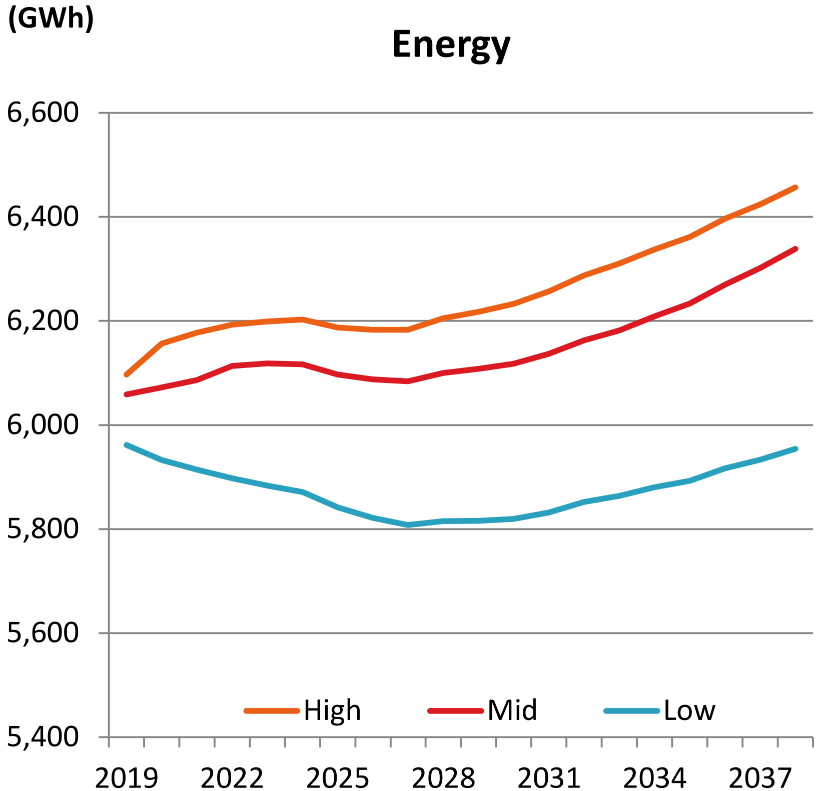


Capacity Value Forecast

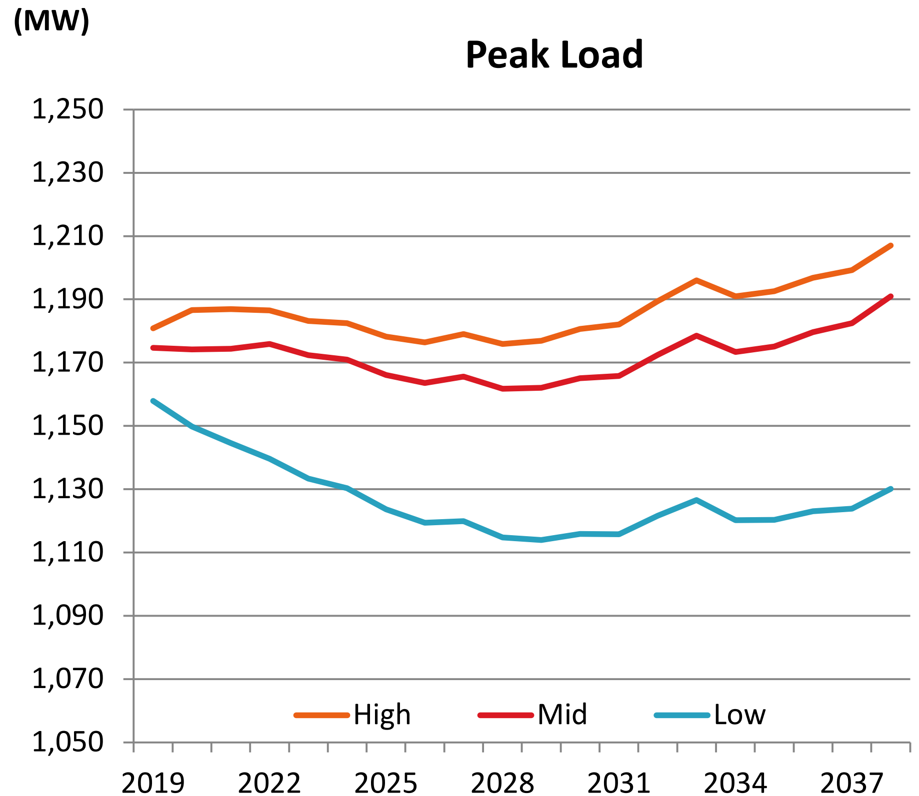


Peak Load & Energy Forecast

3 demand forecasts were created for the ENO IRP: a low, medium, and high



10 Year CAGR (%)	2019 – 2028	2029 – 2038
Low	- 0.28%	0.26%
Medium	0.08%	0.41%
High	0.20%	0.42%



Peak Load (MW)	2019	2024	2029	2033	2038
Low	1,158	1,130	1,114	1,127	1,130
Medium	1,175	1,171	1,162	1,179	1,191
High	1,181	1,182	1,177	1,196	1,207

Section 4
Timeline and Next Steps

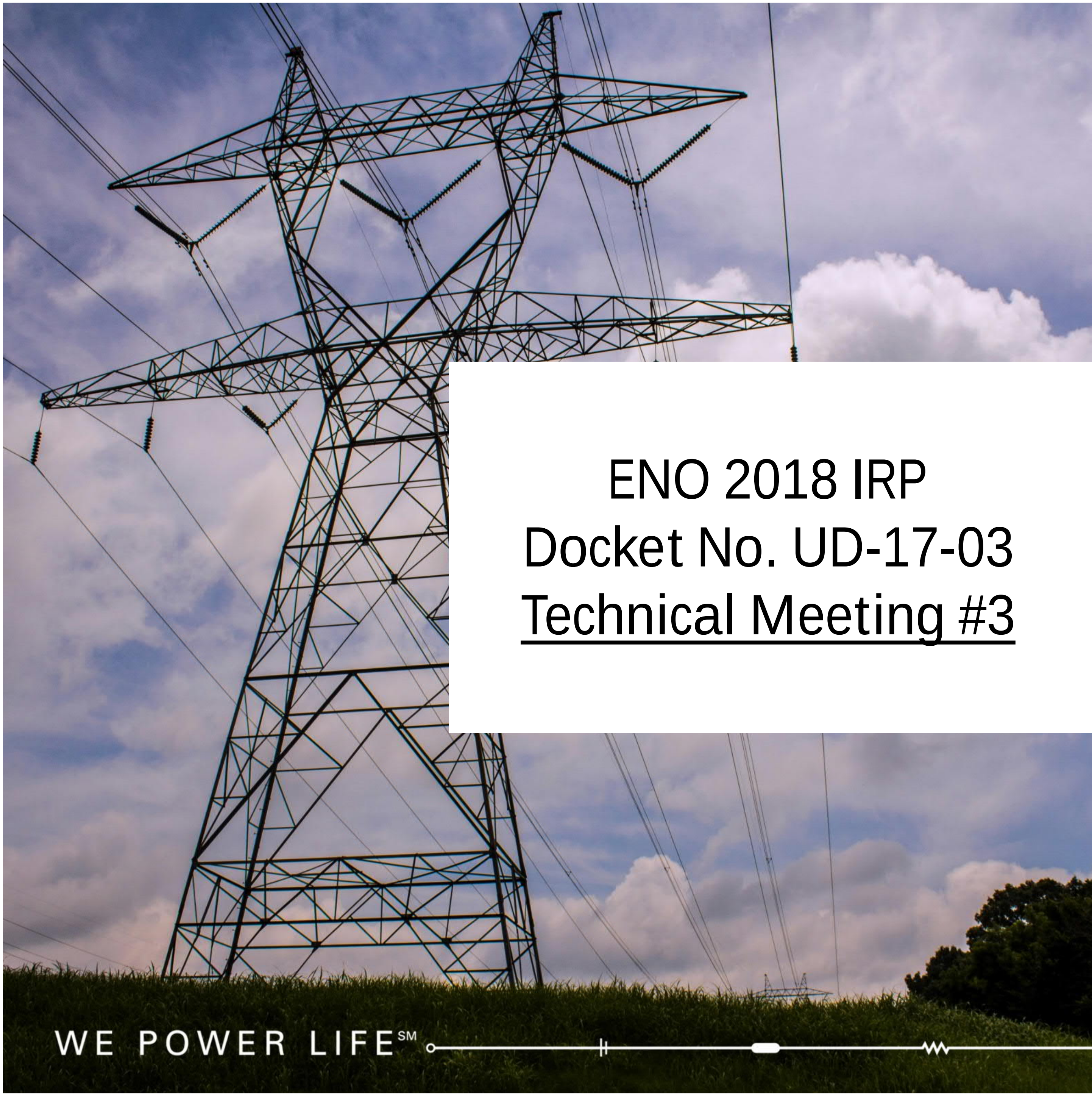
Current Timeline

Description	Target Date	Status
Public Meeting #1- Process Overview	September 2017	✓
Technical Meeting #1 Material Due	January 2018	✓
Technical Meeting #1	January 2018	✓
Technical Meeting #2 Material Due	August 2018	✓
Technical Meeting #2	September 2018	✓
Technical Meeting #3 Material Due	November 2018	-
Technical Meeting #3	November 2018	-
IRP Inputs Finalized	**December 2018**	-
Optimized Portfolio Results Due	**April 2019**	-
Technical Meeting #4 Material Due	April 2019	-
Technical Meeting #4	April 2019	-
File IRP Report	July 2019	-
Public Meeting #2 Material Due	July 2019	-
Public Meeting #2 - Present IRP Results	August 2019	-
Public Meeting #3 Material Due	August 2019	-
Technical Meeting #5 Material Due	August 2019	-
Public Meeting #3 - Public Response	September 2019	-
Technical Meeting #5	September 2019	-
Intervenors and Advisors Questions & Comments Due	September 2019	-
ENO Response to Questions and Comments Due	October 2019	-
Advisors File Report	December 2019	-

Appendix

Technical Meeting Purpose

Technical Meeting	Purpose
Technical Meeting 1 (January 22nd)	The purpose of this meeting will be to discuss Planning Scenarios and Strategies. ENO should be prepared to present its Reference (and two alternative) Planning Scenarios, the Least Cost Planning Strategy, and the Utility's proposed Reference Planning Strategy.
Technical Meeting 2 (September 14th)	The purpose of this meeting is to either confirm the consensus Scenario and Strategy or to confirm that ENO is prepared to include the Stakeholder Scenario and Strategy pursuant to the discussions of Technical Meeting 1.
Technical Meeting 3 (November 19th – November 30th)	Purpose is to finalize the Planning Scenarios and Strategies by all parties and lock down of all IRP inputs. The results of the DSM Potential Studies will be provided in the input format required for modeling in the IRP. This meeting will also contain the initial discussion of scorecard metrics.
Technical Meeting 4 (April 22nd – May 3rd)	The purpose of this meeting is to review the Optimized Resource Portfolios, finalize the Scorecard Metrics, and conduct an initial discussion regarding Energy Smart Program budgets and savings goals. For this meeting, ENO should prepare initial proposed Energy Smart Program budgets, and savings goals for discussion.
Technical Meeting 5 (August 28th – September 11th)	The purpose of this meeting is to discuss Energy Smart implementation for Program Years 10-12.



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ENO 2018 IRP
Docket No. UD-17-03
Technical Meeting #3

November 28, 2018

Goals and Agenda of Technical Meeting #3

Goals

- As described in the Initiating Resolution (R-17-430), the main purpose of this meeting is for ENO, the Advisors, and Intervenors to finalize the Planning Scenarios and Strategies, lock down all of the IRP inputs, provide the results of the DSM Potential Studies, and engage in an initial discussion regarding scorecard metrics.

