REPLY COMMENTS OF DUKE ENERGY INDIANA REGARDING THE DRAFT DIRECTOR'S REPORT FOR
COMPANY'S 2021 INTEGRATED RESOURCE PLAN

I. Introduction

On December 15, 2021, Duke Energy Indiana, LLC ("Duke Energy Indiana" or "Company") submitted its 2021 Integrated Resource Plan ("IRP") to the Indiana Utility Regulatory Commission ("Commission"). Stakeholder comments were received on May 10, 2022, from Advanced Energy Economy, Inc. dba Indiana Advanced Energy Economy ("AEE"), and on May 16, 2022 from Sierra Club, Reliable Energy, Inc., Duke Energy Indiana Industrial Group ("DEI Industrial Group"), Energy Matters Community Coalition, Inc. ("EMCC"), Hoosier Environmental Council, Inc. ("HEC"), Office of Utility Consumer Counselor ("OUCC"), Indiana State Conference of the National Association for the Advancement of Colored People ("NAACP"), and Citizens Action Coalition of Indiana, Inc., Earthjustice, and Vote Solar (jointly) (collectively, "Joint Commenters"). Duke Energy Indiana submitted its response to stakeholder comments on July 22, 2022. On December 2, 2022, Dr. Bradley Borum issued his Draft Director's Report to Duke Energy Indiana's 2021 IRP (the "Draft Director's Report"). Duke Energy Indiana values the feedback provided in comments and the Draft Director's Report and commits to an improved outcome for its 2024 IRP with respect to the concerns identified in the comments and by Dr. Borum related to Duke Energy Indiana's technical work and stakeholder process.

II. Duke Energy Indiana's responsive comments to the Draft Director's Report

Dr. Borum's Draft Director's Report sets forth areas of concern that Duke Energy Indiana will address in turn. Specifically, he discusses three areas of desired improvement: load forecasting; demand-side resources; and the public advisory process. Additionally, the Company will briefly address select comments provided by stakeholders; however, a more comprehensive response to the stakeholder comments was submitted to the Commission on July 22, 2022 and is included as Appendix D to these reply comments.

The Company recognizes the importance of the IRP and related stakeholder process and will make a focused effort to incorporate feedback provided in the Draft Director's Report as well as from conversations with stakeholders. Duke Energy Indiana will build upon the portfolio development and risk analysis with more detail and transparency as it conducts the 2024 IRP and stakeholder process.

A. Load Forecasting

Dr. Borum stated that the Company provided little information on how load is forecasted. Specifically, Dr. Borum indicated that Appendix B provides no information on the drivers used for the residential and commercial sectors or how the industrial load is projected and also lacks information to evaluate the methodology or assumptions for the electric vehicles (EVs) and rooftop solar included in Appendix B.

In response, Duke Energy Indiana is providing additional explanation as follows: The Company appreciates the desire to have a deeper understanding of the forecasting process. As a result, the information provided below and in the attached Appendix A provides additional information describing the forecasting process. Appendix A includes: historical trend data; customer count by class; methodology framework information; forecast driver data; load modifier data; and supplemental data on model specification and output statistics. The Company will look to incorporate additional information that would be helpful in understanding the forecasting process in future filings.

Duke Energy Indiana relies on Itron's Statistically Adjusted End-Use Model (SAE) to create reliable forecasts for its service territory. This forecasting tool is a regression-based framework that uses projected appliance saturation and efficiency trends developed by Itron using Energy Information Administration data. It incorporates naturally occurring efficiency trends and government mandates more explicitly than other models. The SAE model considers a wide range of internal and external data sources, including historical usage and usage patterns, End-Use Intensities, historical weather, economic projections, demographic trends, electricity price data, and other information.

The retail forecast consists of forecasts for the four major classes of customers: residential, commercial, public authority/governmental, and industrial. Each of these major customer classes are forecasted separately using a wide range of inputs that best relate to the class being forecasted.

The residential class sales forecast is comprised of two projections. The first is the number of residential customers, which is driven primarily by population. The second is energy usage per customer, which is driven by weather, regional economic and demographic trends, electricity prices, and appliance saturations and efficiencies.

The commercial forecast also includes end-use intensities that capture naturally occurring as well as government mandated efficiency changes. The industrial class is forecasted by an econometric model, with drivers such as weather, total manufacturing and industrial indices. The government class econometric model uses drivers such as weather and the number of people employed by the government.

