Entergy Services, LLC
639 Loyola Avenue
P. O. Box 61000
New Orleans, LA 70161-1000
Tel 504 576 6571
Fax 504 576 5579
tcragin@entergy.com

Timothy S. Cragin
Assistant General Counsel
Legal Department -- Regulatory

July 30, 2021

Via Electronic Delivery
Lora W. Johnson, CMC, LMMC
Clerk of Council
Room 1E09, City Hall
1300 Perdido Street
New Orleans, LA 70112

**Re: 2021 Triennial Integrated Resource Plan of Entergy New Orleans, LLC
Council Docket No. UD-20-02**

Dear Ms. Johnson:

Entergy New Orleans, LLC ("ENO") respectfully submits its 2021 Integrated Resource Plan Demand Side Management ("DSM") Potential Study in the above-referenced docket. As a result of the remote operations of the Council's office related to Covid-19, ENO submits this filing electronically and will submit the original and requisite number of hard copies once the Council resumes normal operations, or as you direct. ENO requests that you file this submission in accordance with Council regulations as modified for the present circumstances.

Please do not hesitate to contact me if you have any questions.

Sincerely,

Timothy S. Cragin

TSC/rdm
Enclosures

cc: Official Service List via email

Entergy New Orleans, LLC

2021 Integrated Resource Plan DSM Potential Study

FINAL REPORT

Prepared for:

Entergy New Orleans, LLC

Submitted by:

Guidehouse Inc.
1200 19th Street, NW
Suite 700
Washington, DC 20036
Telephone (202) 973-2400

Reference No.: 217146
July 27, 2021

Table of Contents

List of Tables

List of Figures

List of Acronyms

AC	Air Conditioning
ACEEE	American Council for an Energy-Efficient Economy
AMI	Advanced Metering Infrastructure
BAU	Business as Usual
BP20	Business Plan 2020 Update
BTMS	Behind-the-Meter Storage
BYOT	Bring Your Own Thermostat
C&I	Commercial and Industrial
CBECS	Commercial Buildings Energy Consumption Survey
CBSA	Commercial Building Stock Assessment
CPP	Critical Peak Pricing
DI	Direct Install
DLC	Direct Load Control
DOE	Department of Energy (US)
DR	Demand Response
DRSim™	Demand Response Simulator
DSM	Demand Side Management
DSMSim™	Demand-Side Management Simulator
EE	Energy Efficiency
EIA	Energy Information Administration (US)
EMS	Energy Management Systems
ENO	Entergy New Orleans, LLC
EUI	End-Use Intensities
EUL	Effective Useful Life
FERC	Federal Energy Regulatory Commission
GWh	Gigawatt-Hour
HVAC	Heating, Ventilation, and Air Conditioning
IRP	Integrated Resource Plan
ISO	Independent System Operator
kW	Kilowatt
kWh	Kilowatt-Hour
LED	Light Emitting Diode
MISO	Midcontinent Independent System Operator
MW	Megawatt
NEW	New Construction
NPV	Net Present Value
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
RTO	Regional Transmission Operator
SEER	Seasonal Energy Efficiency Ratio
SF	Square Feet
SIC	Standard Industrial Classification
T&D	Transmission and Distribution
TMY	Typical Meteorological Year
TOU	Time-of-Use
TRC	Total Resource Cost
TRM	Technical Resource Manual
TSD	Technical Support Documents

Executive Summary

Introduction

In support of the 2021 Integrated Resource Plan's (IRP's) development, Entergy New Orleans, LLC (ENO) engaged Guidehouse Consulting, Inc. ("Guidehouse" or "the team") to prepare a demand side management (DSM) potential study.[1] The study assesses the long-term potential for reducing energy consumption in the residential and commercial and industrial (C&I) sectors by using energy efficiency and peak load reduction measures and improving end-user behaviors.

ENO previously engaged Navigant Consulting, Inc. (as Guidehouse was named at the time) to prepare a DSM potential study to be used in its 2018 IRP. The 2018 study included four cases, Base, Low, High, and 2%, and informed both the 2018 IRP analysis and the Implementation Plan for Energy Smart (ES) Program Years 10-12 that was later approved by the Council of the City of New Orleans (Council) in Docket UD-17-03.

The 2018 study projected certain levels of achievable energy savings and program costs based on business assumptions and historical results of Energy Smart at the time. The PY10-12 Implementation Plan developed with ENO's Third-Party Administrator, Aptim, and subsequent actual program results reflect more aggressive splits between incentive and administrative costs and greater utilization of behavioral efficiency programs than were identified in the 2018 study. This 2021 study highlights the long-term effects of such aggressive incentives.

For the 2021 study, the team approached the energy efficiency (EE) component of the potential study with a rigorous analysis of input data. This data was necessary for Guidehouse to run the DSM Simulator (DSMSim™) model, which calculates various levels of EE savings potential across the ENO service area. Guidehouse further delineated the achievable potential using a range of assumptions for alternative cases to estimate the effect on customer participation of funding for customer incentives, awareness, and other factors.

For the demand response (DR) potential component of this study, the team similarly began with a rigorous analysis of input data necessary for the DRSim™ model. Inputting a range of reasonable assumptions, the team used the DRSim™ model to estimate the DR potential for a range of cases.

ENO intends to inform the 2021 IRP with the results from the potential study. Although these results may also be used to further ENO's DSM planning and long-term conservation goals, EE program design efforts, long-term load forecasts, and long-term potential studies do not replace the need for detailed near-term implementation planning and program design. Accordingly, ENO should only use this study to inform those planning and design efforts in combination with ENO's Energy Smart program experience and the market intelligence and insights of the Council and its Advisors and stakeholders.

Study Objectives

ENO will use the results of the potential study as an input to its 2021 IRP, providing 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. Guidehouse

[1] The study period for the potential study is 2021-2040.

designed its project approach to ensure the study results adequately address ENO's objectives and the Council's IRP rules. Table 1 summarizes the study's objectives and how Guidehouse met those objectives.

Table 1. Study Objectives Overview

Objective		Guidehouse's Approach
1	Use consistent methodology and planning assumptions	Guidehouse has 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 study.
2	Reflect current information	Guidehouse leveraged 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.) in this study.
3	Quantify achievable potential	Guidehouse quantifies achievable potential for both EE and DR by first calculating the technical and economic (EE only) 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 10-12.
4	Provide input to the IRP	Guidehouse's approach provides the following for all modeled market cases: • Supply curve of conservation potential for input to ENO's IRP • Outputs available with 8,760 hourly impact load shapes

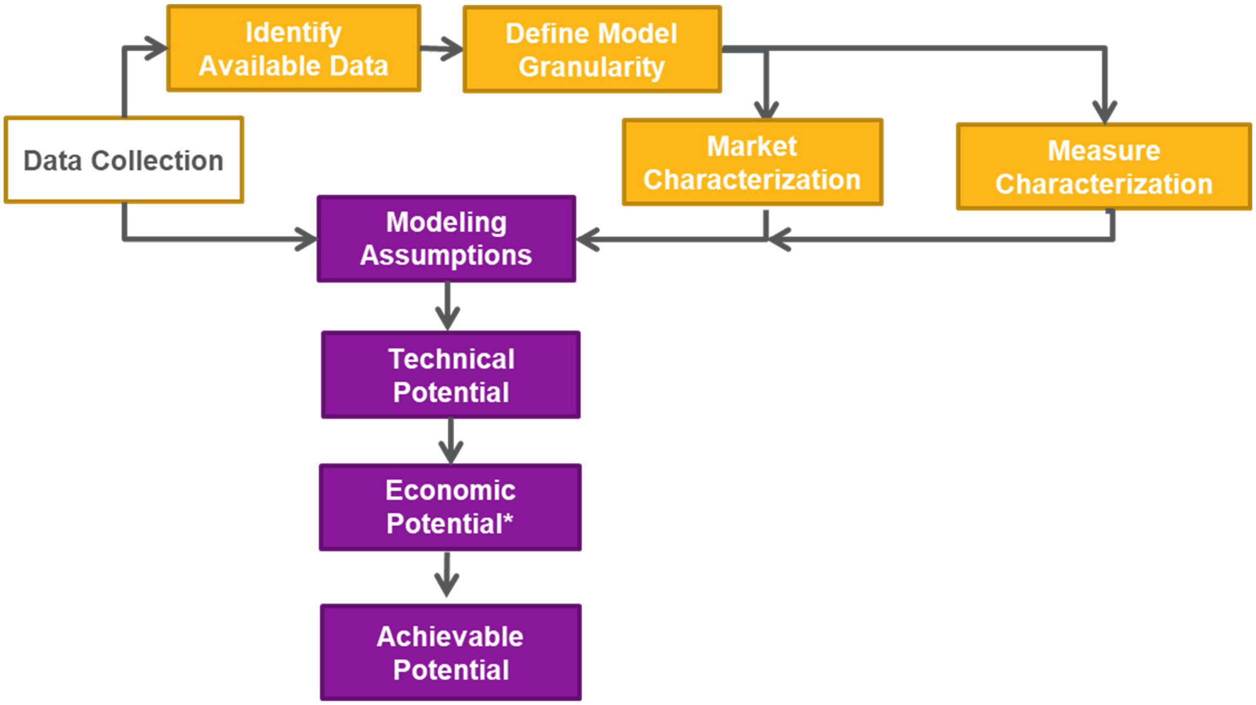
Source: Guidehouse

Energy Efficiency

Detailed Approach

Guidehouse analyzed potential in the ENO service area for 2021 through 2040. After gathering existing data sources, the team characterized the market and measures, and estimated potential using the DSMSim^{TM} tool, a bottom-up stock forecasting model. The third step involved three sequential stages—calculating technical, economic, and achievable potential. Figure 1 illustrates our EE analysis approach.

Figure 1. EE Analysis Approach Overview



*Not calculated for DR potential

Source: Guidehouse

Market Characterization

Characterizing the market involved identifying and understanding key factors defining the service area or market and codifying assumptions for the model to accurately represent the market. Specifically, the market characterization required defining the sales and stock[2] for 2019 (the study's base year consumption),[3] and then forecasting sales and stock out from 2021-2040 to create the study's base forecast consumption, or baseline. To complete this effort, Guidehouse collected multiple datasets including:

- 2019 ENO billing and customer account data
- ENO Business Plan 2020 (BP20) forecast sales and customer counts
- US Energy Information Administration (EIA) Commercial Buildings Energy Consumption Survey (CBECS)
- US Department of Labor SIC
- Guidehouse research

[2] Sales refers to the kWh consumption, typically by sector. Stock refers to the customer count, typically per household for the residential sector and per 1,000 square feet for the non-residential sector. For the potential analysis, Guidehouse prefers more disaggregated analysis at the segment level (or building types).

[3] The base year is typically the most recent full year of utility available data for sales and stock.

After defining sales and stock for the base year and base forecast consumption, the team determined energy use at the customer segment and end use levels. Guidehouse based the level of disaggregation for the segments and end uses on existing program definitions, data availability to accomplish disaggregation, and the level of granularity needed for stakeholders to draw meaningful conclusions from the study. The study details the selected customer segments and assumptions about the stock, electricity sales, end use breakdown, and energy use intensity (EUI) for each segment and end use.

The team also aggregated additional inputs from ENO for inclusion in the model, including various economic and financial parameters such as carbon pricing, avoided costs, inflation, and historic program costs.

Measure Characterization

Measure characterization consisted of defining enough data points for all measures included in the study to accurately model them. Key data points used to characterize measures included assumptions about energy and demand savings, codes and standards, measure life, and measure costs. We used data provided by ENO, data from regional efficiency programs offered by other utilities, and Technical Reference Manuals (TRMs) primarily from New Orleans v4,[4] and other state TRMs to fill the gaps.

The team used a measure list with sufficient characteristics to identify and focus our efforts on technologies likely to have the highest feasible, cost-effective contribution to savings potential over the study horizon. The study does not account for unknown or emerging but unproven technologies that may arise and increase savings opportunities over the forecast horizon. It also does not account for broader societal changes that may affect levels of energy use in unanticipated ways.

Estimation of Potential

After defining the market and measure characteristics, Guidehouse employed the DSMSim™ potential model to estimate the technical, economic, and achievable savings potential for electric energy and demand across ENO's service area from 2021 to 2040. Each type of potential is defined below:

- **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.

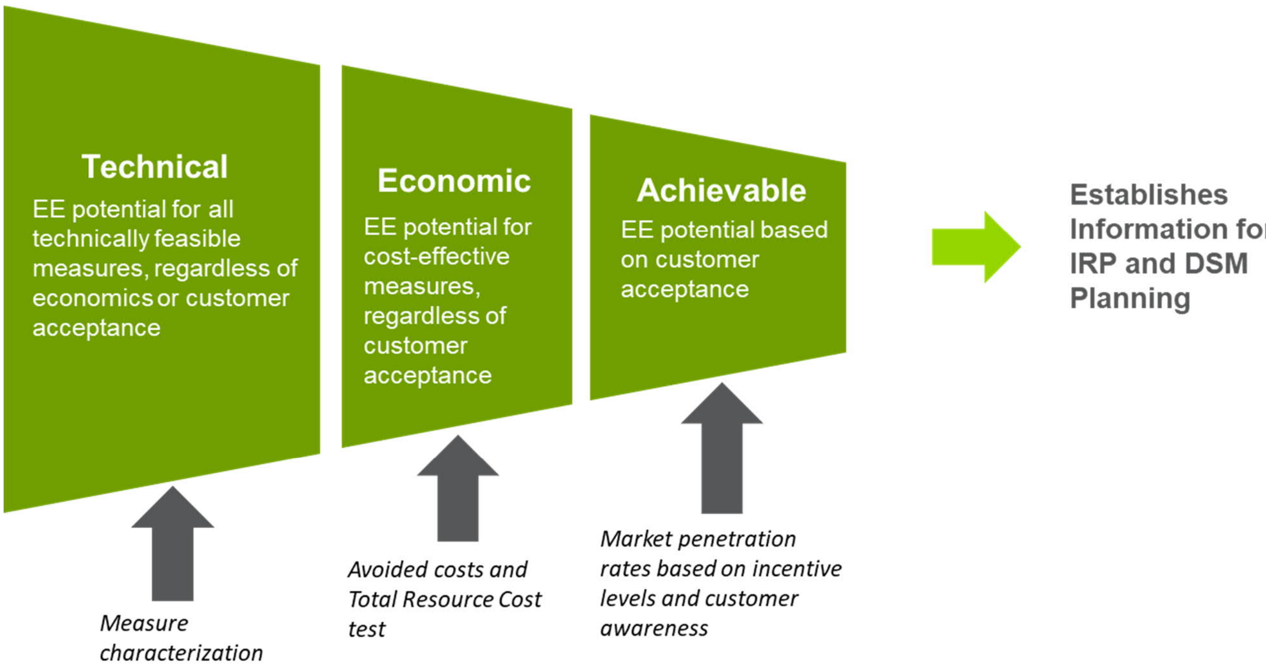
- **Economic potential** is a subset of technical potential, using the same assumptions regarding immediate replacement as in technical potential, but including only those measures that have passed the benefit-cost test chosen for measure screening; in this study, that is the Total Resource Cost (TRC) test.

[4] New Orleans Energy Smart Technical Reference Manual: Version 4.0, September 2020, prepared by ADM Associates, Inc.

- **Achievable potential** is a subset of economic potential. The team determined achievable potential by modifying economic potential to account for measure adoption ramp rates and the diffusion of technology through the market.

Figure 2 depicts each potential types and their respective data inputs.

Figure 2. Energy Efficiency Potential Analysis Approach



Source: Guidehouse

With these definitions and data inputs, the DSMSim™ uses a bottom-up technology diffusion and stock tracking model implemented by means of a system dynamics framework to estimate the different potential types.[5] The model outputs technical, economic, and achievable savings potential for the service area, sector, customer segment, end use category, and highest impact measures.

Results

Given ENO's objective to quantify the achievable potential for use in the 2021 IRP and gain a better understanding as to the best path for planning ENO's Energy Smart programs, the project team modeled several possible future cases, including:

1. **2% Program case:** The 2% program case is defined by the approved Energy Smart PY10-12 implementation plan, Scenario 2.[6] Guidehouse set incentives at 86% and 32% of the full measure cost for residential and C&I measures, respectively. Guidehouse calibrated

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

[6] https://cdn.entergy-neworleans.com/userfiles/content/energy_smart/Program_Year_10-12/Correction_Revised_Implementation_Plan_%20PY_10-12_1-24-20.pdf?_ga=2.216502932.327611312.1611206281-15932630.1611206281 and https://cdn.entergy-neworleans.com/userfiles/content/energy_smart/Program_Year_10-12/Revised_Implementation_Plan_PY_10-12_1-22-20.pdf?_ga=2.216502932.327611312.1611206281-15932630.1611206281

the model results by adjusting adoption parameters and behavior program rollout to align with the historical program achievements and planned savings as documented in the implementation plan.

2. **Low Program case:** The low case uses the same inputs as the 2% program case, (ENO implementation plan, Scenario 2) except for lower levels of behavior program participation rollout (50% of the 2% program case). Incentives are set to 50% of full measure cost for residential and 25% for C&I. Administrative costs on a dollar per kWh saved basis are the same as the 2% program case.

3. **High Program case:** The high case is based off the 2% program case but with higher incentives as a percent of full measure cost at 100% for residential and 50% for C&I. Additionally, there is a more aggressive plan for behavior program rollout. Behavioral program rollout for the residential sector increases slightly compared to the 2% case and reaches the maximum achievable level.[7] Administrative costs on a dollar per kWh saved basis are relatively equal to those in the 2% program case.

4. **Reference case:** In an effort to develop a case reflecting an industry-standard level of incentives, and because the actual program results for the approved PY10-12 plan are tracking to higher levels of administrative costs and kWh savings than are often seen in long term potential studies, it was useful to provide a Reference Case that tied back to the Base case from the 2018 study. This Reference case reflects the Base case from the 2018 study where the program administrative costs reflected current spend targets on a dollar per kWh saved basis and the incentives were set at 50% of incremental measure costs. In Guidehouse's experience in incentive level setting and potential study analysis, others have set incentives or cap incentives at 50% of incremental measure cost. Behavior program roll out matches the low program case levels as a conservative assessment of the potential roll out of the recommended programs for the ENO portfolio.

The study reports savings as gross versus net of free ridership impacts. Providing gross potential is advantageous because it permits a reviewer to more easily calculate net potential when new information about net-to-gross ratios or changing EUI with natural occurring energy become available. Study results can then be used to define the portfolio energy savings goals, projected costs, and forecasts.

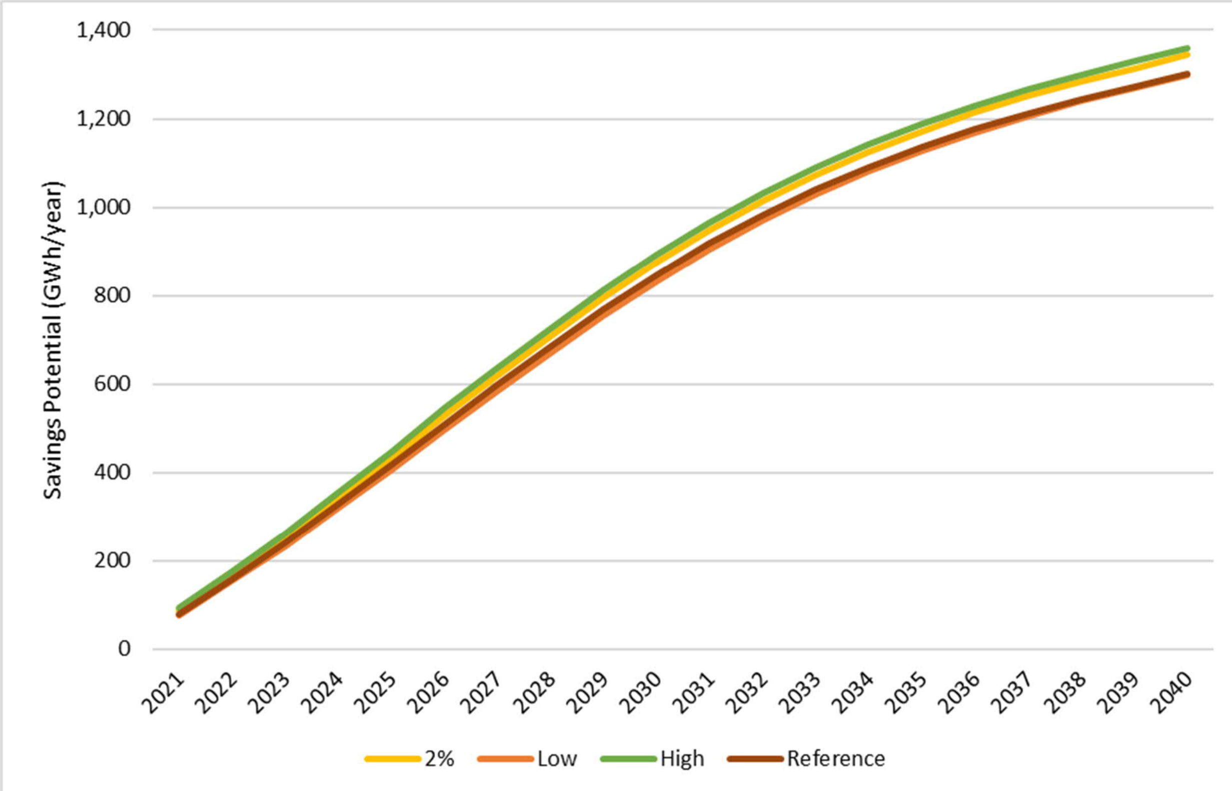
This study only includes known, market-ready, quantifiable measures. However, over the lifetime of EE programs, new technologies and innovative program interventions could result in additional cost-effective energy savings. ENO should periodically revisit and reanalyze the potential forecast to account for these technologies and programs.

Results

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

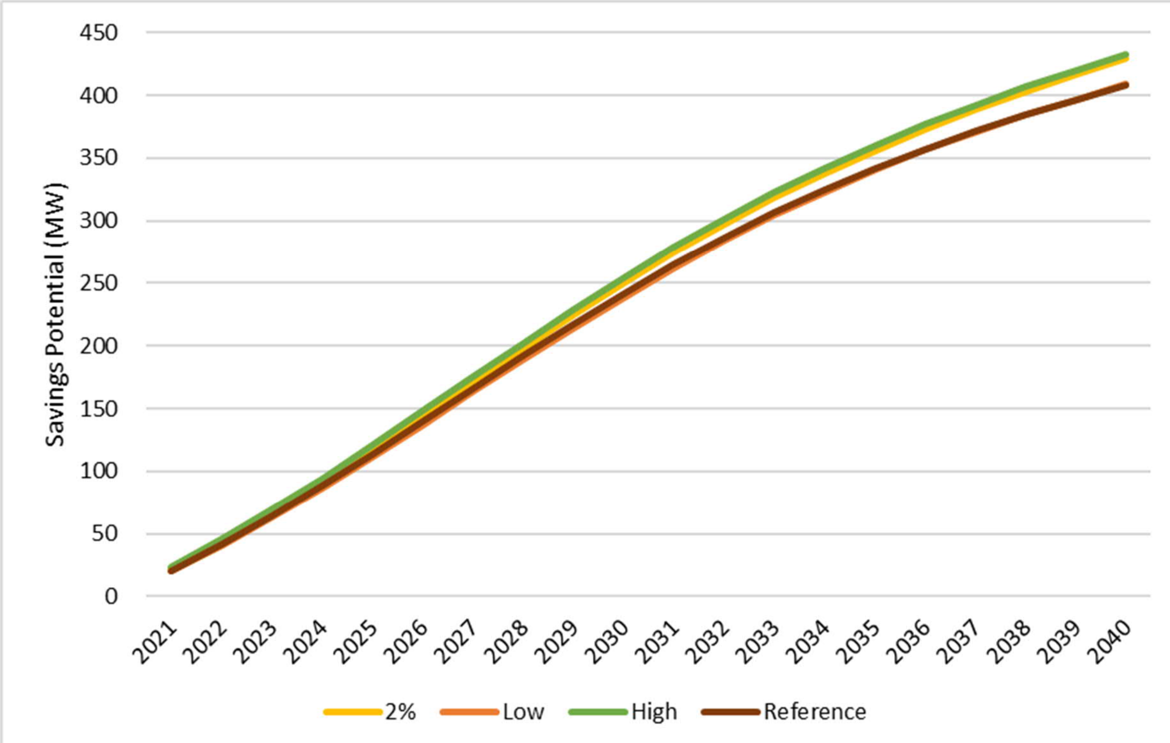
[7] Residential behavior programs using a control group to assess energy savings result in an ability to treat less than 100% of the suitable participant pool.

Figure 3. Cumulative Energy Achievable Savings EE Potential by Case



Source: Guidehouse analysis

Figure 4. Cumulative Peak Demand Achievable Savings EE Potential by Case



Source: Guidehouse analysis

The various cases do not show significant differences from each other; however, each case has marked differences in the program design, i.e., changes in ENO-influenced parameters including incentive level setting and behavioral program rollout.[8] Table 2 summarizes the EE potential study results, showing achievable annual incremental energy and peak demand savings by case in 5-year increments. Total cumulative EE potential energy and peak demand savings for the 2% program case are 1,344 GWh and 429 MW, respectively, between 2021 and 2040.

Table 2. Annual Incremental Achievable Energy Efficiency Savings by Case

Year	Electric Energy (GWh/Year)				Peak Demand (MW)			
	2%	Low	High	Reference	2%	Low	High	Reference
2021	89	77	93	79	22	20	23	21
2025	119	101	126	103	26	25	26	25
2030	115	96	123	96	25	25	26	24
2035	86	66	94	65	18	17	18	17
2040	73	51	81	50	13	12	13	12
Total	**1,344**	**1,299**	**1,359**	**1,302**	**429**	**409**	**432**	**408**

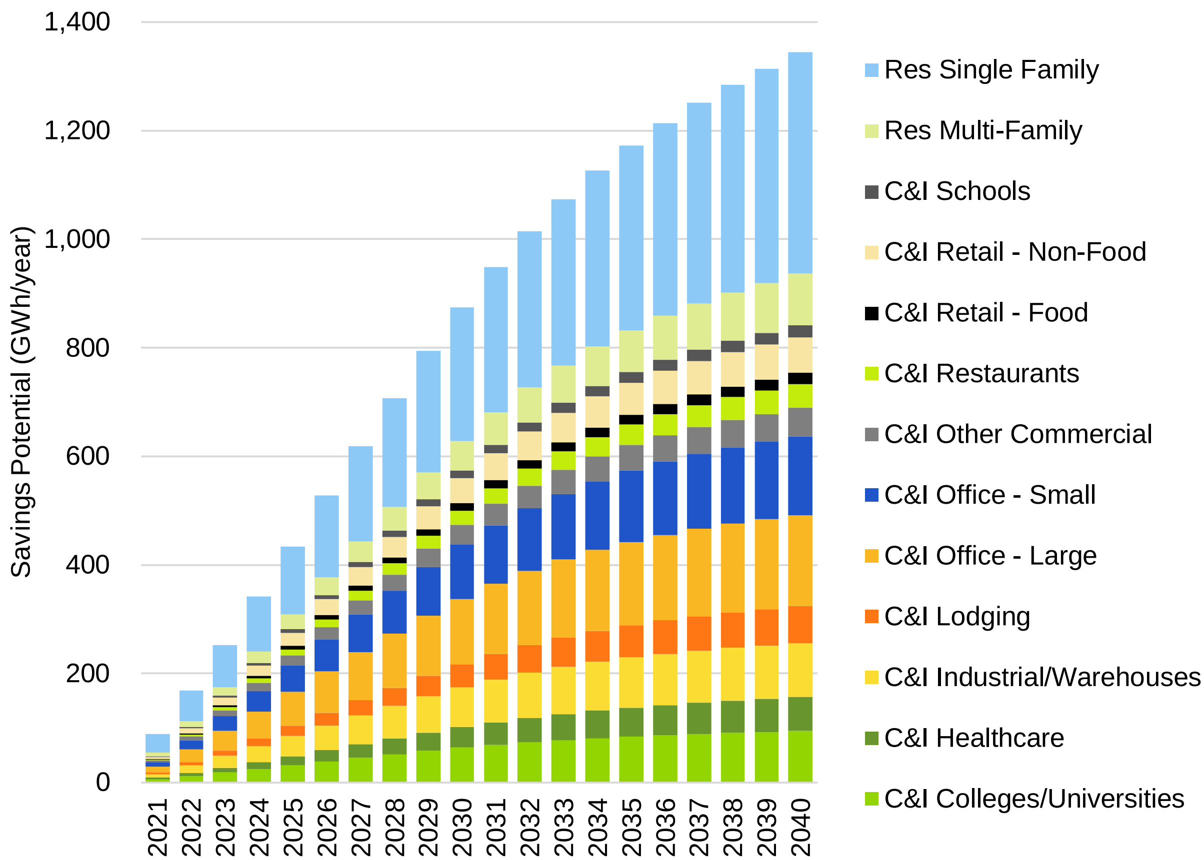
[8] Incentive levels change the customer payback period. Depending on amount of change will result in a change on the payback acceptance curve influencing the market share potential of the energy efficient option. The payback acceptance curve was developed as a result of customer surveys of hypothetical situations from a Midwest utility.

Source: Guidehouse analysis

In the subsequent data, the report highlights the 2% Program case, which most reflects the current ENO PY10-12 Implementation Plan.

Figure 5 shows the cumulative electric energy achievable potential by customer segment. Single-family homes make up the largest residential segment, while large and small offices contribute the most savings to the C&I sector.

Figure 5. 2% Program Case Cumulative Achievable Potential Savings Customer Segment Breakdown



Source: Guidehouse analysis

Table 3 shows the incremental electric energy achievable savings as a percentage of ENO's total sales for each case in 5-year increments. The 2% program case, which was calibrated to the current PY10-12 Implementation Plan, achieves at least 2% of sales savings from 2025 through 2029. The 2% program case and the high case fall below 2% in later years because most of the measures will have been adopted, depleting the available potential in the future years. Behavior program participation maintains the 2% program and high case at greater than 1% throughout the forecast period.

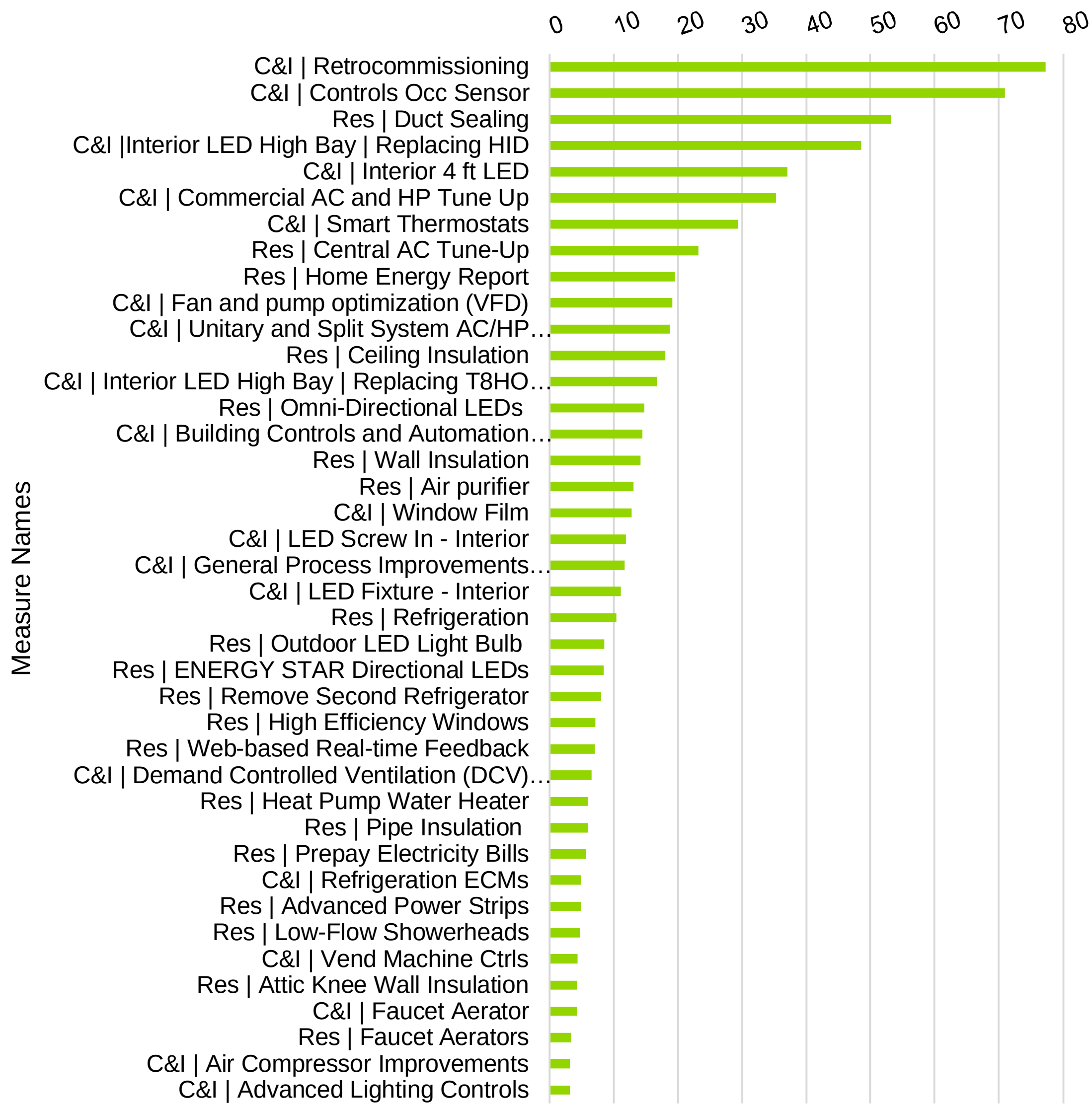
Table 3. Incremental Energy Achievable Savings Potential as a Percentage of Sales by Case (%, GWh)

Year	2%	Low	High	Reference
2021	1.54%	1.34%	1.62%	1.38%
2025	2.05%	1.75%	2.18%	1.78%
2030	1.97%	1.65%	2.10%	1.64%
2035	1.45%	1.12%	1.59%	1.09%
2040	1.22%	0.85%	1.36%	0.84%
Total	22.54%	21.78%	22.79%	21.83%

Source: Guidehouse analysis

Figure 6 shows the top 40 measures contributing to the electric energy achievable potential in 2028 (representative of the 20-year results). Retrocommissioning in the C&I sector provides the most savings, followed by occupancy sensor controls, interior high bay LEDs, 4-foot LEDs and smart thermostats. Residential duct sealing, central AC tune-up and home energy reports provide the highest three residential sector savings.

Figure 6. Top 40 Measures for Cumulative Electric Energy 2% Program Case Achievable Savings Potential: 2028 (GWh/year)



Source: Guidehouse analysis

The total, administrative, and incentive costs for each case are provided in Table 4 in 5-year increments for the study period. 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 4. Spending Breakdown for Achievable Potential ($ Millions/Year)[9]

Year	Total				Incentives				Admin			
	2%	Low	High	Reference	2%	Low	High	Reference	2%	Low	High	Reference
2021	$14	$12	$17	$15	$8	$6	$11	$9	$6	$6	$6	$6
2025	$20	$17	$23	$20	$12	$9	$15	$12	$8	$8	$8	$8
2030	$21	$18	$24	$19	$13	$10	$16	$11	$8	$8	$8	$8
2035	$15	$13	$16	$13	$10	$8	$12	$8	$5	$5	$5	$5
Total	$349	$293	$394	$321	$220	$166	$265	$194	$129	$127	$129	$127

Source: Guidehouse analysis

Table 5 shows the portfolio TRC to be cost-effective for all cases. One of the screening criteria in the potential analysis is for the measures to pass the TRC test. A handful of measures were allowed into the analysis that fell below 1.0. As a result, the portfolio is still cost-effective. Typically, the more aggressive the portfolio, the lower the TRC as less cost-effective measures are added and administrative efforts to address more services to the market are increased.

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

Year	2%	Low	High	Reference
2021-2040	1.85	1.88	1.84	1.86

Source: Guidehouse analysis

Demand Response

Detailed Approach

Guidehouse developed ENO's DR potential and cost estimates using a bottom-up modeling approach consisting of five steps:

1. Characterize the market
2. Develop baseline projections
3. Define and characterize DR options
4. Develop key assumptions for potential and costs
5. Estimate potential and costs

Guidehouse used primary data from ENO and relevant secondary sources for this analysis as documented in Section 2. Figure 7 summarizes the DR potential estimation approach.

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

Figure 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/large C&I) and by building type.
Step 2: Develop Baseline Projections	Develop baseline projections for customer count and peak demand over the study period (2021-2040).
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; develop itemized cost assumptions.
Step 5: Estimate Potential and Costs; Assess Cost-effectiveness of Programs	Present potential estimates by DR option and customer segments, annual and levelized costs, and cost-effectiveness results by scenarios.

Source: Guidehouse

Market Characterization

The team segmented the market appropriately for analysis in the market characterization process for the DR assessment. Guidehouse aggregated data on key characteristics including customer count and peak demand by customer class and segment and end use to input to the model. The customer segmentation for the DR analysis is based on an examination of ENO's rate schedules combined with the customer segments established in the EE potential study.

As part of characterizing the market, the team identified the demand response target period, defined as the peak period. For ENO, this peak period within the summer is defined as the top 40 hours of demand during the hours of 2:00 p.m. through 6:00 p.m., June through September.

ENO expressed a desire to align the peak period definition with times the Midcontinent Independent System Operator (MISO) is expected to see peak demand. This allows ENO to use 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 period (June through August) during the hours from 2:00 p.m. through 6:00 p.m."[10] Guidehouse 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, Guidehouse only included the top 40 weekday hours within this window, which is the typical limit for calling summer DR events. This assumption is consistent with the 2018 study assumption which found that 95% or greater of ENO's system peak occurred within the top 40 hours based on an examination of historical system load data, which is what utilities typically target to call DR events.