Agenda

1. Planning Scenarios and Strategies—Discussion and Decision
2. Navigant DSM Potential Study Results—Presentation by Navigant
3. Scorecard Metrics—Initial Discussion

Technical Meeting #2—Follow Ups

- DSM Input Files
  - HSPM workpapers and supporting files for Navigant Study
    - ENO provided to Advisors and Intervenors on 10/1/18
  - Requirements for Aurora input files necessary to model Optimal study results in IRP
    - Call to discuss w/ENO, Advisors, and Optimal on 10/18/18
  - DSM Program Input files from Optimal
    - Provided by Optimal on 11/13/18
- Proposed Planning Scenarios
  - Information on DER assumptions in ENO load forecasts
    - ENO provided on 10/17/18
  - Intervenors to develop proposed Scenario #4
    - Consensus Stakeholder Scenario provided by AAE on 11/13/18
- Proposed Planning Strategies
  - Intervenors to develop proposed Strategy #4
    - Notes on strategy ideas provided by AAE on 11/13/18

Section 1
Planning Scenarios and Strategies

Proposed Planning Scenarios – Assumptions

	Scenario 1 (Moderate Change)	Scenario 2 (Customer Driven)	Scenario 3 (Policy Driven)	Scenario 4 (Stakeholder)
Peak Load & Energy Growth	Medium	Low	High	Low
Natural Gas Prices	Medium	Low	High	High
Market Coal & Legacy Gas Deactivations	60 years	55 years	50 years	50 years
Magnitude of Coal & Legacy Gas Deactivations[1]	17% by 2028 57% by 2038	31% by 2028 73% by 2038	46% by 2028 76% by 2038	46% by 2028 76% by 2038
MISO Market Additions Renewables / Gas Mix	34% / 66%	25% / 75%	50% / 50%[2]	50%/50%[2]
CO_2 Price Forecast	Medium	Low	High	High (start 2022)

1. "Magnitude of Coal & Legacy Gas Deactivation" driven by "Market Coal and Legacy Gas deactivation" assumptions (e.g. 55 Years; 31%/73%) for BP19
2. Includes storage to support market LMPs

ENO Proposed Planning Strategies--Assumptions

	Strategy 1[1]	Strategy 2[2]	Strategy 3[3]
Objective	Least Cost Planning	0.2/2% DSM Goal	Renewables, Storage & DSM Alternatives
Capacity Portfolio Criteria and Constraints	Meet 12% Long-term Planning Reserve Margin (PRM) target using least-cost resource portfolio	Include a portfolio of DSM programs that meet the Council's stated 2% goal	Meet peak load need + 12% PRM target using DSM, solar, and battery resources
Description	Assess demand- and supply-side alternatives to meet projected capacity needs with a focus on total relevant supply costs	Assess portfolio of DSM programs that meet Council's stated 0.2/2% goal along with consideration of additional supply-side alternatives	Assess demand- and supply-side alternatives to meet projected capacity needs with a focus on adding solar and batteries
DSM Input Case	Navigant Base	Navigant 2%	To be discussed

1 Least Cost Strategy – required by IRP Rules Sec. 7(D)1
2 Policy Goal Strategy – required by IRP Rules Sec. 7(D)3
3 Proposed Consensus/Reference Strategy – required by IRP Rules Sec. 7(D)2

Intervenor Planning Strategy Notes (11/13/18)

	Council DSM Strategy	Strategies for Consideration	
Portfolio Criteria & Constraints	Optimal DSM Program	Renewables Replacement (ENO Scenario 3)	Distributed/ Resilience Scenario 4 (Stakeholder)
Description	Stakeholders believe ENO must run Optimal plan similar to ENO's proposed "Strategy 2" to get clear picture of the impact of Optimal's program on its own.	Over course of time horizon, all deactivated ENO fossil assets are replaced with renewable energy resources and Demand Side Management.	Priority on significant resources distributed in Orleans Parish, including microgrids/smart grid technology. Intended to build a resilient distribution level system that also provides every day reliable energy services to residents /businesses. Customer sited/owned resources are a priority. This strategy acknowledges and attempts to capture ENO's "smart cities" and grid modernization upgrades described in Council Dockets UD-18-01 and UD-18-07
DSM input	Optimal Program level DSM	Optimal Program level DSM	Optimal Program Level DSM + higher DR (per AEMA letter)

Intervenors did not find firm consensus, on a "stakeholder strategy" considering a lack of clarity on ENO's strategy inputs, including DSM input. Many Intervenors are interested in the strategies above, but are unsure how the priorities are developed as inputs for Aurora modeling.

Section 2
DSM Potential Study Results
(Separate Deck for Navigant Presentation)

Section 3

Scorecard Metrics

(Separate Excel File with Draft Scorecard Format)

Section 4
Timeline and Next Steps

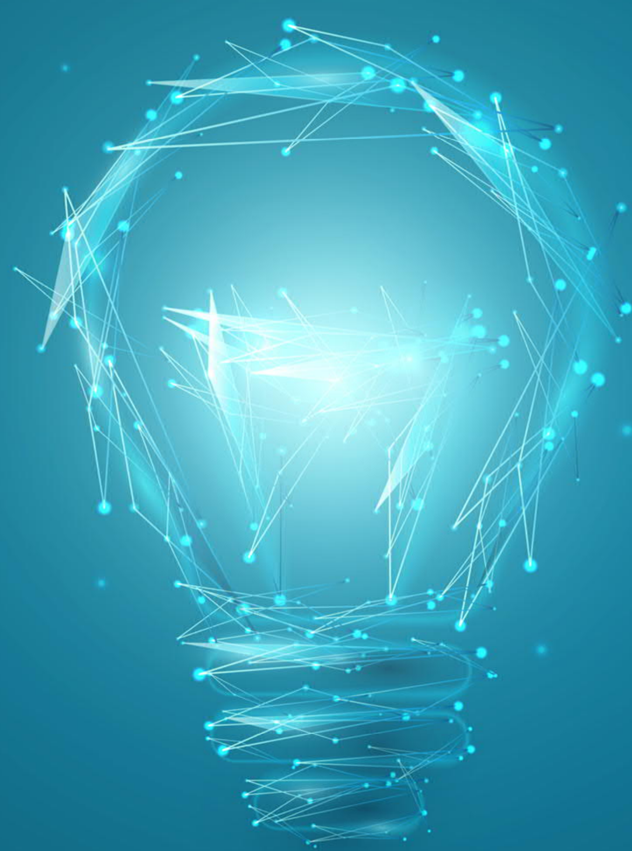
Current Timeline

Description	Target Date	Status
Public Meeting #1- Process Overview	September 2017	✓
Technical Meeting #1 Material Due	January 2018	✓
Technical Meeting #1	January 2018	✓
Technical Meeting #2 Material Due	August 2018	✓
Technical Meeting #2	September 14, 2018	✓
Technical Meeting #3 Material Due	November 14, 2018	✓
Technical Meeting #3	November 28, 2018	✓
IRP Inputs Finalized	December 7, 2018	-
Optimized Portfolio Results Due	April 8, 2019	-
Technical Meeting #4 Material Due	April 2019	-
Technical Meeting #4	April 2019	-
File IRP Report	July 2019	-
Public Meeting #2 Material Due	July 2019	-
Public Meeting #2 - Present IRP Results	August 2019	-
Public Meeting #3 Material Due	August 2019	-
Technical Meeting #5 Material Due	August 2019	-
Public Meeting #3 - Public Response	September 2019	-
Technical Meeting #5	September 2019	-
Intervenors and Advisors Questions & Comments Due	September 2019	-
ENO Response to Questions and Comments Due	October 2019	-
Advisors File Report	December 2019	-

Utility Reimagined

ENOL 2018 IRP Technical Meeting #4
Docket No. UD-17-03
May 1, 2019

Entergy New Orleans, LLC



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Goals and Agenda of Technical Meeting #4

Goals

- The Initiating Resolution (R-17-430) contemplates several goals for this Technical Meeting:
  - First, the parties need to review and discuss the Optimized Resource Portfolios selected through the Aurora capacity expansion modeling, then reach consensus on the subset of portfolios to be carried through the total supply cost analysis and cross testing;
  - Next, the parties need to finalize the Scorecard Metrics initially presented at Technical Meeting #3;
  - Finally, there will be an initial discussion regarding Energy Smart Program budgets and savings goals for Program Years 10-12.

Agenda

1. Optimized Resource Portfolio Discussion
2. Scorecard Metrics Discussion
3. Risk Assessment Discussion
4. Energy Smart Program Discussion
5. Next Steps and Timeline

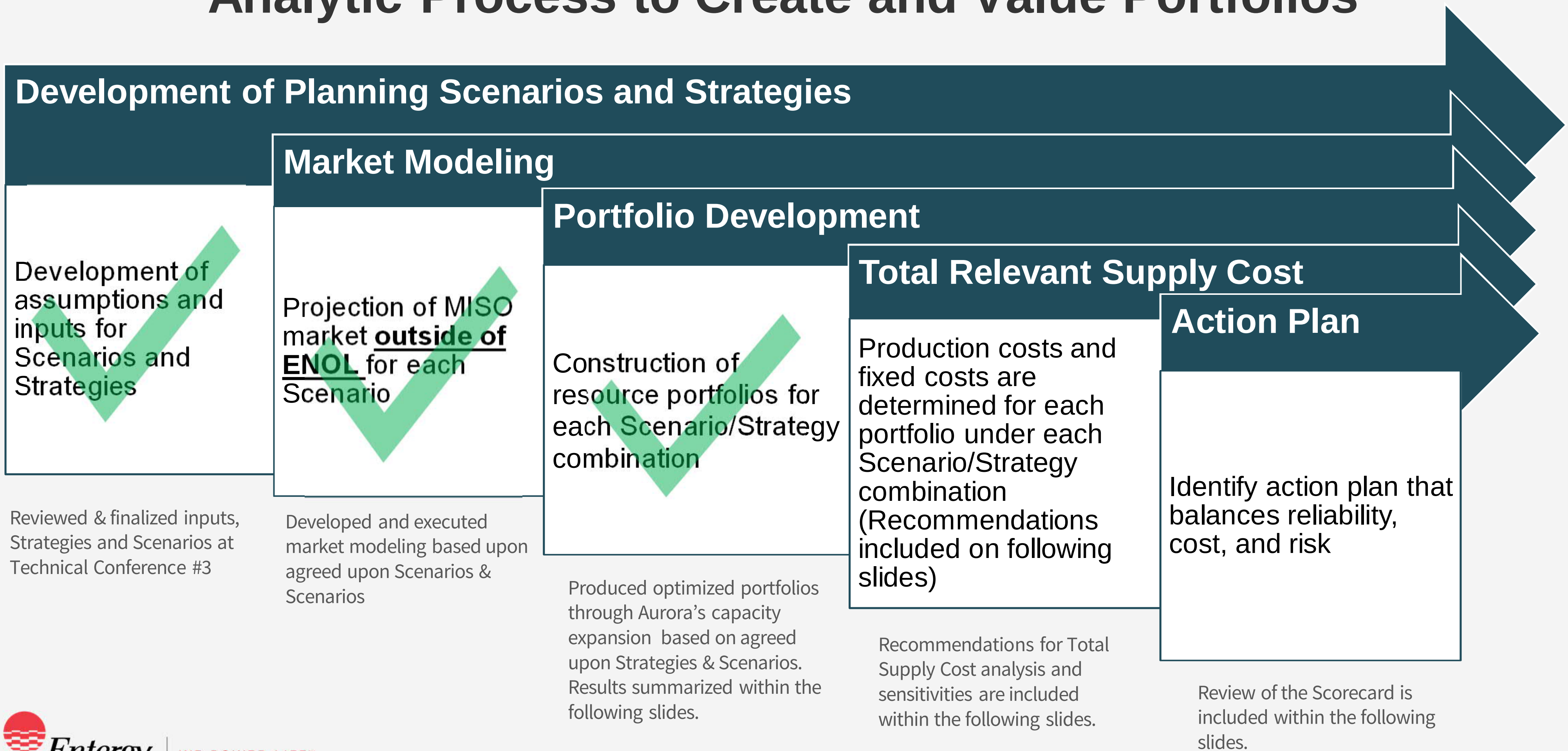
Technical Meeting #3- Follow Ups

- Technical Meeting #3 occurred on November 28, 2018.
- **Strategies and Scenarios**
- The Parties discussed Planning Scenarios and Strategies and reached consensus on 3 Scenarios and 5 Strategies.
- On December 4, 2018, the Council's Advisors circulated slides summarizing the consensus achieved on the Planning Scenarios and Strategies and requested that the Parties disclose any desired modifications, or objections, to the Strategies and Scenarios on or before December 6, 2018. When none were submitted, the Scenarios and Strategies became final for use in modeling.
- **DSM Inputs**
- To enable Aurora to optimize selection of programs from the DSM cases used in Strategies 1 and 5, SPO required additional data files beyond those originally provided. Navigant provided these for Strategy 1 in late January and Optimal provided these for Strategy 5 in mid-February.
- **Score Card Draft Template**
- At Technical Meeting #3, ENO presented a draft Score Card for initial review and comment. As of the date these materials were submitted (April 17, 2019), no written comments or feedback have been received.