Weather impacts are incorporated into the models by using Heating Degree Days and Cooling Degree Days. The forecast of degree days is based on a 30-year average, which is updated every year.

Impacts to load due to adoption of EVs and rooftop solar are forecasted separately (these forecasting processes are described below), and then aggregated with the load expectations for each of the major classes to generate the jurisdictional forecast of energy sales and peaks.

In regard to the forecast for EV adoption, Duke Energy Indiana's EV load forecast was derived using an EV adoption forecast paired with load charging profiles to come up with energy and load impacts. The Electric Power Research Institute (EPRI) provides EV forecasts specific to Duke Energy Indiana's service area using five electric vehicle types. Those five vehicle types are two battery electric vehicles (BEV) with a range of 100 or 250 miles and three plug in hybrid electric vehicles (PHEV) with ranges of 10, 20, or 30 miles. EPRI forecasts are based on a blend of published forecasts from others, and those forecasts use a range of assumptions and methodologies. In recent years, Duke Energy Indiana has used EPRI's base adoption case with minor adjustments as needed for known or expected changes in the market. EPRI's base forecast uses current EV registration data for a benchmark, near-term expectations of growth, and a long-term expectation that the EV market will continue to expand steadily over time while still coexisting out in 2050 with a portfolio of other technologies (conventional and/or hybrid-electric, possibly some fuel cell). The confidential EPRI forecasts are included in Appendix A to these comments.

Most of the success of EVs for the past ten or so years has been due to excitement around the Tesla brand, combined with the California Zero Emissions Vehicles (ZEV) program, the federal tax credit, and other state and local incentives. Increased EV volume has enabled EV (primarily battery) cost reductions. The base forecast assumes EV costs continue to drop gradually and naturally and/or through incentives with no big bumps up or down.

Unique hourly load profiles (kWh per vehicle per day) are developed internally for each vehicle type, for weekdays and weekends, and for residential (i.e. private) and public charging. These are developed using an internal program which monitors a select group of EV owners' driving habits. This data is used to form an average daily load forecast energy amount and a charge profile for light duty vehicles that is then paired with the EV adoption forecast to develop the EV energy forecast. The daily load forecast and load profiles used in the IRP are included in Appendix A to these comments.

The EPRI vehicle load forecast and the unique hourly load profiles are used to develop jurisdictional hourly level load profiles that are an input to the Duke Energy Indiana load forecast used in the 2021 IRP. The final forecast input used to modify the load is provided as Workpaper 1 to this Reply.

Importantly, since filing the 2021 IRP, the Company has enhanced its EV forecasting capabilities to include impacts from medium duty and heavy duty vehicle fleet electrification, as well as forecasts of the charging infrastructure needed to support electric vehicle growth in Duke Energy Indiana's service territory. These enhancements will be reflected in future IRP filings.

Load reduction from rooftop solar, which partially offsets load growth from electric vehicles, is also included as an input to the Duke Energy Indiana load forecast. Rooftop solar refers to behind-the-meter solar PV (photovoltaic) generation for residential, commercial, and industrial customers. Energy produced by rooftop solar is consumed by the customer and offsets their electric load consumption. Excess energy is exported to the grid and credited to the customer at rates specific to the net energy metering (NEM) policies in Indiana. As of the IRP filing, the NEM rates were full retail rates but were forecasted to decrease to 125% of the marginal electricity price starting July 1, 2022. Despite this decrease in NEM rates and the corresponding increase in the payback period, forecasted rooftop solar adoptions are expected to increase over the planning horizon due to declining technology costs and an increase in customer preference for self-generation.

The rooftop solar generation forecast is created from the capacity forecasts and hourly production profiles for residential, commercial, and industrial customers.

The capacity forecast is developed as the product of a customer adoption forecast and an average capacity value. The customer adoption forecast is based on linear regression modeling in Itron MetrixND and relies on current adoption rates and both current and future payback periods (amount of time to recover the cost of installing rooftop solar) to generate a customer adoption forecast. Hourly rooftop solar production profiles are generated based on historical irradiance data specific to Duke Energy Indiana's service territory. Additional details regarding the methodology for developing the customer adoption forecast and energy production from rooftop solar are included in Appendix A.

Additional data and information on the development of the load forecast is provided in Appendix A to these comments and will be provided in future IRPs.