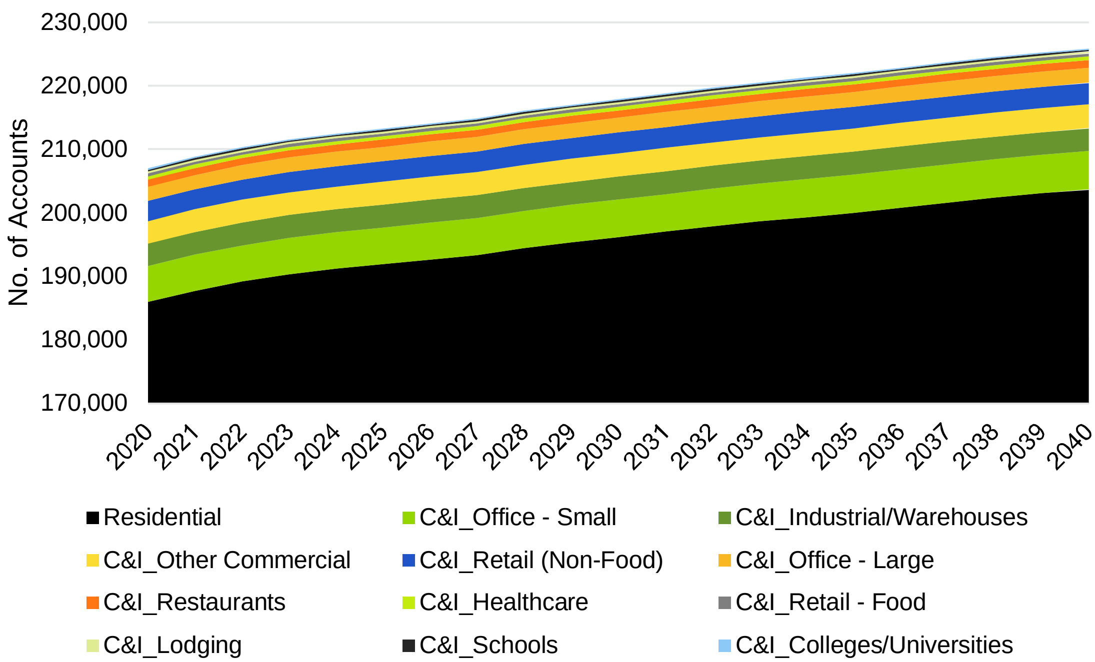
[10] MISO. *Business Practice Manual,* BPM 026, -Demand Response. Effective date: July 20, 2020, pg 20.

Baseline Projections

Baseline projections in the DR potential assessment are a forecast of customer demand over the study period based on existing trends and market characteristics, similar to the base forecast in the EE potential study. The project team used these projections as a basis for modeling savings. More specifically, Guidehouse applied the year-over-year change in the stock forecast of the 2019 customer count data broken out by customer class and segment for the projections. These projections are calibrated to the sector-level customer count forecast ENO provided.

Figure 8 shows the aggregate customer count forecast by segment, summed across all customer classes.

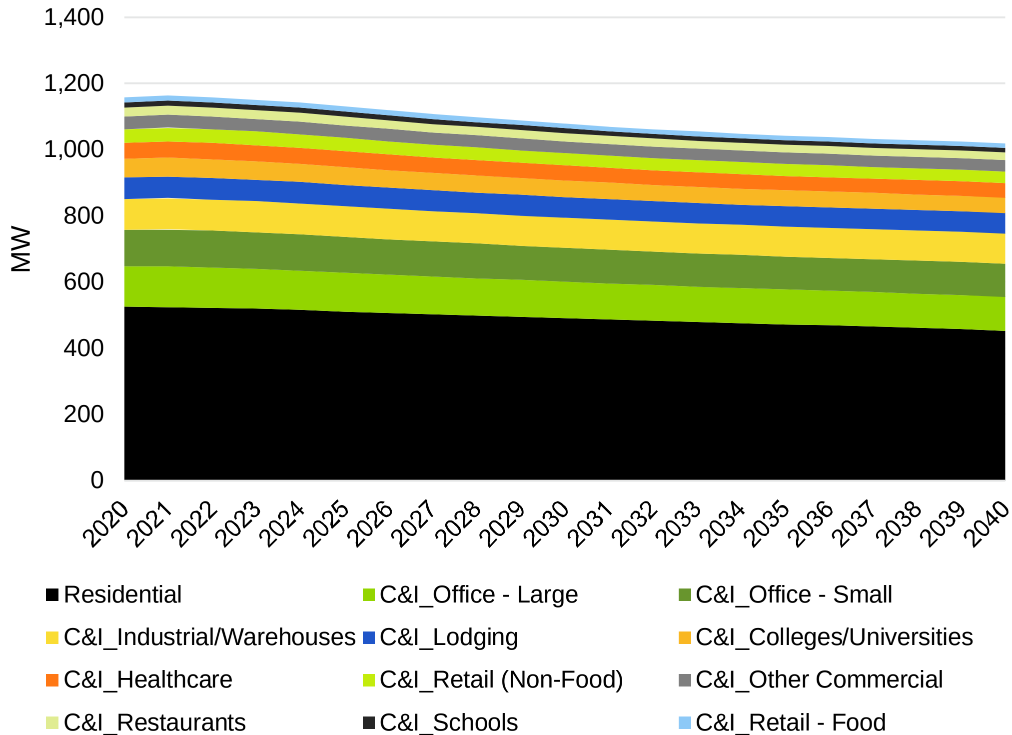
Figure 8. Customer Count Projections for DR Potential Assessment



Source: Guidehouse analysis

Figure 9 shows the summer peak demand projections Guidehouse developed by combining 2019 hourly system load data, 2019 customer count and sales data by NAICS code, load profiles by revenue class, and sales projections by revenue class. Section 2 describes the approach used by Guidehouse to develop disaggregate peak demand projections by customer class and segment. The peak demand projections are adjusted with EE potential estimated to derive the net load post EE, which serves as the baseline load for DR potential estimation. Guidehouse developed the baseline peak demand projections for all three cases (mid, low, and high) corresponding to the EE achievable potential estimates for these three cases. Figure 9 below shows the summer peak demand projections for the mid case. The baseline peak demand projections progressively decline over time due to higher penetration of EE.

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



Source: Guidehouse analysis

DR Options

Once the baseline peak demand projections were developed, the team characterized different types of DR options that could be used to reduce peak demand.

Error! Reference source not found. summarizes the DR options included in the analysis. The DR options represent ENO's current DR program offers and those that are commonly deployed in the industry. These programs 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." A study of a battery storage program was also included as required by the 2021 IRP Initiating Resolution.[11]

[11] Council Resolution No. R-20-257, p. 12

Table 6. Summary of DR Options

DR Option	Characteristics	Eligible Customer Classes	Targeted/ Controllable End Uses and/or Technologies
DLC[12] ✓ Load control switch ✓ Thermostat	Control of cooling load using either a load control switch or smart thermostat; control of water heating load using a load control switch.	Residential Small C&I	Cooling, water heating
C&I Curtailment[13] ✓ Manual ✓ Auto-DR enabled	Firm capacity reduction commitment with pay-for-performance ($/kW) based on nominated amount or actual performance.	Large C&I	Various load types including HVAC, lighting, refrigeration, and industrial process loads
Dynamic Pricing[14] ✓ Without enabling technology ✓ With enabling technology	Voluntary opt-in dynamic pricing offer, such as Critical Peak Pricing (CPP)	All customer classes	All
BTMS ✓ Standalone battery storage	Dispatch of BTM batteries for load reductions during peak demand periods.	All customer classes	Batteries

Source: Guidehouse

Estimation of Potential

With the market, baseline projections, and DR options characterized, Guidehouse estimated technical and achievable potential by inputting their parameters into its model. Guidehouse developed programmatic assumptions such as participation, unit impacts, and costs to estimate potential and assess cost-effectiveness. The team developed variations in assumptions across the three cases to assess variations in potential estimates with varying levels of incentives and participation projections. The achievable potential estimates presented in the results represent potential from cost-effective DR options that pass the benefit-cost threshold of 1.0 based on the TRC test.

---

[12] This represents both the switch-based and smart thermostat based “Easy Cool” program offered by ENO to residential and small business customers (switch-based option offered only to residential customers and smart thermostat-based option offered to both residential and small business customers).

[13] This represents the current Large Commercial Demand Response program offered by ENO to Large C&I customers with greater than 100 kW demand.

[14] Guidehouse 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.

Guidehouse used the following key variables for potential and cost estimates:

1. Program participation/enrollment assumptions and the rates at which these ramp up
2. Technology market penetration (e.g., penetration of DR-enabling technologies such as smart thermostats and energy management system)
3. Realizable load reduction from different types of control mechanisms, referred to as unit impacts
4. Annual attrition and event opt-out rates
5. Itemized fixed and variable costs which are incurred upfront and on a recurring basis for running DR programs (program development, program administration, marketing and recruitment, incentives, O&M, etc.)

Guidehouse used the following definitions for calculating technical and achievable DR potential:

- **Technical potential** refers to load reduction that results from 100% of eligible customers/load enrolled in DR programs. This is a theoretical maximum.
- **Achievable potential** estimates are derived by applying participation assumptions to the technical potential estimates. The team calculated this by multiplying achievable participation assumptions (subject to program participation hierarchy) by the technical potential estimates.

Unlike EE, the DR analysis does not develop separate economic potential estimates for DR since the cost-effectiveness screening of DR options takes place at the program level under achievable participation assumptions. The achievable potential results presented later in the report only includes cost-effective DR options.

Results

Achievable peak demand reduction potential is estimated to grow from 12 MW in 2021 to 70 MW in 2040. Cost-effective achievable potential makes up approximately 7% of ENO’s peak demand in 2040. Guidehouse observed the following:

- DLC has the largest achievable peak demand reduction potential: 39% share of total potential in 2040. DLC potential grows from 6.8 MW in 2021 to 27.4 MW in 2040.
- Dynamic pricing has a 36% share of the total potential in 2040. The dynamic pricing offer begins in 2023 because it is tied to ENO’s advanced metering infrastructure implementation plan and readiness to implement the option. The program ramps up over a 5-year period (2023-2027) until it reaches a value of 24 MW. From then on, potential slowly increases until it reaches a value of 25.6 MW in 2040.
- C&I curtailment makes up the remainder of the cost-effective achievable potential with a 25% share of the total potential in 2040. C&I curtailment potential grows rapidly from 5 MW in 2021 to 17.5 MW in 2024. This growth follows the S-shaped ramp assumed for the program over a 3-5-year period. Beyond 2024, the program attains a steady participation

level and its potential slightly decreases (due to changing market and energy intensity forecasts over time) over the remainder of the forecast period, ending at 17.3 MW in 2040.

Table 7**Error! Reference source not found.** lists the DR potential results by option in 5-year increments. The calculated achievable potential for peak load reduction is 70.3 MW in 2040.

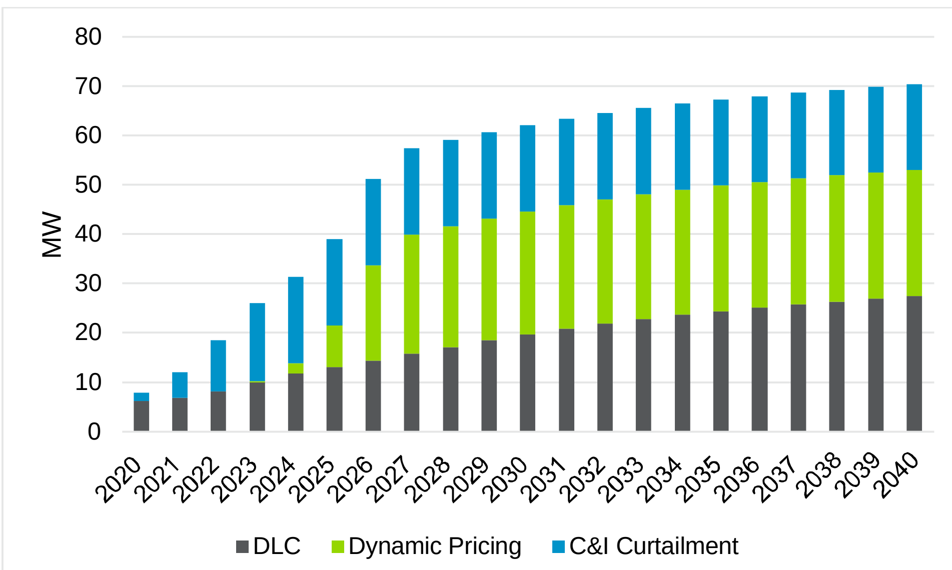
Table 7. Incremental Achievable Summer DR Potential by Option (MW)

Year	DLC	Dynamic Pricing	C&I Curtailment	Total
2021	6.8	0.0	5.2	12.0
2025	13.0	8.5	17.5	39.0
2030	19.7	24.9	17.5	62.1
2035	24.4	25.4	17.4	67.2
2040	27.4	25.6	17.3	70.3

Source: Guidehouse analysis

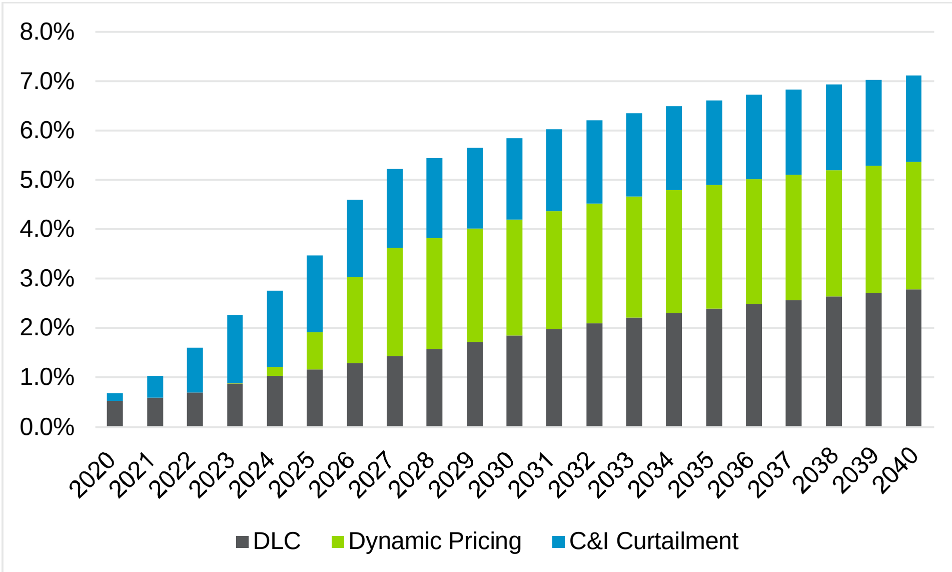
Figure 10 and Figure 11 summarize the cost-effective programs where the benefits exceed the costs (TRC ≥1.0) and achievable potential by DR option for the mid case in megawatts and as a percentage of ENO's peak demand.

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



Source: Guidehouse analysis

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

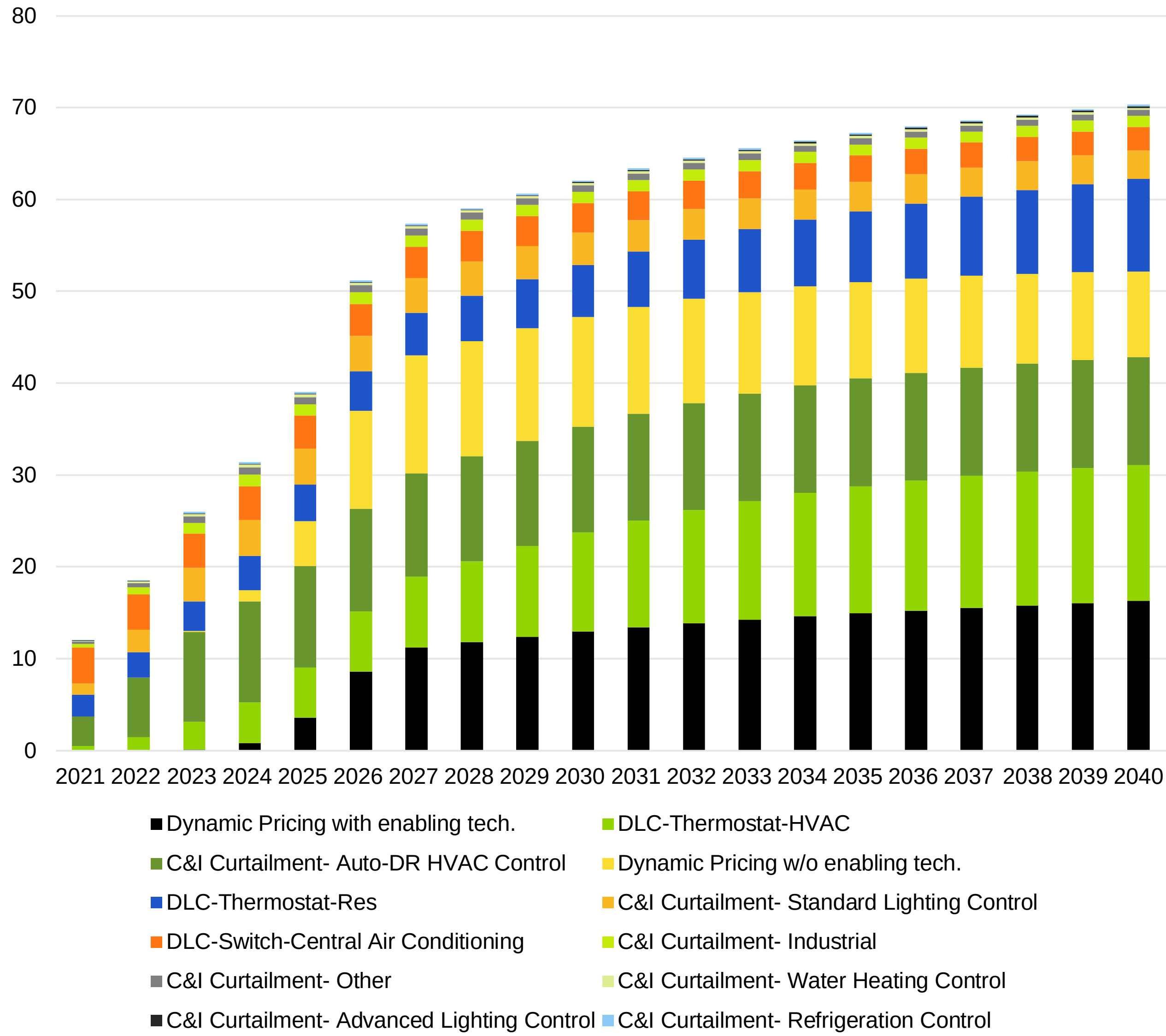


Source: Guidehouse analysis

Figure 12 summarizes the cost-effective achievable potential by DR sub-option for the mid case. Analysis of the mid case results by sub-option yielded the following key observations:

- Only direct control of HVAC loads (DLC-Switch and DLC-Thermostat in Figure 12) is cost-effective (and not water heating). This sub-option makes up nearly 40% of the total cost-effective achievable potential in 2040 at 27 MW. Of this 27 MW, 24.9 MW is from thermostat-based control, while the remaining 2.6 MW is from switch-based control.
- Dynamic pricing makes up 36% of the total cost-effective achievable potential in 2040. Potential from customers with enabling technology in the form of thermostats/energy management systems is almost two times higher than that from customers without enabling technology—16 MW versus 9 MW in 2040.
- Under the C&I curtailment program, reductions associated with refrigeration control, advanced and standard lighting control, water heating control, industrial, and auto-DR HVAC control make up 25% of the total cost-effective potential in 2040.

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



Source: Guidehouse

Conclusions and Next Steps

The team benchmarked the study results against the 2018 study and similar utilities and identified how the results could be used in ENO's 2021 IRP.

2018 Potential Results

The 2018 and 2021 potential studies leveraged the same methodology, however, there are differences between the two studies.

Energy Efficiency

The 2018 and 2021 studied differed for the following areas:

1. Calibration targets differed for the two studies

   a. 2018 study relied on the historical programs and the 2018 immediate program goal, including delivery costs
   b. 2021 study relied on the existing program framework which has the program plans at or near 2% of consumption
2. Different assumptions on planned rollout for home energy reports
3. Updated data on residential saturation and density data using the Entergy residential appliance saturation study data
4. Updates to commercial saturation values based on year over year program data (for measures where data was available)
5. Changes in commercial lighting baseline and efficient assumptions
6. Updates in the TRM from version 1.0 to version 4.0
7. Addition of new measures
8. Assumptions on measures costs both from Guidehouse sources and the TRM were lower than the 2018 study

Demand response

The 2018 and 2021 demand response analysis differed in the following ways:

1. Guidehouse used actual data of implementation for C&I curtailment. There has been growth in program participation compared to the data from 3 years ago.
2. There is updated data on the penetration of smart thermostat data and updated AMI rollout plan.

These changes resulted in differences in program potential.

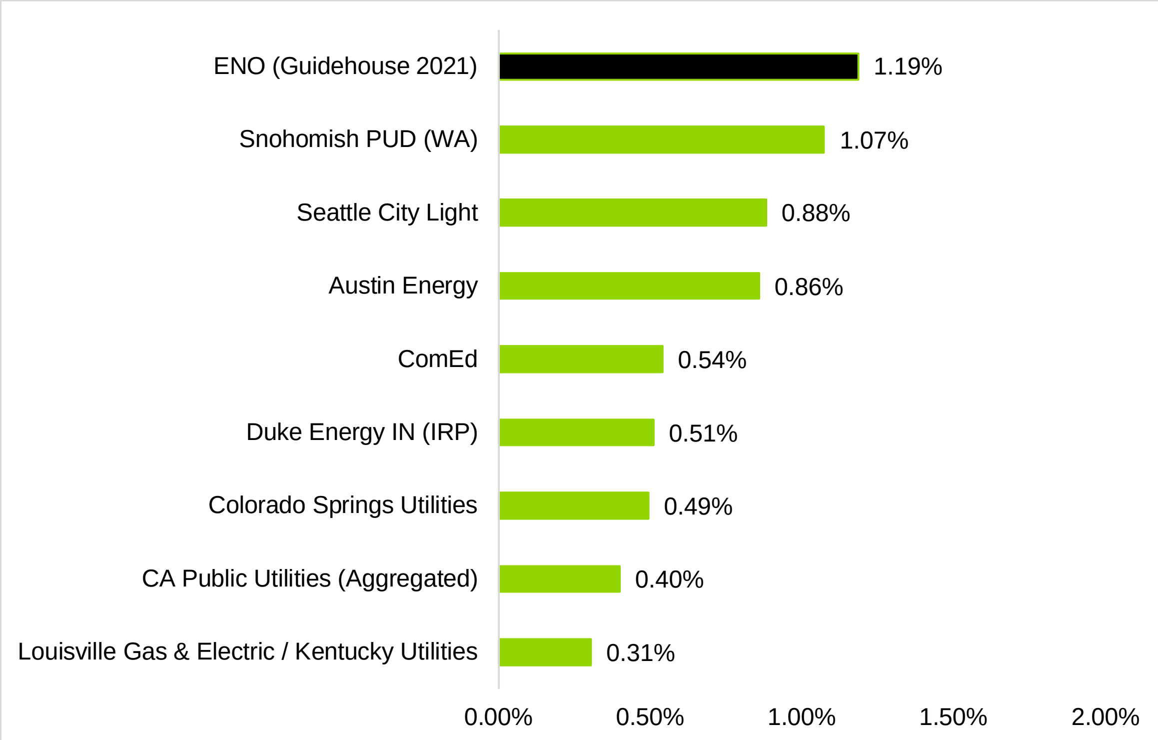
Benchmarking

Guidehouse benchmarked the EE and DR achievable potential results against the potential study findings of other utilities to provide context for our results and to understand how results may be influenced by various factors such as region or program spend.

Figure 13 illustrates how ENO's achievable EE savings potential compares with peer utilities as a percent of sales.[15] ENO is higher than other peer utilities.

[15] There have not been many updates to the peer utility data reports as of the 2018 ENO potential study.

Figure 13. Benchmarking Pool Average EE Achievable Potential Savings (% of Sales)[16]



Source: Guidehouse analysis

The team compared potential estimates and found that although the utilities included in the benchmarking pool may have some similar characteristics, no two utilities are the same; so 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.

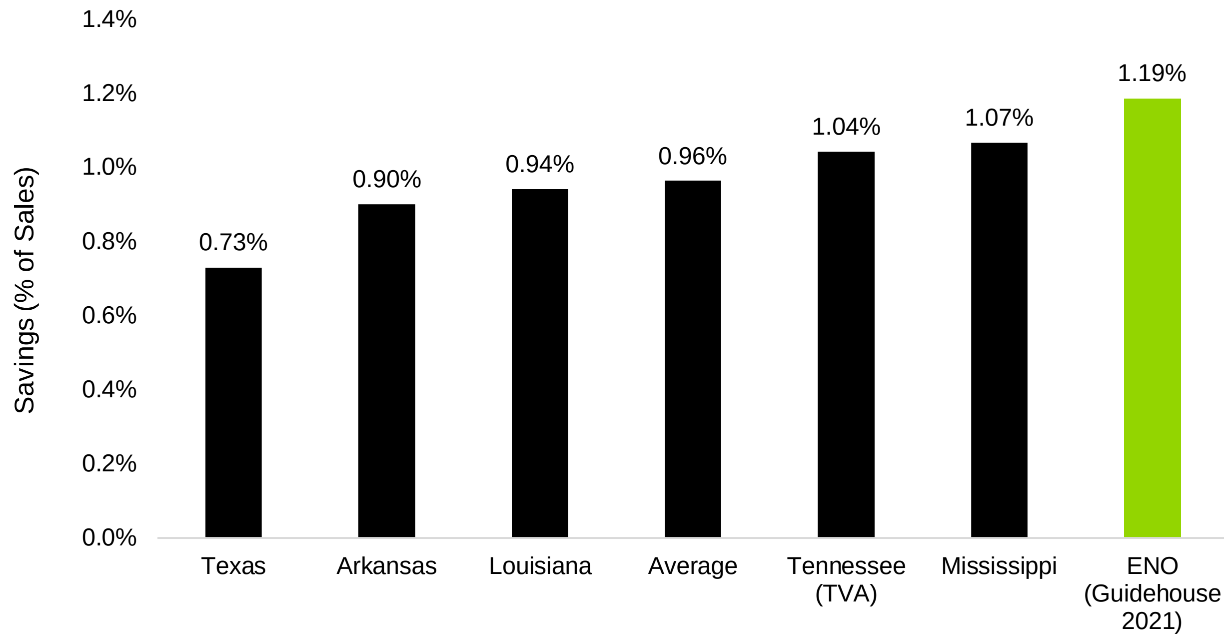
ENO's achievable potential is at the top of the range over the study period (2021-2040). This is similar to Snohomish PUD. Interestingly, both utilities operate in large metropolitan areas and have similar governance structures in that they are regulated by a city council.[17]

In addition to benchmarking the results at the utility level, Guidehouse created a peer pool at the state level. The team's goal 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 so may experience similar levels of achievable potential savings. Figure 14 shows how ENO's achievable potential is much higher than the broader state-level context.

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

[17] 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. No updates to Austin Energy and Seattle City Light data have been published since the 2018 DSM study.

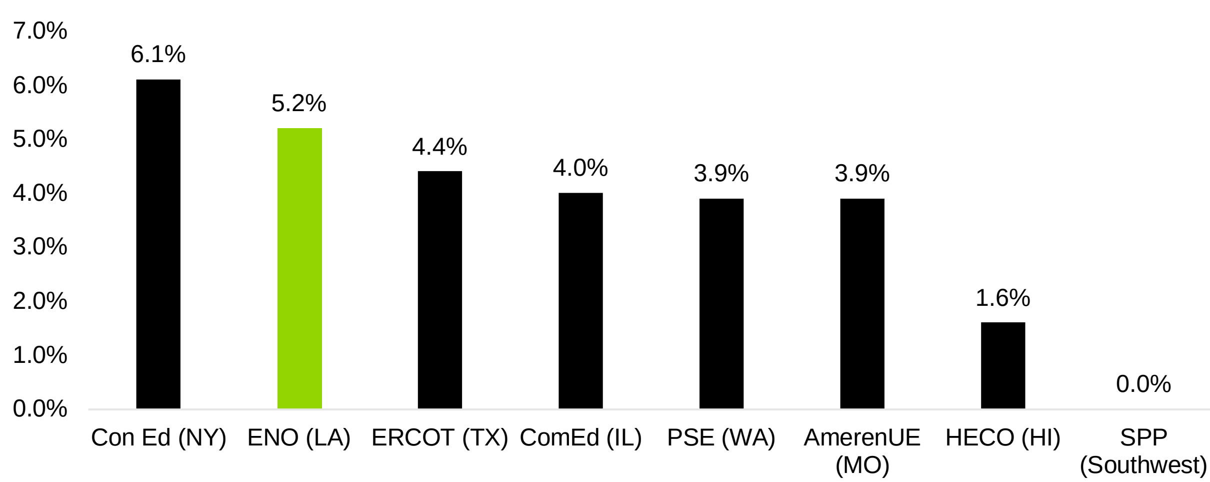
Figure 14. Benchmarking Pool State-Level EE Achievable Potential (% of Savings)



As Figure 14 shows, ENO's achievable potential savings is in the top of the range for the region at 1.19%. When reviewing the comparison, it is important to pay attention to the potential model framework differences, input assumptions, and other parameters for a complete picture of the benchmarking results

Guidehouse also benchmarked DR. Figure 15 displays the results.

Figure 15. Benchmarking Pool DR Potential (% of Savings)



As Figure 15 shows, ENO falls in the top of the benchmarking pool, only slightly higher than ERCOT and slightly below Con Edison in New York. Given that DR, like EE, varies based on program administration and geographic location, among other factors, ENO's DR potential aligns closely to its peers.

IRP

Guidehouse used the study's EE and DR potential savings findings to provide ENO with savings forecast inputs to include in the 2021 IRP modeling process. Guidehouse developed these inputs by sector, segment, and end use, as each combination of these classifications is mapped to a load shape within the IRP analysis (see **Error! Reference source not found.**).

Creating savings inputs for the IRP began with mapping each EE measure to one or more DSM programs. Guidehouse then developed a load shape representative of each DSM program as a whole based on its constituent measures. The resulting DSM program-level load shapes represent the aggregate hourly energy savings for the measures included in the program over the 20-year planning period spanning 2022 to 2041. These load shapes then define the hourly usage profiles for the DSM program portfolio within the IRP model.

Program Planning

This potential study provides ENO with a wealth of data to support and inform DSM program planning efforts. However, programmatic design considerations such as delivery methods and marketing strategies will impact savings goals and costs. **As a result, near-term savings potential, actual achievable goals, and program costs for measure-level implementation will differ from the savings potential and costs estimated in this long-term study.** The findings from this study can effectively be used along with historical program participation, current marketing conditions, and other relevant factors to aid in program design.

Key findings from this potential study may inform program planning, and include the following observations on high potential measures:

- Significant savings potential exists in promoting retro-commissioning, occupancy sensor controls and interior high bay and 4ft LEDs for the C&I sector.
- There is high potential in operations and maintenance (residential duct sealing and AC tune up) and behavior-type programs such as home energy reports in the residential sector.
- Significant demand response potential in the C&I sector for C&I curtailment and DLC; with the residential sector leading in peak demand reduction potential with the increased penetration of enabling technologies like smart thermostats.

As ENO proceeds to future program years, the Guidehouse team suggests research in the following areas:

- Review and update the TRM for high impact measures (for example ceiling insulation and duct sealing)
- Explore cost-effective opportunities, pricing structures, and research on additional benefits to behind the meter generation, including battery storage.

1. Introduction

1.1 Context and Study Goals

Entergy New Orleans, LLC (ENO) engaged Guidehouse to prepare a demand side management (DSM) potential study for electricity as an input to its 2021 Integrated Resource Plan (IRP) for the 2021-2040 period. The study assesses the long-term potential for reducing energy consumption in the residential and commercial and industrial (C&I) sectors by analyzing energy efficiency (EE) and peak load reduction measures and improving end-user behaviors. The EE potential analysis efforts provide input data to Guidehouse's DSM Simulator (DSMSim™) model, which calculates achievable savings potential across the service area. This study also includes demand response (DR) program potential analyzed within Guidehouse's DRSim™. While ENO primarily plans to use the results from the potential study to inform the IRP, these results may also be used as inputs to DSM planning, long-term conservation goals, and EE program design.

1.1.1 Study Objectives

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

Guidehouse designed its study approach to ensure the results adequately address ENO's objectives and the requirements of the Council's IRP rules. **Error! Reference source not found.** details these objectives and offers Guidehouse's approach to meeting each objective.

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

Objective		Guidehouse's Approach
1	Use consistent methodology and planning assumptions	Guidehouse 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 worked closely with ENO to ensure transparency, vet methodology, assumptions, and inputs at each stage of this study.
2	Reflect current information	Guidehouse used 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	Guidehouse quantifies achievable potential for EE and DR by first calculating the technical and economic (EE only) potential. The achievable potential 2% program case is then calibrated to the historical Energy Smart program data and the current programs approved by the Council for Energy Smart PYs 10-12.

	Objective	Guidehouse's Approach
4	Provide input to the IRP	Guidehouse'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

Source: Guidehouse

1.2 Organization of the Study

Guidehouse organized this study into five sections that detail the study's approach, results, and conclusions. The following list describes each section.

- **Section 1** summarizes the study, including its background and purpose.
- **Section 2** describes the methodologies and approaches Guidehouse used to estimate energy efficiency and demand reduction potential, including discussions of base year calibration, base forecast, and measure characterization.
- **Section 3** details the EE achievable potential forecast, including the approach and results by case, segment, end use, and measure.
- **Section 44** describes the process for estimating DR potential and details the achievable potential savings forecast for ENO, including the modeling results by customer segment. This section also includes our analysis of energy storage potential.
- **Section 5** summarizes the next steps that result from this study's findings and benchmarks those findings against similar potential studies' findings and actual savings achieved by other utilities.

The appendices detail 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. Potential studies typically begin as a bottom-up effort and then are calibrated to system and sector base year and base forecast consumption. They are an exercise in data management and analysis requiring a careful balancing of abundant data for some inputs with scarce data for others. Accordingly, the team must understand what data gaps exist, and determine how to fill them, to provide reasonable and realistic savings potential estimates. This study documents Guidehouse's approach and the decisions made in cases where appropriate data was not available. Throughout this study, the team leveraged the work conducted for ENO's 2018 IRP Potential study to maximize value to ENO's customers and ensure consistency.

1.3.1 Forecasting Limitations

Guidehouse obtained historic and forecasted energy sales and customer counts from ENO by sector. Each rate class forecast (i.e., residential and C&I) contains its own set of assumptions based on ENO's expertise and models. The team leveraged these assumptions frequently as inputs to develop the base forecast stock and energy demand projections. Where sufficient information could not be extracted due to the limited granularity of the available data, Guidehouse developed independent projections based on better practices. These independent projections were based on secondary data resources and produced in collaboration with ENO. Secondary resources and any underlying assumptions used are referenced throughout this study. Guidehouse referenced the previous 2018 IRP potential study and the existing, approved Energy Smart implementation plans to calibrate the forecast.

1.3.2 Segmentation

Guidehouse obtained data from ENO to segment the residential and C&I sectors, including customer counts by premise type for residential and industry type for C&I. The team supplemented this data through its subject matter expertise and ENO's experience and judgment to ensure alignment of sales and stock data with segments. Government customers were included as part of the C&I sector. Savings potential analysis from city-owned street lighting is not included in this study as the majority of lamps have been converted to LEDs.

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 considerable cost and time considerations. Guidehouse deemed existing primary and secondary data sources as most appropriate to this study.

Energy efficiency measures: The study's scope did not include primary data collection. The EE potential analysis relied on the New Orleans TRM[18] and included data from ENO and other regional efficiency programs and utilities to inform inputs to DSMSim™. Guidehouse sourced density and saturation data for the residential section from an Entergy residential appliance saturation study. Guidehouse used historical program participation data for the C&I programs to provide evidence on saturation levels of efficient technologies.

Guidehouse developed the measure list in this study to focus on those technologies likely to contribute the highest level of savings over the study horizon. As the study excluded nascent technologies not yet marketed, emerging technologies may arise that could increase savings opportunities over the forecast horizon. There is also the potential for broader societal changes (which are not captured in this study) to affect levels of energy use in unforeseen ways. This study does not model these potentially disruptive and unforeseen changes.

DR programs: The scope of this study leveraged available ENO data from the direct load control (DLC) pilot and "EasyCool" program to characterize DR program participation and costs. Additional DR characterization is based on Guidehouse's research on programs nationwide and other potential studies. The team used ENO load and account data to size the market eligible for DR program participation.

1.3.4 Measure Interactive Effects

This study models EE measures independently. The total aggregated EE potential estimates may be higher or lower than the actual potential available if a customer installs multiple measures in

[18] New Orleans Energy Smart Technical Reference Manual: Version 4.0, September 2020, prepared by ADM Associates, Inc. https://cdn.entergy-neworleans.com/userfiles/content/energy_smart/New_Orleans_TRM/New_Orleans_TRM_Version_4.pdf

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. If the controls reduce cooling requirements at the cooling unit, the savings from the efficient cooling unit are reduced. An example of a cross end-use interactive effect is when a homeowner replaces heat-producing, less efficient 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 HVAC system.

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

- Where measures compete for the same application (e.g., an air source heat pump being replaced by 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 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.

The team did not always consider the stacking of savings. These instances 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. Guidehouse did address stacking for residential behavior programs due to the planned rollout of the residential behavior program to a large percentage of ENO residential customers.