Section 1

Optimized Resource Portfolios

Analytic Process to Create and Value Portfolios



IRP Planning Scenarios

Scenarios finalized at ENOL IRP Technical Meeting #3

	Scenario 1 (Moderate Change)	Scenario 2 (Customer Driven)	Scenario 3 (Stakeholder)
Peak Load & Energy Growth	Medium	High	Low
Natural Gas Prices	Medium	Low	High
Market Coal & Legacy Gas Deactivations	60 years	55 years	50 years
Magnitude of Coal & Legacy Gas Deactivations[1]	17% by 2028 57% by 2038	31% by 2028 73% by 2038	46% by 2028 76% by 2038
MISO Market Additions Renewables / Gas Mix	34% / 66%	25% / 75%	50% / 50%[2]
CO_2 Price Forecast	Medium	Low	High (Start 2022)

1. "Magnitude of Coal & Legacy Gas Deactivation" driven by "Market Coal and Legacy Gas deactivation" assumptions (e.g. 55 Years; 31%/73%)
2. Included storage to support market LMPs

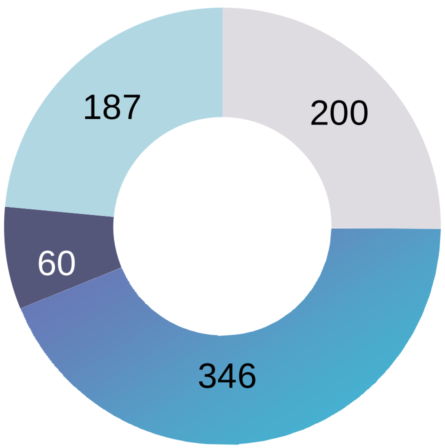
IRP Planning Strategies

Strategies finalized at ENOL IRP Technical Meeting #3

	Strategy 1	Strategy 2	Strategy 3	Strategy 4	Strategy 5
Objective	Least Cost Planning	0.2/2% DSM Goal	Optimal Program Achievable DSM	Navigant High DSM	Stakeholder Strategy
Capacity Portfolio Criteria and Constraints	Meet 12% Long-term Planning Reserve Margin (PRM) target using least-cost resource portfolio	Include a portfolio of DSM programs that meet the Council's stated 2% goal	Meet peak load need + 12% PRM target using Optimal Program Level DSM and resources selected by model	Meet peak load need + 12% PRM target using Navigant High Case DSM and resources selected by model	Meet peak load need + 12% PRM target using Optimal Program Level DSM, renewables, and energy storage
Description	Assess demand- and supply-side alternatives to meet projected capacity needs with a focus on total relevant supply costs	Assess portfolio of DSM programs that meet Council's stated 0.2/2% goal along with consideration of additional supply-side alternatives	Assess portfolio of DSM from Optimal Program Achievable case along with consideration of additional supply side alternatives	Assess portfolio of DSM from Navigant High case along with consideration of additional supply side alternatives	Assess demand and Supply-side alternatives to meet projected capacity need with a focus on adding renewables and storage
DSM Input Case	Navigant Base (Optimized)	Navigant 2%	Optimal Program Achievable	Navigant High	Optimal Program Achievable (Optimized)

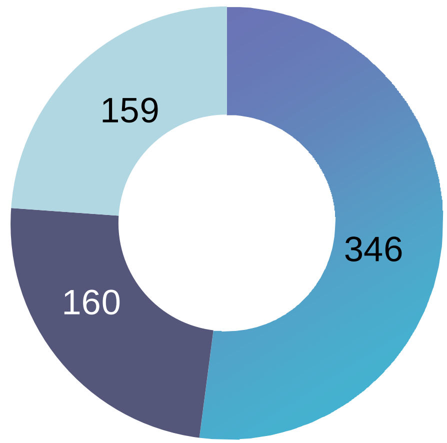
Strategy 1 - Capacity Expansion Portfolios

SCENARIO 1★



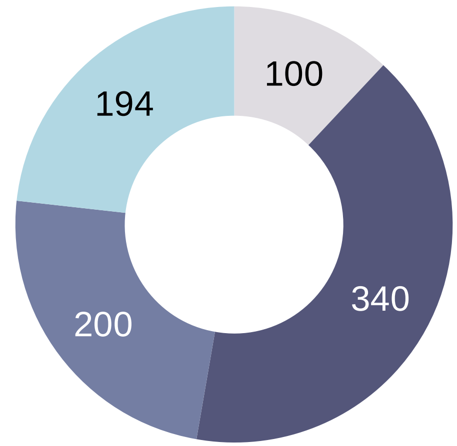
Resource	Year	Installed Cap (MW)
M 501 J CT	2033	346
Solar	2033	200
Battery	2033	20
Battery	2034	20
Battery	2035	20

SCENARIO 2



Resource	Year	Installed Cap (MW)
M 501 J CT	2033	346
Battery	2033	120
Battery	2034	20
Battery	2038	20

SCENARIO 3



Resource	Year	Installed Cap (MW)
Solar	2033	100
Battery	2033	320
Wind	2034	200
Battery	2038	20

Solar M501 CT Battery Wind DSM*

**DSM value represents last year's (2038) peak reduction throughout study period, inclusive of EE and DR contribution*

Resource MW capacity amounts represent installed capacity

★ Indicates initial recommendation for further Total Supply Cost evaluations

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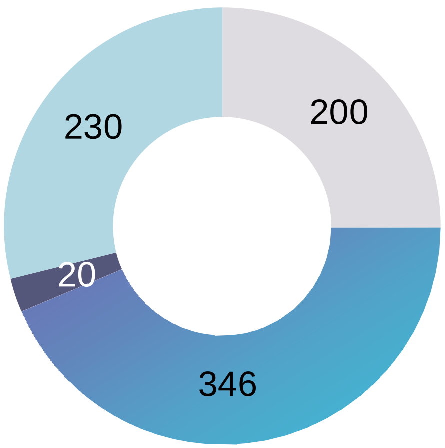
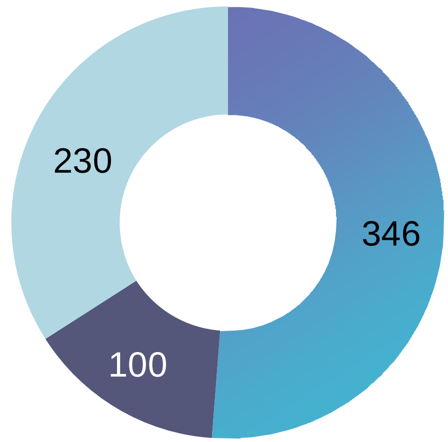
Strategy 2 - Capacity Expansion Portfolios

SCENARIO 1★



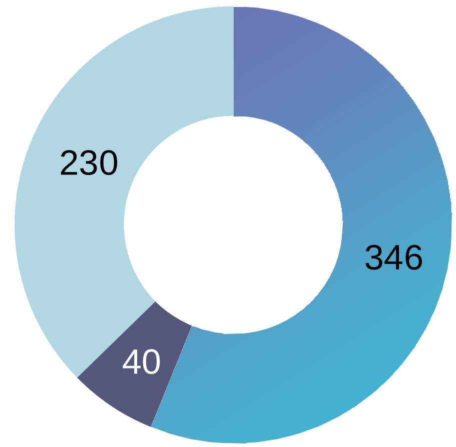
Resource	Year	Installed Cap (MW)
M 501 J CT	2033	346
Solar	2033	200
Battery	2038	20

SCENARIO 2



Resource	Year	Installed Cap (MW)
M 501 J CT	2033	346
Battery	2033	60
Battery	2035	20
Battery	2038	20

SCENARIO 3



Resource	Year	Installed Cap (MW)
M 501 J CT	2033	346
Battery	2038	40

Solar M501 CT Battery Wind DSM*

**DSM value represents last year's (2038) peak reduction throughout study period, inclusive of EE and DR contribution*

Resource MW capacity amounts represent installed capacity

★ Indicates initial recommendation for further Total Supply Cost evaluations

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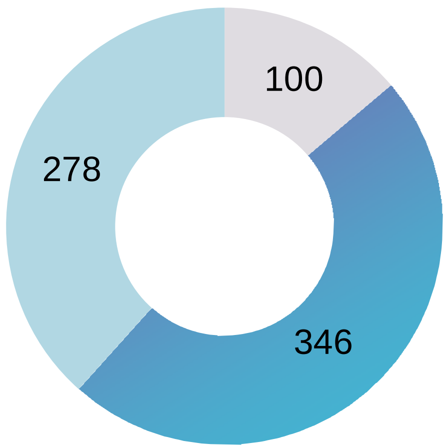
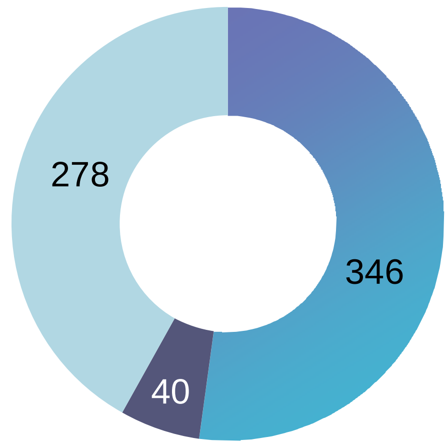
Strategy 3 - Capacity Expansion Portfolios

SCENARIO 1



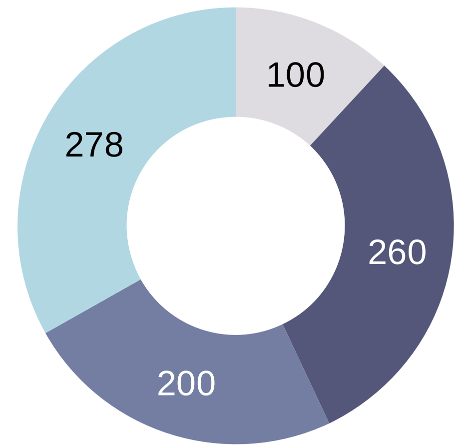
Resource	Year	Installed Cap (MW)
M 501 J CT	2033	346
Solar	2034	100

SCENARIO 2



Resource	Year	Installed Cap (MW)
M 501 J CT	2033	346
Battery	2034	40

SCENARIO 3 ★



Resource	Year	Installed Cap (MW)
Solar	2033	100
Battery	2033	240
Battery	2034	20
Wind	2038	200