B. Demand-Side Resources

The Director expressed concern about the limited modeling and analysis included in the IRP associated with Energy Efficiency (EE) and Demand Response (DR). Duke Energy Indiana recognizes that much of the EE/DR work was performed behind the scenes with key stakeholders as part of its Market Potential Study (MPS) process. In the future, Duke Energy Indiana will be sure to detail this work in the IRP itself and in response to the Draft Director's Report provides the following details. Notably, in preparation for the 2024 IRP, a new MPS will be created that takes into consideration the MISO seasonal capacity construct.

The Company believes that a comprehensive MPS performed by third-party expert consultants to develop a detailed, bottoms-up assessment of energy savings potential is a more rigorous and quantitatively sound approach than an arbitrary top-line target. It is important to recognize that customer adoption of EE/DR measures is not something that can be forced, only encouraged through marketing, outreach, and incentives. The purpose of developing the

Achievable Potential estimates in the multiple scenarios of the MPS is to identify the range of EE/DR savings that can reasonably be included in system planning where reliability is a fundamental requirement.

In 2020, the Company retained Resource Innovations (formerly Nexant, Inc.) to conduct a comprehensive assessment of EE/DR market potential for Duke Energy Indiana, which is included in Appendix B. Resource Innovation's methods are industry-leading, its analysis relies on the best data available at the time to support the study, and its results were specific to the customers and characteristics of the Company's service territory. The MPS includes all currently known technologies, estimated costs, and energy and demand reduction impacts for these EE and DR measures and determines the Technical, Economic, and Achievable Potential of these programs applicable to Duke Energy Indiana customers. Resource Innovation collaborated extensively with the Indiana DSM Oversight Board (OSB) (which includes the Company's key EE/DR stakeholders) to ensure the list of measures, their impacts and their applicability to energy end uses was vetted by all applicable parties and their comments were incorporated in the final study results. This collaboration with the OSB consisted of meetings starting in August 2020 for the MPS project kickoff. After that meeting, Resource Innovations met monthly with the OSB to answer questions and provide updates throughout the process along with interim workpapers along the way. Overall, Resource Innovations met with the Duke Energy Indiana OSB nine times as a group and responded to all emails with requests for data, questions, and input. The process and dates of these meetings is included as part of the appendices to the MPS document. In addition, Resource Innovations presented the study timeline and OSB stakeholder process during the July 15, 2021 Contemporary Issues Technical Conference. The OSB was appreciative of the consistent engagement and comprehensive communication that occurred throughout the process.

Direct comparisons of EE savings as a percentage of load is of limited value across disparate utilities due to significant differences in factors influencing the cost effectiveness and adoption of EE programs including climate, age and type of housing stock, fuel types for space and water heat, as well as other energy end uses, retail energy prices, avoided energy costs, EE program maturity, opt-out rules, and average usage per retail customer. Additionally, the Company's EE achievements in recent years have exceeded the national average, thereby eroding the remaining achievable potential of existing technologies by "pulling forward" adoption from future years. Furthermore, recent performance across different utilities cannot always be maintained at a given level as much recent success has been driven by implementing lighting and other highly cost-effective measures. This is another reason why it is imperative to consider program maturity and past successes when comparing future potential projections across disparate utilities. Finally, it is important to incorporate the impact of rising baseline efficiency standards applicable to lighting and other programs which reduce the opportunity for incremental future savings driven by, and credited to, utility-sponsored programs.

As noted in the IRP document and as explained in the stakeholder meetings, the two MPS scenarios used to develop the EE bundles were selected collaboratively with OSB members and represented the most cost effective Achievable Potential scenarios on a levelized, cost-per kWh basis. The IRP optimization models were permitted to select either of the two available bundles in each time window or no bundle. As would be expected, in modeling scenarios with higher avoided energy costs (resulting from higher fuel costs or a carbon price) the model often selected the larger, more expensive bundles as they were a lower cost resource than other supply side options. The Company maintains that its approach maximized the opportunity for the IRP models to select the most cost-effective combination of EE resources that are realistically achievable.

Additionally, the Director has some specific questions related to EE/DR, which are addressed below:

1. Does the anticipated roll-off effect reflect any other adjustment to the load forecast related to the end-life of selected EE measures besides the adjustments related to the prevailing codes and standards (DEI IRP page 227)? Where and how would these adjustments be accounted for in the planning process?

No. The Company does not make any other adjustment to the load forecast related to the end-life of select EE measures. The load forecast does not include incremental energy savings driven by utility EE (UEE) programs during the life of those measures. However after the life of the measure is exhausted, the measure is expected to be replaced with equivalent or more efficient savings equipment. Thus, these savings shift out of UEE (roll off) and become embedded in the load forecast as existing savings from prevailing codes and standards. The load forecast also includes the effects of historical UEE savings and their associated roll-off in the same manner.