1.3.5 Measure-Level Results

This study includes a high level account of potential results across the ENO service area and focuses largely on aggregated forms of potential. Guidehouse 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

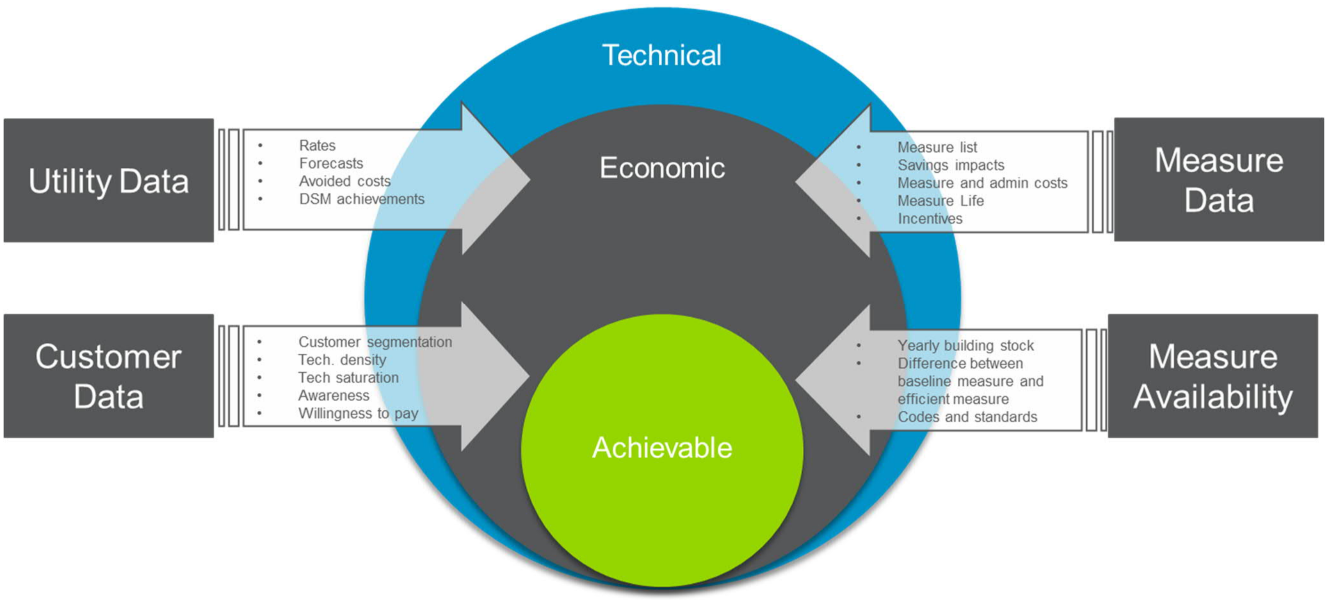
Savings in this study are shown at the gross level, meaning natural change (either natural conservation or natural growth in consumption) or, in other words, free-ridership, is not included in the savings estimates. Providing gross potential is advantageous because it permits a reviewer to easily calculate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

2. Study Approach and Data

2.1 Energy Efficiency

Guidehouse forecast technical, economic, and program achievable electric savings potential in the ENO service area from 2021 through 2040 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 thorough 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 Figure 2-1 illustrates.

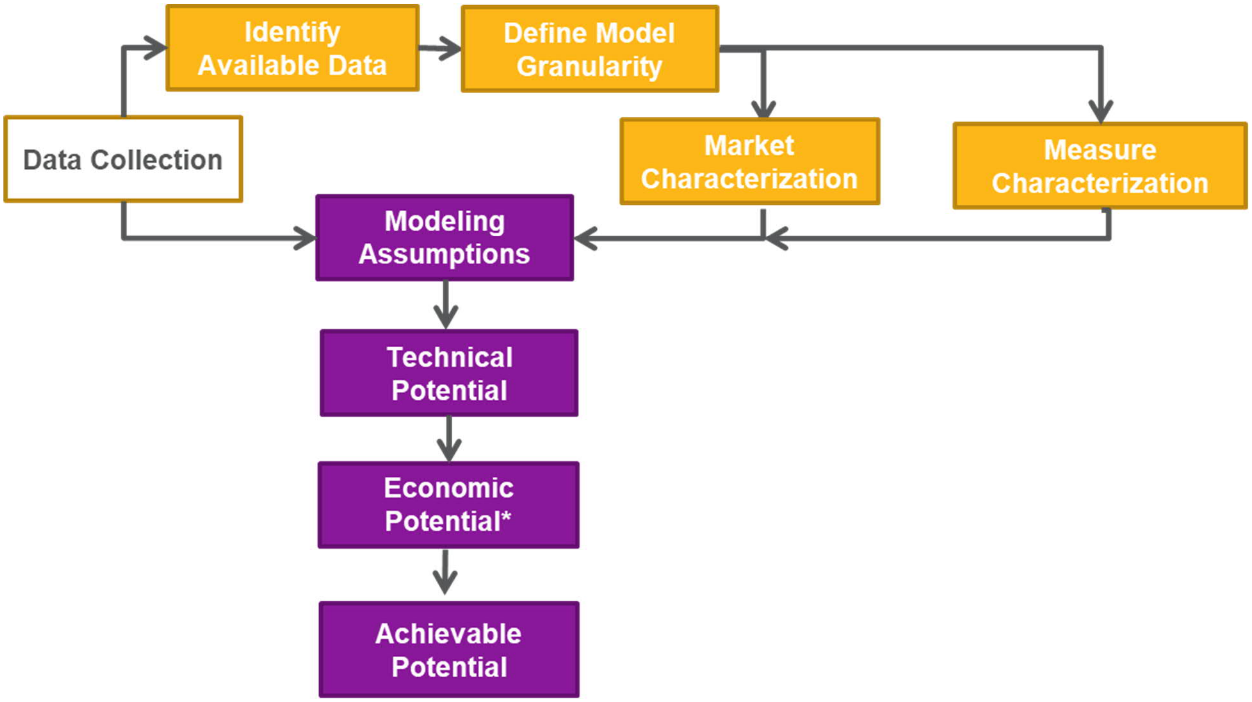
Figure 2-1. Potential Study Inputs



Source: Guidehouse

Calculating achievable potential includes several elements such as a base year calibration, a base forecast consumption, 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



*Not calculated for DR Potential

Source: Guidehouse

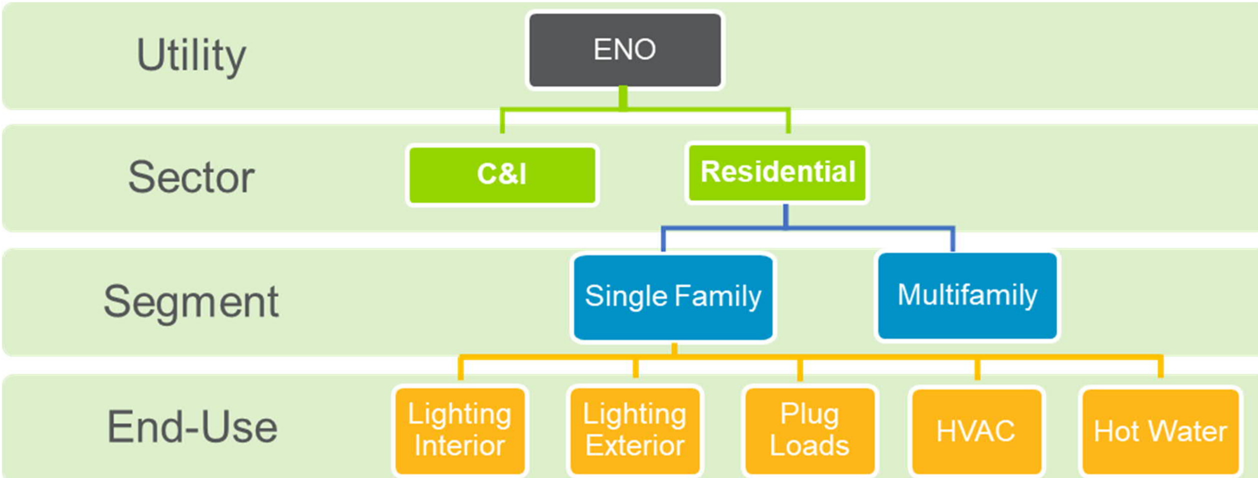
2.1.1 Market Characterization

Guidehouse'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 the base year profile and base forecast consumption used to calculate potential.

2.1.1.1 Base Year Profile

This section describes the approach used to develop the base year (2019) 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 and segment (Figure 2-3). The end use level data is not used in calculating potential. The selected year is the most recent year with actual (not forecasted) reported data. The model uses the base year as the foundation to develop the base forecast consumption of electricity demand from 2021 through 2040.

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



Source: Guidehouse

Guidehouse developed the base year profile based on ENO's 2019 billing and customer account data because it was the most recent year with a fully complete and verified dataset. Where ENO-specific information was unavailable, Guidehouse used data from publicly available sources such as the US Energy Information Administration (EIA) Commercial Buildings Energy Consumption Survey (CBECS) and the US Department of Labor Standard Industrial Classification (SIC) System, in addition to internal Guidehouse data sources. The team used these resources to support ENO's data sources and to ensure consistency.

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 the 2018 study, TRM characterization, data availability, and level of detail. Table 2-1. Customer Segments by Sector 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: Guidehouse analysis

2.1.1.3 Residential Segments

After establishing the study sectors and segments, Guidehouse and ENO aligned ENO's data to the definitions established in Table 2-1 established. For residential, the team divided the sector into two segments based on consumption: single family and multifamily. ENO provided Guidehouse with a 2016 household split survey, which broke down residential customers by household segment: single-family detached, duplexes, townhouses, and the like. Guidehouse mapped the household segments to the appropriate customer segment (single-family or 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, duplex/triplex/fourplex, attached row and/or townhouses (condominium), and mobile homes residential dwellings
Multifamily	Apartment units located in low rise or high rise apartment buildings

Source: Guidehouse

2.1.1.4 C&I Segments

Guidehouse combined the commercial, industrial, and government sectors, noted as C&I. Working with ENO, the team divided the C&I sector into 11 customer segments. Table 2-3. C&I Segment Descriptions describes 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 v4[19] and the SIC code for the account and kilowatt-hour sales data from ENO. This study differs from those sources; 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.

[19] There are different building types in the V4 of the TRM depending on the measure.

Segment	Description
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.
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: Guidehouse

2.1.1.5 Defining End Uses

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

The end uses in Table 2-4. End Uses by Sector, are important for reporting and defining savings, among other reasons. For instance, the team uses the categories to report achievable savings with more granularity than at the sector and segment levels. Guidehouse derives these reported end-use savings by rolling up individual EE 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
HVAC	HVAC
Hot Water	Hot Water
	Refrigeration

Source: Guidehouse

In addition to the end uses shown in Table 2-4. End Uses by Sector, Guidehouse reported savings for total facility. These savings represent the sum of all the individual end uses and any miscellaneous loads not captured. The previous study defined heating, cooling, heating and cooling (which was the sum of the heating and cooling), and ventilation separately.

2.1.1.6 Base Year Inputs

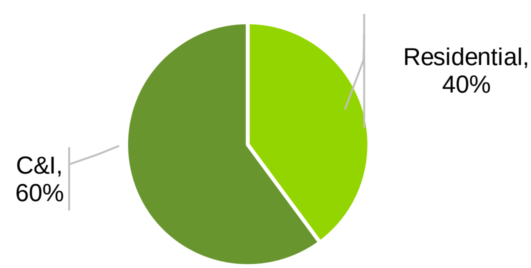
This section summarizes the breakdown of stock (households), electricity sales, and EUIs at the sector, segment, and end-use levels. The team used base year sales as direct inputs to the potential model. Appendix A describes the methodology used to develop these estimates. The DR portion of this study reconciles and derives the breakdown of demand across the sectors, segments, and end uses.[20]

Table 2-5. and Figure 2-4 show the high level breakdown of electricity sales by sector. Of total ENO reported 2019 electricity sales, 60% comes from the C&I[21] sector and 40% from the residential sector.

Table 2-5. 2019 Base Year Electricity Sector Sales (GWh)

Sector	GWh
Residential	2,353
C&I	3,468
Total	**5,821**

Figure 2-4. 2019 Base Year Electricity Sector Breakdown (%, GWh)



Source: Guidehouse analysis of ENO 2019 electricity sales

All other base year inputs are shown and detailed in the following sections.

Residential Sector

To define the base year residential sector inputs, Guidehouse began by determining the base year stock using ENO's number of households in the class breakdown, which was an estimated number of households in 2019 based off of an ENO survey conducted in 2016 and provided in Table 2-6.

Table 2-6. 2016 Survey Household Splits

Household Type	Percent of Total
Single-Family Detached House	63%
Duplex, Triplex, or Fourplex	13%
Condominium/Townhouse/Apartment	24%
Mobile Home or Manufactured Home	1%
Weekend or Vacation Home	1%

[20] Guidehouse developed the peak demand base year using the average peak demand factors from the 2019 sales data for the top 40 hours in each season.

[21] As noted in Section 2.1.1.4, C&I includes commercial, industrial and government sales.

Source: ENO data

Base year sales used the 2019 reported sales provided by ENO. Guidehouse used the 2016 household split survey results to calculate the segment-level base year sales by multiplying the household split by the total. From the 2018 study, Guidehouse had determined that multifamily households consume 67% of the electricity that a single-family household does based on data provided by ENO. Using this ratio, the single family and multifamily household splits were multiplied by the ratio of their energy use – 1 for single family, and 0.67 for multifamily – to calculate weighted household splits. Then to calculate the percentage of sales for each segment, the weighted household splits for each segment were divided by the summed weight of the single family and multifamily household splits. To calculate segment-level sales, Guidehouse multiplied the percentage of sales by the total reported 2019 sales.

Table 2-7. shows the base year residential stock, electricity sales, and average electricity usage per home by segment. The base year residential stock is approximately 186,000 homes and accounts for just over 2,350 GWh of sales.

Table 2-7. Base Year Residential Results

Segment	Stock (Accounts)	Electricity Use (GWh)	kWh per Account
Multifamily	46,100	425	9,219
Single-Family	140,143	1,928	13,759
Total	**186,243**	**2,353**	**12,635**[22]

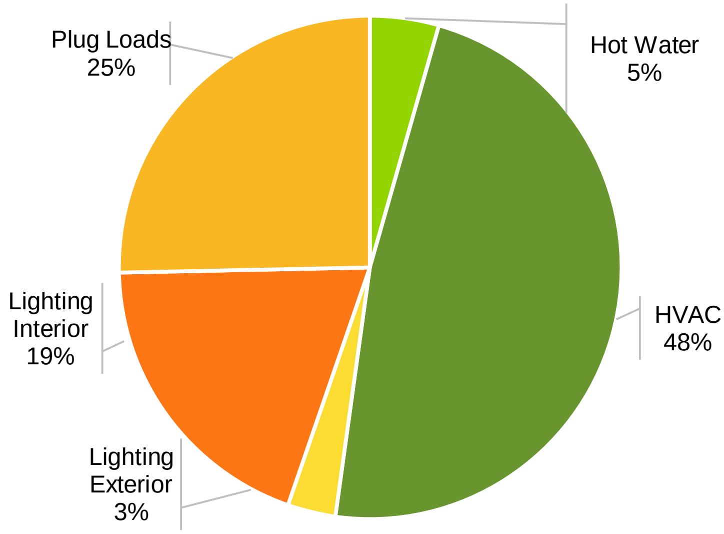
Source: Guidehouse analysis of ENO data

Figure 2-5 shows the breakdown of base year residential electricity sales by end use and segment. In terms of end uses, lighting, HVAC, and plug loads represent the largest residential end uses and account for 90% of residential electricity sales. HVAC represents the largest portion of the residential end uses at 48% of the total, and includes the sum of heating, cooling, and ventilation. This end use allocation was based on the 2018 study.[23]

[22] 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

[23] ENO provided Guidehouse end use breakdown analysis for its load forecast. The residential allocation was similar to Guidehouse's previous estimates.

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



Source: Guidehouse analysis

C&I Sector

Similar to the residential sector, Guidehouse 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. Guidehouse followed two steps to determine these values for the base year:

1. Define sales usage based on ENO's account and billing data
2. Determine the base year stock

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

For step 1, Guidehouse used a mapping of SIC codes to customer segment to aggregate ENO's account and billing data to the segment level for the base year 2019. Once the segment mapping was complete, Guidehouse used the segment-level intensities from EIA that were also used in the 2018 study for industrial. For commercial and government intensities, Guidehouse took the EIA segment-level intensities and adjusted them so the C&I sector-level intensity equaled the Itron intensity for 2019. Using the resulting intensities, Guidehouse calculated stock (square feet) for each segment by dividing sales by intensity.

Table 2-8 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 247 million SF and contributes approximately 3,468 GWh of sales.

Table 2-8. Base Year C&I Results

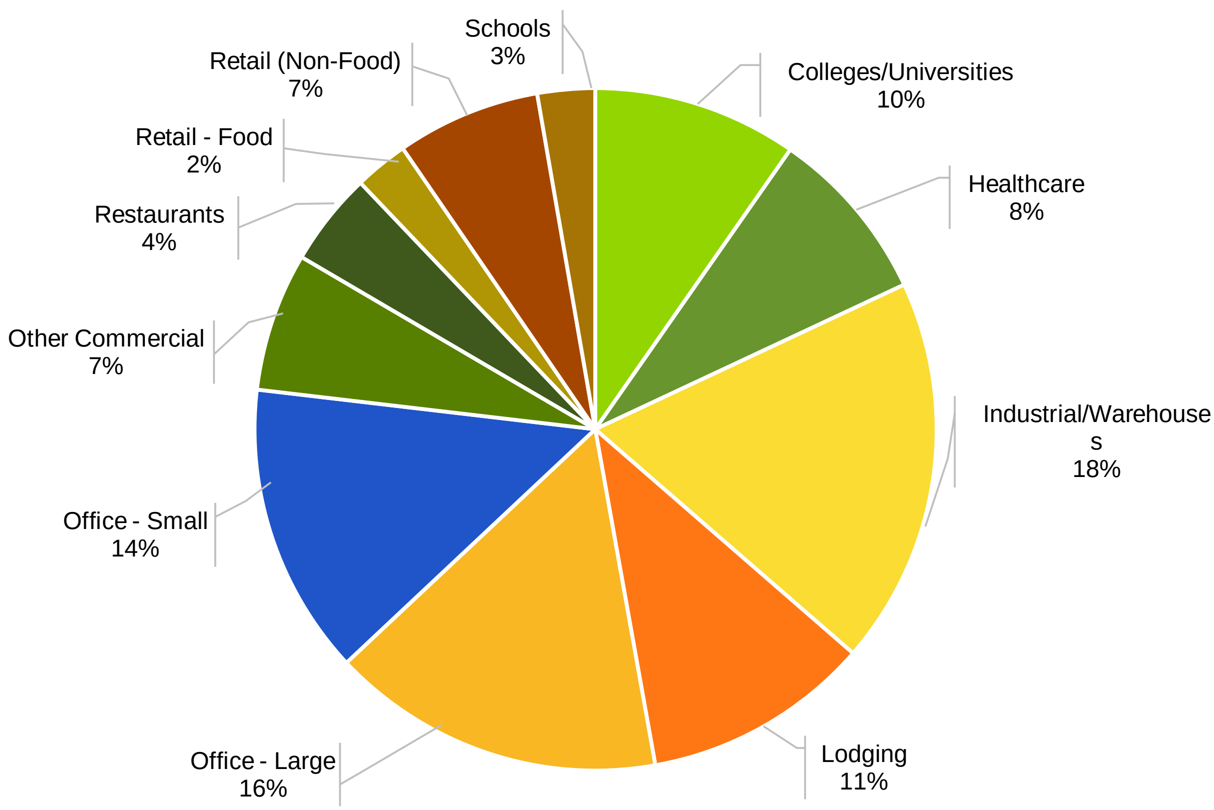
Segment	Stock (thousands SF)	Electricity Use (GWh)	kWh per SF
College/University	38,282	340	8.9
Healthcare	14,738	293	19.9

Segment	Stock (thousands SF)	Electricity Use (GWh)	kWh per SF
Industrial/Warehouse	22,602	642	28.4
Lodging	35,475	372	10.5
Office – Large	45,426	539	11.9
Office – Small	40,537	481	11.9
Other Commercial	15,243	229	15.0
Restaurant	4,754	153	32.2
Retail – Food	2,609	88	33.9
Retail – Non-Food	17,022	235	13.8
School	10,991	98	8.9
Total	**247,679**	**3,468**	-

Source: Guidehouse analysis

Figure 2-6 shows the breakdown of base year C&I electricity sales by segment. Offices and lodging consume the most electricity, accounting for almost half (40.5%) of C&I electricity sales.

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

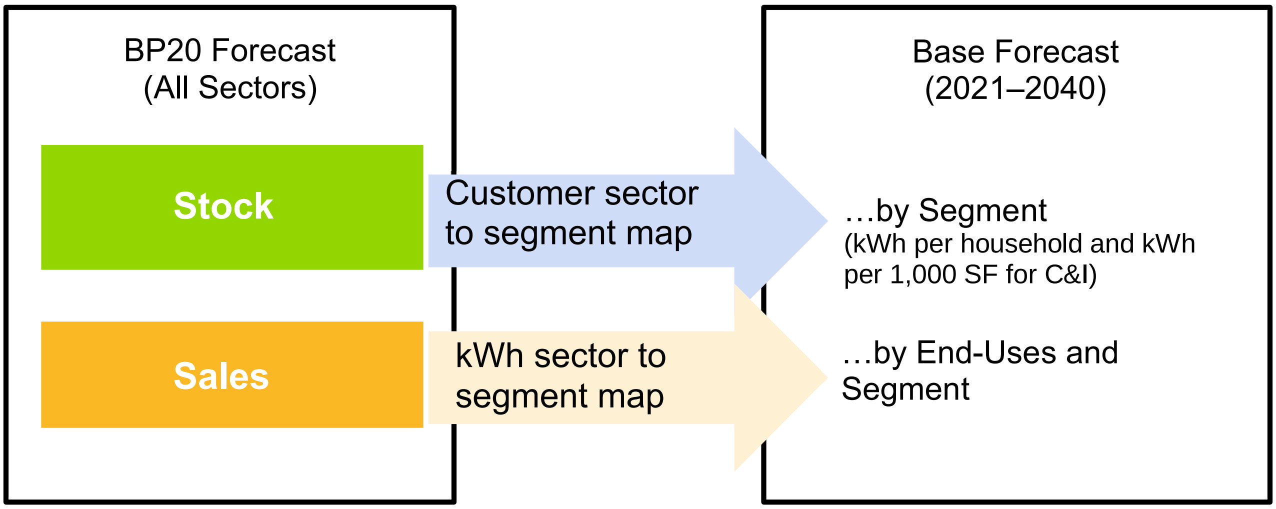


Source: Guidehouse analysis

2.1.2 Base Forecast Consumption

This section presents the base forecast consumption from 2021 to 2040. The base forecast consumption represents the expected level of electricity sales over the study period, absent incremental DSM activities or load impacts from rates. Electricity sales in the base forecast consumption are consistent with ENO's load forecast. The base forecast consumption is significant because it acts as the point of comparison (i.e., the baseline) for the calculation of achievable potential cases. Figure 2-7 illustrates the process Guidehouse used to develop the base forecast consumption. The base forecast consumption uses the Business Plan 2020 (BP20) forecast as its foundation and converts it to the required customer segments to develop the residential and C&I forecasts.

Figure 2-7. Schematic of Base Forecast Consumption



Source: Guidehouse

Guidehouse constructed the base forecast consumption by using the BP20 sales forecast and disaggregating from ENO sectors[24] to customer segments. The forecast applies 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. Appendix A provides the details.

2.1.2.1 Residential Base Forecast Consumption

Guidehouse used the BP20 residential customer count forecast to develop the base forecast consumption for stock. Using the same 2016 household split survey Section 2.1.1.5 describes, Guidehouse disaggregated the residential forecast to the segment level (single-family and multifamily) by multiplying the household segment percentages by the total residential forecast. Table 2-9. shows the growth in residential stock forecast from 2020 to 2040. Residential stock increases at an average annual growth rate of 0.5% from approximately 186,000 accounts in 2020 to around 205,000 accounts in 2040.

[24] ENO sectors were residential, commercial, industrial, and government.

Table 2-9. Residential Base Stock Forecast (Accounts)

Segment	2020	2040
Single-Family	140,143	154,780
Multifamily	46,100	50,914
Total	**186,243**	**205,694**

Source: Guidehouse analysis of ENOs residential load forecast

Guidehouse followed a similar methodology for sales, using ENO's forecasting. The team used the BP20 sales forecasts and disaggregated to the segment level using the class breakdowns adjusted for energy use, as Section 2.1.1.5 describes.

Guidehouse reviewed new ENO data sources (ENO load research data) with the 2018 study approach for defining the end-use proportion. Guidehouse determined that the 2018 method is suitable for use in the 2021 study since it aligned well with the ENO data sources.. Appendix A.2 details the end use energy intensity calculations.

2.1.2.2 C&I Base Forecast Consumption

Like the residential base forecast, Guidehouse built the C&I base forecast on the BP20 sales forecast from ENO. Appendix A.3 describes the process used to develop the C&I stock forecast.

To forecast the customer counts and sales, Guidehouse used the ENO forecast, which was at the ENO sector level (commercial, industrial, and government). Guidehouse converted the forecast to the segment level using a customer segment to sector map derived from the account and billing data.

To forecast the stock, Guidehouse developed escalators using the sales forecast and the Itron intensity forecast. For non-industrial segments, Guidehouse divided the sales forecast by the Itron intensity forecast and converted the resulting time series into an escalation factor. For industrial segments, Guidehouse escalated stock based on the forecasted number of customers. Then the escalation factors were applied to the base year stock to develop the base forecast through 2040.

Table 2-10. shows the results of the reference case analysis.

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

Segment	2019	2040
Colleges/Universities	37,477	46,548
Healthcare	14,443	17,939
Industrial/Warehouses	22,242	22,389
Lodging	35,396	43,962
Office – Large	45,886	54,077
Office – Small	40,150	49,867
Other Commercial	15,035	18,673
Restaurants	4,745	5,894
Retail – Food	2,604	3,234
Retail – Non-Food	16,981	21,090

Segment	2019	2040
Schools	10,663	13,244
Total	**245,623**	**296,917**

Source: Guidehouse analysis

Guidehouse used the 2018 end-use proportions to distribute energy use among end uses. Appendix A.3 details the 2018 process. The new ENO data from the load research analysis did not provide end use allocation by building segment. The building segment specific end use energy intensity is a more definitive data set for the potential analysis.

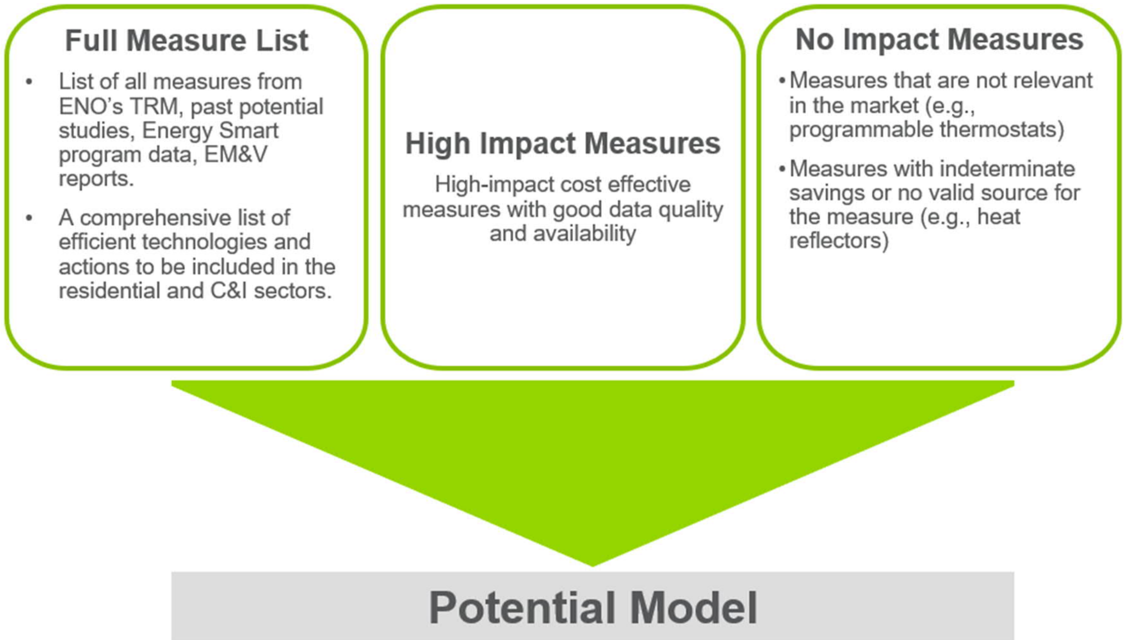
2.1.3 Energy Efficiency Measure Characterization

Guidehouse characterized 146 measures across ENO's residential and C&I sectors. While finalizing the measure list, the team prioritized high impact, cost-effective measures with good data quality and availability.

2.1.3.1 Measure List

Guidehouse developed a thorough list of EE measures likely to contribute to achievable potential. The team used the measure list from the 2018 ENO potential study as the basis and updated it with measures in the New Orleans Energy Smart TRM v4, current ENO Energy Smart program offerings, and potential model measure lists from other states to identify EE 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 California, Illinois, and the mid-Atlantic. Guidehouse 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 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 2-8 shows the process Guidehouse implemented to finalize the measure list.

Figure 2-8. Measure Screening Process



Source: Guidehouse

There were measures included in the initial screen that did not make it into the study. Working sessions with ENO staff revealed the following measure information:

- **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. Programmable thermostats were not included in this study as they have limited potential with the advent of Wi-Fi thermostats.

- **Industrial measures:** ENO reported that its industrial energy use is relatively low compared to commercial and residential sectors. Guidehouse retained the industrial measures from the 2017 potential study and did not add any new industrial measures. The team aggregated the industrial sector potential with the commercial sector potential.

2.1.3.2 Measure Characterization Key Parameters

The measure characterization effort involved defining nearly 50 individual parameters for each measure included in this study. This section defines the top 14 parameters and how each influences the technical and economic (and also achievable) potential savings estimates.

Table 2-11. includes parameters used to qualitatively define each characterized measure.

Table 2-11. Measure Characterization Parameter Definitions

Parameter Name	Definition	Example
Baseline Measure	Existing inefficient equipment or process to be replaced.	Central Air Conditioner 15 SEER
Energy Efficiency Measure	Efficient equipment, process, or project to replace the baseline.	ENERGY STAR Central Air Conditioner 18 SEER
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 solar water heaters compared to a baseline of regular storage water heaters	Storage Water Heater: 10 years Solar Water Heater: 15 years
Measure 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.	Baseline cost: $690 Efficient cost: $500
Replacement Type	Identifies when in the technology or building's life an efficiency measure is introduced. Replacement type affects when in the potential study period the savings are achieved as well as the duration of savings and is discussed in greater detail in Section 2.1.4.1	Retrofit (RET), replace-on-burnout (ROB) and new construction (NEW)
Annual Energy Consumption	The annual energy consumption in electricity (kWh), demand (kW) for each baseline and energy efficiency measure.	Baseline: 196 kWh/year Efficient: 163 kWh/year
Unit Basis	The normalising unit for energy, demand, cost, and density estimates.	Per bulb, per hp, per kWh consumption.
Scaling Basis	The unit used to scale the energy, demand, cost and density estimate for each measure according to the reference forecast.	Per home, per 1,000 SF of commercial area, etc.
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.	ENERGY STAR room air conditioners are mapped to the HVAC end use in the single family and multi-family segments.
Measure Density	Used to characterise the occurrence or count of a baseline or energy efficiency measure, or stock, within a residential household or within 1,000 square feet of a commercial building. This parameter was not defined for industrial measures.[25]	35 bulbs per household.

[25] Guidehouse sourced density estimates from the Entergy 2016 Residential Appliance Saturation Survey (ENO RASS), Energy Smart program data and other related secondary sources. Additionally, the density value addressed any reference to fuel type splits for space and water heating.

Parameter Name	Definition	Example
Energy Efficiency Saturation	The fraction of the residential housing stock or commercial building space that has the efficiency measure installed each year. For the industrial sector, saturations are based on energy consumption.	40% of all residential bulbs are LEDs so saturation of LEDs is 40%.
Technical Suitability	The percentage of the base technology that can be reasonably and practically replaced with the specified efficient technology.	Occupancy sensors have a technical applicability of less than 1.0 because they are only practical for interior lighting fixtures that do not need to be on at all times.
Competition Group	Identifies measures competing to replace the same baseline density in order to avoid double counting of savings. Section 2.1.4.1 provides further explanation on competition groups.	Efficient storage tank water heater or a tankless water heater can replace an inefficient storage water heater, but not both.

2.1.3.3 Measure Characterization Approaches and Sources

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

Table 2-12. Measure Characterization Input Data Sources

Measure Input	Data Sources
Measure Costs, Measure Life, Energy Savings	• New Orleans Energy Smart Technical Reference Manual: Version 4.0 • Energy Smart program data • 2018 ENO potential study data • US DOE Appliance Standards and Rulemakings supporting documents • Engineering analyses • TRMs • Guidehouse measure database and previous potential studies
Fuel Type Applicability Splits, Density, Baseline Initial Saturation, Technical Suitability, End-Use Consumption Breakdown	• Entergy 2016 Residential Appliance Saturation Survey (ENO RASS) • Energy Smart program data • Guidehouse's previous potential studies
Codes and Standards	• US DOE engineering analyses • Local building code

Source: Guidehouse

2.1.3.4 Energy Savings

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

1. **New Orleans TRM calculations:** The New Orleans Energy Smart TRM v4 was the primary source for unit energy savings calculations. The TRM provided deemed (default) savings values for majority of the measures in the study.
2. **Standard algorithms:** Guidehouse used standard algorithms for unit energy savings calculations for most measures not contained in the New Orleans TRM. To supplement this, the team used ENO Energy Smart Program Evaluation Reports, other relevant TRMs such as the Illinois and Mid-Atlantic TRM, and DOE Appliance Standards and Rulemaking supporting documents.
3. **Engineering analysis and engineering studies:** Guidehouse used engineering algorithms to calculate energy savings for any measures not included in the New Orleans TRM or other available TRMs. The team also referenced established engineering studies with savings estimates in absence of engineering algorithms. The team used its internal expertise with potential studies to calculate energy savings for measures that were not a part of the New Orleans TRM v4.

2.1.3.5 Peak Demand Savings

Peak demand savings were either from the New Orleans Energy Smart TRM v4 or 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. According to the TRM, the defined peak period is the average peak demand savings, Monday-Friday, non-holidays from 4-6 p.m. in June, July, and August.

2.1.3.6 Incremental Costs

New Orleans Energy Smart TRM v4 was the primary source for incremental cost information. The team conducted secondary research and used other publicly available cost data sources such as the Illinois and the Mid-Atlantic TRMs, California TRM, ENERGY STAR, US DOE Appliance Standards and Rulemaking for measures where cost information was not available in the ENO TRM.

2.1.3.7 Densities

For the residential density values, we used the Entergy 2016 Residential Appliance Saturation Survey to extract square footage of home by housing type, space heating and cooling system splits, density and saturation values for measures such as dishwashers, clothes washers, dryers, refrigerators, thermostats, windows, attic insulation, central air conditioners and room air conditioners. Our team cross tabulated the data for each housing type to get these values for single-family and multifamily segments.

For commercial measures, the density values from the previous potential study were retained for most measures. Measure saturations were updated for measures available in the Energy Smart Program data. The Commercial Building Stock Assessment (CBSA) and previous potential studies in other jurisdictions were reviewed for any other overall updates to the saturation values. For water and space heating measures, the fuel type multipliers from the previous ENO potential study were incorporated directly into the measures. For commercial lighting, measure densities were updated based on recent lighting studies in other jurisdictions as the previous ENO potential study was using values from an older study conducted in 2015.

2.1.3.8 8,760 Load Profile

No updates were made to the 8,760 load profiles in the 2021 study. This study leverages the 2018 developed load profiles **Error! Reference source not found.** describes. There was no new data to leverage or to develop new load profiles. These load shapes should still be representative of customer usage patterns in ENO territory. These profiles are 8,760 (i.e., hourly annual) end-use load shapes. These profiles are by end use (e.g., heating, lighting), by sector (e.g., residential, commercial), and by commercial and industrial segments (e.g., retail, office).

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)[26] contain information on energy and cost impacts of each appliance standard. In the TSD, Chapter 5 includes engineering analysis, Chapter 7 includes energy use analysis, and Chapter 8 includes cost impact. 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. Guidehouse accounts for the effect of codes (including building code[27]) 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. Guidehouse incorporated the 2023 residential central ACs 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 study's first year.[28]

These codes and standard adjustments were made to the following measures based on DOE standards:

- Omni-Directional LEDs
- Advanced Networked Lighting Controls with Omni-Directional LEDs
- Furnace Fan Motor Retrofit
- Energy Star Pool Pumps

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

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

[28] It is important to note that the second tier of Energy Independence and Security Act of (EISA) 2007 regulations went 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.

- Energy Star Dehumidifiers
- Air Source Heat Pump
- Central AC
- Ground Source Heat Pump
- Ductless Heat Pump - ROB and NEW

2.1.3.10 Measure Quality Control

Guidehouse 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 operations and maintenance (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

2.1.4 Potential Estimation Approach

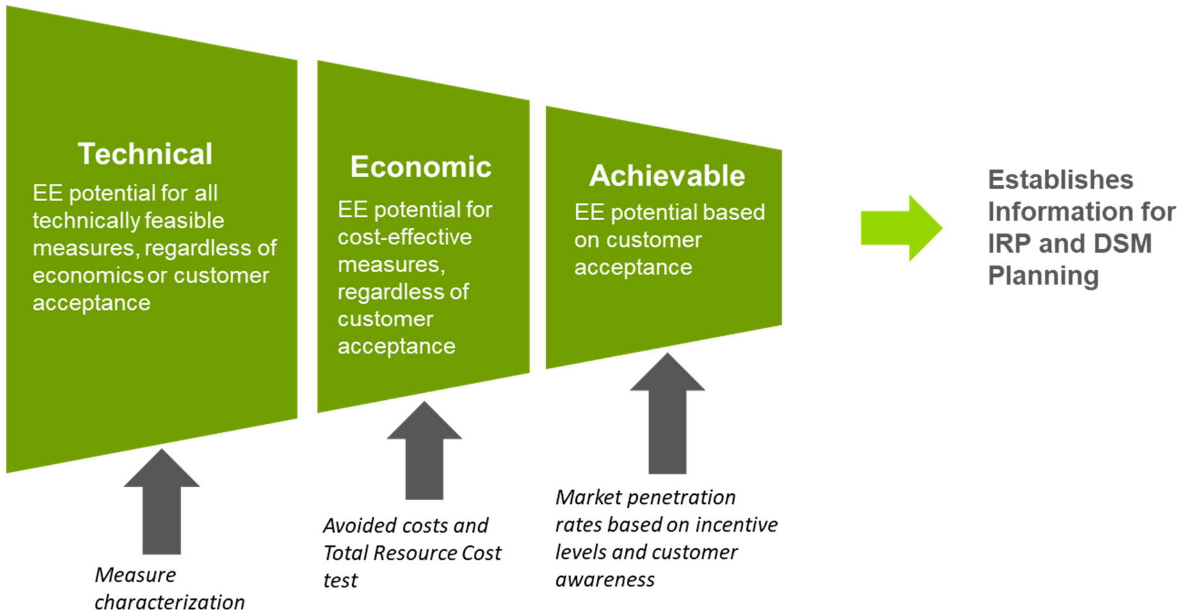
Guidehouse used its proprietary DSMSim™ potential model to estimate the technical, economic, and achievable savings potential for electric energy and demand across ENO's service area. DSMSim™ is a bottom-up technology diffusion and stock tracking model implemented using a System Dynamics[29] framework. The DSMSim™ model accounts for different efficiency 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. This assumption is made 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

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

is analyzed based on the measure adoption ramp rates and the diffusion of technology through the market. Figure 2-9 details the methodology.