Solar M501 CT Battery Wind DSM*

**DSM value represents last year's (2038) peak reduction throughout study period, inclusive of EE and DR contribution*

Resource MW capacity amounts represent installed capacity

★ Indicates initial recommendation for further Total Supply Cost evaluations

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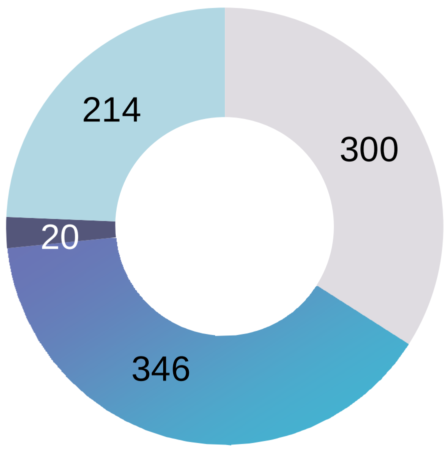
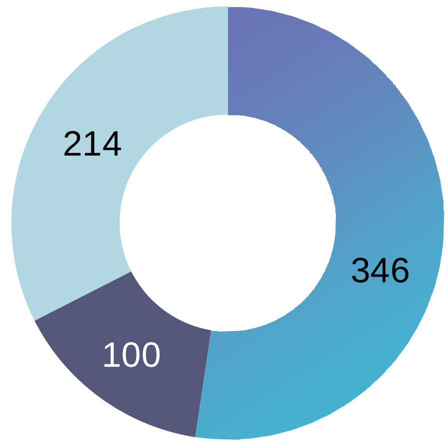
Strategy 4 - Capacity Expansion Portfolios

SCENARIO 1



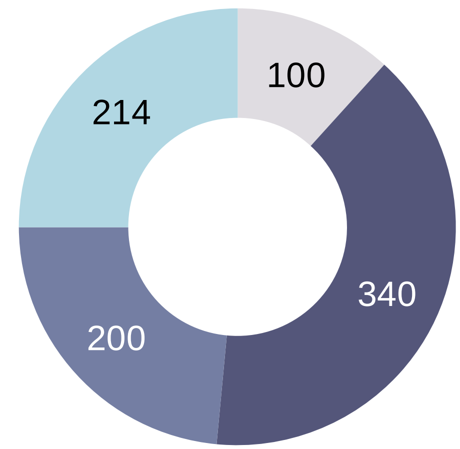
Resource	Year	Installed Cap (MW)
M 501 J CT	2033	346
Solar	2033	100
Battery	2033	20
Solar	2034	100
Solar	2038	100

SCENARIO 2 ★



Resource	Year	Installed Cap (MW)
M 501 J CT	2033	346
Battery	2033	60
Battery	2034	20
Battery	2035	20

SCENARIO 3



Resource	Year	Installed Cap (MW)
Solar	2033	100
Battery	2033	300
Battery	2034	20
Battery	2035	20
Wind	2037	200

Solar M501 CT Battery Wind DSM*

**DSM value represents last year's (2038) peak reduction throughout study period, inclusive of EE and DR contribution*

Resource MW capacity amounts represent installed capacity

★ Indicates initial recommendation for further Total Supply Cost evaluations

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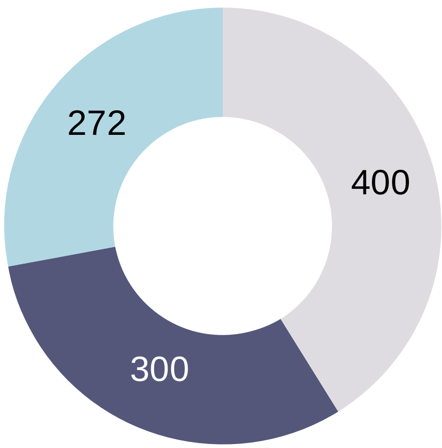
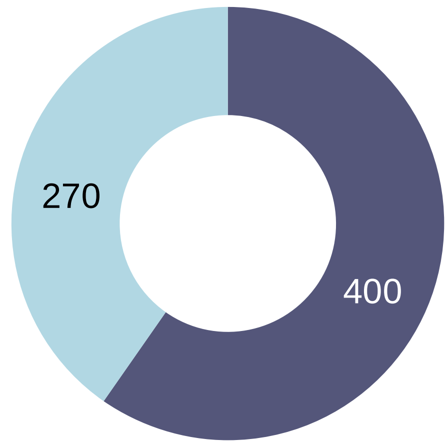
Strategy 5 - Capacity Expansion Portfolios

SCENARIO 1★



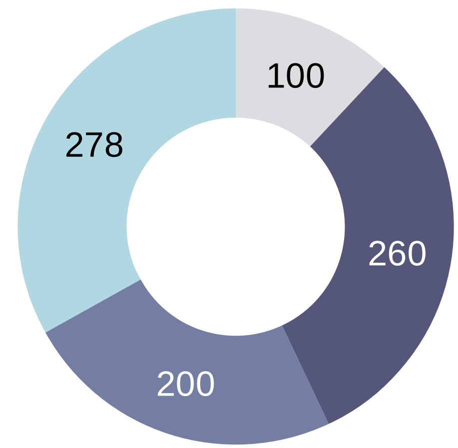
Resource	Year	Installed Cap (MW)
Battery	2033	240
Solar	2033	400
Battery	2034	40
Battery	2038	20

SCENARIO 2



Resource	Year	Installed Cap (MW)
Battery	2033	360
Battery	2034	40

SCENARIO 3



Resource	Year	Installed Cap (MW)
Solar	2033	100
Battery	2033	240
Battery	2034	20
Wind	2038	200

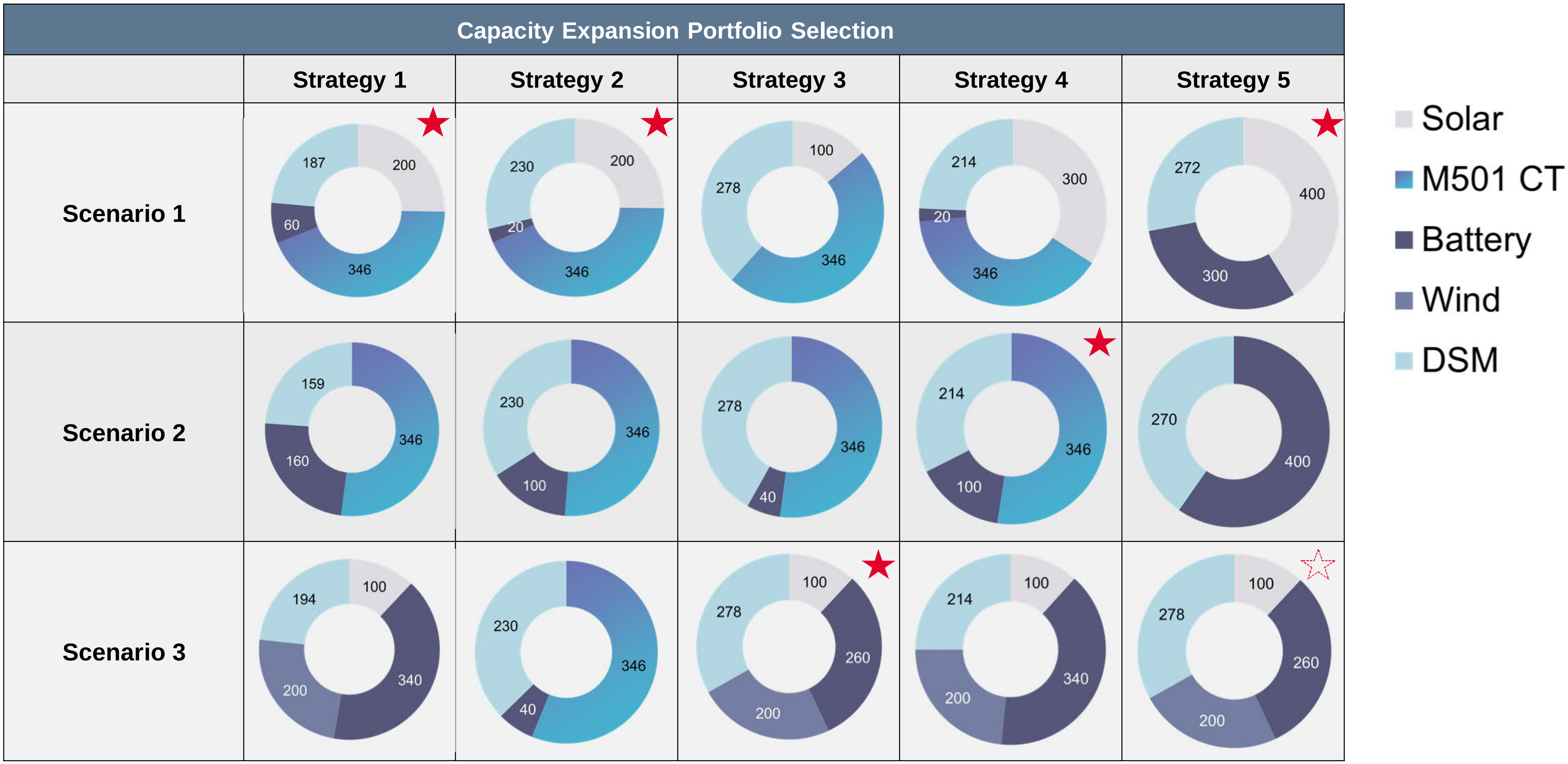
Solar M501 CT Battery Wind DSM*

**DSM value represents last year's (2038) peak reduction throughout study period, inclusive of EE and DR contribution*

Resource MW capacity amounts represent installed capacity

★ Indicates initial recommendation for further Total Supply Cost evaluations

Capacity Expansion Portfolio Selections



★ Indicates initial recommendation for further Total Supply Cost evaluations

☆ Strategy 3, Scenario 3 Portfolio is identical to Strategy 5, Scenario 3 Portfolio

Strategy 1 & 5 Energy Efficiency Selections

Under Strategies 2-4, all DSM programs identified in the selected DSM Input cases contributed towards meeting ENOL's supply needs.

Strategy 1 (Navigant Base DSM)			
Program	**Scenario 1**	**Scenario 2**	**Scenario 3**
Com Behavior	✓	✓	✓
Large C&I	✓	✓	✓
Small C&I	✓	✓	✓
Consumer Products	✓ *2033*	✓ *2033*	✓
HPwES	✓	✓ *2033*	✓
HVAC	✓	✓ *2033*	✓
Low Income and Multi Family	✓	✓ *2033*	✓
Res Behavior	✓	✓	✓
School Kits	✓	✓	✓

Strategy 5 (Optimal Program Achievable DSM)			
Program	**Scenario 1**	**Scenario 2**	**Scenario 3**
Home Energy Services	✓	✓ *2033*	✓
Res HVAC	✓	Not Selected	✓
Res Efficient Products	✓	✓	✓
Res Lighting	Not Selected	Not Selected	✓
Efficient New Homes	Not Selected	Not Selected	✓
Appliance Recycling	✓	✓	✓
CVR- Res	✓	✓	✓
Small Business DI	✓	✓	✓
Commercial Prescriptive	✓	✓	✓
Commercial Custom	✓	✓	✓
Retro commissioning	✓	✓	✓
New Construction	✓	✓	✓
CVR – C&I	✓	✓	✓

Demand Response Programs

Under each Strategy, all Demand Response programs identified through the selected DSM Input case were assumed to be economic and contributed to meeting ENOL's supply needs.

Navigant Demand Response	
Program	**Description**
DLC-thermostat- HVAC	Control of cooling load using a PCT.
Dynamic Pricing w/o Enabling Tech	Voluntary opt-in dynamic pricing offer with enabling technology.
Dynamic Pricing with Enabling Tech	Voluntary opt-in dynamic pricing offer without enabling technology.
DLC-Switch-HVAC	Control of cooling load using a load control switch.
C&I Curtailment-Manual HVAC Control	Firm capacity reduction Commitment. $/kW payment based on contracted capacity plus $/kWh payment based on energy reduction during an event.

Optimal Demand Response	
Program	**Description**
RES DLC/ADR	Reduce residential peak demand during load control events through remotely controlled programs and software.
Res- Pricing- PTR	Pay-for-performance incentive programs that pay participants to reduce energy use during certain hours of selected days when a peak event is called.
Large Cust SOP	The customer is paid to allow the utility to curtail load for a maximum number of times during set periods, usually with 24 hour advance notice.