2. Why is DR kept constant for the reference case and many other scenarios beyond 2025? Is there any reason to assume that there will not be any additional growth going out beyond this year?

The DR forecast is based upon the Company's internal program forecasts and takes into account current program saturation, customer adoption trends, and verified program performance metrics. The forecast grows from 497 MW to 613 MW by 2025 and remains at that level for the remainder of the planning horizon, reflecting the maturity of the programs reflected in the forecast.

The MPS from Resource Innovations does estimate incremental DR potential of 326 MW by 2045 in its base scenario and 555 MW under a high scenario representing aggressive marketing. These incremental reductions are from the starting baseline of 497 MW resulting in a 2045 reduction potential of 823 MW – 1052 MW. Additionally, emerging technologies, new government mandates or standards, carbon pricing, FERC order 2222, or other drivers could increase the ultimate savings potential, but those are not yet sufficiently known to support a more aggressive DR target.

3. This IRP reports the projected annual gross MWh impacts from the EE programs (DEI IRP, Table D-1, page 225). However, there is no information about the net-to-gross ratios that were used to calculate the gross numbers from the net annual savings or the approach used to project the future number of free riders in the system. This information would be useful to have a better understanding of methodology utilized to estimate the savings from the selected EE programs.

The annual "Gross" EE kWh savings forecast shown in IRP Table D-1 is developed by adjusting the net savings represented in the selected EE bundles using the Net-to-Gross (NTG) ratios in the currently approved EE/DSM portfolio. The Company agrees with the Director's recommendation that it would be valuable in future filings to expand Table D-1 to show the Net forecast, the NTG ratios used, and the resulting Gross forecast. We have provided an updated table showing these inputs in Appendix C to these comments.

4. What are all the parameters considered to group the EE programs into bundles? Was it based on hourly saving load shapes, measure cost, time periods and/or other factors? The IRP mentions that the bundles were modeled based on two MPS scenarios: Expanded Measure List and the Expanded Measure List with Avoided Cost Sensitivity (DEI IRP page 222). However, the IRP does not provide more detailed information about this methodology.

As described in the narrative response above, the Company collaborated closely with stakeholders and their consultants to select the MPS scenarios used to develop the bundles as well as the method for grouping the MPS data. As was requested by stakeholders, the two MPS scenarios with the lowest levelized costs were used to develop the bundles. In this IRP, stakeholders requested that the Company group all residential and non-residential measures together given the lower levelized cost of the non-residential measures as this would make the entire bundle likely to be selected. The only grouping used was time-based. The 2021-2023 bundles were based on the existing, approved EE portfolio but also included all low-income measures for the entire planning horizon in this "must-select" bundle given their relatively higher costs. This was requested by stakeholders as to not inflate the cost of the future, selectable bundles. The next bundle covered 2024-2026 to align with the Company's next DSM filing. The remaining twenty-four years modeled were broken into three eight-year bundles.

C. Public Advisory Meetings

Although Dr. Borum recognized the Company hosted as many or more public advisory meetings as other Indiana utilities, including two evening sessions, he commented that the content of the sessions was lacking when compared to material presented by other utilities in their public advisory sessions. He stated that this is not a new problem for Duke Energy Indiana but one that has become larger as other Indiana utilities' IRP processes evolve more rapidly. In addition, he stated Duke Energy Indiana's tone discouraged open discussion, as the Company's representatives often appeared defensive and argumentative. Mr. Borum, in the Draft Director's Report, noted that this tone carried over to the IRP itself, contributing to a perceived unwillingness to be forthcoming about key parts of the analysis. Dr. Borum recommended that Duke Energy Indiana learn from the actions of other Indiana utilities.

In response, Duke Energy Indiana appreciates the importance of the stakeholder public advisory process and has endeavored to make the meetings as meaningful as possible. There was certainly no intent on the part of the Company not to be forthcoming regarding the analysis or to discourage stakeholder input. With the increase in participants in the stakeholder process, including many Duke Energy Indiana residential customers, the Company took the approach to make the IRP material more accessible to increased numbers of non-technical customers and to address more technical questions with key stakeholders in several separate meetings where we discussed the modeling in more detail and worked to specify stakeholder portfolios. The Company acknowledges that balancing the level of detail included in the broader stakeholder meetings was a challenge and clearly, Duke Energy Indiana did not strike the right balance as indicated in the Draft Director's Report.