Figure 2-9. Potential Calculation Methodology



Source: Guidehouse

Savings reported in this study are gross rather than net, meaning they do not include the effects of natural change. Providing gross potential 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 help 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 or technology—wherever technically feasible. This assumption is made regardless of the cost, market acceptance, or whether a measure has failed and must be replaced.

Guidehouse's modeling approach considers an energy efficient measure to be any change made to a building, piece of equipment, process, or behavior that saves energy.[30] 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 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., AC equipment) are best characterized on a basis that is normalized to a certain aspect of the equipment, such as per ton

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

of AC 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. Equation 2-1 through Equation 2-3 show the formulae used to calculate technical potential by replacement type.

Retrofit and ROB Measures
Commonly referred to as advancement or early retirement measures, RET measures are replacements of existing equipment before the equipment fails. RET measures can also be efficient processes that are not in place and that are not required for operational purposes. These 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 thus would incur no costs. In contrast, ROB measures—sometimes referred to as lost opportunity measures—are replacements of existing equipment that 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 to NEW measures. In any given year, the model uses the existing building stock to calculate technical potential.[31] 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 added throughout the simulation. For RET and ROB measures, annual potential is equal to total potential, offering an instantaneous view of technical potential. Equation 2-1 calculates technical potential for RET and ROB measures.

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

$$Total\ Potential = Existing\ Stock\ x\ Measure\ Density\ x\ Savings\ x\ Technical\ Suitability\ \ x\ Baseline\ Initial\ Saturation$$

Where:

- Total Potential: kWh
- Existing Stock:[32] C&I floor space per year or residential households per year
- Measure Density: Widgets per unit of stock
- Savings: kWh per widget per year

[31] 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.

[32] 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.).

- 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.[33] 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; 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. Equation 2-2 and Equation 2-3 provide calculations of technical potential for new construction measures.

Equation 2-2. Annual Incremental NEW Technical Potential

$$\begin{gathered} Annual\ Incremental\ NEW\ Technical\ Potential \\ = New\ Stock\ x\ Measure\ Density\ x\ Savings\ x\ Technical\ Suitability \end{gathered}$$

Where:

- Annual Incremental NEW Technical Potential: kWh
- New Stock:[34] 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. Occupancy sensors have a technical applicability of less than 1.0 because they are only practical for interior lighting fixtures that do not need to be on at all times.

Equation 2-3. Total NEW Technical Potential

$$Total\ NEW\ Technical\ Potential = \sum_{YEAR=2020}^{YEAR=2040} Annual\ Incremental\ Technical\ Potential_{YEAR}$$

Competition Groups

Guidehouse'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

[33] 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.

[34] 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.)

pump or a ground source heat pump, but not both. These efficient technologies compete for the same installation.

Guidehouse used several competing technologies characteristics 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, Guidehouse'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 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 Guidehouse'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).

Guidehouse 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. 0 presents the avoided costs, discount rates, and other key data inputs used in the TRC calculation. The study's results did not include the effects of free ridership, 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, except for behavioral programs, 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 avoided 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" that 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 of 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.

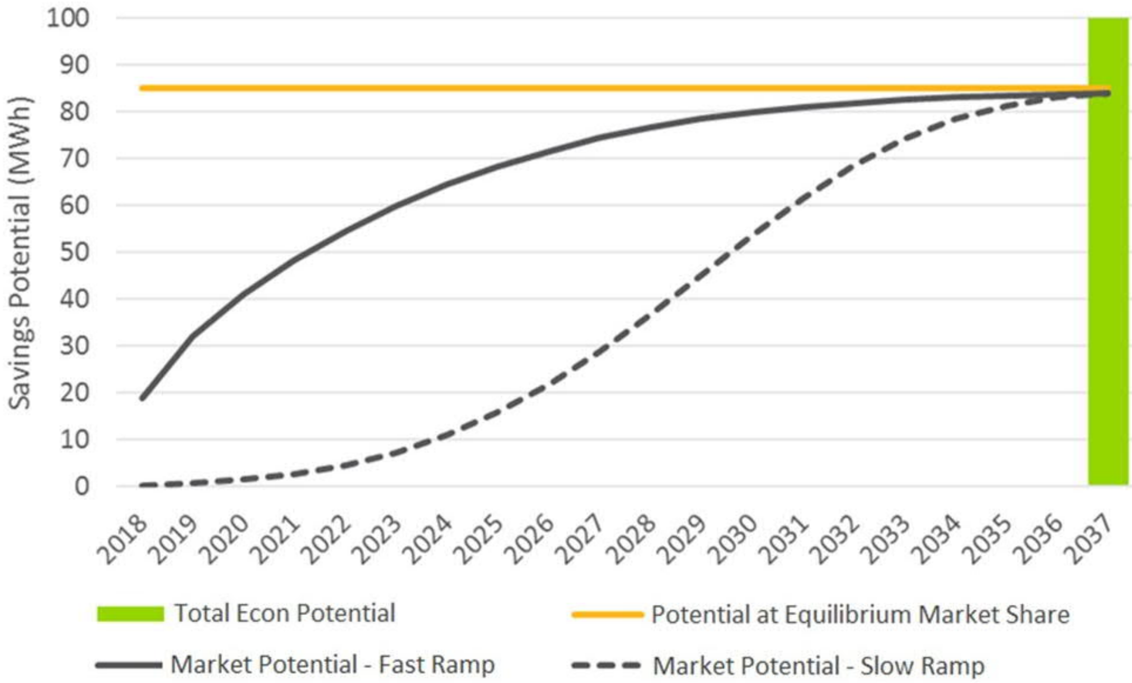
Using the definitions of cumulative total technical potential provided in Section 2.1.4.1, Equation 2-5 shows the calculation for achievable potential. Guidehouse calculated achievable potential by multiplying each measure's total economic potential by its maximum achievability factor and then applying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

Equation 2-5. Achievable Potential

$$\begin{aligned} &Achievable\ Potential_{Year} \\ &\qquad = Total\ Economic\ Potential \times Max\ Achievability\ Factor \times Ramp\ Rate_{Year} \end{aligned}$$

Figure 2-10 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 2-10**. Illustration of Achievable Potential Calculation**



Source: Guidehouse

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).

Guidehouse 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

Guidehouse prepared a DR potential assessment for ENO's electric service area from 2021 to 2040 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.

Guidehouse 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. **DLC:** This program controls water heating and cooling loads for residential and small business customers using either a DLC device (switch) or a PCT. For air conditioning control, this option represents the "EasyCool" program that ENO offers to residential and small business customers using load control switches and smart thermostats.[35]
2. **C&I Curtailment:** This represents the "Energy Smart Large Commercial Demand Response" program that ENO currently offers where large commercial customers agree to reduce load by a specific amount when called and get paid based on performance.
3. **Dynamic pricing:** This program encourages load reduction through a critical peak pricing (CPP) tariff, with a 6:1 critical peak to off-peak price ratio. All customer types are eligible to participate.
4. **Behind-the-meter storage (BTMS):** As required for study by the Council's initiating resolution, this program triggers power dispatch from behind-the-meter (BTM) battery storage systems that are grid-connected during peak load conditions. Battery dispatch helps reduce net system load during DR event periods.

Guidehouse developed programmatic assumptions (participation, unit impacts, and costs) for these DR options and estimated potential and cost-effectiveness under "achievable" participation assumptions. The team 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. Guidehouse assessed the cost-effectiveness of the DR program options and included only cost-effective DR options in the final achievable potential estimates.

2.2.1 General Approach and Methodology

Guidehouse developed ENO's DR potential and cost estimates using a bottom-up analysis, which 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 Guidehouse'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.

[35] The switch based DLC program is only offered to residential customers and the smart thermostat-based program is offered to both residential and small business customers.

- **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 2-13. presents the different levels of market segmentation for the DR potential assessment. It is based on Guidehouse's examination of ENO's rate schedules and the customer segments established in the EE potential study. The team finalized the market segmentation for the DR potential assessment in consultation with ENO.

The methodology Guidehouse 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 2-13. 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[36] 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: Guidehouse

[36] Descriptions of these customer segments can be found in Table 2-3. C&I Segment Descriptions.

Guidehouse 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, Guidehouse segmented C&I customers into two sizes (small and large) and further segmented them into customer segments. To do this, the team requested 2019 account-level maximum billed demand data from ENO. As Section 2.1.1 notes, 2019 was chosen as the base year because it would have been the most recent year with a fully complete and verified dataset. However, the account level maximum demand data was not available for 2019 and therefore Guidehouse used the segment level small/large split from the 2018 Potential Study.[37]

The team mapped the SIC codes associated with individual accounts to customer segments in the analysis, similar to the approach used by the EE potential study team in its market characterization effort. Then, the team used the 2018 study split of customers into small and large C&I by customer segment, using a cutoff value of 100 kW maximum demand for the small vs. large classification.[38] This cutoff value was determined in consultation with ENO and is aligned to ENO's EE programs when there is a specific offer to the small business 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 the type of DR program offer varies by customer size.

2.2.3 Baseline Projections

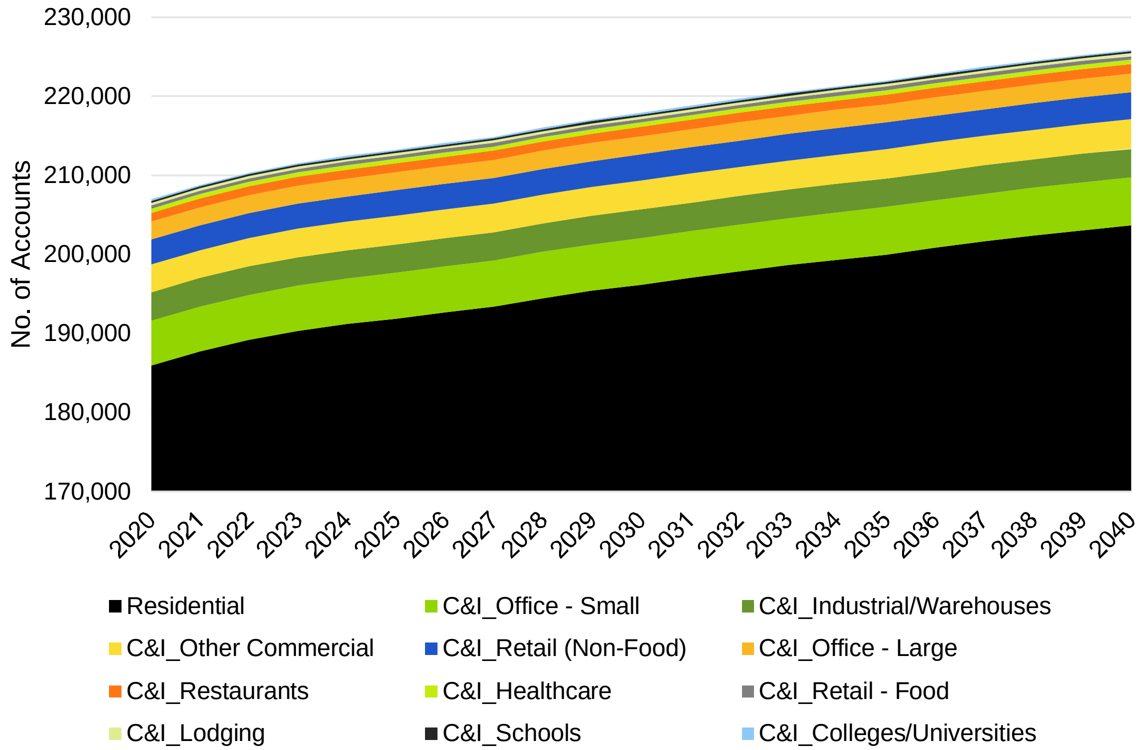
2.2.3.1 Customer Count Projections

Guidehouse applied year-over-year change in the stock forecast (described in Appendix A.2 and A.3) to the 2019 customer count data segmented by customer class and customer segment to produce a customer count forecast for the DR potential study. The team trued up this forecast to the sector-level customer count forecast provided by ENO. Figure 2-11 shows the aggregate customer count forecast by segment only, summed across all customer classes.

[37] "2018 Integrated Resource Plan DSM Potential Study"; prepared for Entergy, submitted by Navigant Consulting; August 31, 2018.

[38] Since specific SIC codes map to small and large offices, Guidehouse 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 2-11. Customer Count Projections for DR Potential Assessment



Source: Guidehouse

2.2.3.2 Peak Demand Projections

The first step in developing peak demand projections is to define the peak period. This study only considered DR potential for summer peak reduction. Guidehouse kept the same summer peak definition as the 2018 potential study based on an examination of the 2019 hourly system load data. The system load shape for 2019 is similar to what the 2018 study used. Additionally, Guidehouse wanted to maintain consistency in the peak definition with the previous study. ENO expressed a desire to align the peak period definition with times MISO is expected to see peak demand. This allows ENO to use 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 period (June through August) during the hours from 2:00 p.m. through 6:00 p.m."[39] Guidehouse 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, Guidehouse only included the top 40 weekday hours within this window, which is the typical limit for calling summer DR events. This assumption is consistent with the 2018 study assumption which found that 95% or greater of ENO's system peak occurred within the top 40 hours based on an examination of historical system load data, which is what utilities typically target to call DR events.

Once the team defined the peak period, Guidehouse developed a disaggregated bottom-up peak demand forecast by customer class and segment. The team also estimated the end-use breakdown of the peak demand for C&I customers, as reduction estimates are typically expressed

[39]MISO. *Business Practice Manual,* BPM 026, -Demand Response. Effective date: July 20, 2020, pg 20.

as a percentage of baseline load for these customers. The step-by-step methodology Guidehouse used to develop the baseline peak load projections follows:

1. **Disaggregate sales forecast by customer class and customer segment:** Guidehouse first projected the base year (2019) sales data, segmented by customer class and customer segment, over the study horizon using the year-over-year change in building stock. The team used the segment level sales projections developed for the EE potential assessment and applied the rate class split from the 2018 potential study, since the maximum demand data for differentiation into small and large categories was not available from ENO for the current study.
2. **Use 8760 load profiles by revenue class to calculate coincident peak load factors by revenue class:** Guidehouse received 8760 load profiles by revenue class from ENO for 2019. Based on the peak period definition, the team used the load profiles to estimate the average coincident peak load factor by revenue class. The team calculated the average hourly demand by revenue class, coincident with the top 40 system load hours, and used this in conjunction with the sales data by revenue class to calculate the coincident peak load factor by revenue class. Per industry-standard definition, coincident peak load factor is calculated as follows:

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

3. **Estimate weighted average coincident peak load factors by customer class and segment:** Guidehouse developed weighted average coincident peak load factors by customer class and segment by combining the coincident peak load factors by revenue class, developed in step 2 above, with the revenue class distribution data (distribution based on sales) within each customer class and segment to estimate the weighted average coincident peak load factor by customer class and segment. The peak load factor derived in this manner is shown in Table 2-14.

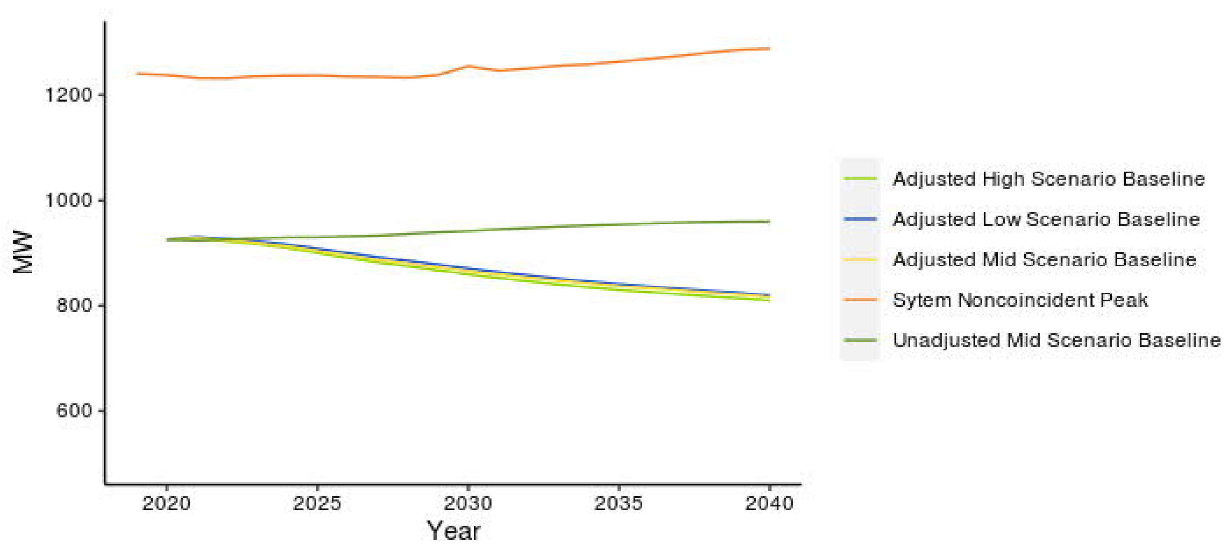
Table 2-14. Peak Load Factor by Segment

Customer Segment	Peak Load Factor
C&I_Colleges/Universities	0.68
C&I_Healthcare	0.68
C&I_Industrial/Warehouses	0.80
C&I_Lodging	0.66
C&I_Office - Large	0.50
C&I_Office - Small	0.50
C&I_Other Commercial	0.67
C&I_Restaurants	0.65
C&I_Retail - Food	0.65
C&I_Retail (Non-Food)	0.66
C&I_Schools	0.70
Residential	0.50

Source: Guidehouse

4. Apply weighted average coincident peak load factors to sales projections to estimate average coincident peak demand by customer class and segment: Guidehouse applied the average coincident peak load factors by customer class and segment, developed in step #3 above, to the disaggregate sales projections by customer class and segment (described earlier in step#1) to develop average coincident summer peak demand projections by customer class and segment. The team retained the end-use shares in peak demand from the 2018 study since there were no updates to building simulation runs from the 2018 study in the current study. Therefore, the end-use load profiles by segment from the 2018 study served as the best available information source for end-use shares in peak demand.
5. **Adjust baseline load for DR potential estimation with EE achievable potential estimates**: Since EE leads to permanent load reductions in the baseline load, the baseline load for DR needs to be adjusted with EE potential estimates. Figure 2-12 below shows the disaggregate peak demand projections before and after EE adjustments. The top line in the figure below represents ENO's noncoincident peak demand projections at the system level.[40] This is used as a reference to compare the disaggregated bottom-up peak demand projections by customer class and segment. The "unadjusted mid case baseline" represents the bottom up disaggregate peak demand projections by customer class and segment, described in steps #1 through #4 above. This projection is adjusted with the EE achievable potential estimates for all three cases (low, mid, and high) to derive the downward sloping "adjusted baseline" projections for all three cases. This graph indicates that the baseline peak demand projections progressively decline over time with higher penetration of EE.

Figure 2-12. Peak Demand Forecast Comparisons



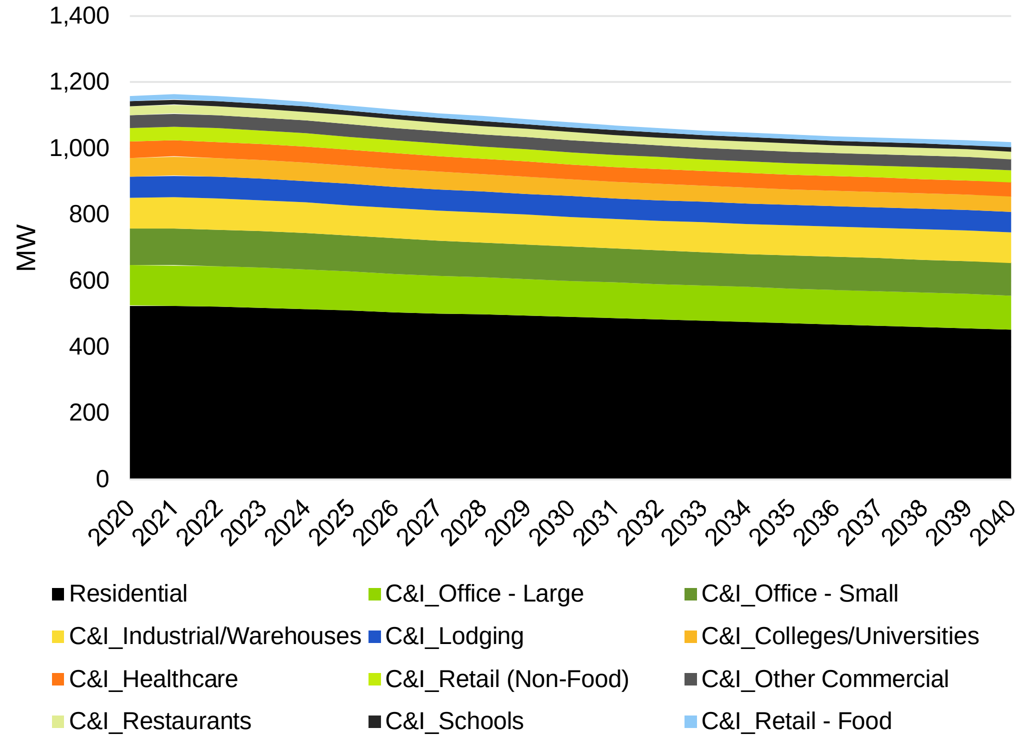
Source: Guidehouse

Figure 2-13 shows the disaggregate peak demand projections by customer segment and Figure 2-14 shows the disaggregate C&I peak demand by end-use for the mid case, derived from all five

[40] The noncoincident system peak is the sum of the sectoral peak demands provided by ENO.

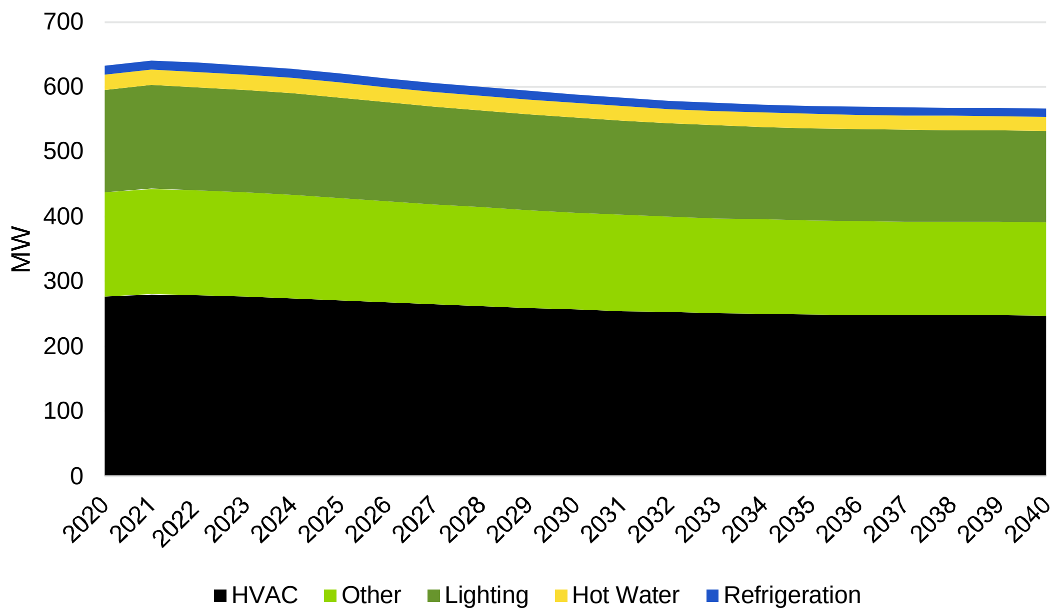
steps described above. The disaggregated peak demand projections establish the foundation for DR potential estimates.

Figure 2-13. Peak Load Forecast by Customer Segment (MW)



Source: Guidehouse

Figure 2-14. Peak Load Forecast by End Use for C&I Customers (MW)



Source: Guidehouse

2.2.4 Descriptions of DR Options

Once the baseline peak demand projections were developed, the team characterized different types of DR options that could be used to reduce peak demand. Table 2-15 summarizes the DR options included in the analysis. The DR options represent ENO's current DR program offers and those that are 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 detailed below.

Additionally, the Council requested a specific analysis of battery storage potential in the 2021 IRP Initiating Resolution, R-20-257:

"Whereas, further, the Council is specifically interested in evaluating the feasibility of a customer DER program whereby customers would receive an incentive to install energy storage facilities on their property controlled by the utility, such that the utility could direct when the storage units dispatch stored electricity onto the distribution grid. The Council directs ENO to include such a measure as one of the measures evaluated in the DSM potential…"

Guidehouse analyzed battery storage potential with details provided in 5.4Appendix D documenting the approach and analysis results. This analysis addressed the feasibility of a customer DER program for receiving an incentive to install dispatchable storage units.

Table 2-15. Summary of DR Options

DR Option	Characteristics	Eligible Customer Classes	Targeted/ Controllable End Uses and/or Technologies
DLC[41] ✓ Load control switch ✓ Thermostat	Control of cooling load using either a load control switch or smart thermostat; control of water heating load using a load control switch.	Residential Small C&I	Cooling, water heating
C&I Curtailment ✓ Manual ✓ Auto-DR enabled	Firm capacity reduction commitment with pay-for-performance ($/kW) based on nominated amount or actual performance.	Large C&I	Various load types including HVAC, lighting, refrigeration, and industrial process loads

[41] This represents both the switch-based and smart thermostat based "Easy Cool" program offered by ENO to residential and small business customers (switch-based option offered only to residential customers and smart thermostat-based option offered to both residential and small business customers).

DR Option	Characteristics	Eligible Customer Classes	Targeted/ Controllable End Uses and/or Technologies
Dynamic Pricing[42] ✓ Without enabling technology ✓ With enabling technology	Voluntary opt-in dynamic pricing offer, such as Critical Peak Pricing (CPP)	All customer classes	All
BTMS ✓ Standalone battery storage	Dispatch of BTM batteries for load reductions during peak demand periods.	All customer classes	Batteries

Source: Guidehouse

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 2-16 summarizes this segmentation. The different types of DR options are described in detail below.

Table 2-16. 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-CAC/Heat Pump (BYOT)	Residential
	Switch-CAC/Heat Pump	Residential
	Thermostat-HVAC (BYOT)	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	

[42] Guidehouse 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.

DR Option	DR Sub-Option	Eligible Customer Classes
BTMS	BTMS-Battery Storage	Residential, Small C&I, Large C&I

Source: Guidehouse

2.2.4.1 Direct Load Control

DLC involves ENO directly controlling electric water heating and cooling load using a load control switch or a smart thermostat. ENO currently offers the "EasyCool" program that uses a load control switch for cycling Central Air Conditioning (CAC) or heat pump system. In addition, ENO offers the Bring Your Own Thermostat (BYOT) option to residential and small business customers under the same programs. The DLC option modeled in this potential study represents both the switch-based and the smart thermostat-based program offers. In the switch-based option, ENO is responsible for installing the switch to control the CAC/heat pump unit. The smart thermostat-based option represents a BYOT approach where the residential and small business customers are responsible for smart thermostat purchase and installation and ENO does not bear any responsibility for that. In addition, the DLC option includes electric water heating control for residential and small C&I customers using a load control switch where ENO is responsible for purchase and installation of the switches for controlling water heaters.

Table 2-17 summarizes the DLC program characteristics considered in this study.

Table 2-17. 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 C&I customers using either a DLC device (switch) or a smart thermostat. PCT, where and when applicable. • Both switch-based and smart thermostat-based (BYOT) offers apply to residential customers, while only the smart thermostat-based offer (BYOT) applies to small C&I customers.[43] • Switch-based electric water heating load control apply to both residential and small C&I customers.
Purpose/Trigger	DLC events will be called primarily to meet capacity shortfalls during summer, triggered primarily by a high day-ahead temperature forecast.

[43] These assumptions are consistent with ENO's current program offers.

Item	Description

Key Program Design Parameters	• Events will be called during peak demand periods in summer (June 1 through September 30), only on non-holiday weekdays.
	• Switch-based option for CAC/heat pump control[44]:
	  o CAC or heat pump cycled for 2-4 hours during events
	  o Event window: 12 p.m. to 8 p.m.
	  o Enrolled customers receive upfront $25 incentive payment at the time of enrollment, plus $40 each season they participate.
	  o No advanced notification provided to customers.
	  o Customers can opt-out of an event by calling ENO
	• Smart thermostat-based option[45]
	  o Maximum 15 events called during summer
	  o Enrolled customers receive upfront $25 incentive payment at the time of enrollment, plus $40 each season they participate.
	  o Eligible thermostats listed in the EasyCool program site.
	  o Event notification varies by thermostat provider
	  o Load reduction achieved through a max. 4-degree temp. offset
	  o Event window: 12 p.m. to 8 p.m.
	  o Max. event duration: 4 hours
	  o Customers can opt-out any time at the thermostat, mobile device or web app
	• Customers may be precooled prior to an event taking place.

Participation Eligibility	• Residential and small C&I customers with CAC and heat pumps • Residential and small C&I customers with electric water heaters
Dependent Technology and Metering	**Technology:** Switches control water heating, central air conditioning, or heat pumps. Smart thermostats control 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: Guidehouse

2.2.4.2 C&I Curtailment

The C&I curtailment program modeled in the potential assessment represents the "Energy Smart Large Commercial Demand Response" program that ENO currently offers.[46] Under this program, ENO contracts with a DR service provider to deliver a fixed amount of load reduction. Enrolled participants nominate a certain amount of load reduction. In return, they receive a fixed incentive

44 https://www.energysmartnola.info/wp-content/uploads/2020/07/2020-EasyCool-Switch-FAQs.pdf
45 https://enrollmythermostat.com/faqs/entergyno/
46 https://energysmartadr.com/wp-content/uploads/2020/06/Energy-Smart-Large-Commercial-DR-Trifold-Brochure-V4.pdf

payment in the form of reservation payments (expressed as $/kW-year) for being on call. Participants are paid based on performance when DR events are called. Only customers with greater than 100 kW demand qualify for enrollment. The program requires a minimum 20kW curtailment per metered site for enrollment[47]. Once enrolled, customers are required to fulfill the nominated amount of load reduction when DR events are called. A specific site could curtail a variety of end-use loads depending on the types of business processes. All load reductions are Auto-DR enabled.

Table 2-18 describes the C&I curtailment program characteristics considered in this study.

Table 2-18. C&I Curtailment Program Characteristics

Item	Description
Program Name	C&I Curtailment[48]
Program Description	This is a voluntary program offer to large C&I customers with greater than 100 kW demand The Large Commercial Demand Response Program ("DR Program") is a voluntary program that pays incentives to commercial and industrial customers for reducing a specified level of load reduction through on-site load reduction equipment. Customers receive fixed $/kW-yr. payment for being on call to deliver load reductions when DR events take place. When DR events are called, customers are paid based on the actual kW reduced during an event against their baseline load. This program is currently being administered by a third-party. 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. The entire load curtailment in this program is Auto-DR (ADR) enabled.
Purpose/Trigger	DR events could be triggered by operating, reliability, and/or economic purposes.[49]
Key Program Design Parameters	• Sites require to fulfill minimum 20 kW load reduction for participation. However, ENO may allow 10 kW reduction per site in cases where two or more sites in aggregate curtail at least 30 kW. • Event window: May 1 to September 30 during summer • Maximum event hours: 40 hours during summer; 30 hours during winter. • Event notification: Day-of (via email and/or text) • Incentive: $23/kW for summer[50]
Participation Eligibility	Large C&I customers with greater than 100 kW demand.

[47] Entergy may lower this requirement if a customer with two or more sites can curtail at least 30 kW.

[48] Represents the Energy Smart Large Commercial DR program currently offered by ENO.

[49] This study estimates summer peak reduction potential only from this program.

[50] A reduction in credit applies for underperformance. If Customer fails to meet at least 75% contracted reduction performance, corresponding Incentive Payment will be pro-rated based on actual performance. If Customer's seasonal average exceeds 150% of contracted reduction performance, corresponding Incentive Payment will be reduced by 50% of kW reduced past 150% *(Source: Entergy Commercial DR Agreement).*

Item	Description
Dependent Technology and Metering	**Dependent technology:** 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 energy management systems (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 or smart meters.

Source: Guidehouse

2.2.4.3 Dynamic Pricing

Dynamic pricing refers to a Critical Peak Pricing (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 on-peak price ratio. The off-peak rate is lower than the customer's Otherwise Applicable Tariff (OAT) and therefore customers have an incentive to enroll in the CPP rate vis-à-vis their existing tariff. It is best practice in the industry to provide bill protection during the first year of enrollment in the tariff so that customer bills do not exceed what they would have paid under their existing tariff. 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. ENO could offer CPP 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 advanced metering infrastructure (AMI) meters for settlement purposes. Hence, the rate offer is tied to AMI deployment. This study assumes that ENO offers the CPP rate from 2023 onward to account for lead time for rate design and approval before launching the program. Table 2-19 describes the dynamic pricing program characteristics considered in this study.

Table 2-19. Dynamic Pricing Program Characteristics

Item	Description
Program Name	Dynamic Pricing

Item	Description
Program Description	Opt-in CPP offer to all customers with a 6:1 critical peak to off-peak price ratio.
Purpose/Trigger	• Events are primarily called for economic purposes (high market prices). • Events can be called during summer months. • Current study estimates potential for summer peak reduction.
Key Program Design Parameters	• Event window: May 1 to September 30 during summer. • Event notification is typically day-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: Guidehouse

2.2.4.4 Behind-the-Meter Storage

BTMS refers to a program through which ENO would offer an incentive to customers to install battery storage behind the meter in their homes or businesses in exchange for the customers' allowing ENO to control their battery systems to discharge power to the grid during peak load conditions. ENO does not have data on the number or capacity of non-grid interconnected backup generators at customer sites in its service area, so the technology was not considered for this program in this study. Guidehouse assumed the market adoption and size for battery storage systems using internal analysis, described in 5.4Appendix D. Customer adoption of batteries is driven by customer economics (payback period). Guidehouse assumed that ENO shares a portion of the installed battery costs and additionally provides performance incentives (on a $/kW basis) for dispatching batteries. Both the upfront cost sharing and the pay for performance incentives are built in the customer economics calculation to estimate likelihood of battery adoption by customers.

Table 2-20 describes the BTMS program characteristics.

Table 2-20. BTMS Program Characteristics

Item	Description
Program Name	Behind-the-Meter Storage (BTMS)

Item	Description
Program Description	• Program assumes an arrangement between ENO and the end-use customer where customers receive incentives for purchase and battery installation with a commitment to ENO to have the battery capacity available for dispatch by ENO during system needs. • 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. • ENO shares a portion of the upfront battery capital plus installation cost. Program assumes that ENO shares 50% of the upfront battery capital plus installation cost for residential customers and 20% of the upfront battery capital plus installation for C&I customers in order to incentivize battery adoption. In addition, ENO pays customers on a $/kW basis for the dispatched capacity (kW) when called.
Purpose/Trigger	Events are called any time of the year to meet grid needs. Events could be triggered by emergency/reliability needs, economic purposes and to fulfill operating reserve requirements (spin, non-spin, regulation).
Key Program Design Parameters	• Batteries can be dispatched any time of the year based on grid needs. • Average event duration: 2-3 hours per event. • Event notification is typically day-ahead and/or 1-2 hours ahead[51]. • No. of annual events: can go considerably higher than other programs/technologies since batteries are highly dispatchable. Maximum number of annual events can be set at 60.[52]
Participation Eligibility	• Residential – customers with solar • Commercial – customers with solar and/or demand charges
Dependent Technology and Metering	All customers need PV-tied or standalone batteries with grid interconnection.

Source: Guidehouse

2.2.5 Key Assumptions for DR Potential and Cost Estimation

This study includes two key variables that feed the DR potential calculation:

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

[51] The notification time will vary based on the on the type of trigger. If ENO were to use batteries for meeting operating reserve requirements (spin, non-spin, regulation), the notification time could be considerably shorter as these services require fast response.

[52] National Grid's Connected Solutions sets maximum number of events at 60. https://www.nationalgridus.com/media/pdfs/bus-ways-to-save/connectedsolutions-madailydispatchflyer.pdf

Other variables that impact DR potential calculation include participation opt-out rates, technology market penetration, and enrollment attrition rates. Guidehouse 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. 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. Equation 2-6 summarizes the technical potential calculation.

Equation 2-6. DR Technical Potential

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

Guidehouse calculated the achievable potential by multiplying achievable participation assumptions (subject to the program participation hierarchy) by the technical potential estimates. Market potential also accounts for customers opting out during DR events. Equation 2-7 shows the calculation for achievable potential.

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. Guidehouse 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, technology lifetimes, and a discount rate. Table 2-21 summarizes the variables Guidehouse used to calculate DR potential and its associated costs in this analysis. These variables are discussed further in the following subsections.

Table 2-21. 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: Guidehouse

2.2.5.1 Participation Assumptions and Hierarchy

Participation assumptions differ by customer class and segment. Participation assumptions are informed by ENO's current program enrollment data and projections from program implementers, and benchmarking with similar programs offered by other utilities.

Participation assumptions are developed as "% of eligible customers". For the EasyCool program, eligible customers are those with CAC/heat pump and electric water heating. For the Bring Your Own Thermostat (BYOT) option within DLC, the DR team obtained smart thermostat penetration from the EE study and used that data to inform total number of eligible customers for the BYOT program. The team applied participation assumptions to these eligible customers. For the C&I Curtailment program, only automated DR (ADR) is considered based on ENO's current Large Commercial Demand Response program offer. Therefore, customers with Energy Management System that can be pre-programmed to execute curtailment strategies in response to DR event signals are eligible to participate. In this case, the DR team obtained EMS saturation projections from the EE analysis and used that information to establish eligibility in C&I Curtailment DR program participation. For dynamic pricing, Guidehouse assumed that the Critical Peak Pricing (CPP) rate is offered to customers once AMI is deployed. For the BTMS program, only customers with BTM batteries can participate and therefore participation in the DR program is tied to battery adoption projections.