Section 2

Risk Assessment

Proposed Risk Assessments

Following agreement at Technical Meeting #4 on the subset of 5-6 portfolios to be carried through the total relevant supply cost analysis, selected portfolios will be passed through two rounds of risk analysis to comply with Section 8 of the IRP rules:

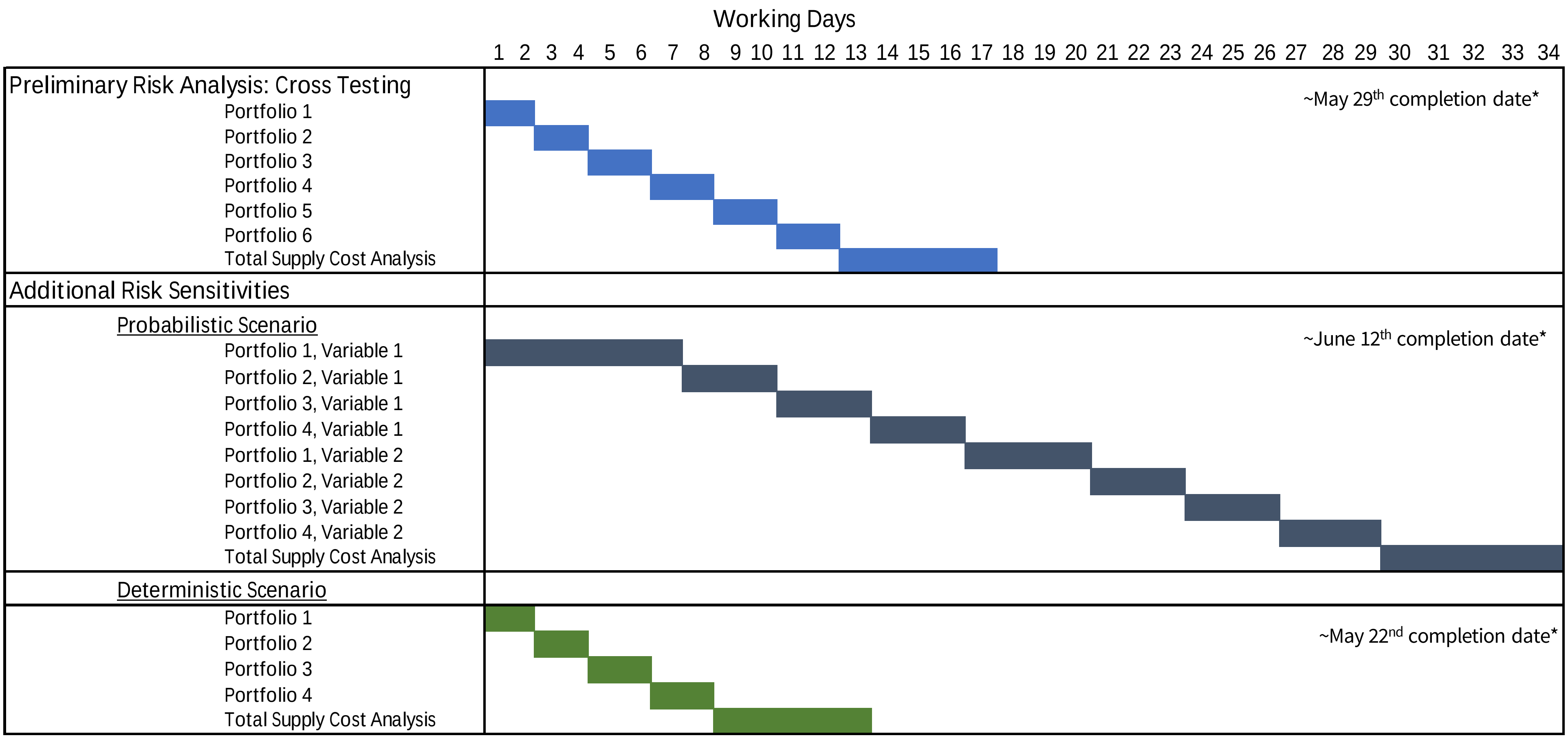
1. Primary Risk Analysis: Cross-Testing
   A. Time Necessary to Complete: 2 days per portfolio
      a) Cross-testing determines how each portfolio's total supply costs change under the assumptions of the 3 Scenarios.
2. Secondary Risk Analysis: Additional Sensitivities on Variable Supply Cost Inputs
   A. ENOL proposes analyzing variations for two key inputs:
      i. Gas Price
      ii. CO_2 Forecast
   B. Next, portfolios would be analyzed using <u>one</u> of two possible Alternative Sensitivity Evaluation methods:
      i. Probabilistic Assessment: variable supply cost simulation based on a distribution of possible outcomes around two individual inputs.
         a) Use a single Scenario (recommend Scenario 1)
         b) 29 days required to complete (assumes four portfolios, which is the limit possible under current timeline)

      <u>OR</u>

      i. Deterministic Assessment: variable supply cost simulations based on a high or low forecast of a single or multiple inputs
         a) 2 days per portfolio per scenario to complete

Proposed Risk Assessments

All estimated dates assume a May 6th start date with no schedule modifications.



Section 3

Scorecard Metrics

Proposed Scorecard

Scoring Criteria	Scoring Weight	Scoring Parameters / Descriptions 1	4	7	10
Cost and Risk	50.0%				
Expected Value (Average Cost Across Futures)	20.0%	≤ 2.50	2.51 - 5.00	5.01 - 7.50	> 7.50
Downside Risk (Maximum Cost - Expected Cost)	15.0%	≤ 2.50	2.51 - 5.00	5.01 - 7.50	> 7.50
Upside Potential (Expected Value - Lowest Cost)	15.0%	≤ 2.50	2.51 - 5.00	5.01 - 7.50	> 7.50
Operational Flexibility	20.0%				
Flexible Resources (MW of Ramp)	6.7%	≤ 2.50	2.51 - 5.00	5.01 - 7.50	> 7.50
Quick-Start Resources (MW of Quick-Start)[1]	6.7%	≤ 2.50	2.51 - 5.00	5.01 - 7.50	> 7.50
UCAP/ICAP Ratio (UCAP/ICAP)	6.7%	≤ 2.50	2.51 - 5.00	5.01 - 7.50	> 7.50
Environmental Impact	20.0%				
CO_2 Intensity (Tons CO_2/GWh)	10.0%	≤ 2.50	2.51 - 5.00	5.01 - 7.50	> 7.50
Groundwater Usage (% of Portfolios with Groundwater Usage)	10.0%	< 33%	> 33%	>66%	= 100%
Policy Goals/Sustainability	5.0%				
100% Low Carbon (% of Carbon Free Energy from New Resource)[2]	1.7%	< 33%	> 33%	>66%	= 100%
255 MW Solar Added (Total Solar MW in Portfolio)	1.7%	< 150 MW	> 200MW	>225 MW	≥ 255 MW
3.3% Annual Energy Savings (CAGR over 20 Years)	1.7%	< 1.0%	> 1.0%	>2.0%	≥ 3.3%
Economic Impact	5.0%				
Macroeconomic Factor (To be developed)	5.0%	≤ 2.50	2.51 - 5.00	5.01 - 7.50	> 7.50

Notes:
1. Quick-Start includes supply and demand side dispatchable
2. Carbon-Free Resources include Energy Efficiency

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Section 4

Energy Smart Program

Energy Smart Implementation Plan Timeline

IRP Technical Meeting #4	May 1, 2019
2018 IRP Report filed	July 19, 2019
IRP Technical Meeting #5	August 28, 2019- September 11, 2019
Intervenor Comments (IRP)	September 16, 2019
Draft of Implementation Plan	Early November 2019
Proposed Technical Conference	November 12, 2019 - November 22, 2019
Advisors' Report	December 2, 2019
Implementation Plan Filing	December 9, 2019

DSM Program Matrix

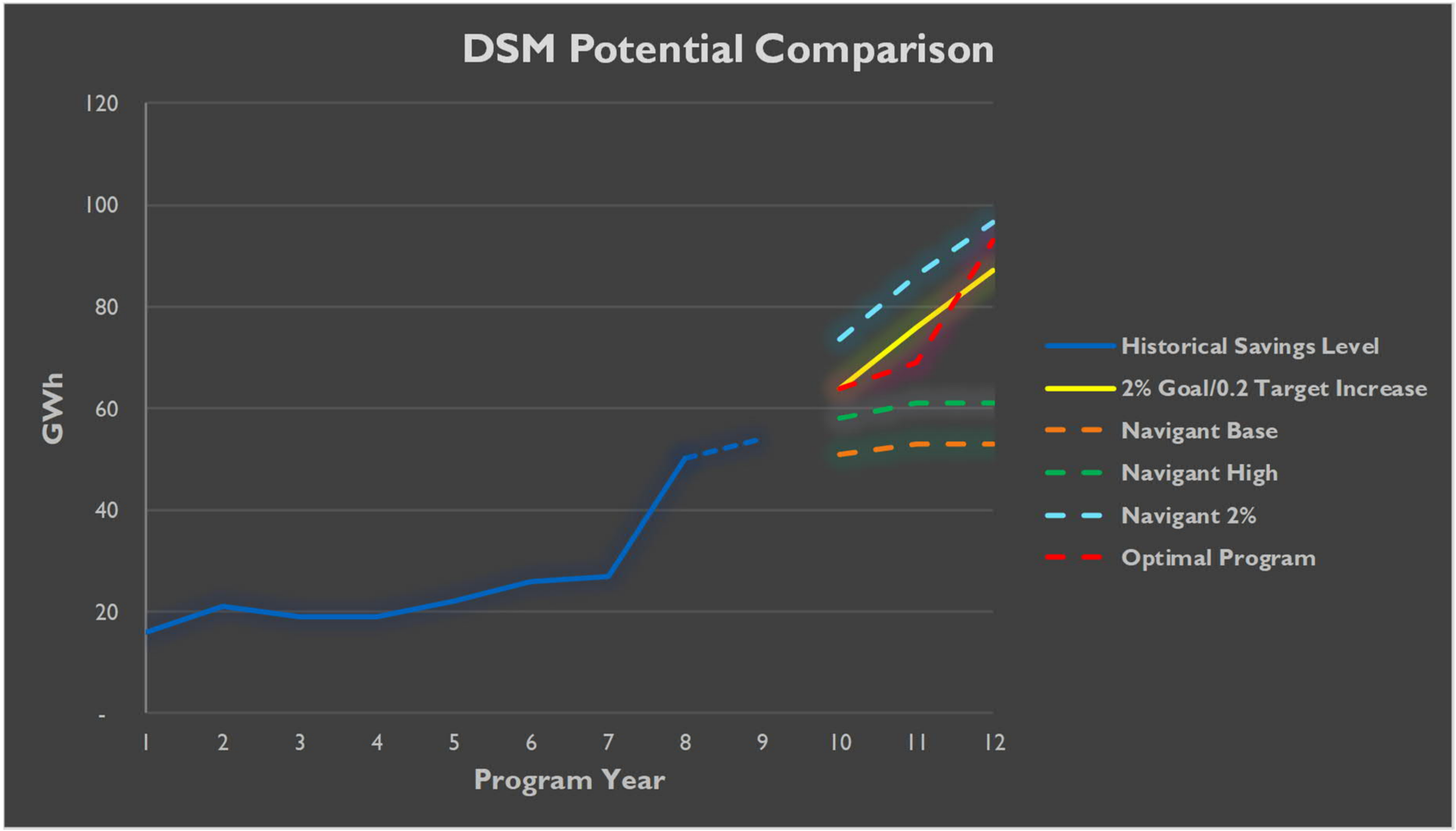
Current Programs	Navigant	Optimal
Home Performance w Energy Star	Home Performance w Energy Star	Home Energy Services
Energy Smart for Multifamily	Low Income & Multifamily	
High Efficiency AC Tune Up	HVAC	Res HVAC
Residential Lighting and Appliances	Consumer Products	Res Lighting & Res Efficient Products
Behavioral	Residential Behavioral	
	Commercial Behavioral	
Low Income	Low Income & Multifamily	
School Kits	School kits	
Small Commercial Solutions	Small C&I	Small Business DI, Commercial Custom, Retrocommissioning and Commercial Prescriptive
Large Commercial Solutions	Large C&I	
Publicly Funded Institutions		
		New Construction
		Appliance Recycling
		Efficient New Homes
		CVR- Res
		CVR - C&I