During the process, some stakeholders expressed an appreciation of the Company's inclusiveness, welcoming atmosphere, engagement, collaboration, and the ability to contribute, and other stakeholders expressed frustration with access to modeling files and critiqued information flow. The Company also worked extensively with stakeholders that expressed interest to develop portfolios that reflect their perspectives and priorities. During the IRP process, there were times Duke Energy Indiana did not meet the timing expectations for distributing information prior to stakeholder meetings, and the Company ran into modeling and timing challenges, which did not provide for as much advanced provision of modeling data to key stakeholders as they would have preferred. Duke Energy Indiana regrets this lapse in timeliness and is committed to improving its performance going forward.

Duke Energy Indiana appreciates the Director's feedback to include more detail in the broader stakeholder meetings and to provide key information earlier in the process, such as the scorecard evaluation criteria. As such, Duke Energy Indiana will conduct a thorough review of the stakeholder public advisory process in 2023 in order to redevelop the IRP stakeholder process from the ground up to better support the 2024 Duke Energy Indiana IRP. The scope of this review will include, but will not be limited to:

i. Gathering ideas and suggestions from key stakeholders prior to the start of the process, during the process and after the process, including scorecard evaluation criteria;
ii. Benchmark the IRP and stakeholder processes with other Indiana utilities, especially as it relates to the content, timing, and detail provided in the IRP and in broader stakeholder meetings;
iii. Evaluate the ways to better convey appropriate level of detail for a wide range of stakeholders;
iv. Evaluate the benefits and drawbacks of using public data sources which may aid in transparency of the modeling;
v. Evaluate how the modeling process and timeline can be improved to better support the stakeholder process, in particular for stakeholders interested in parallel modeling or development of stakeholder portfolios; and
vi. Evaluate the facilitation of the stakeholder meetings to ensure open and transparent communication and discussion.

III. Duke Energy Indiana's responsive comments to stakeholder comments

As noted in the Director's Draft Report, stakeholder comments were received from Sierra Club, Reliable Energy, Inc., DEI Industrial Group, EMCC, HEC, the OUCC, NAACP, AEE, and the Joint Commenters (Citizens Action Coalition, Earthjustice, and Vote Solar). On July 22, 2022, Duke Energy Indiana submitted its response to stakeholder comments, which is included with this reply as Appendix D. While Duke Energy Indiana has comprehensively responded to the stakeholder comments, it is providing additional information on select stakeholder comments here.

EMCC commented that the Company should include a Deep Decarbonization and Rapid electrification (DDRE) scenario and optimized portfolio in the next IRP. The Director concurred that a broad range of scenarios should be evaluated in the integrated resource planning process, stating that a DDRE scenario, or something similar, is a possible future that should be analyzed to better understand potential implications of near-term resource choices.

The DDRE scenario is particularly interesting in terms of what the nation needs to do to become carbon neutral. This effort extends beyond the electrical sector, which creates challenges in terms of how other parts of the economy react and how that in turn affects electric demand, fuel supplies, as well as the necessary regulation that promulgates the themes of the DDRE scenario. The Company met with EMCC and its consultant numerous times and appreciates thoughtful feedback such as this from stakeholders. The Company will continue to work with stakeholders to address their concerns.

The OUCC stated Duke Energy Indiana did not provide the numerical cost information associated with the capital and O&M costs assumed for these environmental regulations. The OUCC commented that while it does not find the assumptions Duke Energy Indiana described in Appendix F of the IRP to be unreasonable, it is necessary to know the cost details to determine if the cost is reasonable. As noted by the Director, all costs used in the IRP development should be made available to entities that have signed a non-disclosure agreement. The Company will provide the OUCC with environmental cost data.

The NAACP, in its comments, proposed the addition of more renewables and a portfolio that benefits disadvantaged communities. Duke Energy Indiana takes serving low income and disadvantaged communities very seriously and has a number of programs to assist. Going forward the Company will be looking to leverage the extra tax credits related to energy communities and other programs that could include new pricing and voluntary renewables programs.

AEE provided comments on 1) Fuel prices and Market Risk, 2) Energy Efficiency modeling, 3) Demand Response, and 4) Energy Storage. In response to AEE's comments, the Director stated that there is little discussion in the IRP about how energy storage was analyzed and how the EnCompass model evaluates the numerous characteristics of battery storage which differentiates storage from other resource options. The Director indicated he expected that Duke Energy Indiana will continually improve its planning process in general and, regarding battery storage as a specific example, provide better documentation so that others can better understand how the analysis was done and why.