Guidehouse also accounted for participation overlaps among the different DR programs in estimating potential. Table 2-22 presents the participation hierarchy for 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)[53] and adopted in other DR potential studies. The participation hierarchy helps avoid

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

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 2-22. Program Hierarchy to Account for Participation Overlaps

Customer Class	DR Options	Eligible Customers
Residential	DLC - Thermostat	Customers with central AC or heat pumps controlled using smart thermostats
	DLC - Switch	• For CAC/Heat Pump control: customers with CAC/heat pump • For water heating control: customers with electric water heating
	Dynamic Pricing	Customers not enrolled in DLC
	BTMS	Customers with batteries
Small C&I	DLC - Thermostat	Customers with central AC or heat pumps controlled using smart thermostats
	DLC - Switch	For water heating control: customers with electric water heating
	Dynamic Pricing	Customers not enrolled in DLC
	BTMS	Customers with batteries
Large C&I	C&I Curtailment	Customers with Energy Management System (EMS) to enable Auto-DR
	Dynamic Pricing	Customers not enrolled in C&I Curtailment
	BTMS	Customers with batteries

Source: Guidehouse

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 differ and are specified accordingly. Unit impacts can be specified either directly as kilowatt reduction per participant or as percentage of enrolled load[54]:

- DLC sub-options use kilowatt 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

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

- BTMS uses a percentage of the battery load

This study used 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

Guidehouse 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) 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 $/year, which primarily includes full time equivalent 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.

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

- **Nominal discount rate** of 7.09% used for net present value (NPV) calculations.

- **Inflation rate** of 2% used to inflate the costs over the forecast period (2021-2040).

- Transmission and distribution (T&D) line loss of 4.4%.

- **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 and account for program design constraints. These design constraints include 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 dispatchable generator, which does not have similar availability constraints and could be available round the clock.[55]

To assess the benefits associated with DR programs, Guidehouse used the avoided generation capacity projections provided by ENO. Guidehouse calculated benefit-cost ratios for the TRC, program administrator cost (PAC), ratepayer impact measure (RIM), and PCT for this study, consistent with the Council's IRP rules. The TRC Benefit-Cost ratios are used for screening for cost-effectiveness using a 1.0 B/C ratio threshold.

[55] "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
"2016 Demand Response Cost-Effectiveness Protocols", July 2016, California Public Utilities Commission
"2019-2021 ADR BCR Model" for National Grid, which shows no derating for batteries.

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 is challenging, as future data is not available to compare against model predictions. While engineering models 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. DSM models must rely on other techniques to provide the developer and the recipient with a level of comfort that simulated results are reasonable. For this study, Guidehouse 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 2019) and planned savings for Energy Smart PY10-12. Although in some studies DSM potential models are calibrated to ensure first-year simulated savings precisely equal prior-year reported savings, Guidehouse notes that forcing such precise agreement may 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). Although the team endeavored to achieve reasonable agreement between past results and forecasted first-year results, the team's approach did not force the model to do so, providing 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 kilowatt-hour costs and comparing them to 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 full measure cost approach. This approach calculates measure-level incentives based on a specified percentage of full measure costs. ENO provided Guidehouse data regarding the average incentives as a percent of the installation invoice (in other words, the full measure cost) by sector. For example, if the specified incentive percentage was 50% and a measure's cost was $100, then the calculated incentive for that measure would be $50. Guidehouse used the full measure cost strategy since ENO provided its historical program incentives based on full measure costs.[56]

3.1.2 Achievable Cases Analysis

For the 2021 IRP Potential Study, Guidehouse ran four cases for achievable EE potential. Three of the cases were derived from Scenario 2 of the approved Energy Smart PY10-12 implementation plan and set incentives for potential measures based on a percentage of the Full Measure Cost (FMC). One case was derived from the base case used in the 2018 IRP Potential Study and set incentives for potential measures based on a percentage of the Incremental Measure Cost (IMC) in order to offer a case showing an industry standard level of incentives.

FMC takes into account the full cost of installing a measure, while IMC represents the additional cost of installing a higher energy efficiency measure as compared to installing a base level energy efficiency measure. Guidehouse set incentive levels at 86% and 32% of FMC for residential and commercial programs in the 2% Program case, respectively. These percentages are consistent with what is currently being seen in Energy Smart program implementation when looking at incentive level compared with the full invoice cost of the measure. Guidehouse then varied the percentages for the Low and High Program cases. The Reference case used IMCs because it was based on the Base case from the 2018 IRP Potential Study performed by Navigant, in which IMCs were also used. Either IMCs or FMCs can be used to tie back to historical performance without significant variance in model results.

2% Program Case

The 2% program case is defined by the approved Energy Smart PY10-12 implementation plan, Scenario 2.[57] Guidehouse set incentives at 86% and 32% of the full measure cost for residential and C&I measures, respectively. Guidehouse calibrated the model results by adjusting adoption parameters and behavior program rollout to align with the historical program achievements and planned savings as documented in the implementation plan.

Low Program Case

The low case uses the same inputs as the 2% program case, (ENO implementation plan, Scenario 2) except for lower levels of behavior program participation rollout (50% of the 2% program case). Incentives are set to 50% of full measure cost for residential and 25% for C&I. Administrative costs on a dollar per kWh saved basis are the same as the 2% program case.

High Program Case

---

[56] In all cases, incentives are capped at a levelized cost to prevent paying more incentives than the equivalent avoided cost benefit.

[57] https://cdn.entergy-neworleans.com/userfiles/content/energy_smart/Program_Year_10-12/Correction_Revised_Implementation_Plan_%20PY_10-12_1-24-20.pdf?_ga=2.216502932.327611312.1611206281-15932630.1611206281 and https://cdn.entergy-neworleans.com/userfiles/content/energy_smart/Program_Year_10-12/Revised_Implementation_Plan_PY_10-12_1-22-20.pdf?_ga=2.216502932.327611312.1611206281-15932630.1611206281

The high case is based off the 2% program case but with higher incentives as a percent of full measure cost at 100% for residential and 50% for C&I. Additionally, there is a more aggressive plan for behavior program rollout. Behavioral program rollout for the residential sector increases slightly compared to the 2% case and reaches the maximum achievable level.[58] Administrative costs on a dollar per kWh saved basis are relatively equal to those in the 2% program case.

Reference Case

In an effort to develop a case reflecting an industry-standard level of incentives, and because the actual program results for the approved PY10-12 plan are tracking to higher levels of administrative costs and kWh savings than are often seen in long term potential studies, it was useful to provide a Reference Case that tied back to the Base case from the 2018 study. This Reference case reflects the Base case from the 2018 study where the program administrative costs reflected current spend targets on a dollar per kWh saved basis and the incentives were set at 50% of incremental measure costs. In Guidehouse's experience in incentive level setting and potential study analysis, others have set incentives or cap incentives at 50% of incremental measure cost. Behavior program roll out matches the low program case levels as a conservative assessment of the potential roll out of the recommended programs for the ENO portfolio.

3.2 Energy Efficiency Achievable Potential Results

Achievable potential values 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[59] 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

---

[58] Residential behavior programs using a control group to assess energy savings result in an ability to treat less than 100% of the suitable participant pool.

[59] Cost-effectiveness threshold is a TRC = 1.0. There were measures that were passed through with a TRC ratio <1.0 where it was reasonable to assume that the measure is important to program implementation. These measures include: C&I lighting occupancy sensor controls, interior LED high bay, and retrocommissioning. The following highlights the major differences from the last study and this study for the C&I lighting measures:

1. Incremental costs – For a subset of measures, the 2020 study has lower incremental costs as compared to the 2018 study
2. Density – For a subset of measures in 2020, the densities were updated to more recent data sources versus the last study used a 2015 source.
3. EE saturation – Actual program data was used to update lighting saturation for a subset of measures.

For retrocommissioning, the measure exists in the program portfolio currently and becomes cost-effective in later years.

reach the full economic potential level due to a variety of market and customer constraints that inhibit full economic adoption.[60]

All tables and figures (except for Section 3.2.1) have the potential savings for the 2% program 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 and full measure cost capping and shown in Table 3-1.

Table 3-1. Incentive Setting and Behavioral Program Participation by Case

	2%	Low	High	Reference
Res Incentives	86% Full	50% Full	100% Full	50% IMC
C&I Incentives	32% Full	25% Full	50% Full	50% IMC
Behavioral Participation	Medium forecast	Low forecast	High forecast	Low forecast

Table 3-2 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. The different cases do not show significant difference from each other; however, each case has marked differences in the program design, i.e., changes in ENO-influenced parameters including incentive level setting and behavioral program rollout.[61]

[60] 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.

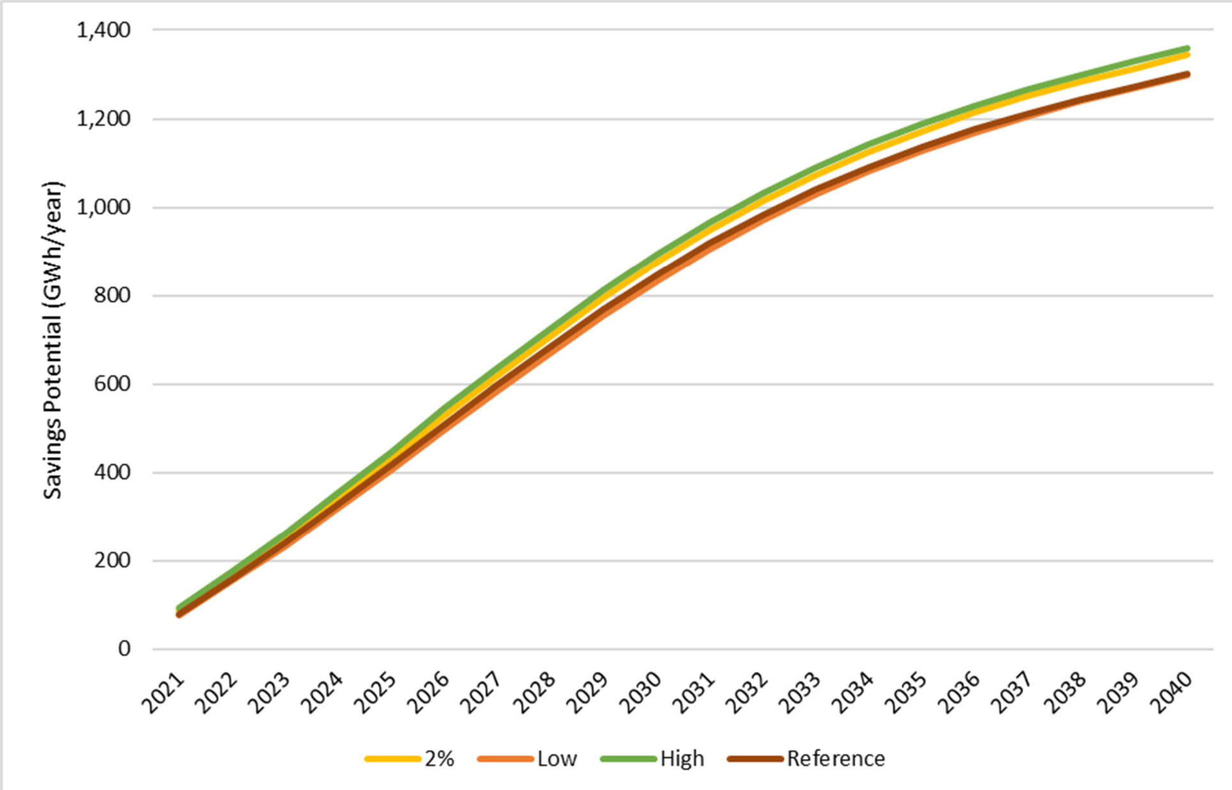
[61] Incentive levels change the customer payback period. Depending on amount of change will result in a change on the payback acceptance curve influencing the market share potential of the energy efficient option. The payback acceptance curve was developed as a result of customer surveys of hypothetical situations.

Table 3-2. Annual Incremental Achievable Energy Efficiency Savings by Case

Year	Electric Energy (GWh/Year)				Peak Demand (MW)			
	2%	Low	High	Reference	2%	Low	High	Reference
2021	89	77	93	79	22	20	23	21
2022	98	86	104	88	22	21	22	21
2023	105	91	111	93	23	22	24	23
2024	112	96	119	99	25	24	25	24
2025	119	101	126	103	26	25	26	25
2026	124	105	132	106	27	26	27	26
2027	122	104	130	104	27	26	27	26
2028	121	102	128	102	27	26	27	26
2029	120	101	128	102	26	25	26	25
2030	115	96	123	96	25	25	26	24
2031	109	90	117	89	24	23	24	23
2032	103	84	110	83	23	22	23	22
2033	97	77	104	76	21	20	21	20
2034	91	71	99	70	20	19	20	18
2035	86	66	94	65	18	17	18	17
2036	83	62	91	61	17	16	17	16
2037	79	58	87	57	16	15	15	14
2038	76	54	84	53	15	13	14	13
2039	72	51	81	50	13	12	13	12
2040	73	51	81	50	13	12	13	12
Total	**1,344**	**1,299**	**1,359**	**1,302**	**429**	**409**	**432**	**408**

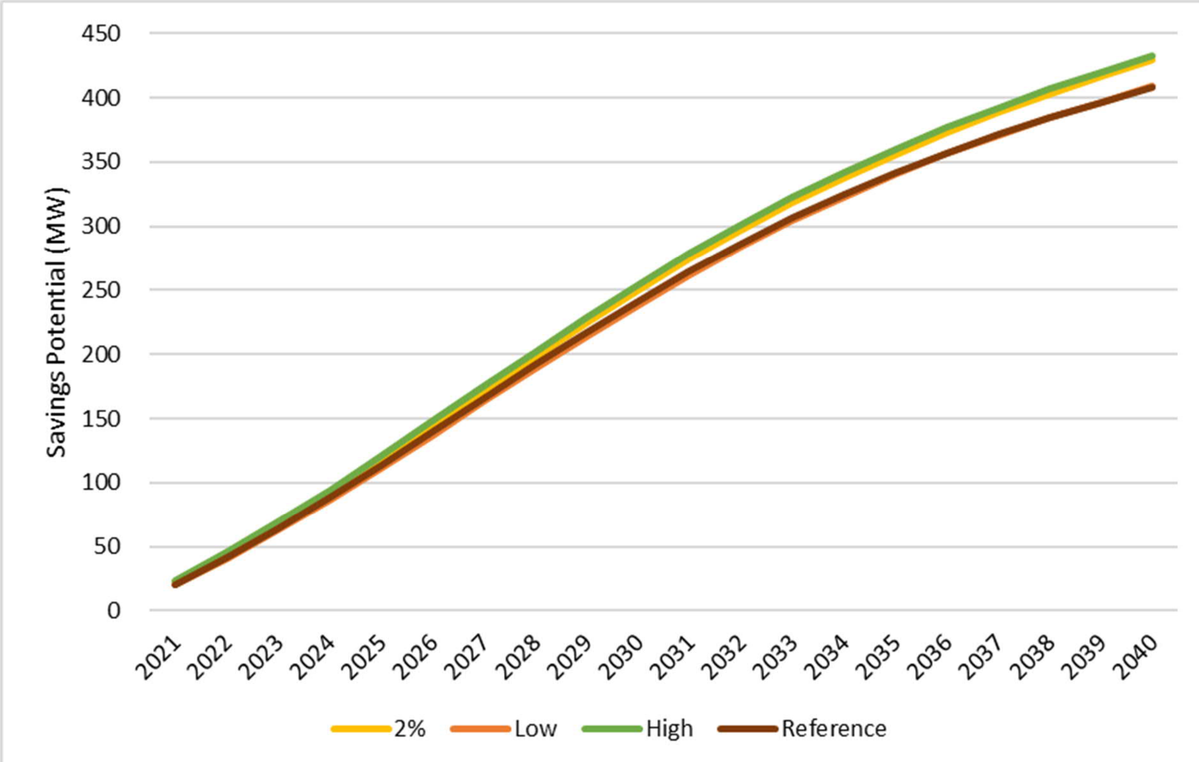
Source: Guidehouse analysis

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



Source: Guidehouse analysis

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



Source: Guidehouse analysis

Table 3-3. shows the incremental electric energy achievable savings as a percentage of ENO's total sales for each case. The 2% program case, which was calibrated to the current approved implementation plan, achieves at least 2% of sales savings from 2025 through 2029. The 2% program case, as well as the high program case, falls below 2% in later years because most of the measures will have been adopted, depleting the available potential in the future years. What keeps the 2% program and high program case at greater than 1% throughout the forecast period are the behavior programs.

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

Year	2%	Low	High	Reference
2021	1.54%	1.34%	1.62%	1.38%
2022	1.71%	1.49%	1.80%	1.53%
2023	1.82%	1.57%	1.93%	1.62%
2024	1.94%	1.67%	2.06%	1.71%

2025	2.05%	1.75%	2.18%	1.78%
2026	2.14%	1.81%	2.28%	1.84%
2027	2.11%	1.79%	2.24%	1.80%
2028	2.07%	1.75%	2.20%	1.76%
2029	2.06%	1.74%	2.20%	1.75%
2030	1.97%	1.65%	2.10%	1.64%
2031	1.86%	1.54%	1.99%	1.52%
2032	1.75%	1.43%	1.88%	1.41%
2033	1.64%	1.31%	1.77%	1.29%
2034	1.54%	1.21%	1.67%	1.19%
2035	1.45%	1.12%	1.59%	1.09%
2036	1.40%	1.05%	1.54%	1.03%
2037	1.33%	0.97%	1.47%	0.95%
2038	1.27%	0.91%	1.42%	0.89%
2039	1.21%	0.85%	1.36%	0.84%
2040	1.22%	0.85%	1.36%	0.84%
Total	**22.54%**	**21.78%**	**22.79%**	**21.83%**

Source: Guidehouse analysis

The total, administrative and incentive costs for each case are provided in Table 3-4. 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 between the cases, with higher spending correlated to higher savings.

Table 3-4. Spending Breakdown for Achievable Potential ($ millions/year)[62]

	Total				Incentives				Non-Incentives			
Year	2%	Low	High	Reference	2%	Low	High	Reference	2%	Low	High	Reference
2021	$14	$12	$17	$15	$8	$6	$11	$9	$6	$6	$6	$6
2022	$16	$13	$19	$17	$9	$7	$12	$10	$7	$7	$7	$7
2023	$17	$14	$20	$18	$10	$7	$13	$11	$7	$7	$7	$7
2024	$19	$16	$22	$19	$11	$8	$14	$11	$8	$8	$8	$8
2025	$20	$17	$23	$20	$12	$9	$15	$12	$8	$8	$8	$8
2026	$21	$18	$25	$21	$13	$9	$16	$12	$9	$8	$9	$9
2027	$22	$18	$25	$21	$13	$10	$16	$12	$9	$8	$9	$9
2028	$22	$18	$25	$20	$13	$10	$16	$12	$9	$8	$9	$8
2029	$22	$18	$25	$20	$13	$10	$16	$12	$9	$8	$9	$8
2030	$21	$18	$24	$19	$13	$10	$16	$11	$8	$8	$8	$8
2031	$20	$17	$23	$18	$13	$10	$15	$11	$7	$7	$7	$7
2032	$19	$16	$21	$17	$12	$9	$14	$10	$7	$7	$7	$7
2033	$18	$15	$19	$15	$11	$9	$13	$9	$6	$6	$6	$6

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

	Total				Incentives				Non-Incentives			
Year	2%	Low	High	Reference	2%	Low	High	Reference	2%	Low	High	Reference
2034	$16	$14	$18	$14	$11	$8	$12	$9	$6	$6	$5	$5
2035	$15	$13	$16	$13	$10	$8	$12	$8	$5	$5	$5	$5
2036	$15	$12	$16	$12	$10	$8	$11	$8	$5	$5	$4	$4
2037	$14	$12	$15	$11	$10	$7	$11	$7	$4	$4	$4	$4
2038	$13	$11	$14	$10	$10	$7	$11	$7	$4	$4	$4	$4
2039	$13	$10	$14	$9	$9	$7	$10	$6	$3	$3	$3	$3
2040	$13	$11	$14	$10	$10	$7	$11	$6	$4	$3	$3	$3
Total	**$349**	**$293**	**$394**	**$321**	**$220**	**$166**	**$265**	**$194**	**$129**	**$127**	**$129**	**$127**

Source: Guidehouse 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

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

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).

Guidehouse 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 **Error! Reference source not found.**A. 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 3-5.. Even with the large increases in incentives for the high case, all cases are cost-effective. Increasing incentives does not necessarily translate to a lower TRC because incentives are considered a transfer cost and are excluded from the TRC benefit-cost calculation. 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.

One of the screening criteria in the potential analysis is for the measures to pass the TRC test. A handful of measures were allowed into the analysis that fell below 1.0. As a result, the portfolio is still cost-effective. Typically, the more aggressive the portfolio, the lower the TRC as more non-cost-effective measures are added and increase administrative efforts to address more services to the market.

Table 3-5. Portfolio TRC Benefit-Cost Ratios for Achievable Potential (Ratio)

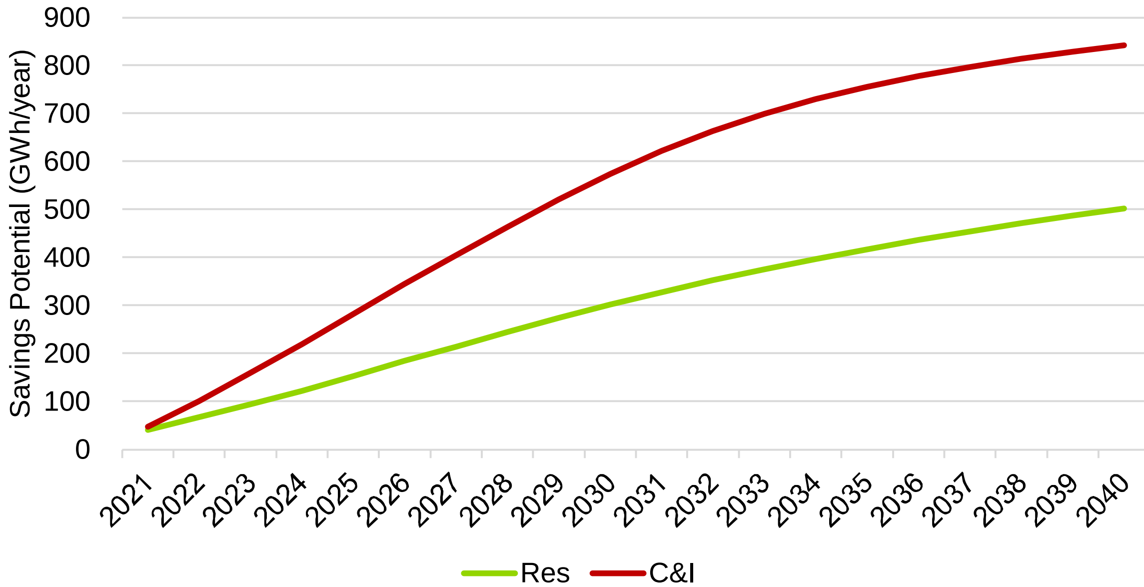
Year	2%	Low	High	Reference
2021	1.45	1.48	1.44	1.46
2022	1.52	1.55	1.50	1.53
2023	1.63	1.66	1.61	1.64
2024	1.69	1.72	1.67	1.70
2025	1.72	1.76	1.71	1.73
2026	1.77	1.81	1.76	1.79
2027	1.81	1.85	1.80	1.83
2028	1.87	1.91	1.86	1.90
2029	1.92	1.96	1.91	1.95
2030	1.97	2.01	1.96	2.00
2031	2.03	2.06	2.02	2.05
2032	2.08	2.11	2.07	2.10
2033	2.13	2.16	2.13	2.16
2034	2.18	2.21	2.19	2.21
2035	2.24	2.26	2.25	2.27
2036	2.27	2.29	2.28	2.31
2037	2.32	2.34	2.33	2.36
2038	2.37	2.38	2.38	2.40
2039	2.40	2.42	2.42	2.45
2040	2.28	2.30	2.30	2.32
2021-2040	1.85	1.88	1.84	1.86

Source: Guidehouse 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 2% program case. The 2% program case is calibrated based on the existing ENO PY10-12 implementation plan.

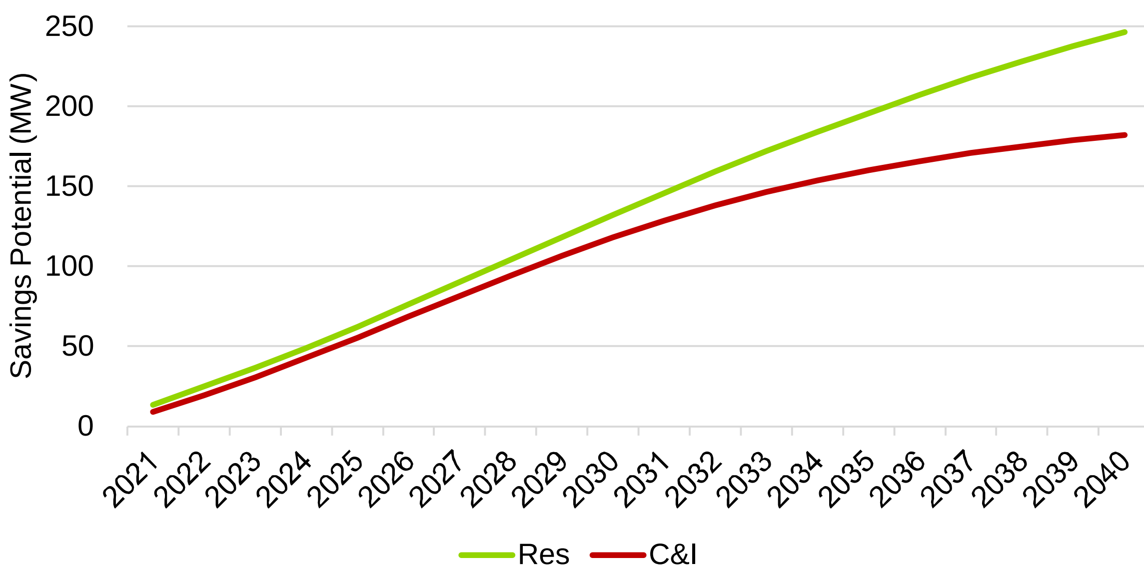
Figure 3-3. Electric Energy Cumulative 2% Program Case Achievable Savings Potential by Sector (GWh/year)



Source: Guidehouse analysis

Figure 3-4 shows the cumulative achievable demand savings potential for all analysis years by sector for the 2% program case.

Figure 3-4. Electric Demand Cumulative 2% Program Case Achievable Savings by Sector (MW)



Source: Guidehouse analysis

Table 3-6. 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 3-6. Cumulative Electric Energy Achievable Savings Potential by Sector as a Percentage of Sales (%, GWh), 2% Program Case

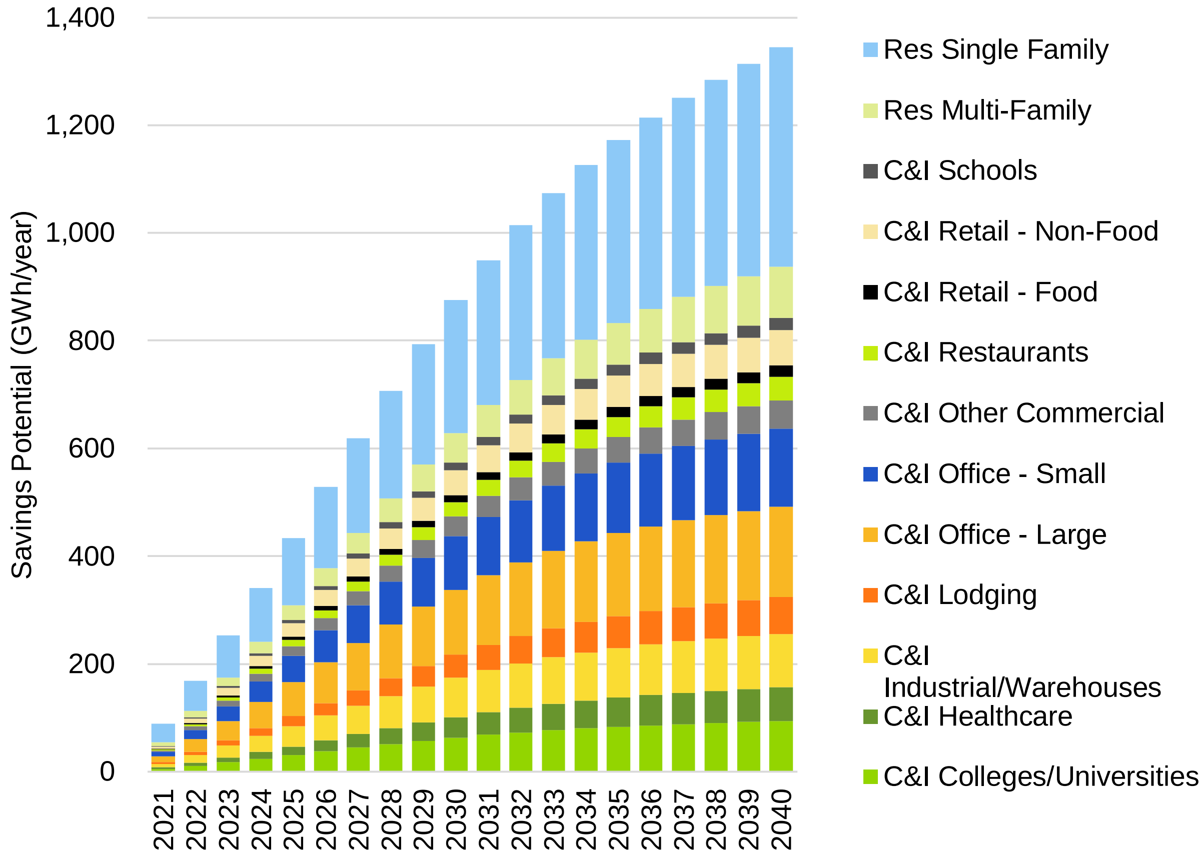
Year	All	Res	C&I
2021	1.5%	1.8%	1.4%
2022	2.9%	3.0%	2.9%
2023	4.4%	4.1%	4.6%
2024	5.9%	5.3%	6.3%
2025	7.5%	6.6%	8.1%
2026	9.1%	8.0%	9.9%
2027	10.7%	9.3%	11.6%
2028	12.2%	10.5%	13.2%
2029	13.6%	11.8%	14.9%
2030	15.0%	12.9%	16.3%
2031	16.2%	14.0%	17.6%
2032	17.3%	15.0%	18.8%
2033	18.2%	16.0%	19.7%
2034	19.1%	16.9%	20.5%
2035	19.8%	17.7%	21.2%
2036	20.5%	18.5%	21.8%
2037	21.1%	19.3%	22.2%
2038	21.6%	20.0%	22.6%
2039	22.1%	20.7%	23.0%
2040	22.5%	21.4%	23.3%

Source: Guidehouse analysis

3.2.3 Results by Customer Segment

Figure 3-5 shows the cumulative electric energy achievable potential by customer segment. Single-family homes make up the largest residential segment, while large and small office contribute the most savings to the C&I sector.

Figure 3-5. 2% Program Case Cumulative Achievable Potential Savings Customer Segment Breakdown



Source: Guidehouse analysis

3.2.4 Results by End Use

Figure 3-6 and Figure 3-7 show the percentage of each end use for each sector. The lighting interior and HVAC end use have the largest potential. The HVAC end uses are high relative to others because this end use includes the sales associated with envelope and systems that affect both heating and cooling. 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.

The total facility end use refers to holistic measures, such as the behavior program.

Figure 3-6. Residential 2021 Electric Energy Achievable Potential End-Use Breakdown (%, GWh)

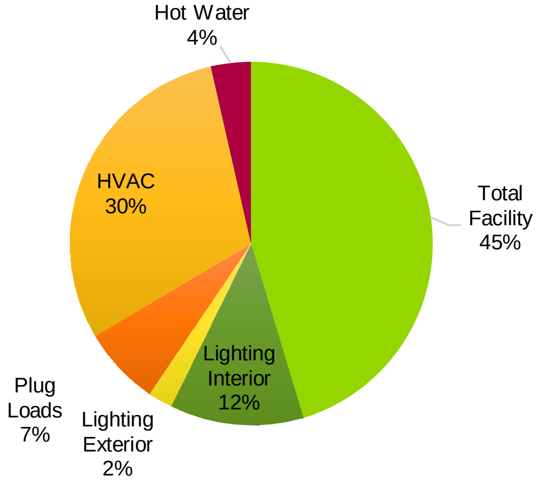
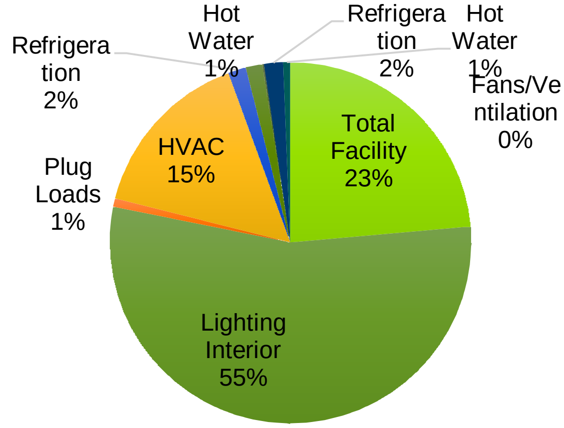


Figure 3-7. C&I 2021 Electric Energy Achievable Potential End-Use Breakdown (%, GWh)

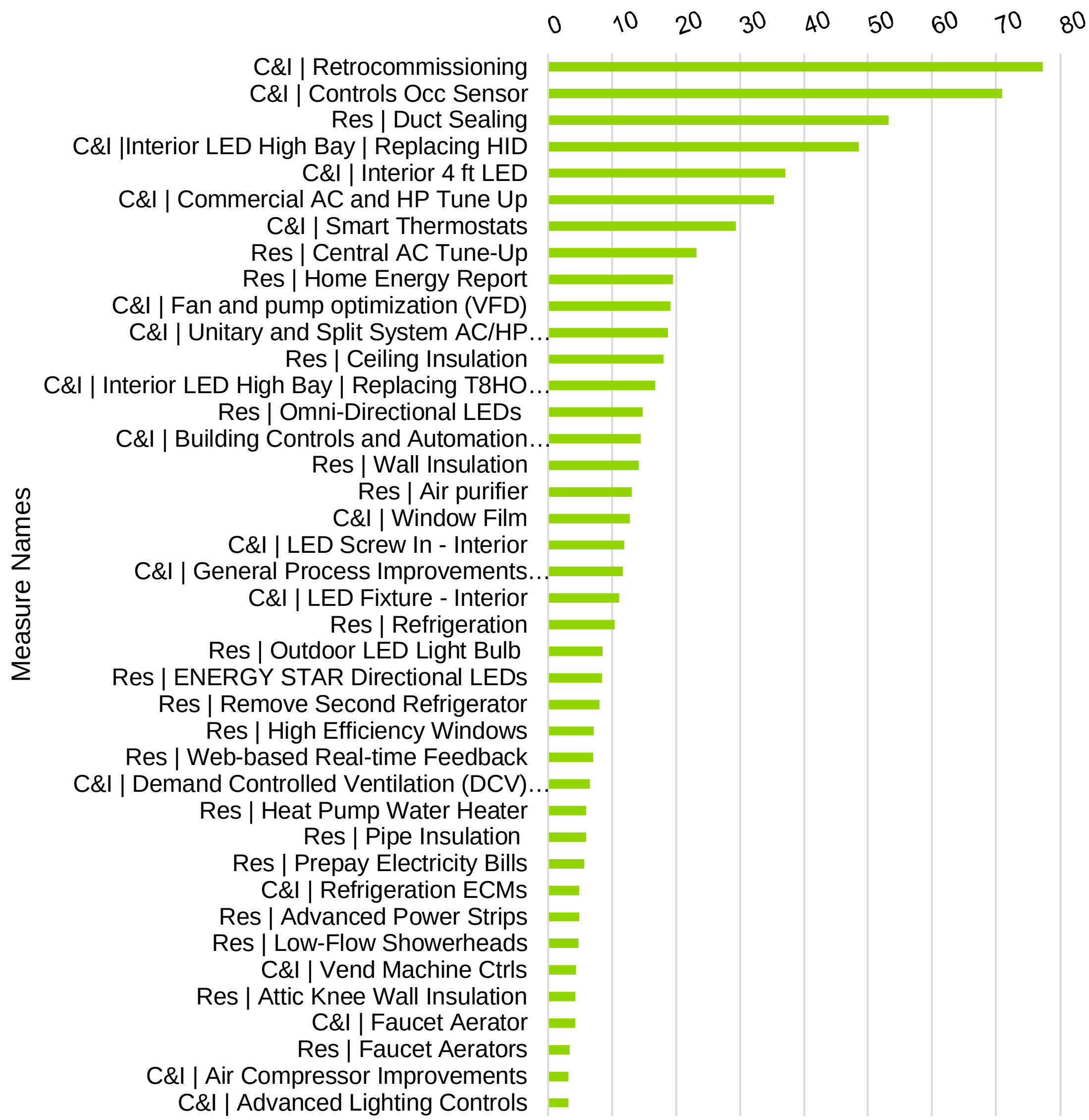


Source: Guidehouse analysis

3.2.5 Achievable Potential Results by Measure

Figure 3-8 shows the top 40 measures contributing to the electric energy achievable potential in 2028 (representative of the 20-year results). Retrocommissioning in the C&I sector provides the most savings, followed by occupancy sensor controls, interior high bay LEDs, 4-foot LEDs and smart thermostats. Residential duct sealing, central AC tune-up and home energy reports provide the highest three residential sector savings.