Program Year 10-12—Potential New Measures

- Residential Measures
  - Heat Pump
  - Refrigerator Recycling and Replacement
  - Conservation Voltage Reduction
  - Ceiling Fans
  - Dehumidifiers
  - ENERGY STAR windows
  - Residential DR – BYOT/DLC

- Commercial Measures
  - Retrocommissioning
  - LED Tube Replacement
  - ENERGY STAR ice makers
  - Cool Roofs
  - C&I DR - Curtailment

Savings Potential Comparison



Section 5

Timeline and Next Steps

Current Timeline

Description	Target Date	Status
Public Meeting #1- Process Overview	September 2017	✓
Technical Meeting #1 Material Due	January 2018	✓
Technical Meeting #1	January 2018	✓
Technical Meeting #2 Material Due	August 2018	✓
Technical Meeting #2	September 14, 2018	✓
Technical Meeting #3 Material Due	November 14, 2018	✓
Technical Meeting #3	November 28, 2018	✓
IRP Inputs Finalized	December 7, 2018	✓
Optimized Portfolio Results Due	April 8, 2019	✓
Technical Meeting #4 Material Due	April 17, 2019	✓
Technical Meeting #4	May 1, 2019	✓
File IRP Report	July 19, 2019	-
Public Meeting #2 Material Due	July 2019	-
Public Meeting #2 - Present IRP Results	August 2019	-
Public Meeting #3 Material Due	August 2019	-
Technical Meeting #5 Material Due	August 2019	-
Public Meeting #3 - Public Response	September 2019	-
Technical Meeting #5	September 2019	-
Intervenors and Advisors Questions & Comments Due	September 2019	-
ENOL Response to Questions and Comments Due	October 2019	-
Advisors File Report	December 2, 2019	-
Energy Smart PY 10-12 Implementation Plan Filed	December 9, 2019	-

Appendix

Renewable Resource Assumptions (Solar PV & Wind)

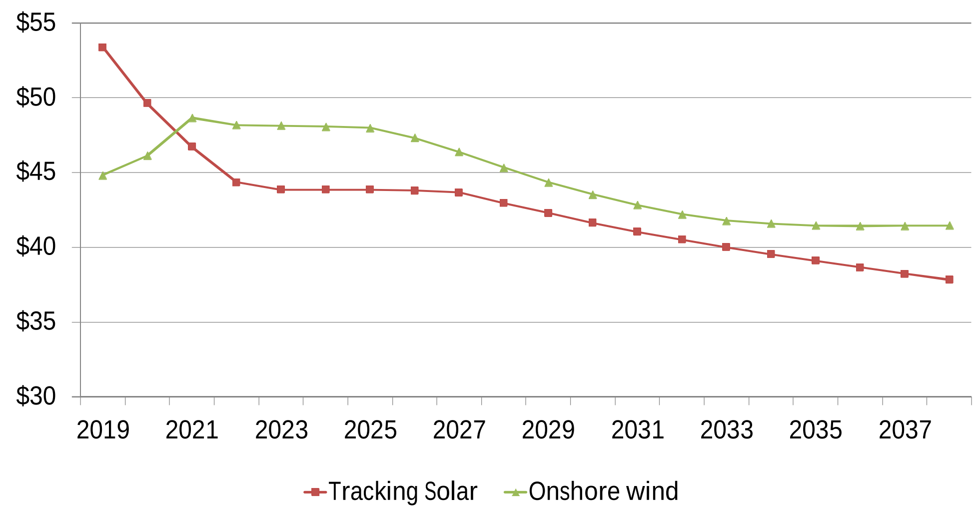
Levelized Real Cost of Electricity (2019$/MWh-AC) [1]

	2019	2020	2021	2022	2023	2026	2029	2032	2035	2038
Solar Tracking [2]	$53.39	$49.64	$46.71	$44.35	$43.86	$43.79	$42.28	$40.51	$39.10	$37.82
Onshore Wind [3]	$44.82	$46.12	$48.65	$48.19	$48.14	$47.32	$44.35	$42.21	$41.47	$41.46

Other Modeling Assumptions

	Solar	Wind
Fixed O&M (2017$/kW-yr-AC)	$16	$36.01
Useful Life (yr)	30	25
MACRS Depreciation (yr)	5	5
Capacity Factor	26%	36%
DC:AC	1.35	N/A
Hourly Profile Modeling Software	PlantPredict	NREL SAM

Levelized Real Cost of Electricity (2019$/MWh) 1



1. Year 1 levelized real cost for a project beginning in the given year
2. ITC normalized over useful life and steps down to 10% by 2023
3. PTC steps down to 40% by 2020 and expires thereafter

Source: The capital cost assumptions for Wind and Solar are based on a confidential IHS Markit forecast.

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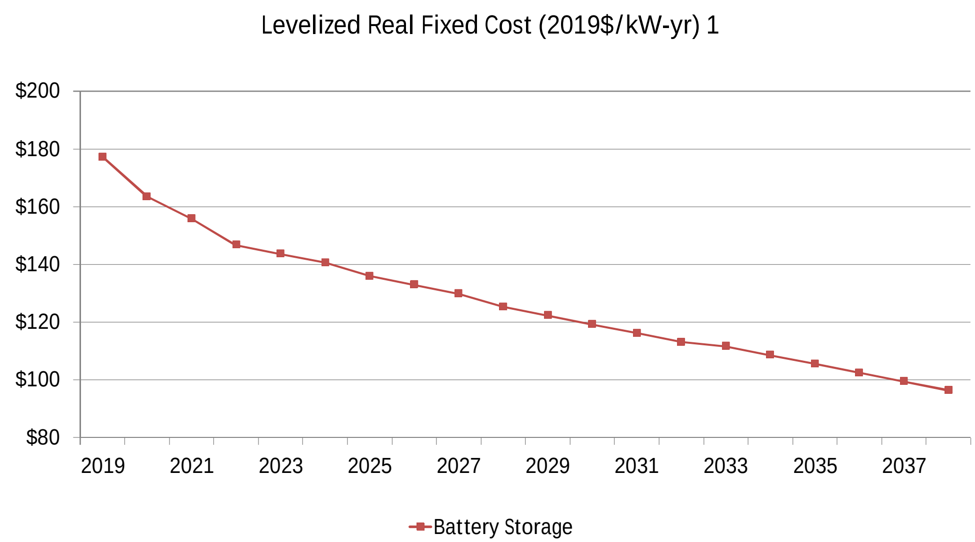
Battery Storage Assumptions

Levelized Real Fixed Cost (2019$/kW-yr) [1]

	2019	2020	2021	2022	2023	2026	2029	2032	2035	2038
Battery Storage	$177	$163	$155	$146	$143	$132	$122	$113	$105	$96

Other Modeling Assumptions

	Battery Storage
Energy Capacity : Power [2]	4:1
Fixed O&M (2017$/kW-yr)	$9.00
Useful Life (yr) [3]	10
MACRS Depreciation (yr)	7
AC-AC efficiency	90%
Hourly Profile Modeling Software	Aurora



1. Year 1 levelized real cost for a project beginning in the given year
2. Current MISO Tariff requirement for capacity credit
3. Assumes daily cycling, no module replacement cost, full depth of discharge

Source: The capital cost assumptions for Battery Storage is based on a confidential IHS Markit forecast.

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Gas Resource Assumptions

Technology		Summer Capacity [MW]	Capital Cost [2017$/kW]	Fixed O&M [2017$/kW-yr]	Variable O&M [2017 $/MWh]	Heat Rate* [Btu/kWh]	Expected Capacity Factor [%]
Combined Cycle Gas Turbine (CCGT)	*1x1 501JAC*	605	$1,244	$16.70	$3.14	6,300	80%
Simple Cycle Combustion Turbine (CT)	*501JAC*	346	$809	$2.37	$13.35	9,400	10%
Aeroderivative Combustion Turbine (Aero CT)	*LMS100PA*	102	$1,543	$5.86	$2.90	9,400	20%
Reciprocating Internal Combustion Engine (RICE)	*7x Wartsila 18V50SG*	128	$1,545	$31.94	$7.30	8,400	30%

*Heat Rate based on full load without duct firing

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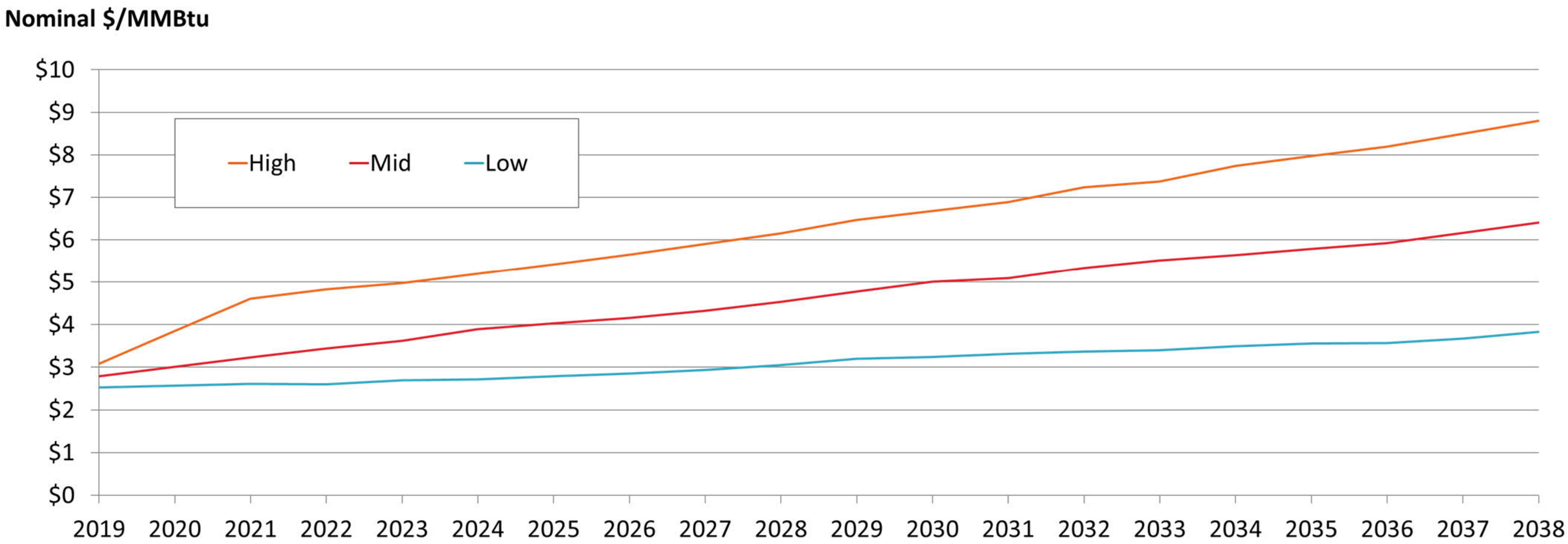
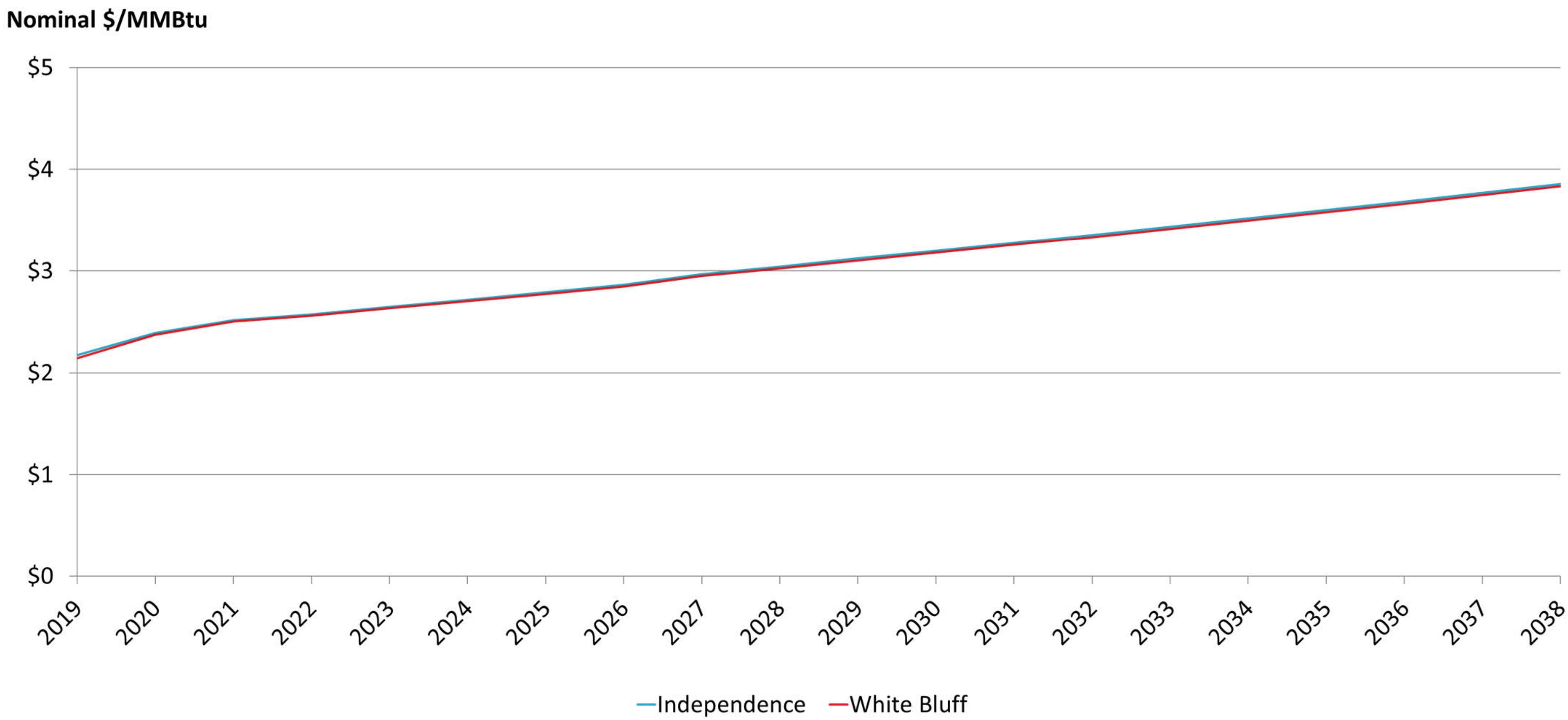
Gas Price Forecast