In future IRPs, the Company will work with stakeholders to refine risk metrics as it relates to fuel and power prices. Additionally, as discussed in length above in response to the Director's concerns regarding the limited modeling and analysis included in the IRP associated with EE and DR, in the future, Duke Energy Indiana commits to detailing the MPS work in the IRP itself. Further, Duke Energy Indiana will work with stakeholders on how to better recognize the value streams that storage has to offer.

The Joint Commenters provided comments critical of the stakeholder process, among other comments. The Director voiced agreement with the Joint Commenters' comments specific to the substance and tone of the public advisory process and pointed to the failure to adequately communicate by Duke Energy Indiana in both the public advisory meetings and the IRP document itself as the reason for many of the other problems raised by the Joint Commenters. The Director cited the brief time allotted to discuss the scorecard performance metrics and placement of the discussion as an example of the communication issues.

The Company appreciates the comments of the Director and the Joint Commenters and, as discussed in detail above, will work with stakeholders to make the IRP and stakeholder process more meaningful to all stakeholders. As part of the Company's initiative to improve the IRP and stakeholder process, a concerted effort will be made to make the data assumptions and methodologies more transparent for stakeholders. As to the scorecard and associated metrics, the Company hears the points of the Director and stakeholders and will move the discussion of the scorecard and its supporting metrics to the beginning of the stakeholder process and ensure ample time for discussion.

IV. Conclusion

Duke Energy Indiana appreciates the importance of the IRP process and the stakeholder public advisory process in providing confidence in the Company's 20 year plan for resource adequacy. We are pleased that the Director recognized the robust modeling and discussion of the Edwardsport IGCC plant and approved of the modeling methodology and selection of Encompass modeling software. We appreciate the feedback received related to the load forecast, energy efficiency and demand response, and have provided additional information in these comments and in the Appendixes for the Director's consideration.

Regarding the Director's comments on the stakeholder advisory process, Duke Energy Indiana commits to a comprehensive review and ongoing improvement, including the evaluation and adoption of best practices among utilities.

CERTIFICATE OF SERVICE

The undersigned hereby certifies that a copy of the foregoing reply comments were mailed electronically this 13th day of January, 2023, to the following:

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APPENDIX A

Load Forecast Methodology and Drivers

In response to the Indiana Utility Regulatory Commission's Draft Director's Report comments requesting more details on the load forecast development, please see below.

Overview

The 2021 Duke Energy Indiana's IRP is supported by a 20-year load forecast for sales, energy, and peak. The forecast is synthesized using Itron's Statistically Adjusted End-Use (SAE) model utilizing relevant drivers of the load, such as weather, appliance intensities and saturation, economic data, and electric rates to generate various forecasts. Additionally, the load impacts from UEE ("Utility Energy Efficiency") programs, rooftop solar generation, and electric vehicle (EV) charging loads are also included in the load forecast.

Duke Energy Indiana is the largest electric utility service provider in the State of Indiana serving approximately 33,000 GWh of retail load to nearly 860,0000 customers across the state. With respect to the retail sales mix, residential sales account for 33%, general service sales account for 30%, and industrial sales account for 37%.

Historical Trend

Table 1: Historical Actual and Weather Normalized Peak and Demand

Year	Energy Actual GWh	Energy W/Normal GWh	Summer Actual MW	Summer W/Normal MW
2011	33,625	33,749	6,749	6,490
2012	31,028	31,369	6,494	6,510
2013	33,104	34,106	6,229	6,461
2014	32,063	31,728	5,830	6,084
2015	32,131	32,003	5,863	6,008
2016	32,318	32,267	6,079	6,181
2017	32,097	32,039	5,838	6,049
2018	31,532	31,547	5,904	5,895
2019	32,191	31,964	5,896	5,686
2020	31,447	31,678	5,755	6,029

As shown in Table 1, the performance of peak demand and energy usage during the past ten years has been relatively flat. The intense impact of Covid-19 on electric consumption sits on the foundation of the Great Recession, the most severe economic recession in the United States since the 1930s. This has left the utility industry in a period of great uncertainty. According to the EIA, "It will take a while for the energy sector to get to its new 'normal,' the pandemic triggered a historic energy demand shock that led to… decreases in energy production, and sometimes volatile commodity prices in 2020. The pace of economic recovery, advances in technology, changes in trade flows, and energy incentives will determine how the United States produces and consumes energy in the future."