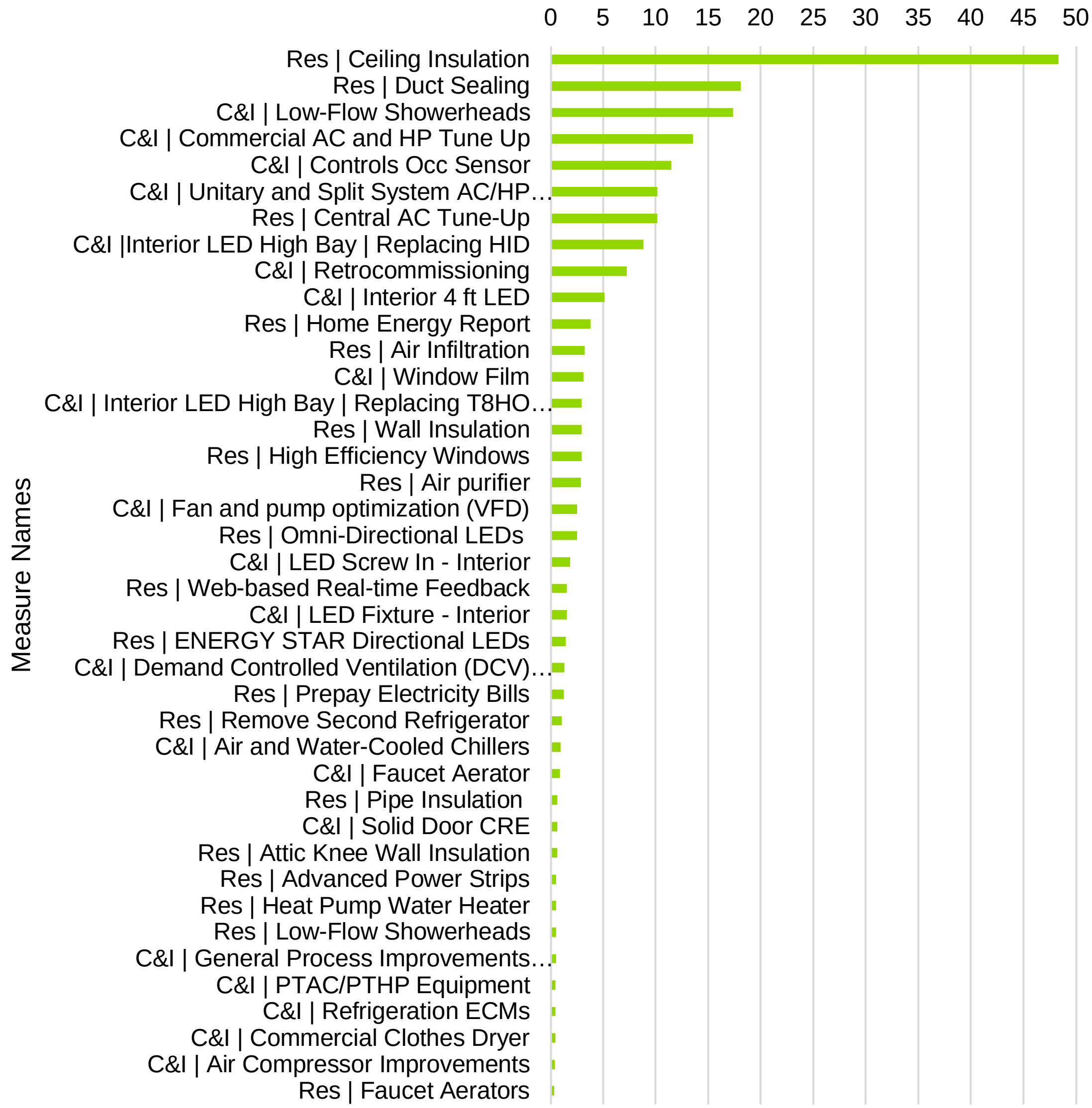
Figure 3-8. Top 40 Measures for Cumulative Electric Energy 2% Program Case Achievable Savings Potential: 2028 (GWh/year)



Source: Guidehouse analysis

Figure 3-9 shows the top 40 measures contributing to the demand achievable potential in 2028. The top measures are different than those listed for electric energy. For the Residential sector, ceiling insulation and duct sealing are the highest demand savings. For the C&I sector, the highest savings come from low flow showerheads, tune-ups, and occupancy sensors. These measures' unit energy and peak demand savings are sourced from the TRM v4.0.

Figure 3-9. Top 40 Measures for Cumulative Electric Demand 2% Program Case Savings Potential: 2028 (MW)



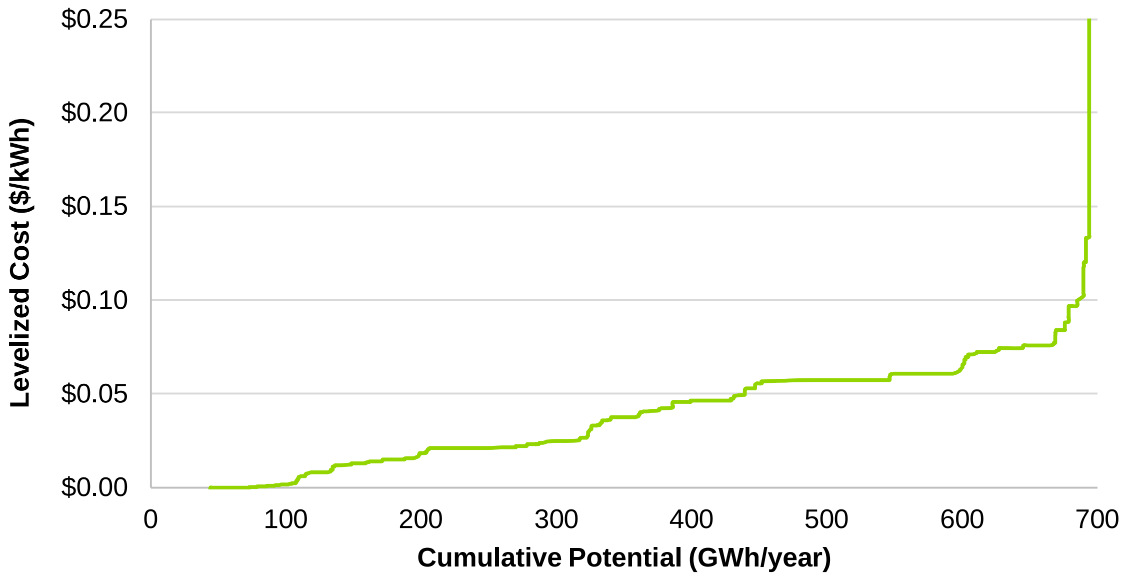
Source: Guidehouse analysis

Figure 3-10 provides a supply curve of savings potential versus the levelized cost of savings in $/kWh for all measures considered in the study. The X-axis shows *cumulative* achievable potential through 2028, which means the cumulated annual savings from 2021-2028. In Figure 3-3 that the cumulative savings in 2028 is about 700 GWh/year, which matches the X-axis in the supply curve. To develop the supply curve, the Guidehouse model calculates the following:

1. Levelized cost which is the net present value of the TRC costs (program non-incentive costs + measure costs) divided by the net present value of the lifetime savings over the measure life.
2. Cumulative potential which is the cumulated annual savings up until the year-of-interest per measure at the specific levelized cost.

The supply curve allows for the comparison of the cost of obtaining demand side energy reductions against the cost of supply side resources. The curve shows that additional units of savings come at an increased cost, eventually resulting in savings that are quite expensive. In other words, certain measures are the “lowest hanging fruit”, and once those measures are expended, we move to the next measure along the curve. By the time we get to 2028, most of the savings from 2021-2028 were obtained below a $0.08/kWh levelized cost.

Figure 3-10. Supply Curve of Electric Energy Achievable Potential (GWh/year) vs. Levelized Cost ($/kWh): 2028

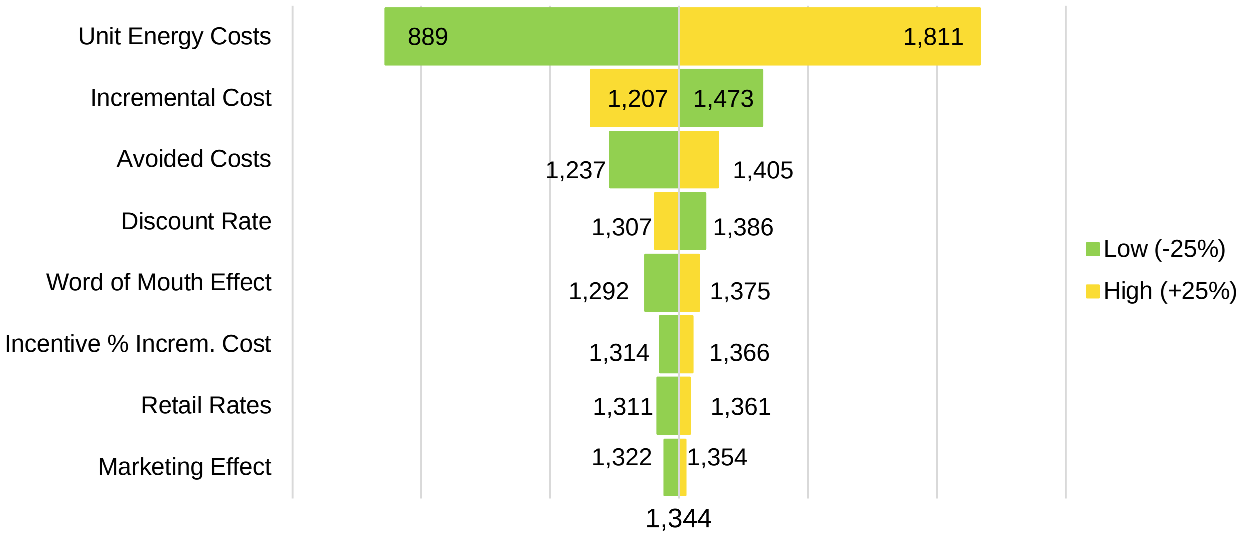


Source: Guidehouse analysis

3.2.6 Sensitivity Analysis

Figure 3-11 shows a sensitivity analysis of the effect on energy savings potential that results from varying the most influential factors by +/- 25%. Table 3-7. shows the percent change to the cumulative energy savings potential for each sensitivity parameter in 2040. Unit energy savings (energy savings of each measure, for example, quantified as a kWh/unit or kWh/ton for HVAC) have the largest impact, followed by incremental costs, avoided costs, and word of mouth effect. Such understandings are critical to evaluating related policy decisions and informing effective program design.

Figure 3-11. Cumulative Achievable GWh Savings in 2040 Sensitivity to Key Variables



Source: Guidehouse analysis

Table 3-7. Percent Change to Cumulative Potential in 2040 with 25% Parameter Change

Parameter	Low (-25%)	High (+25%)
Unit Energy Costs	-34%	35%
Incremental Cost	10%	-10%
Avoided Costs	-8%	5%
Discount Rate	3%	-3%
Word of Mouth Effect	-4%	2%
Incentive % Incremental Cost	-2%	2%
Retail Rates	-2%	1%
Marketing Effect	-2%	1%

Source: Guidehouse analysis

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. Guidehouse 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 not cost-effective:

- **Direct Load Control:** Switch water heating sub-options for residential and small C&I
- **Behind the Meter Storage:** Battery storage for all customer classes

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 assessment. Only cost-effective sub-options are shown in the achievable potential results in subsequent sections.

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

Customer Class	DR Option	DR SubOption	TRC
Residential	Dynamic Pricing	Without enabling tech.	2.27
		With enabling tech.	3.01
	DLC	Switch-Central Air Conditioning	3.06
		Thermostat-Res	1.89
		Switch-Water Heating	0.35
	BTMS	Battery Storage	0.08
Small C&I	Dynamic Pricing	Without enabling tech.	4.91
		With enabling tech.	2.50
	DLC	Thermostat-HVAC	3.74
		Switch-Water Heating	0.10
	BTMS	With enabling tech.	0.13
Large C&I	Dynamic Pricing	Without enabling tech.	3.10
		With enabling tech.	4.03
	C&I Curtailment	Other	5.24
		Advanced Lighting Control	5.35
		Auto-DR HVAC Control	5.28
		Refrigeration Control	5.26
		Water Heating Control	5.25

Customer Class	DR Option	DR SubOption	TRC
		Standard Lighting Control	5.23
		Industrial	5.18
	BTMS	Battery Storage	0.15

Source: Guidehouse

As described in Section 2.2.5, in addition to the mid case, Guidehouse 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. The cost-effective results across the three cases for the DR sub-options match the mid case as shown above. All suboptions pass except for the behind the meter storage and switch – water heating. All other mid case cost-effective measures remain cost-effective under the low and high cases.

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 mid case. Figure 4-2 shows the cost-effective achievable potential as a percentage of ENO's peak demand. Achievable peak demand reduction potential is estimated to grow from 12 MW in 2021 to 70 MW in 2040. Cost-effective achievable potential makes up approximately 7% of ENO's peak demand in 2040. The team made several key observations:

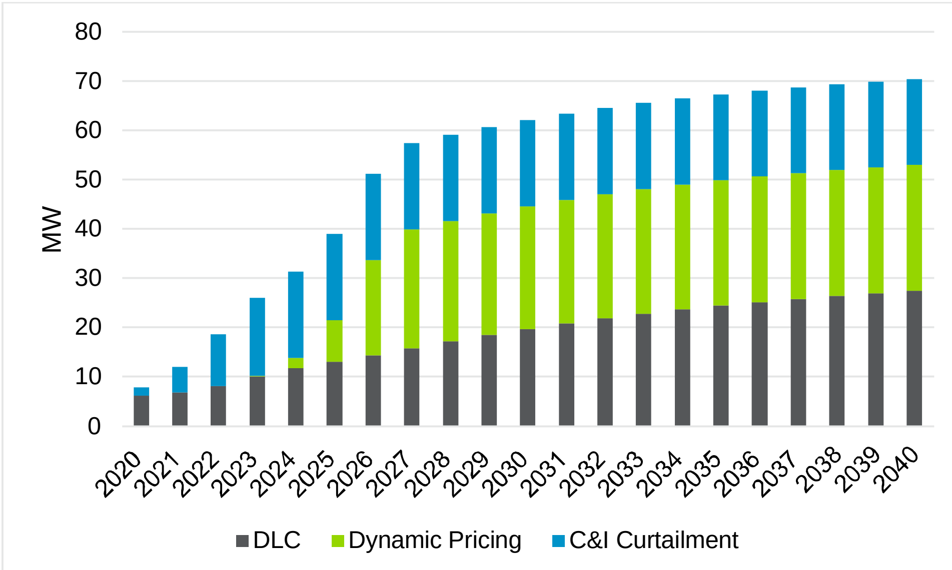
- DLC has the largest achievable potential: 39% share of total potential in 2040. DLC potential grows from 6.8 MW in 2021 to 27.4 MW in 2040.

- Dynamic pricing has a 36% share of the total potential in 2040. The dynamic pricing offer begins in 2023 because it is tied to ENO's advanced metering infrastructure implementation plan and readiness to implement the option. The program ramps up over a 5-year period (2023-2027) until it reaches a value of 24 MW. From then on, potential slowly increases until it reaches a value of 25.6 MW in 2040.

- C&I curtailment makes up the remainder of the cost-effective achievable potential with a 25% share of the total potential in 2040. C&I curtailment potential grows rapidly from 5 MW in 2021 to 17.5 MW in 2024. This growth follows the S-shaped ramp assumed for the program over a 3-5-year period. Beyond 2024, the program attains a steady participation level and its potential slightly decreases (due to changing market and energy intensity forecasts over time) over the remainder of the forecast period, ending at 17.3 MW in 2040.

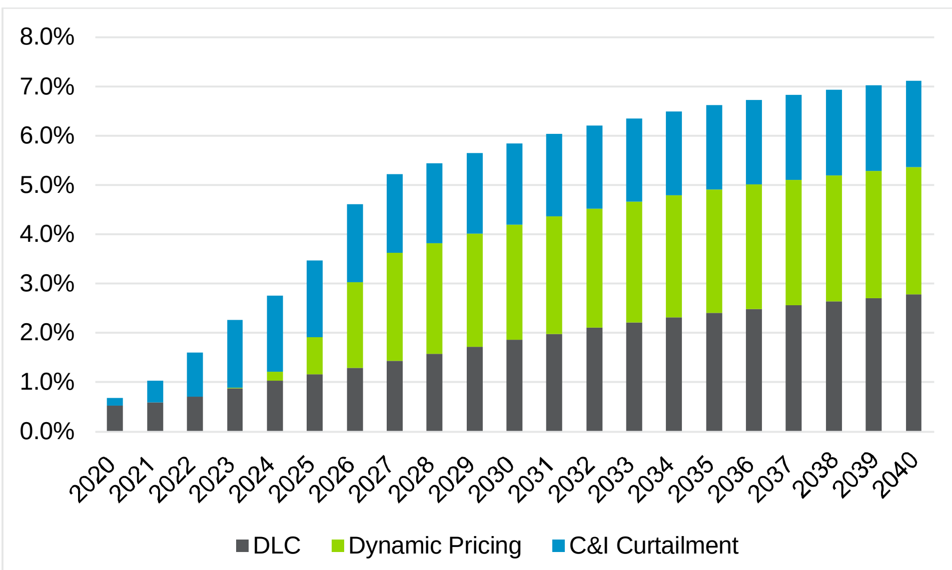
- BTMS, as described in this report, is not cost-effective; thus, it contributes 0 MW to the DR achievable potential.

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



Source: Guidehouse analysis

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



Source: Guidehouse analysis

4.2.2 Case Analysis Results

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

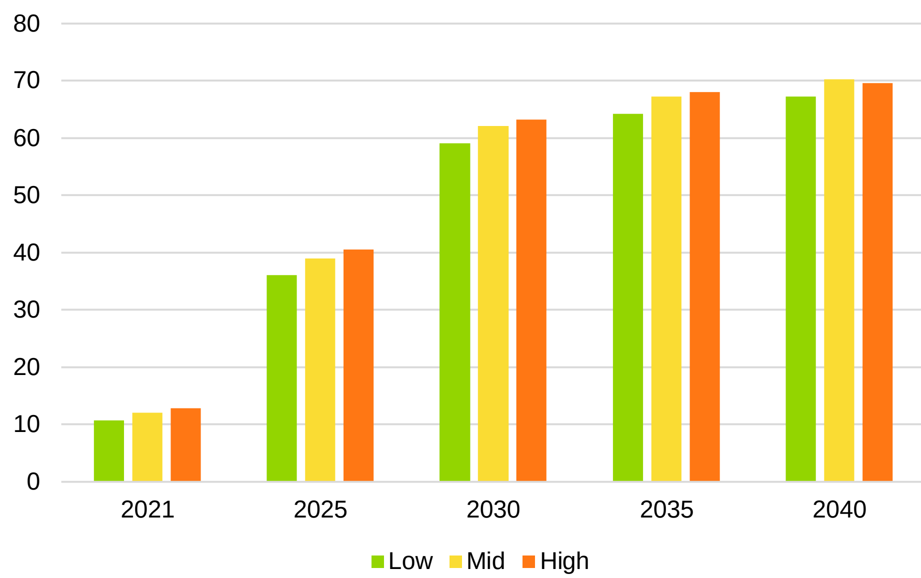
- **Mid case:** Reflects DR program participation based on incentives at levels that match current programs (e.g., ENO's Smart Easy Cool program) and industry best practice.

- **Low case:** Assumes incentives are 50% lower than in the mid case. This drives program participation down and results in lower implementation costs.
- **High case:** Assumes incentives are 50% higher than in the mid 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*.[63, 64]

Figure 4-3 and Figure 4-4 show the achievable potential results in terms of MW and percentage of peak demand, respectively. Under the mid case, the achievable potential makes up approximately 7% of ENO's peak load in 2040. Under the low and high cases, the achievable potential represents approximately 6.6% and 7.0% of ENO's peak demand in 2040, respectively.

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

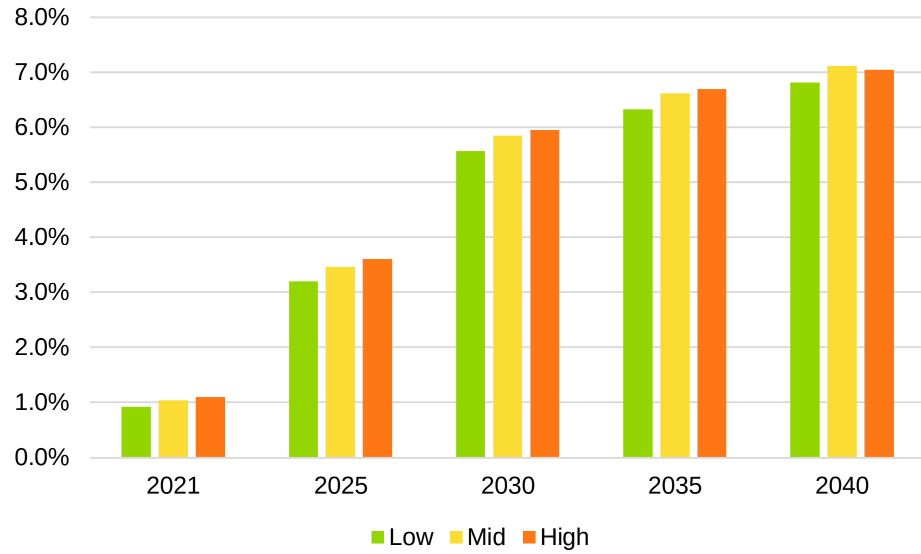


Source: Guidehouse

[63] Lawrence Berkeley National Laboratory. 2025 California Demand Response Potential Study: Charting California's Demand Response Future. Appendix F. March 1, 2017.

[64] Guidehouse assumed medium marketing spending levels for DR programs across cases.

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



Source: Guidehouse 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.

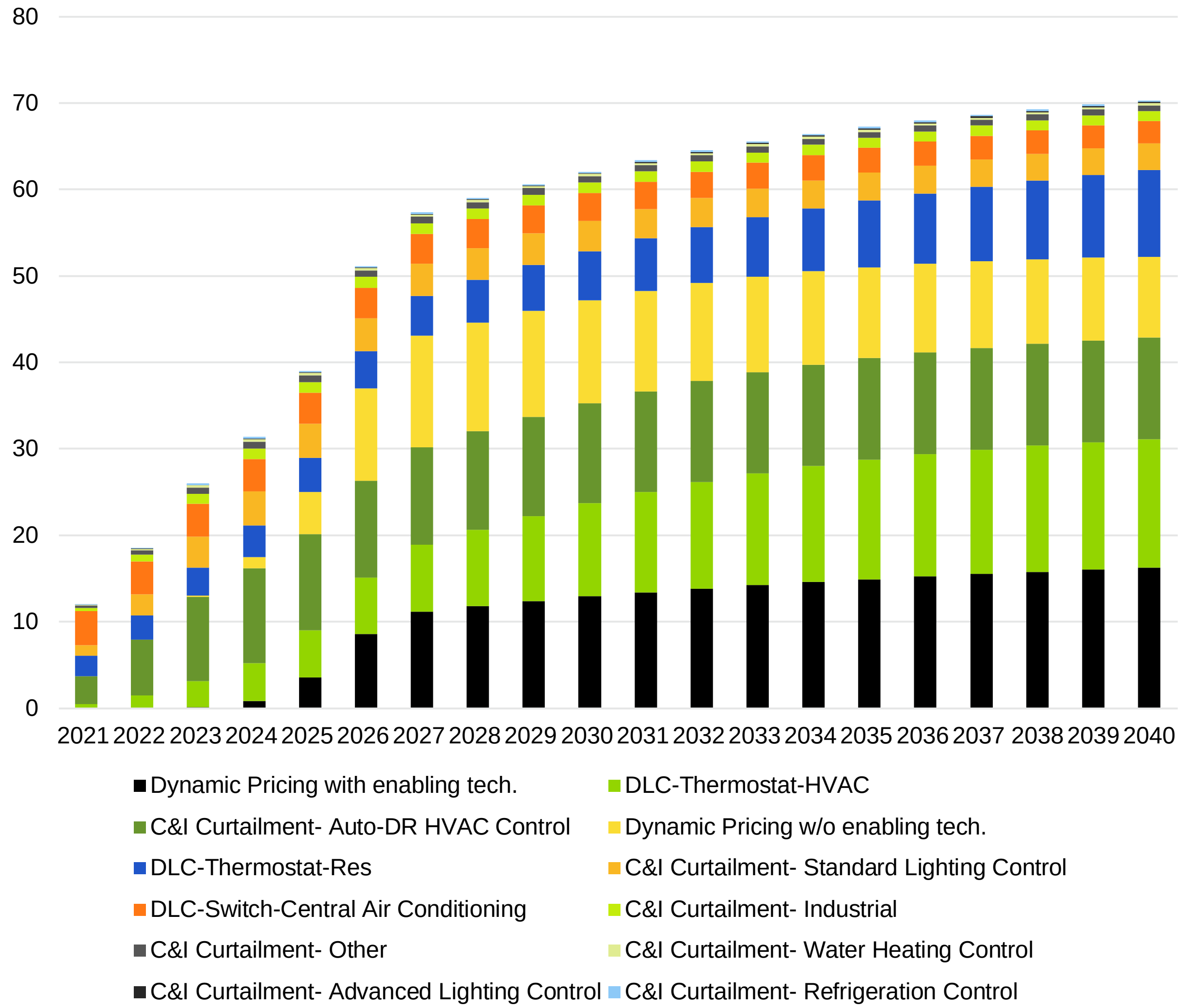
Figure 4-5 summarizes the cost-effective achievable potential by DR option for the mid case. Guidehouse had the following key observations:

- Only direct control of HVAC loads (DLC-Switch and DLC-Thermostat in Figure 12) is cost-effective (and not water heating). This sub-option makes up nearly 40% of the total cost-effective achievable potential in 2040 at 27 MW. Of this 27 MW, 24.9 MW is from thermostat-based control, while the remaining 2.6 MW is from switch-based control.

- Dynamic pricing makes up 36% of the total cost-effective achievable potential in 2040. Potential from customers with enabling technology in the form of thermostats/energy management systems is almost two times higher than that from customers without enabling technology—16 MW versus 9 MW in 2040.

- Under the C&I curtailment program, reductions associated with refrigeration control, advanced and standard lighting control, water heating control, industrial, and auto-DR HVAC control make up 25% of the total cost-effective potential in 2040.

Figure 4-5. Summer DR Achievable Potential by DR Sub-Option



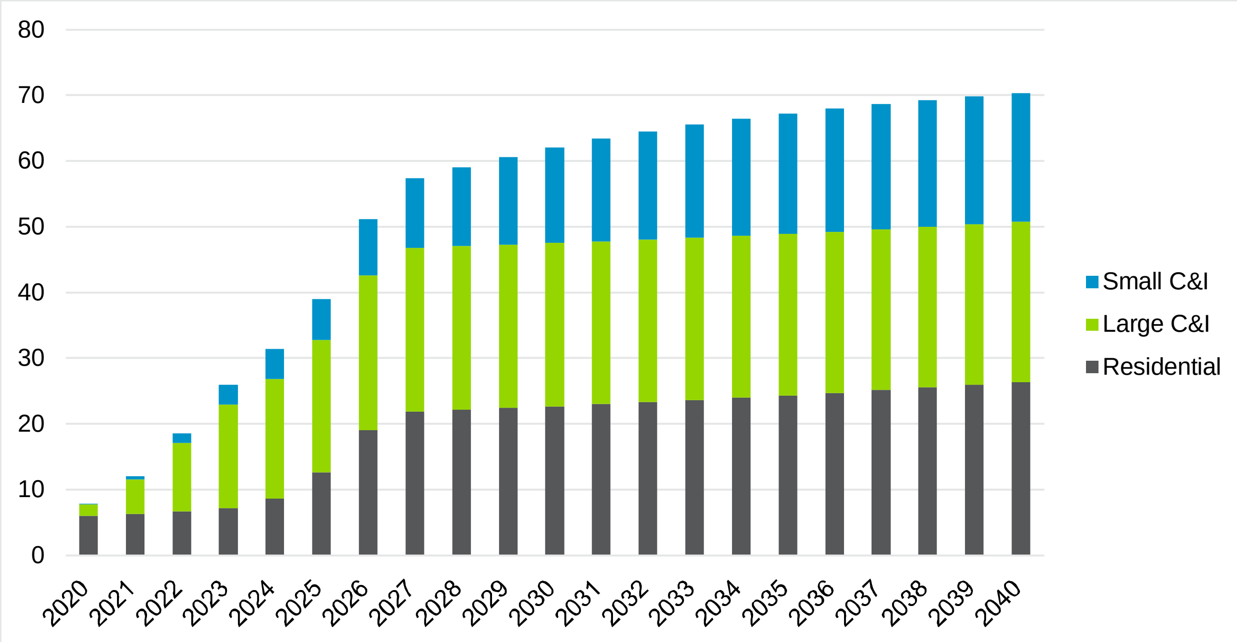
Source: Guidehouse analysis

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 mid case. The team had the following key observations:

- Potential from residential customers makes up 37% (26 MW) of the total cost-effective achievable potential in 2040. C&I customers make up the remaining 63%.
- Potential from small C&I customers makes up 28% (19.6 MW) of the total cost-effective achievable potential in 2040. DLC of HVAC loads makes up 76% of this 19.6 MW, while dynamic pricing with enabling technology in the form of thermostats makes up the remaining 24%.
- Potential from large C&I customers makes up 35% (24.4 MW) of the total cost-effective achievable potential in 2040. C&I curtailment with auto-DR HVAC control makes up 48% at 11.75 MW.

Figure 4-6. Summer DR Achievable Potential by Customer Class (MW)



Source: Guidehouse analysis

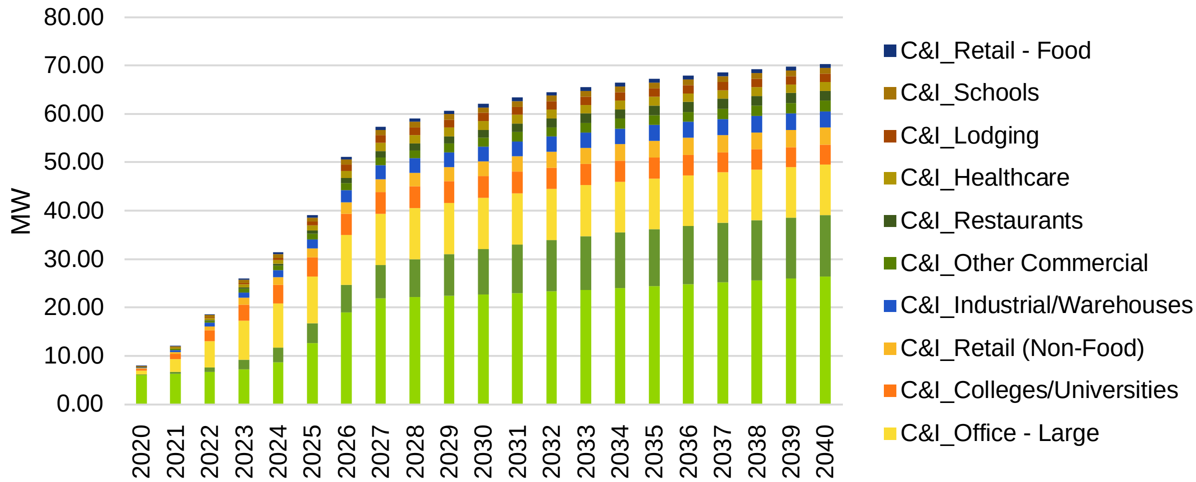
4.2.5 Achievable Potential by Customer Segment

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. Guidehouse 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 4-5 summarizes the cost-effective achievable potential by customer segment for the mid case. Guidehouse had the following key observations:

- Potential from C&I customers primarily comes from small offices, which make up 18% (12.7 MW) of the total cost-effective achievable potential in 2040. This is followed by large office, colleges/universities, and retail building category, which each make up between 5% and 15% of the total cost-effective achievable DR potential in 2040—10.4 MW, 4.14 MW, and 3.6 MW, respectively.
- All other C&I segments make up less than 19% of the cost-effective achievable potential in 2040, which is 13.1 MW.

Figure 4-7. Summer DR Achievable Potential by Customer Segment



Source: Guidehouse analysis

4.3 Program Costs Results

This section presents annual program costs by case and DR option.

4.3.1 Annual Program Costs

4.3.1.1 Annual Costs by Case

Table 4-2. 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 mid 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 4-2. Annual DR Portfolio Costs by Case

Year	Low	Mid	High
2021	$519,519	$702,868	$895,217
2022	$608,747	$883,274	$1,171,919
2023	$1,166,774	$1,542,201	$1,915,297
2024	$1,207,783	$1,638,822	$2,058,366
2025	$1,391,927	$1,848,971	$2,291,861
2026	$1,471,008	$1,960,225	$2,452,973
2027	$1,292,252	$1,819,751	$2,363,080
2028	$1,243,718	$1,810,222	$2,390,361
2029	$1,314,143	$1,917,893	$2,533,508
2030	$2,359,273	$3,067,340	$3,786,826
2031	$1,444,780	$2,128,367	$2,844,754
2032	$1,527,387	$2,250,516	$2,999,916

Year	Low	Mid	High
2033	$1,608,377	$2,371,351	$3,152,043
2034	$1,677,587	$2,478,447	$3,288,266
2035	$1,736,852	$2,575,017	$3,412,241
2036	$1,813,175	$2,690,041	$3,554,488
2037	$1,887,553	$2,803,818	$3,693,295
2038	$1,963,479	$2,920,126	$3,833,182
2039	$2,038,249	$3,036,197	$3,969,900
2040	$3,362,236	$4,482,182	$5,479,758

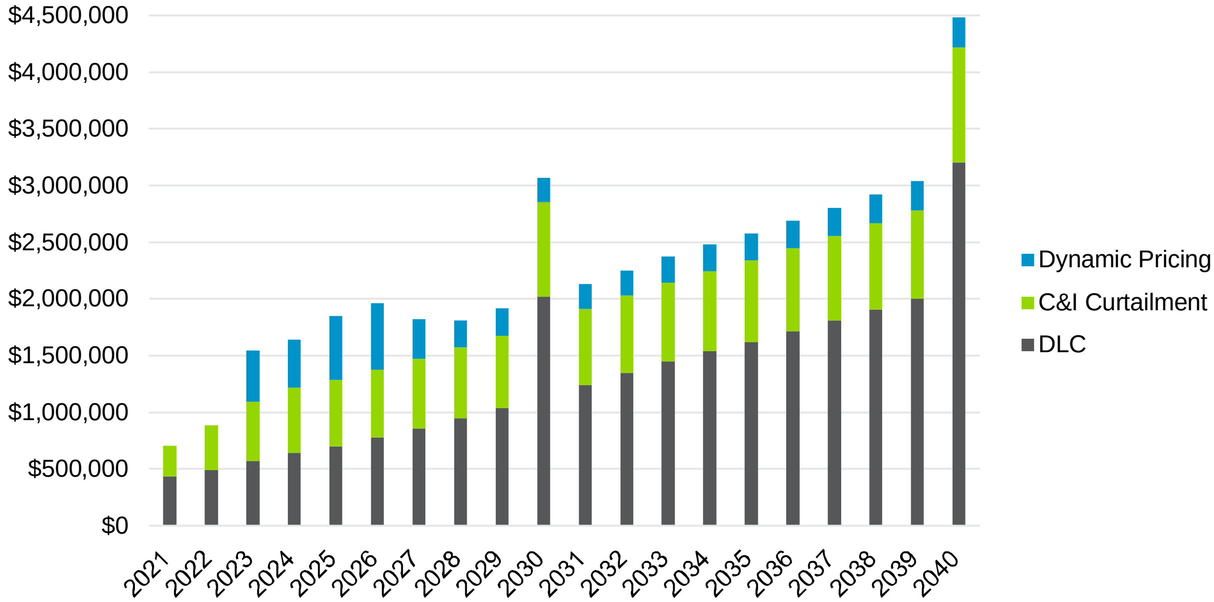
Source: Guidehouse analysis

4.3.1.2 Annual Costs by DR Option

Figure 4-8 summarizes the annual program costs by DR option. The team observed the following:

- The program costs for DLC increase steadily from 2021 to 2040. The costs spike in 2020 (not shown in graph since that is the start year of the program implementation), 2030 and 2040 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 $3.2 million in 2040.
- The program costs for C&I curtailment increase steadily from 2021 to 2022 until the program is fully ramped up. There is a spike in costs in 2030 and 2040 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. In between investments, costs steadily climb with program participation until it reaches its final value of $1.0 million in 2040.
- Dynamic pricing program costs are relatively high during its initial ramp up between 2023 and 2026, and then drop in 2027 when the program is fully ramped up. By 2027, 90% of the program is ramped up, so the incremental cost to recruit new customers is lower in 2027. Beyond 2027, 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

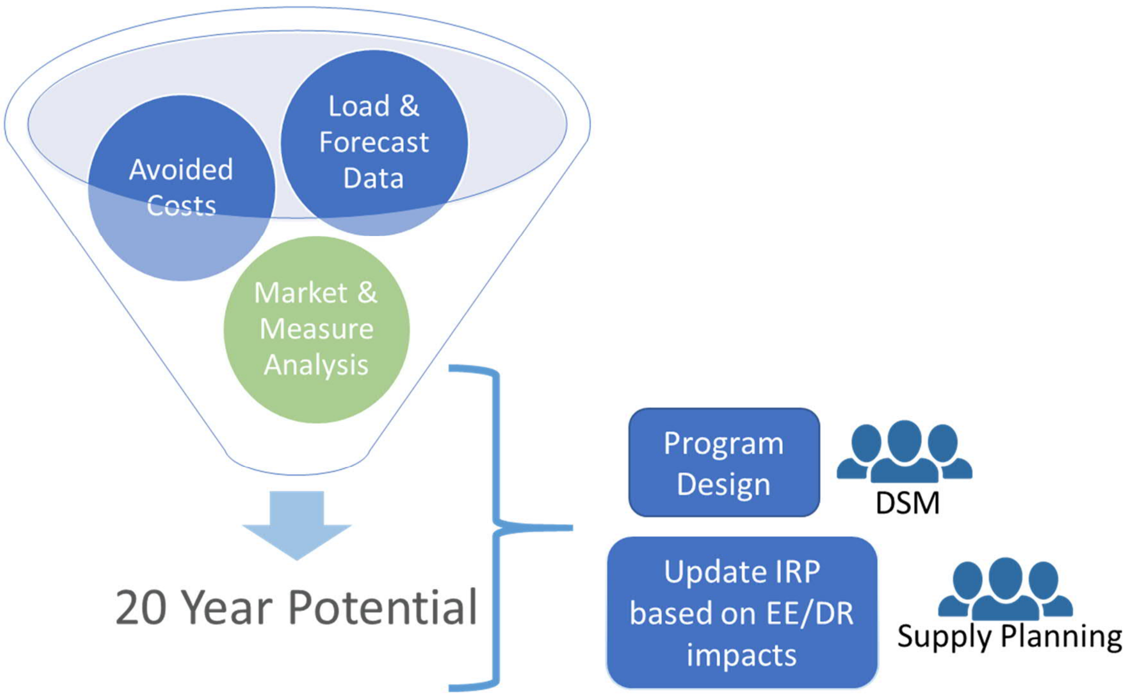


Source: Guidehouse analysis

5. Conclusions and Next Steps

Figure 5-1 illustrates 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: Guidehouse

5.1 Benchmarking the Results

The team benchmarked the study results against the 2018 study and similar utilities and identified how the results could be used in ENO's 2021 IRP.