Case	2019	2026	2031	2038
Low	$2.52	$2.86	$3.32	$3.83
Medium	$2.79	$4.15	$5.09	$6.41
High	$3.09	$5.64	$6.89	$8.80

Coal Price Forecast



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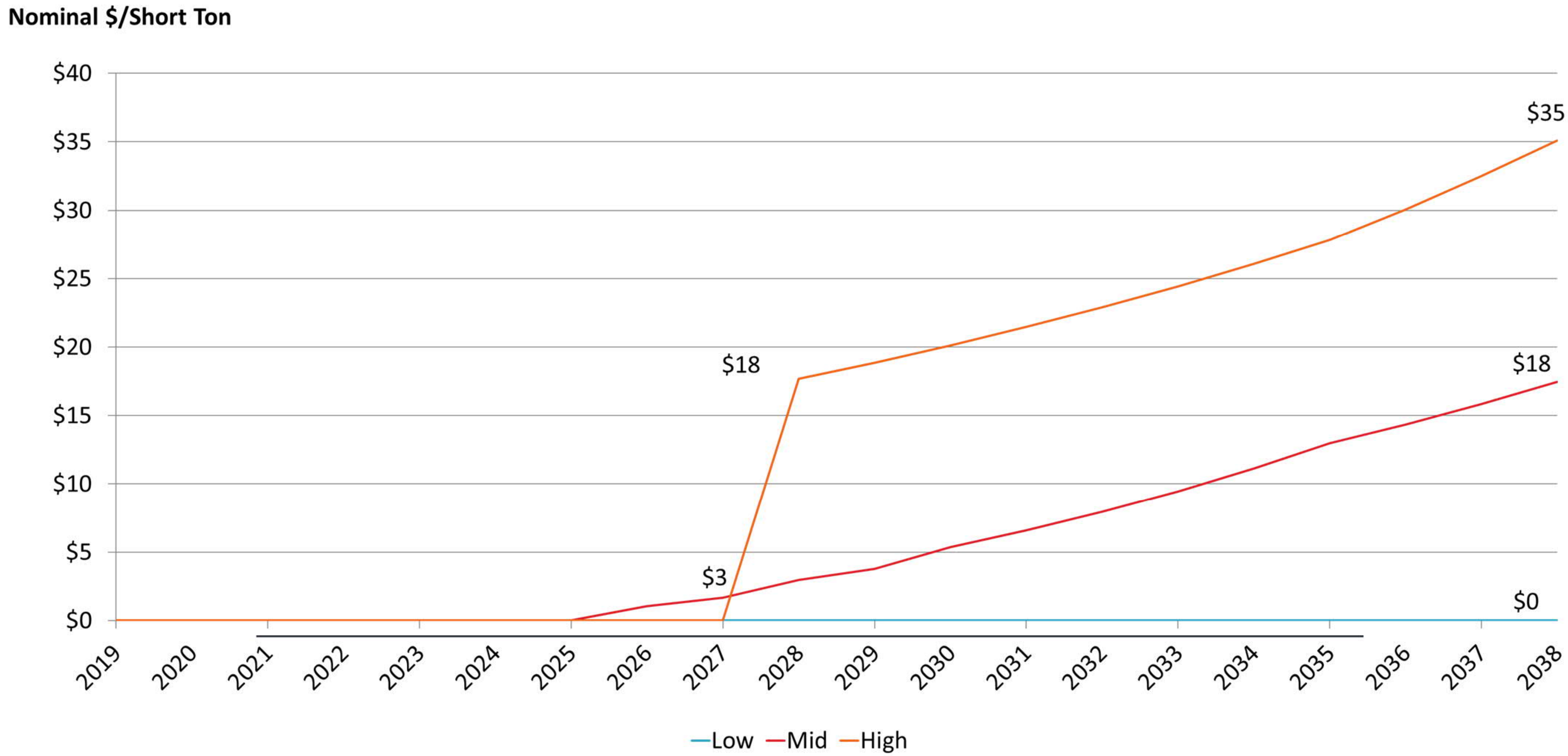
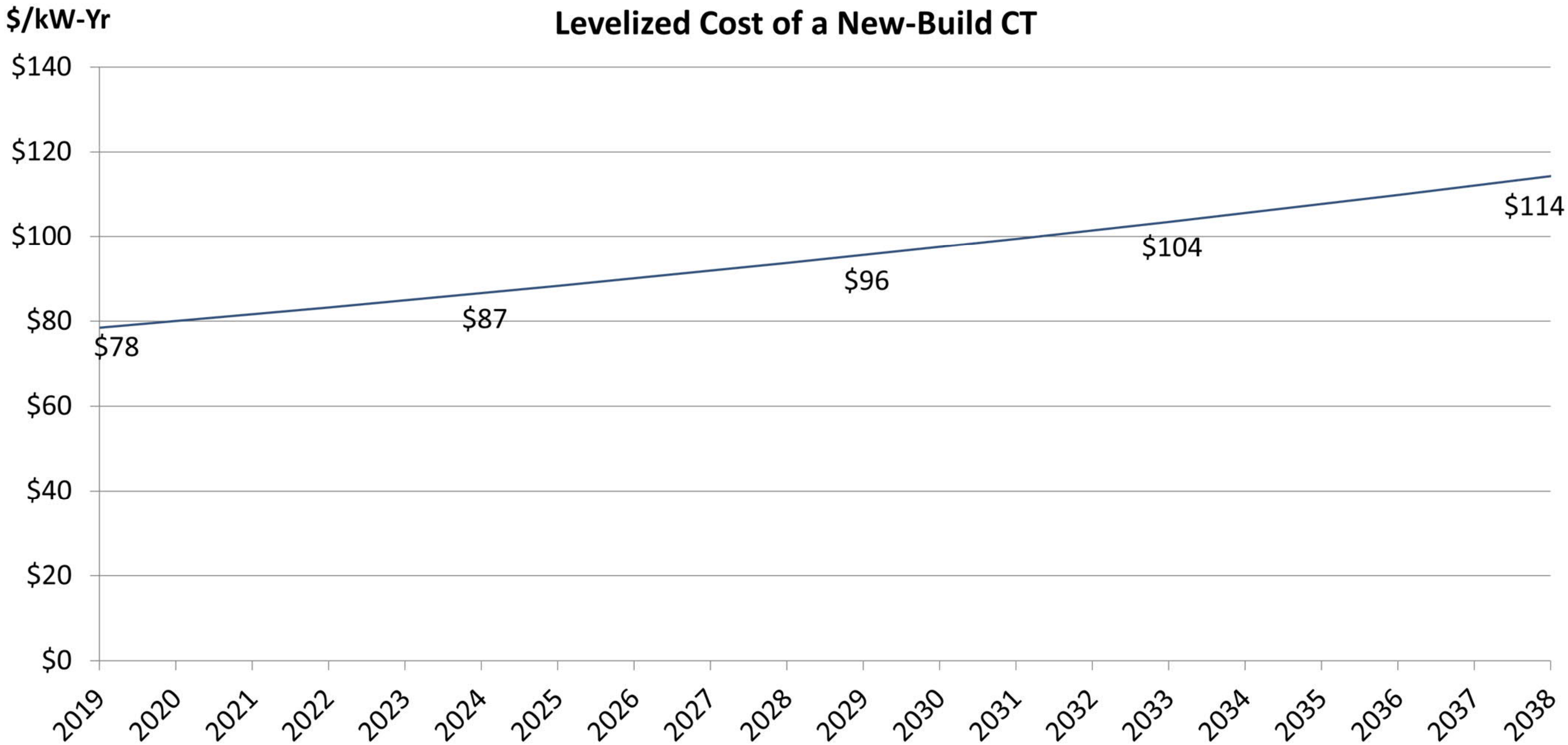
CO_2 Price Forecast