A second factor impacting the level of growth in Duke Energy Indiana peak and energy sales is the adoption of federally mandated highly efficient residential and commercial sector appliances and utility sponsored programs offered to help spur more efficient use of electricity. Duke Energy Indiana has observed that the residential and commercial classes are more likely to participate in utility energy efficiency programs with the current legislative landscape in Indiana for large industrial customers enabled to opt-out of EE programs. Industrial customers are able to implement their own cost saving efforts, including a growing number of combined heat and power (CHP) units.

These events have impacted historical trends shrinking the average annual kWh use per residential customer for several years. We have found that, currently, Itron's SAE (Statistically Adjusted End-use) forecast methodology works best to capture the changing levels of more efficient appliances saturating through the residential households and commercial class end-uses.

While Duke Energy Indiana has been projecting impacts of roof-top solar and electric vehicles upon the energy and peak demand projections for several years, we are continually improving these projections by applying actual solar load shapes and EV "charging time" data to improve our understanding of these influences upon class hourly load shapes.

Table 2: Customer Count by Class

Year	Residential	General Service[1]	Industrial	Retail
2011	680,389	101,193	2,754	784,336
2012	684,734	101,552	2,734	789,019
2013	689,735	101,728	2,726	794,188
2014	694,479	101,865	2,708	799,052
2015	700,953	102,175	2,707	805,835
2016	709,356	102,483	2,721	814,560
2017	715,639	102,827	2,718	821,184
2018	725,966	103,247	2,721	831,934
2019	735,652	103,480	2,692	841,823
2020	746,789	104,280	2,697	853,766

Despite declines in the total energy and peak load, as shown in Table 1, the total number of Duke Energy Indiana customers grew at the average rate of 1.2% in the past 10 years (2011-2020). The majority of the increase is driven by steady growth in the residential class, which grew at the annual average rate of 1.3% during the same period. The commercial class grew at a modest rate of 0.5% over the previous 10 years. The number of industrial and other customers declined at the annual average rate of 0.3% and 0.4%, respectively.

[1] General service includes commercial and other class.

Methodology Framework

The load forecasting process makes use of a number of variables or drivers to forecast the load of the respective classes of customers. Figure 1 illustrates, at a high level, how input variables such as economic data, rates, and appliance stock are used to build relationships that result in building the forecast.

Not all class load forecasts are made using the same variables, but rather each class's load forecast uses the variables that are most statistically significant for that class of customers. Figure 2 details those variables that are used for each class specific load forecast.