Energy Efficiency

The 2018 and 2021 potential studies leveraged the same methodology, however, there are differences between the two studies:

1. Calibration targets differed for the two studies
    a. 2018 study relied on the historical programs and the 2018 immediate program goal
    b. 2021 study relied on the existing program framework which has the program plans at or near 2% of consumption
2. Different assumptions on planned rollout for home energy reports
3. Updated data on residential saturation and density data using the Entergy residential appliance saturation study data
4. Updates to commercial saturation values based on year over year program data (for measures where data was available)
5. Changes in commercial lighting baseline and efficient assumptions

6. Updates in the TRM from version 1.0 to version 4.0
7. Addition of new measures
8. Assumptions on measures costs both from Guidehouse sources and the TRM were lower than the 2018 study

After completing the potential study analysis, Guidehouse benchmarked EE achievable potential results against similar studies by other utilities. This exercise provided context for Guidehouse's results and understanding of how various factors such as region or program spend may affect the results.

For this exercise, Guidehouse conducted a literature review on recent potential studies and aggregated the results. The team aimed to include a mixture of utilities that had comparable electric customer counts, climate regions, regulatory requirements (e.g., publicly owned utilities), or locales (e.g., metropolitan centers). Based on this literature review, Guidehouse 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

The sources and points of comparison differ due to data availability.

In review of the benchmarking data sets, it is important to assess that there are many differences in reporting across jurisdictions. For example, each jurisdiction may have differences in the following areas, but not limited to:

- What is included in the program filing and reporting for costs
- Unit energy savings data source
- Level of evaluation for both realization rates and net-to-gross
- Existing baseline conditions
- Mix of building stock

The following tables 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 Resource Plan to 2027, 2019
Louisville Gas & Electric/ Kentucky Utilities	Louisville Gas & Electric Company and Kentucky Utilities Company, Demand-Side Management Potential Study, 2017[65]

[65] 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

Utility	Data Source
Commonwealth Edison (ComEd)	ComEd Energy Efficiency Potential Study, 2019[66]
Duke Energy (Indiana)	The Duke Energy Indiana 2018 Integrated Resource Plan, 2018[67]
California Public Utilities[68]	California Public Utilities Commission, 2019 Potentials & Goals Report[69]
Colorado Springs Utilities	Colorado Springs Utilities 2015 Demand Side Management Potential Study, 2019[70]
Seattle City Light	Seattle City Light Conservation Potential Assessment, 2019[71]

Table 5-2. EE Achievable Potential Savings by State Benchmarking Pool and Sources

State	Data Source
Arkansas	Arkansas Energy Efficiency Potential Study[72]
Mississippi	A Guide to Growing an Energy-Efficient Economy in Mississippi[73]
Louisiana	Louisiana's 2030 Energy Efficiency Roadmap[74]
Tennessee	Tennessee Valley Authority Potential Study[75]
Texas	Potential for Energy Efficiency, Demand Response, and Onsite Renewable Energy to Meet Texas's Growing Electricity Needs[76]

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 14th Edition[77]
Pasadena Water & Power	
Los Angeles Department of Water & Power	

[66] ICF, *ComEd Energy Efficiency Potential Study*, 2017-2030, May 2019, http://ilsagfiles.org/SAG_files/Potential_Studies/ComEd/ComEd_2017-2030_EE_Potential_Final_Report_5-2019.pdf

[67] Duke Energy Indiana, *The Duke Energy Indiana 2018 Integrated Resource Plan*, 2018, https://www.duke-energy.com/_/media/pdfs/for-your-home/indiana-irp/duke-energy-indiana-public-2018-irp.pdf?la=en

[68] CA Public Utilities are grouped together due to data availability and the study results referenced.

[69] Guidehouse, *California Public Utilities Commission 2019 Potentials & Goals (PG) Study Results Viewer*, 2019, https://www.cpuc.ca.gov/General.aspx?id=6442461220

[70] CADMUS, *Colorado Springs Utilities 2015 Demand Side Management Potential Study*, 2019, https://www.csu.org/CSUDocuments/dsmpotentialstudyvolume1.pdf

[71] Seattle City Light 2019 IRP "Appendix 6, Conservation Potential Assessment," https://www.seattle.gov/light/IRP/docs/2019App-6-Conservation%20Potential%20Assessment.pdf

[72] Guidehouse, *Arkansas Energy Efficiency Potential Study*, 2015, www.apscservices.info/pdf/13/13-002-U_212_2.pdf

[73] ACEEE, *A Guide to Growing an Energy-Efficient Economy in Mississippi*, 2013, http://aceee.org/research-report/e13m

[74] ACEEE, *Louisiana's 2030 Energy Efficiency Roadmap*, 2013, http://aceee.org/research-report/e13b

[75] Global Energy Partners, *Tennessee Valley Authority Potential Study*, 2011, http://152.87.4.98/news/releases/energy_efficiency/GEP_Potential.pdf

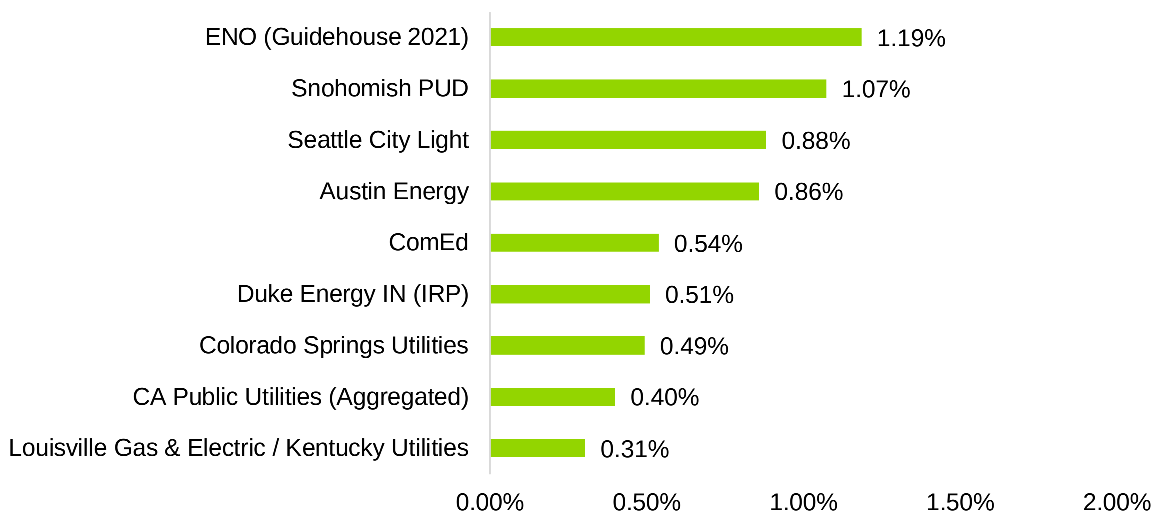
[76] ACEEE, Potential for Energy Efficiency, Demand Response, and Onsite Renewable Energy to Meet Texas's Growing Electricity Needs, 2007, https://aceee.org/research-report/e073

[77] California Municipal Utilities Association, Northern California Power Agency, Southern California Agency, *Energy Efficiency in California's Public Power Sector,* 14th Edition, 2020, http://ncpasharepointservice20161117100057.azurewebsites.net/api/document?uri=https://ncpapwr.sharepoint.com/sites/publicdocs/Compliance/2020%20CMUA%20Energy%20Efficiency%20Report%20Final.pdf.

Utility	Data Source
Sacramento Municipal Utility District	
SWEPCO	Texas Efficiency, Energy Efficiency Accomplishments of Texas Investor-Owned Utilities 2019[78]
Entergy Texas, Inc.	
El Paso Electric	
CPS Energy (City of San Antonio)	Evaluation, Measurement & Verification of CPS Energy's DSM Programs FY 2019[79]
Louisville Gas & Electric/Kentucky Utilities	LG&E/KU DSM Advisory Group Meeting, 2017[80]

Based on the sources above, Guidehouse aggregated the results into the following figures.[81] ENO is higher than other peer utilities.

Figure 5-2. Benchmarking Pool Average Achievable Potential Savings (% of Sales)[82]



Source: Guidehouse analysis

When comparing potential estimates, although the utilities included in the benchmarking pool may have some similar characteristics, no two utilities are the same. 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.

78 Frontier Associates, *Energy Efficiency Accomplishments of Texas Investor-Owned Utilities 2018*, 2017, http://www.texasefficiency.com/images/documents/Publications/Reports/EnergyEfficiencyAccomplishments/EEPR2019.pdf

79 Frontier Associates, *Evaluation Measurement & Verification of CPS Energy's FY 2019 DSM Programs*, https://www.sanantonio.gov/portals/0/files/sustainability/Environment/CPSFY2019.pdf

80 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

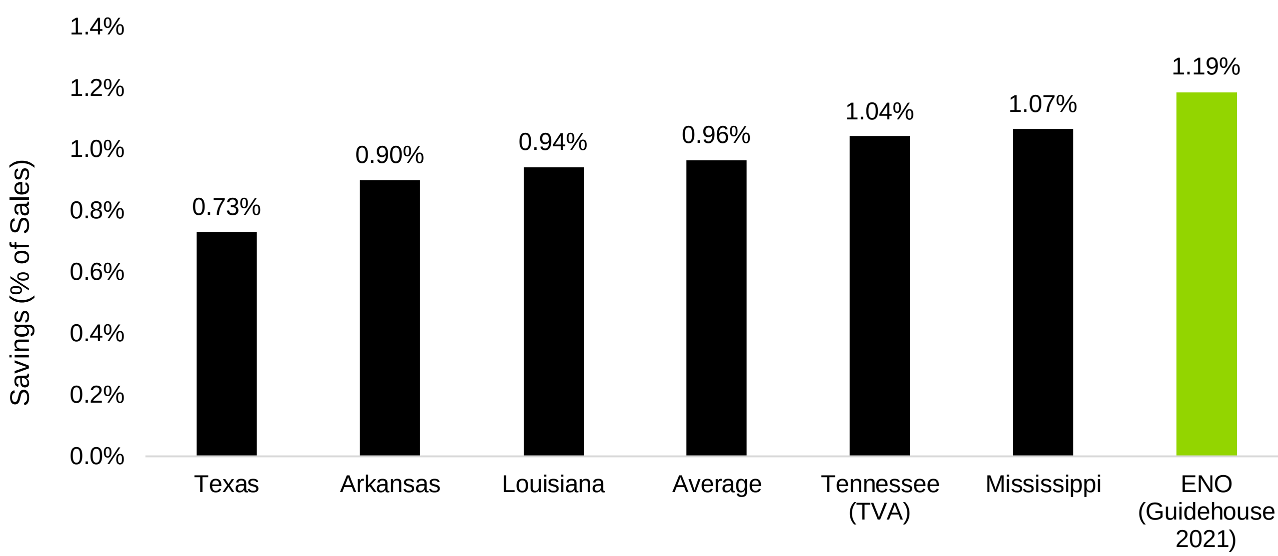
81 There has not been many updates to the peer utility data reports as of the 2018 ENO potential study.

82 These savings are shown as an annual average, which Guidehouse 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.

Achievable potential savings range from 0.31% to 1.19% of sales. Besides ENO, Snohomish Public Utility District in Washington has the highest potential and Louisville Gas & Electric/Kentucky Utilities has the lowest. Many factors may drive these differences, 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 1.19% savings per year over the study period (2021-2040). This is similar to Snohomish PUD. Both utilities operate in large metropolitan areas and have similar governance structures in that they are regulated by a city council.[83]

In addition to benchmarking the results at the utility level, Guidehouse created a peer pool at the state level. The goal 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 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)



Source: Guidehouse analysis

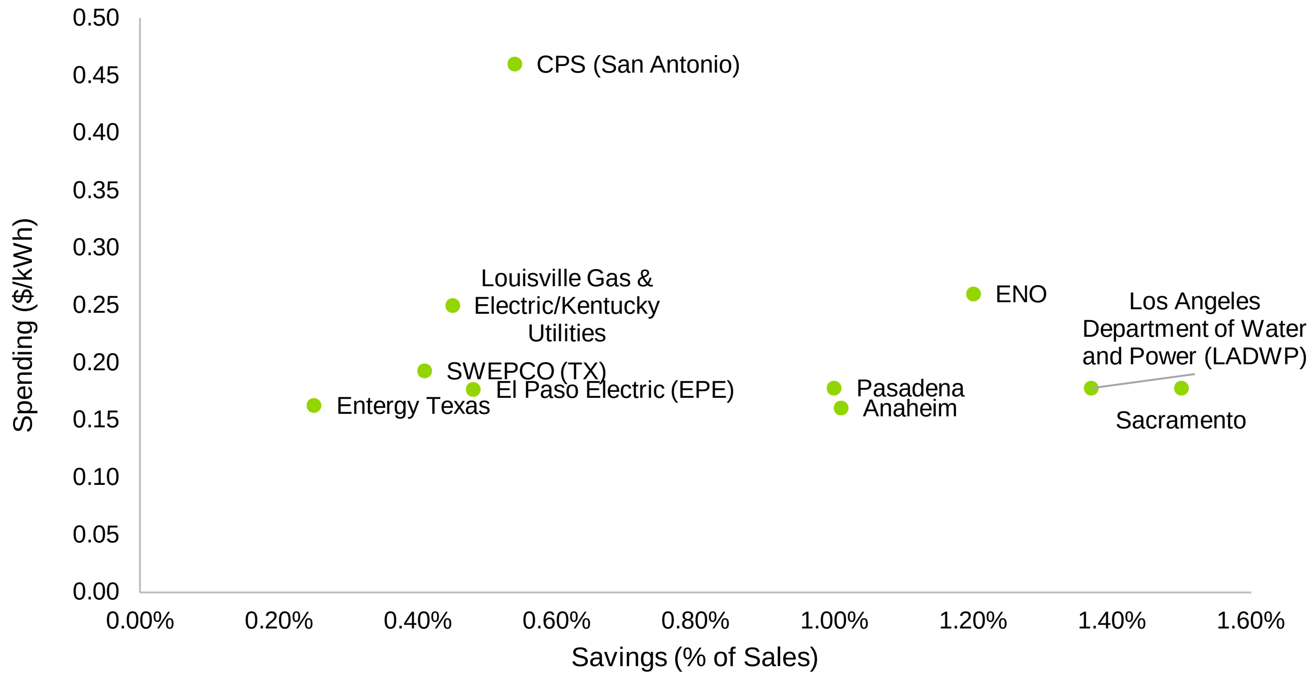
As Figure 5-3 shows, ENO's achievable potential savings are at the top of the range for the similar states. The slight difference in savings of this potential study and the state may be caused by several factors, including:

- Updated data inputs – including measure level unit energy savings

83 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 EE 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: Guidehouse 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. Figure 5-4 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 (1.0%+). ENO falls between these, spending $0.23/kWh and saving ~1.0% in 2020. ENO's most recent spending and savings align closely with California, suggesting strong program administration and design variances.

Demand Response

In addition to EE potential, the team also benchmarked DR potential, following a similar process.

The 2018 and 2021 demand response analysis differed in the following ways:

1. Guidehouse used actual data of implementation for C&I curtailment. There has been growth in program participation compared to the data from 3 years ago.
2. There is updated data on the penetration of smart thermostat data and updated AMI rollout plan.

For the process on benchmarking to different jurisdictions, the Guidehouse team 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). Table 5-4. includes the sources used for this analysis.

Table 5-4. Demand Response Potential Benchmarking Pool and Sources

Utility or ISO/RTO	Data Source
Ameren Union Electric (AmerenUE)	AmerenUE DSM Market Potential Study[84]
Con Edison (Con Ed)	DER Potential Study[85]
Commonwealth Edison (ComEd)	Comprehensive Assessment of Demand-Side Resource Potentials[86]
Electric Reliability Council of Texas (ERCOT)	Assessment of Demand Response and Advanced Metering[87]
Hawaii Electric Company (HECO)	Fast DR Pilot Program Evaluation[88]
Puget Sound Energy (PSE)	2017 IRP Demand-Side Resource Conservation Potential Assessment Report[89]
Southwest Power Pool (SPP)	Assessment of Demand Response and Advanced Metering[90]

Figure 5-5 shows the results of this analysis.

[84] 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.

[85] Guidehouse, DER Potential Study, 2019.

[86] 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

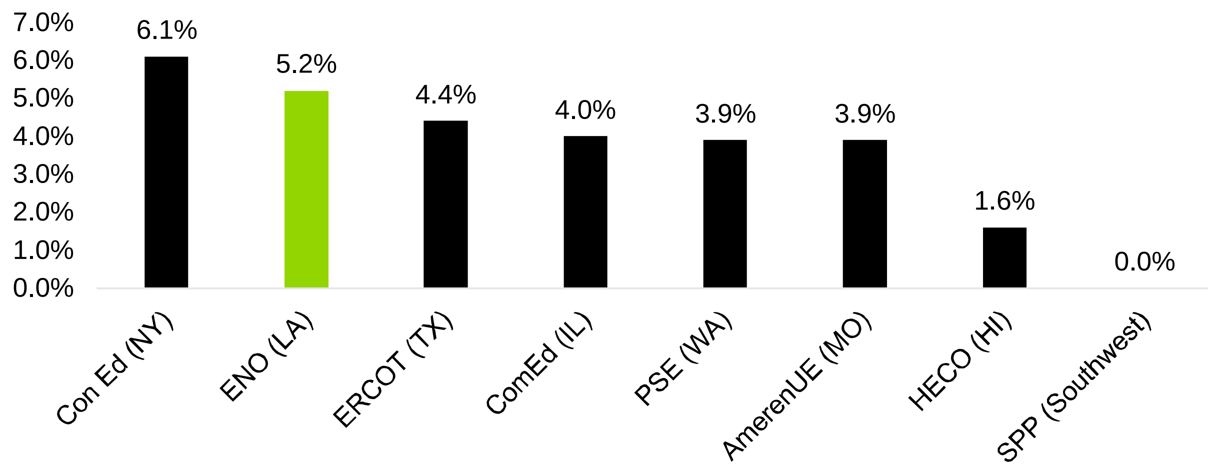
[87] Federal Energy Regulatory Commission (FERC) Assessment of Demand Response and Advanced Metering, 2019, https://www.ferc.gov/sites/default/files/2020-04/DR-AM-Report2019_2.pdf

[88] Guidehouse, Fast DR Pilot Program Evaluation, May 2015, http://media.Guidehouseconsulting.com/emarketing/Documents/Energy/HawaiianElectricFastDREvaluationReport_Sept302014GuidehouseRevisedMay192015v2.pdf

[89] Guidehouse, 2017 IRP Demand-Side Resource Conservation Potential Assessment Report, June 2017, https://pse.com/aboutpse/EnergySupply/Documents/DSR-Conservation-Potential-Assessment.pdf

[90] FERC, Assessment of Demand Response and Metering.

Figure 5-5. Benchmarking Pool DR Potential (% of Savings)



Source: Guidehouse analysis

As Figure 5-5 shows, ENO falls in the top of the benchmarking pool, only slightly higher than ERCOT and slightly below Con Edison in New York. Given that DR, like EE, varies based on program administration and geographic location, among other factors, ENO's DR potential aligns closely to its peers.

5.2 IRP

The ENO IRP is an iterative process to produce possible resource portfolios under different assumptions that 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 EE 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 inform 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 **Error! Reference source not found.**). Each measure is mapped to one or more DSM programs. Guidehouse then develops 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 is aligned with the Council's IRP Rules, which require that the data supplied 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 four standard cost-effectiveness tests.

5.3 Program Planning

DSM potential studies 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, programmatic design (such as delivery methods and marketing strategies) will have implications for the overall savings goals and projected cost.

As mentioned, 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 consider in program design, along with historical program participation and current market conditions (with the team members on the ground).

- Significant savings potential exists in promoting retro-commissioning, occupancy sensor controls and interior high bay and 4ft LEDs for the C&I sector.
- There is high potential in operations and maintenance (residential duct sealing and AC tune up) and behavior-type programs such as home energy reports in the residential sector.
- Significant demand response potential in the C&I sector for C&I curtailment and DLC; with the residential sector leading in peak demand reduction potential with the increased penetration of enabling technologies like smart thermostats.

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 or other market adoption study specific to the ENO service area either via customer survey, Delphi panel of regional stakeholders, or other method
- Exploration of behavior program opportunities in the ENO service territory

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
	HVAC	All cooling, including both central air conditioning and room or portable air conditioning; All heating, including both primary heating and supplementary heating; 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
	HVAC	All cooling equipment, including chillers and direct expansion cooling; All heating equipment, including boilers, furnaces, unit heaters, and baseboard units; 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: Guidehouse

A.2 Residential Sector

The following sections detail the approach used to determine electricity consumption by segment, the approach used to estimate end-use proportions, and the resulting residential household stock. To do this, Guidehouse needed to determine three pieces of information:

1. Base year and forecasted stock

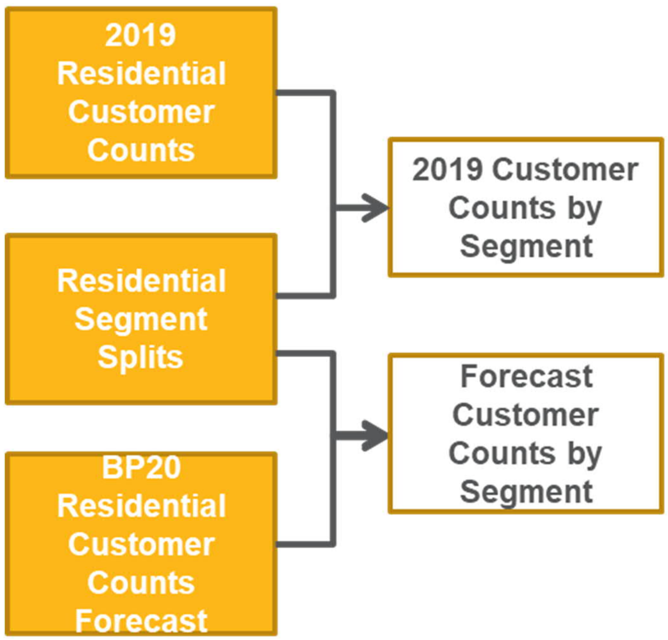
2. Base year and forecasted total consumption

3. Base year and forecasted consumption by end use

1. Base Year and Forecasted Residential Stock

Figure A-1 outlines Guidehouse's approach to determining the base year and forecasted residential stock.

Figure A-1. Residential Stock Base Year and Base Forecast Approach



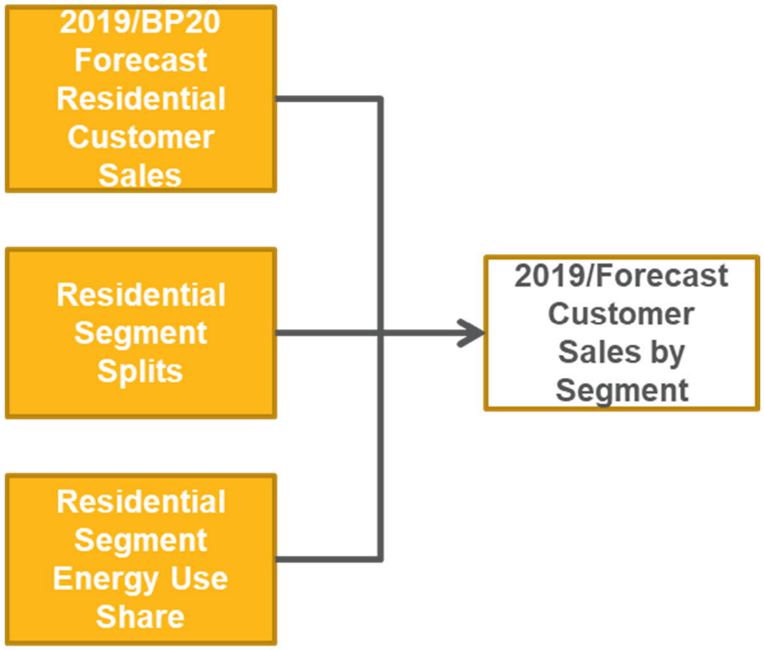
To define the base year residential sector inputs, Guidehouse determined the total base year stock using ENO's number of households in the class breakdown. Guidehouse needed to divide this total into single-family and multifamily segments. To do this, Guidehouse used the class breakdown from the 2016 household split survey and multiplied these splits by the total base year stock.

To define the forecasted residential sector inputs, Guidehouse used the same class breakdown from the 2016 household split survey and multiplied these splits by the total residential customer counts in the BP20 sales forecast.

2. Base Year and Forecasted Total Consumption

Figure A-2 outlines Guidehouse's approach to determining the base year and forecasted residential sales.

Figure A-2. Base Year and Forecasted Residential Sales Approach



Base year sales used the 2019 reported sales provided by ENO. Guidehouse used the 2016 household split survey results to calculate the segment-level base year sales by multiplying the household split by the total. From the 2018 study, Guidehouse determined that multifamily households consume 67% of the electricity that a single-family household does. The team determined this number by dividing the multifamily average annual consumption by the single family average annual consumption shown in Table A-2. The 2018 study used data provided by ENO to determine the average annual consumption by segment.

Table A-2. 2018 Average Annual Consumption (kWh/Account)

Building Segment	Average Annual Consumption	Consumption Ratio[91]
Single-Family	11,903	1
Multifamily	7,975	0.67

Source: Guidehouse analysis

The single family and multifamily household splits were multiplied by their consumption ratios (1 for single family, and 0.67 for multifamily) to calculate consumption-weighted household splits. Guidehouse calculated the new total of the consumption-weighted household splits and divided each weighted split by the total, producing new consumption splits that sum to one for the residential sector. These new consumption splits represent the proportion of the total residential energy used by each of the single family and multifamily segments. Guidehouse multiplied the consumption splits by the total reported 2019 sales to calculate segment-level sales.

3. Base Year and Forecasted Consumption by End Use

[91] Consumption ratio for a given segment is equal to that segment's average annual consumption divided by the average annual consumption of the single-family segment.

To disaggregate the total residential consumption for single-family and multifamily customers to the end-use level, Guidehouse relied on end-use proportions calculated in the 2018 study. In 2018, Guidehouse calculated the proportion of energy used by each end use (e.g., this proportion of the consumption is a percent of the total segment level consumption). Guidehouse derived these proportions using Guidehouse DOE's EnergyPLUS prototypical models with some adjustments to reflect ENO building stock and other Guidehouse adjustments based on lessons learned across utility jurisdictions. Guidehouse assumed the end-use proportions were constant across the forecast period. This assumption has minimal impact to the overall potential since all of the residential sector savings calculations are not dependent on end-use consumption proportions except for behavioral measures.

Table A-3 shows the resulting end use proportions by residential end use, which is an overall percentage of each household.

Table A-3. Residential End Use Proportion (% of whole building kWh)

End Use	Percent
Hot Water	4.4%
HVAC	47.8%
Lighting Exterior	3.1%
Lighting Interior	19.4%
Plug Loads	25.3%
Total	**100.0%**

Source: Guidehouse analysis

A.3 C&I Sector

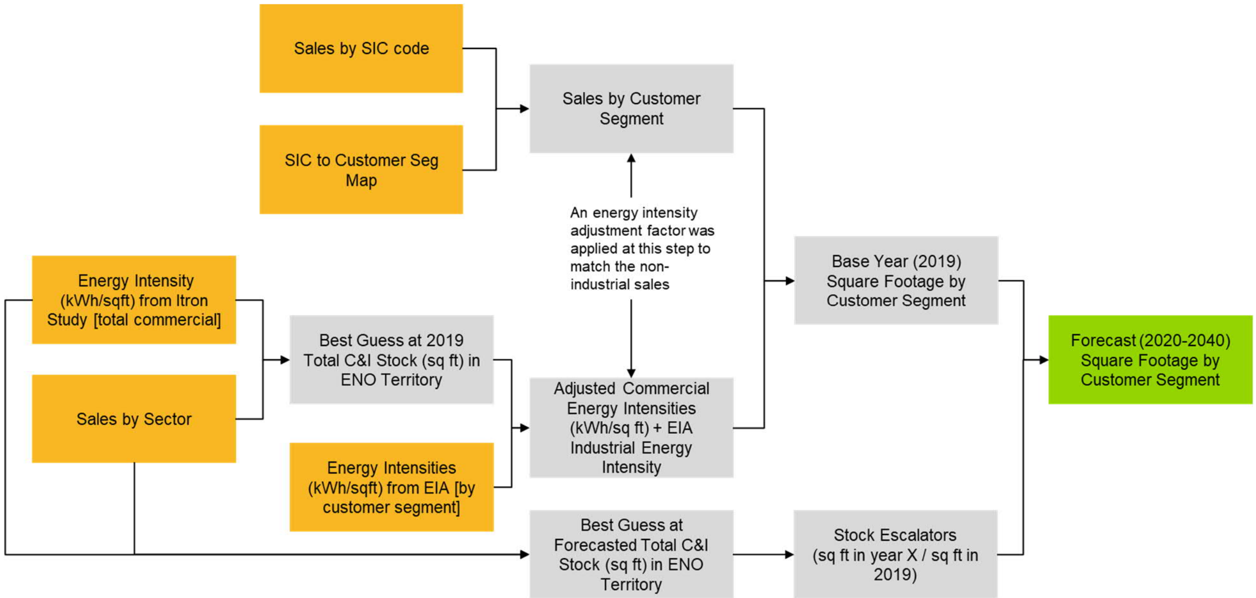
The following sections describe the detailed approach used to determine electricity consumption by segment, the approach used to estimate end-use proportions, and the resulting C&I stock. Guidehouse needed to determine two pieces of information:

1. Base year and forecasted stock and total consumption
2. Base year and forecasted consumption by end use

1. Base Year and Forecasted C&I Stock and Total Consumption

Figure A-3 outlines Guidehouse's approach to determining the base year and forecasted C&I stock.

Figure A-3. C&I Base Year and Forecast Approach



To define the base year C&I sector stock inputs, Guidehouse began with customer level billing data, which included customers' SIC codes and 2019 annual consumption. This data came in three datasets: commercial, industrial, and governmental. Guidehouse used a mapping of SIC codes to customer segments derived as part of the 2018 study. By joining the mapping file to each of the three billing datasets, Guidehouse aggregated the 2019 consumption to the customer segment level for each of the commercial, industrial, and governmental subsectors. ENO also provided 2019 total consumption for each of the commercial, industrial, and governmental subsectors in the class breakdown dataset. Guidehouse adjusted the segment-level usage to equal the sector totals for 2019.

To estimate square footage from segment level energy usage, Guidehouse developed segment-level energy intensities (kWh/square foot). Guidehouse began with segment-level intensities from US EIA. Table A-4. shows the mapping of segments in the EIA intensity data to the segments of this study.

Table A-4. C&I EUI Segments to Study Segment Mappings

EIA Principal Building Activity	Study Segment
Education	Colleges/Universities and Schools
Health Care	Healthcare
Buildings with Manufacturing	Industrial/Warehouses
Lodging	Lodging
Office	Office – Large and Office – Small
Public Assembly	Other Commercial
Food Service	Restaurants
Food Sales	Retail – Food
Mercantile	Retail – Non-Food

For the non-industrial segments, Guidehouse used overall commercial sector intensities from Itron to adjust the segment-level intensities from EIA. To do so, Guidehouse calculated the best estimate of overall square footage in the commercial sector by dividing total 2019 sales by the Itron intensity. Guidehouse then calculated an adjustment factor by dividing the best estimate of total stock by the sum of the segment-level stock derived from EIA intensities. Guidehouse multiplied the adjustment factor by the segment-level EIA intensities to produce final segment-level EIA intensities that average out to the Itron overall intensity. For industrial, Guidehouse used the EIA intensity directly as the final intensity for the industrial segment. Finally, Guidehouse divided the segment level base year sales (kWh) by the adjusted segment-level intensities (kWh/square feet) to calculate segment-level stock (square feet) in the base year.

Guidehouse used the base year segment level stock as the foundation for the stock forecast (2021-2040). For the non-industrial segments, Guidehouse used the BP20 sales forecast divided by the Itron sector level intensity forecasts to calculate forecasted stock (sqft) for the C&I sector as a whole. Guidehouse used this stock forecast to establish escalation factors (sqft in year X/sqft in 2019) for the C&I stock forecast. In doing so, the escalators account for assumed DSM over time for both the sales and intensity. For the industrial segment, Guidehouse used the BP20 sales forecast to calculate escalation factors. Once derived, Guidehouse multiplied the escalation factors by the base year segment level stock to calculate the segment-level stock forecast.

2. Base Year and Forecasted Consumption by End Use

To disaggregate the total C&I consumption for each segment to the end-use level, Guidehouse relied on end-use proportions calculated in the 2018 study. In 2018, Guidehouse calculated the proportion of energy used by each end use (e.g., this proportion of the consumption is X% of the total consumption). Guidehouse derived these proportions using Guidehouse's DOE EnergyPLUS prototypical models with some adjustments to reflect ENO building stock and other Guidehouse adjustments based on lessons learned across utility jurisdictions. Guidehouse assumed the end-use proportions were constant across the forecast period. This assumption has minimal impact to the overall potential since most of the commercial sector savings calculations (except for behavioral) are independent from end use consumption proportions.

Table A-5. shows the resulting end use proportions by C&I end use, which is an overall percentage of each building type segment consumption.

Table A-5. C&I Base Forecast End Use Proportions (% of kWh)

Segment	End Use	2019-2040
Colleges/Universities	Hot Water	1.5%
	HVAC	55.0%
	Lighting Exterior	2.7%
	Lighting Interior	25.4%
	Plug Loads	14.2%
	Refrigeration	1.2%
	Total Facility	**100.0%**
Healthcare	Hot Water	1.2%
	HVAC	52.0%
	Lighting Exterior	0.8%

Segment	End Use	2019-2040
	Lighting Interior	21.0%
	Plug Loads	24.5%
	Refrigeration	0.5%
	Total Facility	**100.0%**
Industrial/Warehouses	Hot Water	12.6%
	HVAC	44.2%
	Lighting Exterior	1.6%
	Lighting Interior	33.2%
	Plug Loads	5.4%
	Refrigeration	3.1%
	Total Facility	**100.0%**
Lodging	Hot Water	25.3%
	HVAC	32.3%
	Lighting Exterior	1.2%
	Lighting Interior	15.9%
	Plug Loads	24.5%
	Refrigeration	0.8%
	Total Facility	**100.0%**
Office - Large	Hot Water	0.4%
	HVAC	49.3%
	Lighting Exterior	0.2%
	Lighting Interior	31.1%
	Plug Loads	19.1%
	Total Facility	**100.0%**
Office - Small	Hot Water	0.4%
	HVAC	50.5%
	Lighting Exterior	0.2%
	Lighting Interior	30.3%
	Plug Loads	18.6%
	Total Facility	**100.0%**
Other Commercial	Hot Water	6.8%
	HVAC	30.5%
	Lighting Exterior	0.9%
	Lighting Interior	13.7%
	Plug Loads	44.5%
	Refrigeration	3.6%
	Total Facility	**100.0%**
Restaurants	Hot Water	5.2%
	HVAC	37.0%
	Lighting Exterior	4.5%

Segment	End Use	2019-2040
	Lighting Interior	7.4%
	Plug Loads	42.7%
	Refrigeration	3.2%
	Total Facility	**100.0%**
Retail - Food	Hot Water	0.1%
	HVAC	24.8%
	Lighting Exterior	1.2%
	Lighting Interior	22.4%
	Plug Loads	11.5%
	Refrigeration	40.1%
	Total Facility	**100.0%**
Retail (Non-Food)	Hot Water	11.0%
	HVAC	33.5%
	Lighting Exterior	3.0%
	Lighting Interior	44.3%
	Plug Loads	5.0%
	Refrigeration	3.2%
	Total Facility	**100.0%**
Schools	Hot Water	2.0%
	HVAC	57.1%
	Lighting Exterior	2.6%
	Lighting Interior	23.9%
	Plug Loads	13.3%
	Refrigeration	1.1%
	Total Facility	**100.0%**

Source: Guidehouse analysis

A.4 Measure List and Characterization Assumptions

Guidehouse developed the measure list and characterizations based on internal expertise, ENO-specific data, the New Orleans TRM, and secondary sources where necessary. This work is provided in a separate workbook.

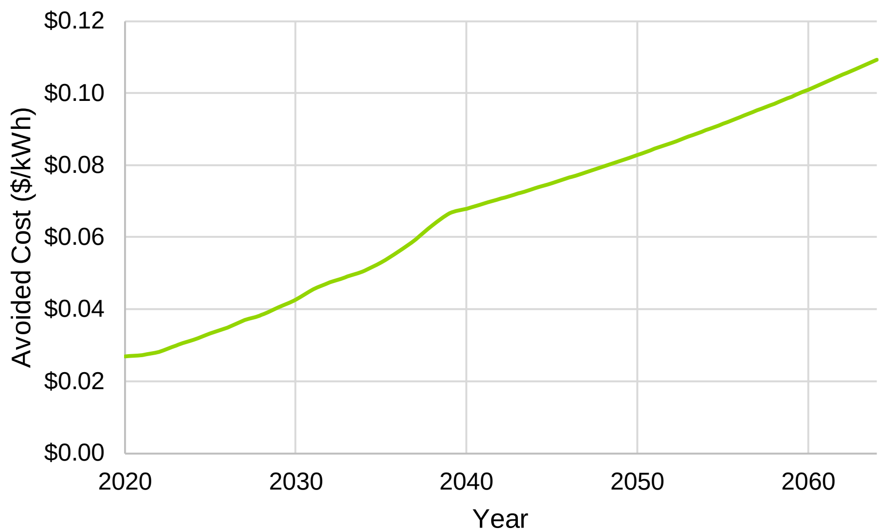
A.5 Avoided Costs and Cost-Effectiveness

Guidehouse input several cost-related inputs to determine the cost-effectiveness of measures over the study period. This section details those inputs.