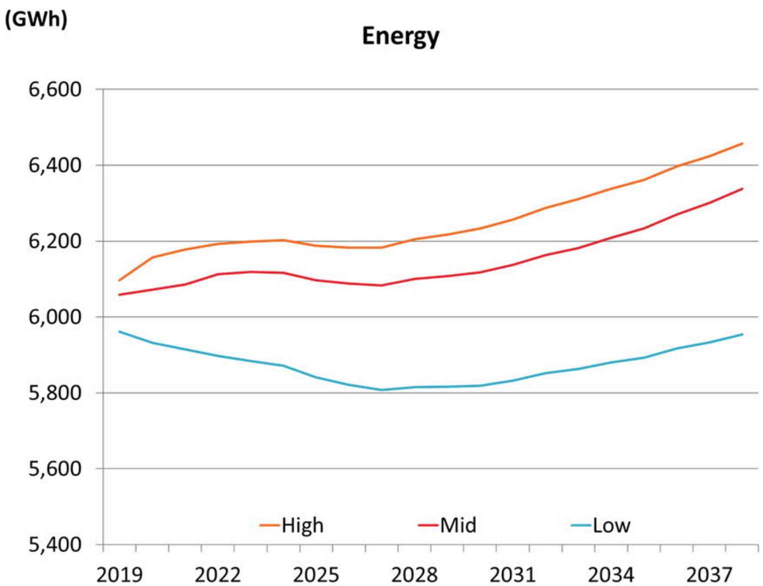


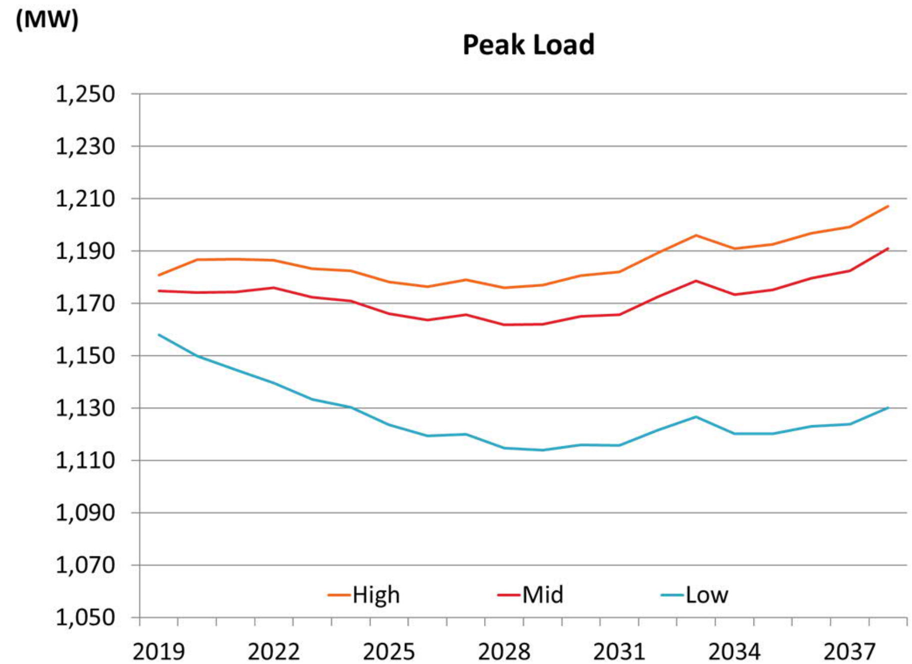
Capacity Value Forecast



Peak Load & Energy Forecast

3 demand forecasts were created for the ENO IRP: a low, medium, and high

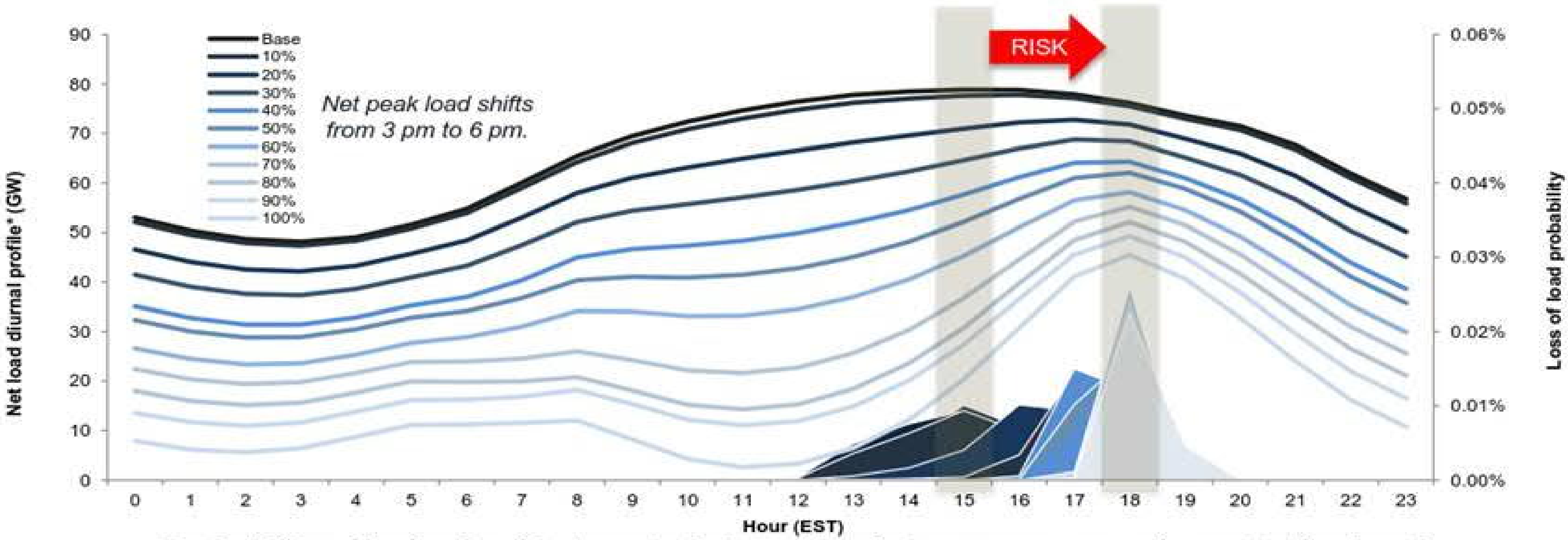




10 Year CAGR (%)	2019 – 2028	2029 – 2038
Low	- 0.28%	0.26%
Medium	0.08%	0.41%
High	0.20%	0.42%

Peak Load (MW)	2019	2024	2029	2033	2038
Low	1,158	1,130	1,114	1,127	1,130
Medium	1,175	1,171	1,162	1,179	1,191
High	1,181	1,182	1,177	1,196	1,207

As renewable penetration increases, the risk of losing load shifts and compresses to a smaller number of hours



- Probability of losing load is targeted at one day in ten years over all penetration levels.
- While aggregate risk remains constant, the risk in particular hours increases.

*Profile shapes represent hourly averages across all days of the 6 study years.

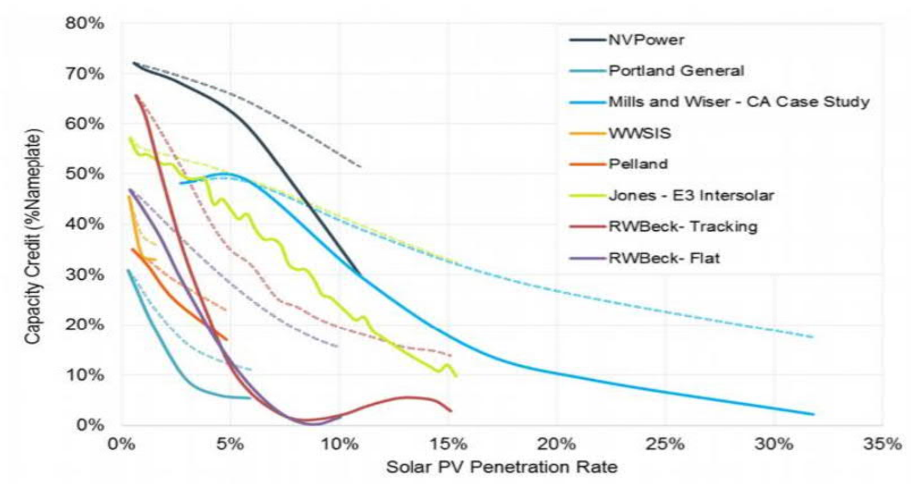
Effective Load Carrying Capability for Solar Generation

Effective Load Carrying Capability (ELCC):

Effective Load Carrying Capability (ELCC) is defined as the amount of incremental load a resource, such as wind or solar, can dependably and reliably serve, while also considering the probabilistic nature of generation shortfalls and random forced outages as driving factors to load not being served.

- ELCC has been used in the determination of capacity value for generation resources as far back as 1966 [1].
- MISO currently uses ELCC to determine the capacity value for wind. The first ELCC-capacity credit in MISO was applied when wind achieved 8% Penetration, or 10 GW Nameplate.

- According to the MISO PY 2019/20 Loss of Load Expectation (LOLE) Study, there is roughly 0.6 GWs of solar active in MISO Market. However, the penetration of solar is expected to increase significantly over the planning horizon.
- MISO along with other balancing authorities have applied or expect to apply in the future an ELCC approach to determining solar capacity value
  - California Public Utility Commission Currently employs this method.
  - PJM is currently studying the implementation of this method.



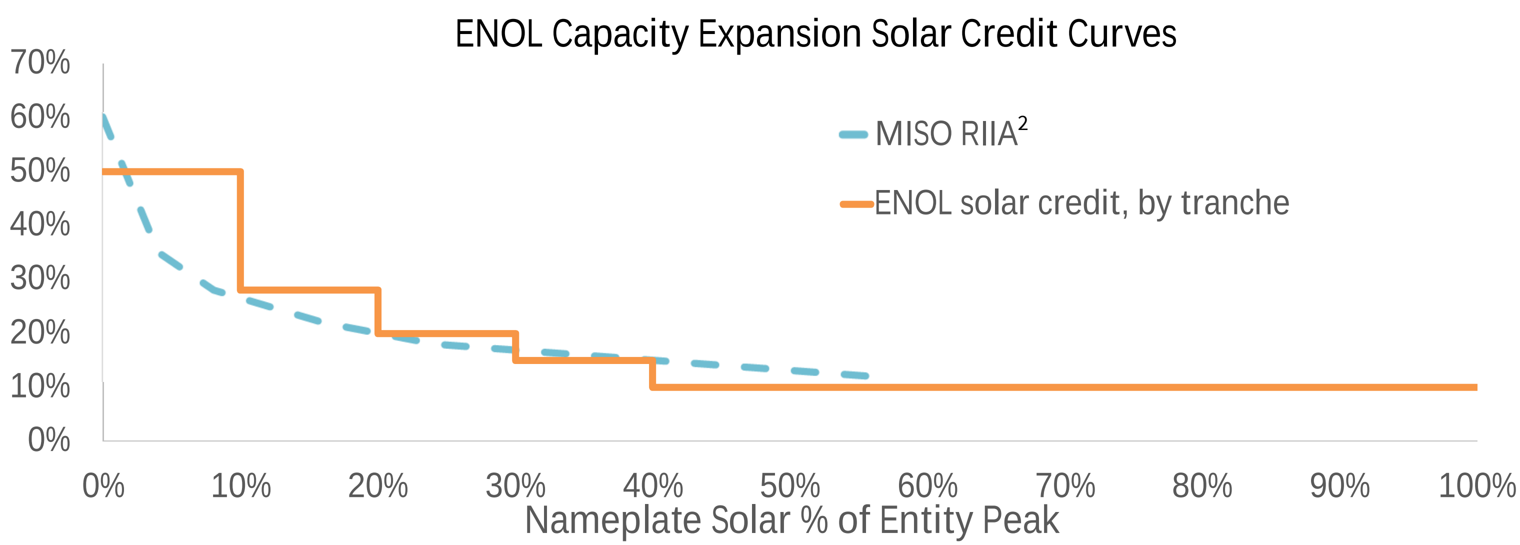
DOE, 2016, "Maintaining Reliability in the Modern Power System", Available Online: https://www.energy.gov/sites/prod/files/2017/01/f34/Maintaining%20Reliability%20in%20the%20Modern%20Power%20System.pdf

Note 1: Garver, L.L.; , "Effective Load Carrying Capability of Generating Units," Power Apparatus and Systems, IEEE Transactions on, vol.PAS-85, no.8, pp.910-919, Aug. 1966

Note 2: *RIIA is MISO's Renewable Integration Impact Assessment; https://cdn.misoenergy.org/20180605%20RIIA%20Workshop%20Presentation213125.pdf

Solar Generation Modeling Assumptions

- Solar Capacity Credit within IRP Evaluation:
  - For the purpose of calculating Total Supply Cost solar will receive 50% Capacity Credit[1]
  - Consistent with the curve reviewed in the MISO Renewable Integration Impact Study (RIIA), for the purpose of capacity expansion beginning in year 2031 solar received decreasing credit towards peak demand based on increasing solar penetration.



Note 1: Consistent with MISO's current solar capacity credit methodology.

Note 2: *RIIA is MISO's Renewable Integration Impact Assessment; https://cdn.misoenergy.org/20180605%20RIIA%20Workshop%20Presentation213125.pdf

CERTIFICATE OF SERVICE
<u>Docket No. UD-17-03</u>

I hereby certify that I have served the required number of copies of the foregoing report upon all other known parties of this proceeding, by the following: electronic mail, facsimile, overnight mail, hand delivery, and/or United States Postal Service, postage prepaid.

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New Orleans, Louisiana, this 19th day of July, 2019.

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