A.5.1 Avoided Energy Costs

ENO provided the BP20[92] avoided costs through 2039 in nominal dollars. Guidehouse projected these costs over the remainder of the study period plus the longest measure life (25 years) using a 2% inflation rate starting in 2040 to input into the model. Figure A-4 shows the avoided energy cost projections or forecasted locational marginal prices in nominal dollars.

Figure A-4. ENO BP20 Avoided Cost Projections



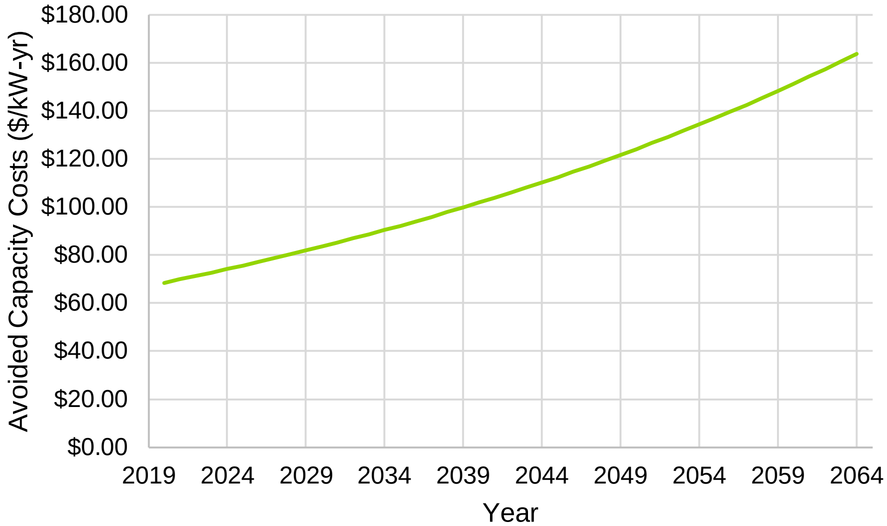
A.5.2 Avoided Capacity Cost

ENO provided the BP20[93] avoided capacity costs through 2049 in nominal dollars. Guidehouse projected these costs over the remainder of the study period plus the longest measure life (15 years) using a 2% inflation rate starting in 2050 to input into the model. Like the avoided energy costs, the capacity costs align with ENO's BP20 and its internal planning. Figure A-5 shows these costs over the study period in nominal dollars.

[92] BP20 refers to the vintage of a set of planning and modeling assumptions. At the time of this study, BP20 was the latest assumption set available.

[93] BP20 refers to the vintage of a set of planning and modeling assumptions. At the time of this study, BP20 was the latest assumption set available.

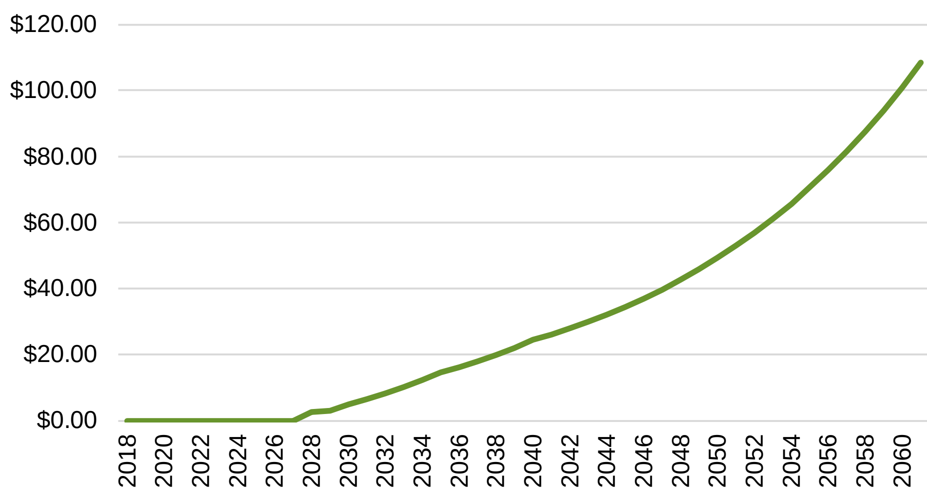
Figure A-5. ENO BP20 Avoided Capacity Projections



A.5.3 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, Guidehouse 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.[94] Figure A-6 shows the carbon pricing estimates provided and extrapolated.

Figure A-6. ENO Carbon Pricing Projections[95]



[94] Note that the growth rate was flat for the remaining 5 years provided.

[95] 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.

A.6 Cost-Effectiveness Calculations

The potential analysis uses two forms of cost-effectiveness calculations. The TRC test is for utility cost-effectiveness. There is also the 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.

A.6.1 TRC Test

The TRC test is a benefit-cost metric that measures the net benefits of EE 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 A-1.

Equation A-1. Benefit-Cost Ratio for TRC Test

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

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.

Guidehouse calculated TRC ratios for each measure based on the present value of benefits and costs over each measure's life. Free ridership's effects 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, the focus is 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.

A.6.2 Participant Payback Period

Guidehouse 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 Section 2.1.4.3. The payback period is calculated after the incentive is applied to the measure cost. Equation A-2 demonstrates the calculation.

Equation A-2. Participant Payback Period

$$Payback = \frac{Annual\ kWh\ Saved\ \times Annualized\ Retail\ Rate\ \left(\$/_{kWh}\right)}{Incremental\ Measure\ Cost - Incentive}$$

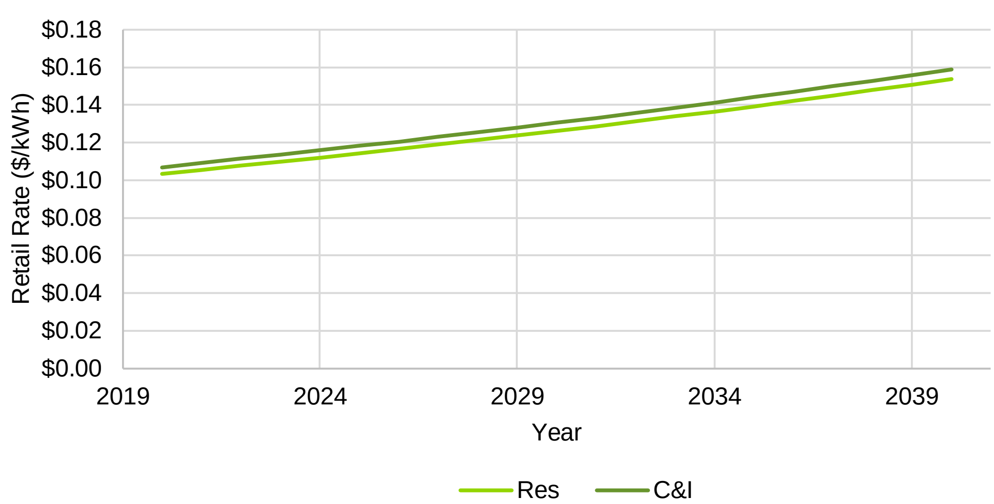
Where:

- 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 A.7).
- 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.

A.7 Retail Rates

Customer economics is a primary driver of energy efficiency measure adoption, so Guidehouse 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 based on historic sales. ENO provided 2019 revenue ($) and sales (kWh) by rate class and rate schedule, as well as customer counts by rate class and rate schedule. For each rate schedule, Guidehouse divided revenue by sales to calculate an average rate ($/kWh). Then, for each sector (residential and non-residential), Guidehouse calculated an average rate ($/kWh) weighted by the number of customers on each rate schedule. Guidehouse then assumed the rates would increase with inflation, or 2% per year.

Figure A-7. Electricity Retail Rate Forecast: 2021-2040



Source: Guidehouse analysis

A.8 Other Key Input Assumptions

As Table A-6 shows, Guidehouse used the discount rate provided by ENO and an inflation rate consistent with the utility's planning.

Table A-6. Potential Study Assumptions

Variable Name	Percentage
Discount Rate	7.09%
Inflation Rate	2.00%

Source: ENO

Appendix B. IRP Model Inputs Developments

The Guidehouse team used the 8,760 loadshapes developed using the approach described in the 2018 report Appendix B to convert the annual potential estimates into hourly potential estimates. In doing so, Guidehouse created program categories (Table B-1) to aggregate these hourly potential estimates to the program level and develop the input files necessary to support the IRP modeling. Guidehouse performed this aggregation using the mapping in Table B-2, below. The table shows a many-to-one mapping between measures and programs because some measures belong to more than one program. Guidehouse used the savings breakdown by program in each case to weight the savings allocation of these measures to programs.

Table B-1. Program Categories

Sector	Program Name	Program Abbreviation
C&I	Commercial Behavior	Com Behavior
	Large Commercial & Industrial	Large C&I
	Small Commercial & Industrial and Publicly Funded	Small C&I
Res	Retail Lighting & Appliances	Retail
	Home Performance with Energy Star	HPwES
	A/C Solutions	HVAC
	Multi Family Solutions and Income Qualified Weatherization	LI_MF
	Residential Behavior	Res Behavior
	School Kits and Education	School Kits

Table B-2. 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 | Building Energy Information Management System
C&I	Com Behavior	C&I | Building Operator Certificate
C&I	Com Behavior	C&I | Business Energy Reports
C&I	Com Behavior	C&I | Refrigeration Retrocommissioning
C&I	Com Behavior	C&I | Retrocommissioning
C&I	Com Behavior	C&I | Strategic Energy Management
C&I	Large C&I	C&I | Advanced Lighting Controls
C&I	Large C&I	C&I | Advanced 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 | Bi-Level Garage Lighting
C&I	Large C&I	C&I | Building Automation System
C&I	Large C&I	C&I | Chiller Plant Optimization
C&I	Large C&I	C&I | Combination Ovens
C&I	Large C&I	C&I | Commercial Air Conditioner and Heat Pump Tune-Up
C&I	Large C&I	C&I | Commercial Clothes Dryer
C&I	Large C&I	C&I | Commercial Clothes Washer

Sector	Program	Measure
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 HVAC Tune-up
C&I	Large C&I	C&I | Commercial Steam Cookers
C&I	Large C&I	C&I | Commercial Water Heater Pipe Insulation
C&I	Large C&I	C&I | Common area clothes washer (Lodging, university)
C&I	Large C&I	C&I | Computer Power Management
C&I	Large C&I	C&I | Control Hotel Room Occ
C&I	Large C&I	C&I | Controls Cont Dimming
C&I	Large C&I	C&I | Controls Occ Sensor
C&I	Large C&I	C&I | Controls Photocells
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 | Door LEDs
C&I	Large C&I	C&I | Ductless Mini-Split Heat Pump
C&I	Large C&I	C&I | Electric Exhaust Hood
C&I	Large C&I	C&I | Electric tankless water heater replacing small (<12 kW) water heater
C&I	Large C&I	C&I | Energy Recovery Ventilator
C&I	Large C&I	C&I | ENERGY STAR Residential-size Refrigerator
C&I	Large C&I	C&I | Evap Fan Ctrls
C&I	Large C&I	C&I | Fan and Pump Optimization
C&I	Large C&I	C&I | Guest Room Energy Management (GREM) Controls
C&I	Large C&I	C&I | Heat Pump Water Heater Replacing Standard Water Heater
C&I	Large C&I	C&I | Electric Storage Water Heater
C&I	Large C&I	C&I | High Efficiency Fans and energy management
C&I	Large C&I	C&I | Ice Maker
C&I	Large C&I	C&I | Industrial Motors
C&I	Large C&I	C&I | Interior 4 ft LED
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 Pre-Rinse Spray Valves
C&I	Large C&I	C&I | Night Covers
C&I	Large C&I	C&I | Packaged Terminal AC/HP (PTAC/PTHP) Equipment
C&I	Large C&I	C&I | Plug Load Occupancy Sensors
C&I	Large C&I	C&I | Premium Efficiency Motors
C&I	Large C&I	C&I | Pump Equipment Upgrade
C&I	Large C&I	C&I | Solid Door CRE
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 | Window Film

Sector	Program	Measure
C&I	Large C&I	C&I | Zero Energy Doors
C&I	Large C&I	C&I |Interior LED High Bay | Replacing HID
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 RTU Controls
C&I	Small C&I	C&I | Bi-Level Garage Lighting
C&I	Small C&I	C&I | Building Automation System
C&I	Small C&I	C&I | Combination Ovens
C&I	Small C&I	C&I | Commercial Air Conditioner and Heat Pump 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 Faucet Aerator
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 HVAC Tune-up
C&I	Small C&I	C&I | Commercial Low-Flow Showerheads
C&I	Small C&I	C&I | Commercial Steam Cookers
C&I	Small C&I	C&I | Commercial Water Heater Pipe Insulation
C&I	Small C&I	C&I | Commercial Weatherization
C&I	Small C&I	C&I | Common area clothes washer (Lodging, university)
C&I	Small C&I	C&I | Computer Power Management
C&I	Small C&I	C&I | Control Hotel Room Occ
C&I	Small C&I	C&I | Controls Cont Dimming
C&I	Small C&I	C&I | Controls Occ Sensor
C&I	Small C&I	C&I | Controls Photocells
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 | Door Heater Controls
C&I	Small C&I	C&I | Door LEDs
C&I	Small C&I	C&I | Ductless Mini-Split Heat Pump
C&I	Small C&I	C&I | Electric Exhaust Hood
C&I	Small C&I	C&I | Electric tankless water heater replacing small (<12 kW) water heater
C&I	Small C&I	C&I | Electronically Commutated Motors (ECMs) for Refrigeration & HVAC
C&I	Small C&I	C&I | Energy Recovery Ventilator
C&I	Small C&I	C&I | ENERGY STAR Residential-size Refrigerator
C&I	Small C&I	C&I | Evap Fan Ctrls
C&I	Small C&I	C&I | Fan and Pump Optimization
C&I	Small C&I	C&I | Heat Pump Water Heater Replacing Standard Water Heater
C&I	Small C&I	C&I | Electric Storage Water Heater
C&I	Small C&I	C&I | Ice Maker
C&I	Small C&I	C&I | Interior 4 ft LED
C&I	Small C&I	C&I | Interior LED High Bay | Replacing T8HO HB

Sector	Program	Measure
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 | LED Traffic Signals
C&I	Small C&I	C&I | Low Flow Pre-Rinse Spray Valves
C&I	Small C&I	C&I | Night Covers
C&I	Small C&I	C&I | Packaged Terminal AC/HP (PTAC/PTHP) Equipment
C&I	Small C&I	C&I | Plug Load Occupancy Sensors
C&I	Small C&I	C&I | Refrigeration ECMs
C&I	Small C&I	C&I | Smart Thermostats (Applicable to Packaged Systems)
C&I	Small C&I	C&I | Solid Door CRE
C&I	Small C&I	C&I | Strip Curtain
C&I	Small C&I	C&I | Unitary and Split System AC/HP Equipment
C&I	Small C&I	C&I | Vend Machine Ctrls
C&I	Small C&I	C&I | Window Film
C&I	Small C&I	C&I | Zero Energy Doors
C&I	Small C&I	C&I |Interior LED High Bay | Replacing HID
Res	HPwES	Res | Advanced Networked Lighting Controls with Directional LEDs
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 | ECM circ pump | Elec
Res	HPwES	Res | ENERGY STAR Directional LEDs
Res	HPwES	Res | Faucet Aerators
Res	HPwES	Res | Floor Insulation
Res	HPwES	Res | Furnace fan motor retrofit
Res	HPwES	Res | Furnace Filter Whistle
Res	HPwES	Res | Heat Pump Water Heater
Res	HPwES	Res | High Efficiency Windows
Res	HPwES	Res | Low-Flow Showerheads
Res	HPwES	Res | Omni-Directional LEDs
Res	HPwES	Res | On demand tankless water heater
Res	HPwES	Res | Outdoor Dusk-Til-Dawn LED Light Bulb
Res	HPwES	Res | Outdoor LED Light Bulb
Res	HPwES	Res | Smart Thermostats - RET
Res	HPwES	Res | Solar Screens
Res	HPwES	Res | Solar Water Heater
Res	HPwES	Res | Thermostatic shower valve
Res	HPwES	Res | Tub spout diverters & Thermostatic shower valve

Sector	Program	Measure
Res	HPwES	Res | Wall Insulation
Res	HPwES	Res | Water Heater Pipe 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 - Early Replacement
Res	HVAC	Res | Ductless Heat Pump- ROB & NEW
Res	HVAC	Res | Ground Source Heat Pump
Res	LI_MF	Res | Advanced Power Strips
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 | Floor Insulation
Res	LI_MF	Res | Furnace fan motor retrofit
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
Res	LI_MF	Res | Smart Thermostats
Res	LI_MF	Res | Solar Screens
Res	LI_MF	Res | Solar Water Heater
Res	LI_MF	Res | Thermostatic shower valve
Res	LI_MF	Res | Tub spout diverters & Thermostatic shower valve
Res	LI_MF	Res | Wall Insulation
Res	LI_MF	Res | Water Heater Pipe Insulation
Res	LI_MF	Res | Window Film
Res	Res Behavior	Res | Home Energy Report
Res	Res Behavior	Res | Inhome display real-time Feedback
Res	Res Behavior	Res | Large Residential Competitions
Res	Res Behavior	Res | Online Audit tool
Res	Res Behavior	Res | Prepay Electricity Bills
Res	Res Behavior	Res | Web-based Real-time Feedback

Sector	Program	Measure
Res	Retail	Res | Energy Star air purifier
Res	Retail	Res | Energy Star Ceiling Fans
Res	Retail	Res | Energy Star Clothes Washers
Res	Retail	Res | Energy Star Dehumidifiers
Res	Retail	Res | ENERGY STAR Directional LEDs
Res	Retail	Res | Energy Star Dishwashers
Res	Retail	Res | Energy Star Dryers
Res	Retail	Res | Energy Star Freezers
Res	Retail	Res | Energy Star Heat pump dryers
Res	Retail	Res | Energy Star Pool Pumps
Res	Retail	Res | Energy Star Refrigerator/Freezer
Res	Retail	Res | Energy Star Refrigerator/Freezer - Early Retirement
Res	Retail	Res | Heat Pump Water Heater
Res	Retail	Res | Omni-Directional LEDs
Res	Retail	Res | On demand tankless water heater
Res	Retail	Res | Outdoor LED Light Bulb
Res	Retail	Res | Smart Plugs
Res	Retail	Res | Window AC
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

Appendix C. Achievable Potential Modeling Methodology Details

C.1 Calculating Achievable Potential

This section demonstrates Guidehouse'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

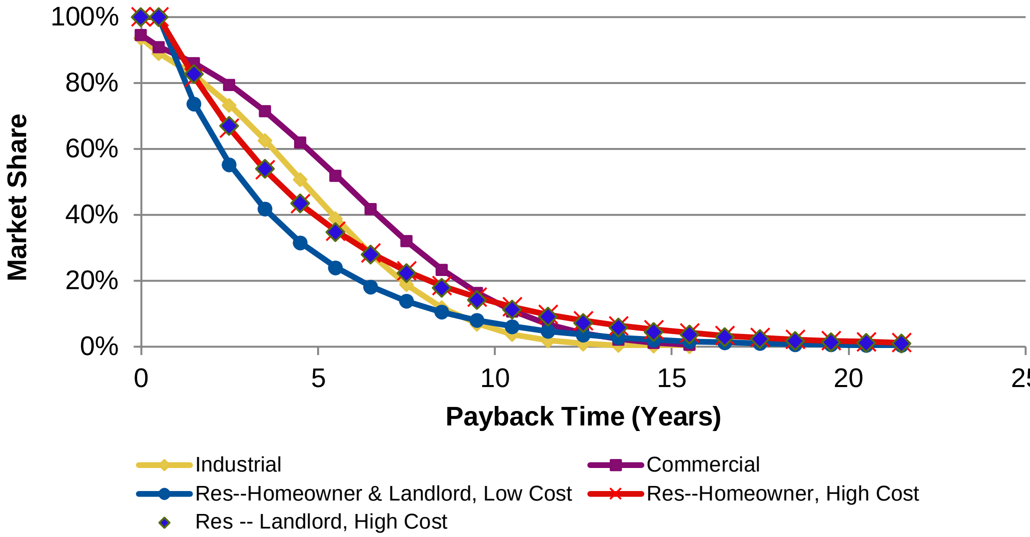
C.2 Calculation of Dynamic Equilibrium Market Share

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 includes the energy and cost savings associated with the efficient technology. That additional efficiency often comes at a premium in initial cost. 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.

Guidehouse uses equilibrium payback acceptance curves that were developed using primary research it conducted in the Midwestern US in 2012.[96] To develop these curves, the team surveyed 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. Guidehouse conducted statistical analysis to develop the set of curves shown in Figure C-1, which were leveraged in the 2021 ENO study. Though ENO-specific data is not currently available to estimate these curves, Guidehouse considers that the nature of the decision-making process is such that the data developed using these surveyed customers represents the best data available for this study at this time.

[96] 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.

Figure C-1. Payback Acceptance Curves



Source: Guidehouse, 2015

Because the payback time of a technology can change over time, as do technology costs or energy costs, the equilibrium market share can also evolve. The equilibrium market share is recalculated for every time-step within the market simulation to ensure the dynamics of technology adoption considers this effect. The term equilibrium market share is a bit of an oversimplification and a misnomer, as it can itself change over time and is never truly in equilibrium. It is used nonetheless to facilitate understanding of the approach.

C.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 ROB (a.k.a. lost opportunity) measures.[97] The following sections summarize each approach at a high level.

C.3.1 Retrofit/New Technology Adoption Approach

Retrofit and new technologies employ an enhanced version of the classic Bass diffusion model[98,99] to simulate the S-shaped approach to equilibrium commonly observed for technology adoption. Figure C-2 illustrates 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. Figure C-1 illustrates the fraction of the population willing to adopt is estimated using the payback acceptance curves.

---

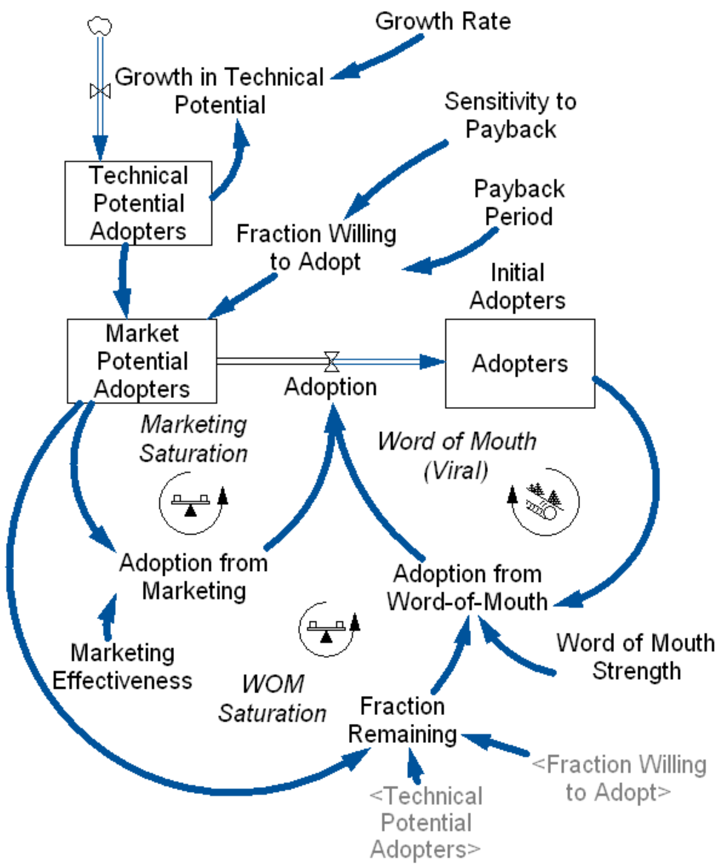
[97] Each of these approaches can be better understood by visiting Guidehouse's technology diffusion simulator, available at: http://forio.com/simulate/Guidehousesimulations/technology-diffusion-simulation.

[98] Bass, Frank (1969). "A new product growth model for consumer durables." *Management Science* 15 (5): p215–227.

[99] See Sterman, John D. Business Dynamics: Systems Thinking and Modeling for a Complex World. Irwin McGraw-Hill. 2000. p. 332.

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.[100] 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 been part of the Bass diffusion model of product adoption since its inception in 1969.

Figure C-2. Stock/Flow Diagram of Diffusion Model for New Products and Retrofits



Source: Guidehouse, 2015

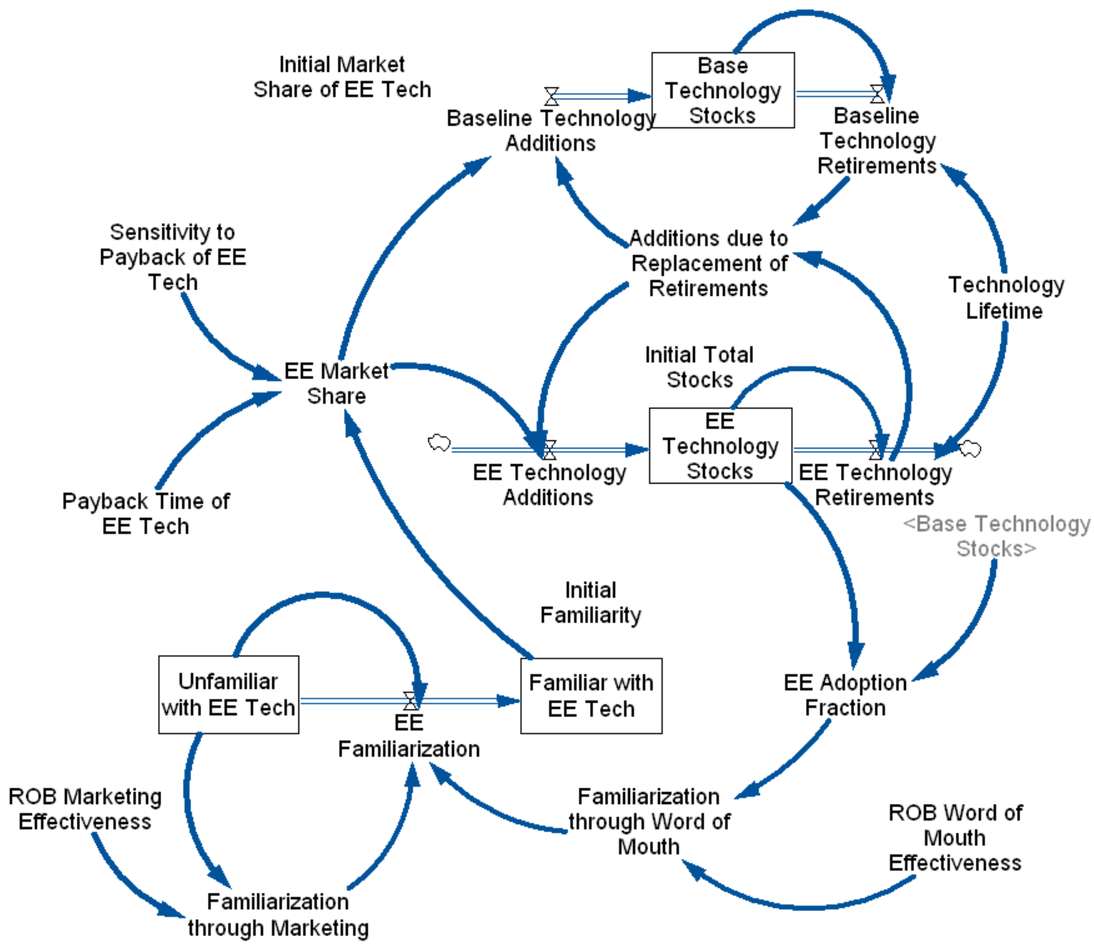
C.3.2 ROB Technology Adoption Approach

The dynamics of adoption for ROB technologies are 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,

[100] 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.

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, is overlaid on the stock tracking model to capture the dynamics associated with the diffusion of technology familiarity. Figure C-3 illustrates a simplified version of the model employed in DSMSim.

Figure C-3. Stock/Flow Diagram of Diffusion Model for ROB Measures



Source: Guidehouse, 2015

Appendix D. Behind the Meter Battery Storage Forecast

D.1 Forecast Methodology

Battery system parameters, customer benefits, and customer costs were developed for each customer segment and inputted into a payback-adoption model to estimate long-run battery adoption. Bass diffusion curves were then applied to estimate the rate of growth in adoption out to 2040.

D.1.1 Battery Parameters

Battery system parameters such as battery capacity, efficiency, and duration were developed for the analysis. A rigorous derivation for the peak output for battery sizing requires a detailed analysis of historical data and weather data, and each customer has unique needs. In Guidehouse's experience, a storage system is typically sized at 15% to 20% of a customer's peak load. In the absence of detailed load data for every single customer, Guidehouse sized the batteries to 15% of the customers' coincident customer peak load for this analysis. Batteries were also assumed to have a 1.9-hour duration, which was the average duration found in an NREL survey of Li-ion projects[101].

D.1.2 Customer Benefits

Guidehouse modeled demand charge reduction, bill savings from evening discharge, and DR-related incentives when considering customer-side economic benefits. Small Electric Service and Large Electric Service rates were applied to customers in the corresponding rate class to calculate bill savings from demand charge reduction and evening discharge. Batteries are assumed to be available to the customer for days where ENO is not dispatching the battery. Similar to the demand response program definition, ENO would dispatch batteries no more than 40 days per year. The analysis also considers bill savings from customers with solar systems who charge the battery with excess solar power during the day to offset energy use in the evening. For C&I customers, bill savings from evening discharge is minor compared to savings from demand charge reduction, but for residential customers, this evening discharge is the primary economic benefit (aside from incentives). Incentives were modeled as an adjustable input. Incentive analysis includes the option to apply upfront incentives, recurring incentives for DR program participation, or both.

D.1.3 Customer Costs

Guidehouse used the battery size and per kW upfront capital costs and ongoing O&M costs from Guidehouse Insights and PNNL[102] to calculate total costs incurred by the customer. Capital costs range from $1800-2200/kW, with larger batteries having a lower per kW cost.

[101] Commercial Scale, Lithium-ion Projects in the U.S, NREL, October 2016. https://www.nrel.gov/docs/fy17osti/67235.pdf

[102] Energy Storage Technology and Cost Characterization Report, PNNL, July 2019. https://www.energy.gov/sites/prod/files/2019/07/f65/Storage%20Cost%20and%20Performance%20Characterization%20Report_Final.pdf

D.1.4 Adoption Modeling

The inputs discussed above were fed into a simple payback calculation (shown below), and the resulting payback period was used, in conjunction with internally developed payback acceptance curves, to estimate long-run economic adoption. Customers who adopt for reasons other than utility bill savings economics (e.g. resiliency) will not be captured in the analysis.

Equation for Storage Payback Period Analysis

$$Payback\ Period = \frac{Installed\ Cost - Upfront\ Incentive}{Demand\ Charge\ Savings + Bill\ Savings\ from\ Discharge + Recurring\ Incentives - Ongoing\ Costs}$$

The model applied Bass diffusion curves to account for the gradual increase in adoptions up to the long-run market share.

D.1.5 Cases for DR Modeling

To develop different adoption forecasts for each of the DR cases, incentive levels and technology suitability parameters were varied according to the table below.

Table D–1. Battery Parameters for DR Adoption Cases

DR Case	Upfront Incentive	DR Participation Incentive	Technology Suitability
No Incentives	$0	$0	Only customers with solar
Base	C&I: 20% of upfront cost Res: 50% of upfront cost	$70/kW	Only customers with solar
Max Achievable	C&I: 20% of upfront cost Res: 50% of upfront cost	$275/kW	All customers

Source: Guidehouse

The demand response achievable potential analysis for the BTMS program used storage as a measure and examined battery program designs for all three cases shown in the table above. The analysis of all cases demonstrated that none of the battery program designs listed were cost-effective. Additional discussion on DR results can be found in Section 4.

D.2 Findings

This analysis shows that high incentives (as compared to the utility avoided costs) are required to drive sufficient adoption to enable meaningful DR savings from batteries. The table below shows the incentive levels at which customers begin to adopt batteries based on economic benefits. Large C&I customers have a more compelling value proposition to adopt storage systems due to their higher demand charges that can be mitigated by discharging storage during their facility peak. Thus, C&I customers will begin adopting battery storage at lower incentive levels compared to residential customers, whose primary benefits from batteries are recurring incentives and bill savings from evening discharge.

Table D–2. Incentive Levels at the Threshold of Adoption

Sector	Upfront Incentives ($)	Recurring Incentives ($/kW-year)
C&I	$0	$70
Res	$0	$120
C&I	40% of upfront cost	$0
Res	Little to no adoption even at 100% of upfront costs*	$0

*This behavior occurs when using a payback-based approach and when recurring O&M costs are greater than recurring benefits from bill savings, which is the case for residential customers.
Source: Guidehouse

While different combinations of upfront and recurring incentive levels could be used to model similar levels of long-run storage adoption, the DR cost-effectiveness results indicate that factors beyond battery program design, such as avoided capacity costs, battery costs, and platform fees, are driving the low cost-effectiveness of the battery program. If battery costs decline or if avoided capacity costs increase, it will be more feasible to create a cost-effective battery program.

CERTIFICATE OF SERVICE
DOCKET NO. UD-20-02

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.

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

Erin Spears, Chief of Staff
Bobbie Mason
Christopher Roberts
Council Utilities Regulatory Office
City of New Orleans
City Hall, Room 6E07
1300 Perdido Street
New Orleans, LA 70112

Andrew Tuozzolo
CM Moreno Chief of Staff
1300 Perdido Street, Rm 2W40
New Orleans, LA 70112

Paul Harang
Interim Chief of Staff
New Orleans City Council
City Hall, Room 1E06
1300 Perdido Street
New Orleans, LA 70112

Sunni LeBeouf
City Attorney Office
City Hall, Room 5th Floor
1300 Perdido Street
New Orleans, LA 70112

Norman White
Department of Finance
City Hall – Room 3E06
1300 Perdido Street
New Orleans, LA 70112

Jonathan M. Rhodes
Director of Utilities, Mayor's Office
City Hall-Room 2E04
1300 Perdido Street
New Orleans, LA 70012

Hon. Maria Auzenne
1615 Poydras Street, Suite 900
New Orleans, Louisiana 70112

Clinton A. Vince, Esq.
Presley R. Reed, Jr., Esq.
Emma F. Hand, Esq.
Adriana Velez-Leon
Dee McGill
Dentons US LLP
1900 K Street NW
Washington, DC 20006

Basile J. Uddo
J.A. "Jay" Beatmann, Jr.
c/o Dentons US LLP
650 Poydras Street, Suite 2850
New Orleans, LA 70130

Joseph W. Rogers
Victor M. Prep
Byron S. Watson
Legend Consulting Group
6041 South Syracuse Way
Suite 105
Greenwood Village, CO 80111

Jeffrey Huber
Rich Hasselman
Richard Spellman
Warren Hirons
GDS Associates, Inc.
1850 Parkway, Suite 800
Marietta, GA 30067

Casey DeMoss
Independent Consultant
248 Cherokee Street, Suite 30
New Orleans, Louisiana 70118

Manish Mardia
President, MSMM Engineering, LLC
4640 South Carrollton Avenue
New Orleans, Louisiana 70119

Corinne Villavaso
President, The Villavaso Group, LLC
7111 Lake Barrington Drive
New Orleans, Louisiana 70128

Courtney R. Nicholson
Vice-President, Regulatory Affairs
Entergy New Orleans, LLC
Mail Unit L-MAG-505B
1600 Perdido Street
New Orleans, LA 70112

Polly Rosemond
Interim Director, Regulatory Operations
Kevin T. Boleware
Brittany Dennis
Keith Wood
Derek Mills
Brandon M. Scott
Ross Thevenot
Entergy New Orleans, LLC
1600 Perdido Street
Mail Unit L-MAG-505B
New Orleans, LA 70112

Vincent Avocato
Entergy New Orleans, LLC
10055 Grogan's Mill Road Parkwood II Bldg, Mail Unit T-PKWD-2A
Suite 500, The Woodlands, TX 77380

Tim S. Cragin
Brian L. Guillot
Entergy Services, LLC
Mail Unit L-ENT-26E
639 Loyola Avenue
New Orleans, LA 70113

Joe Romano, III
Tim Rapier
Entergy Services, LLC
Mail Unit L-ENT-4C
639 Loyola Avenue
New Orleans, LA 70113

Logan Atkinson Burke
Sophie Zaken
Jesse George
Alliance for Affordable Energy
4505 S. Claiborne Avenue
New Orleans, La 70125

Katherine W. King
Randy Young
400 Convention St. Suite 700
Baton Rouge, LA. 70802
Or
P.O. Box 3513
Baton Rouge, LA 70821-3513

Carrie R. Tournillon
900 Poydras St., Suite 3600
New Orleans, LA 70112

Maurice Brubaker
16690 Swigly Ridge Rd., Suite 140
Chesterfield, MO 63017
Or
P.O. Box 412000
Chesterfield, MO. 63141-2000

Simon Mahan
5120 Chessie Circle
Haltom City, TX 76137

Andy Kowalczyk
819 Saint Roch Avenue
New Orleans, Louisiana 70117

Pooja Prazid
Benjamin Quimby
Clare Giesen
Marion Freistadt
Vickie Boothe
1632 8th Street
New Orleans, Louisiana 70115

Brent Newman
Senior Policy Director
3801 Canal Street, Suite 400
New Orleans, Louisiana 70119
Tel: (303) 681-8420

Karl R. Rabago
Rabago Energy, LLC
2025 E. 24th Avenue
Denver, Colorado 80205

Stephen Wright
695 Kiskatom Lane
Mandeville, Louisiana 70471

Jeff Cantin
2803 St. Philip St.
New Orleans, LA 70119

Joshua Smith
Staff Attorney
Sierra Club Environmental Law Program
2101 Webster Street, Suite 1300
Oakland, California 94612

New Orleans, Louisiana, this 30th day of July 2021.

Timothy S. Cragin

Timothy S. Cragin