Figure 1: SAE Model Construct

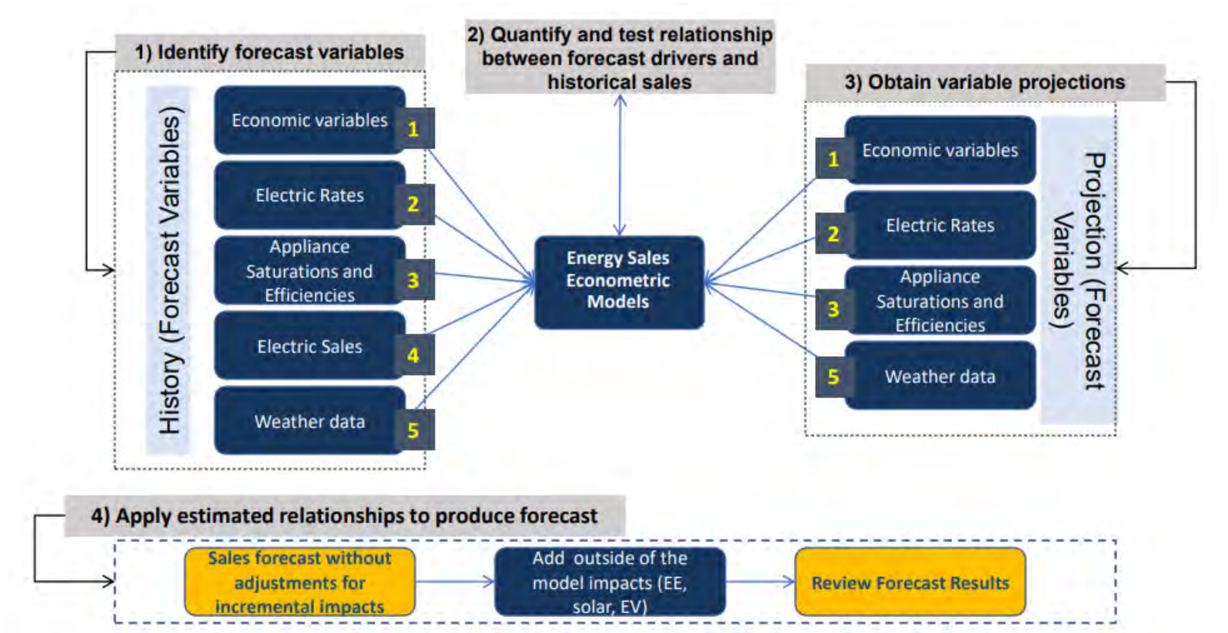
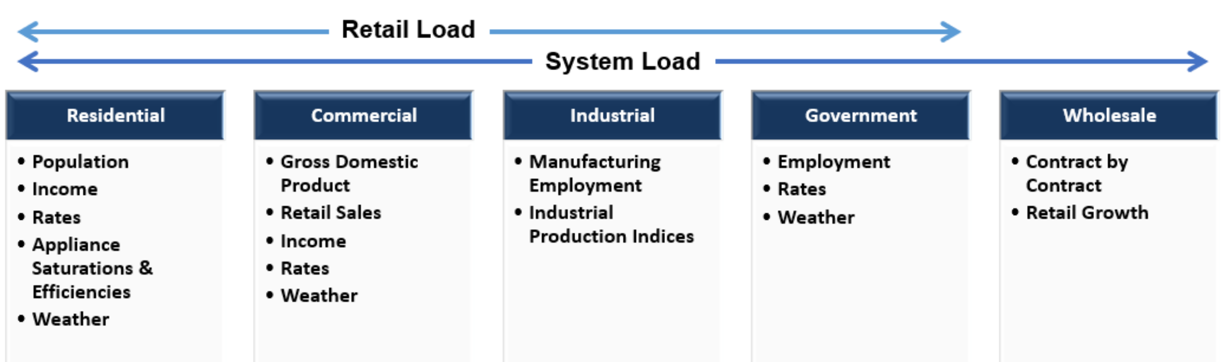


Figure 2 Variables Employed in the Forecast by Class



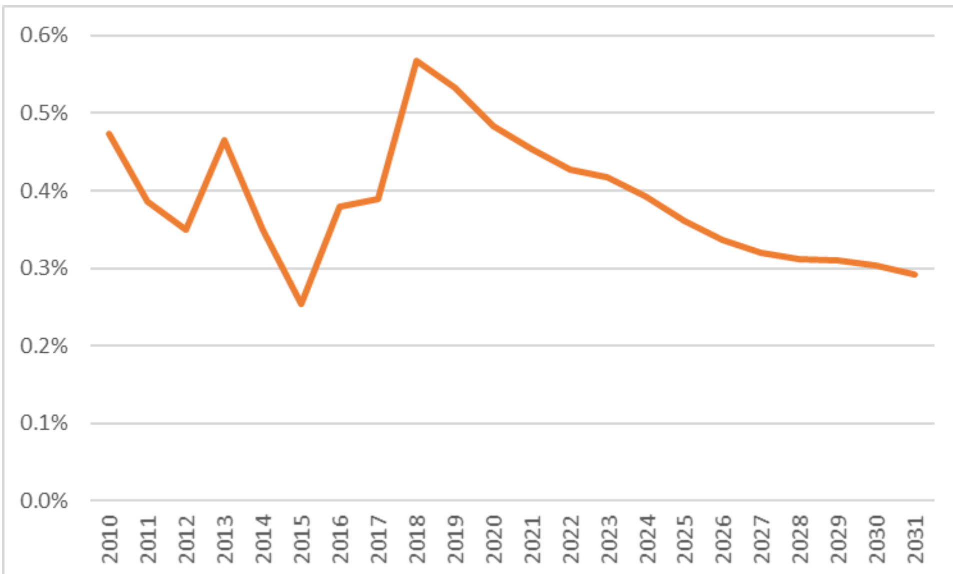
Forecast Drivers

Economic Variables

Duke Energy Indiana procures economic data from Moody's Analytics. Moody's Analytics is a leading economic consulting firm that provide histories and forecasts of key economic and demographic variables.

The 2021 Duke Energy IRP forecast utilized Moody's January 2021 edition for the state of Indiana to generate the baseline.[2]

Figure 3 Indiana Annual Population Growth



[2] See 2021 Duke Energy Integrated Resource Plan pg. 161-163 for more details

Figure 4 Household Size

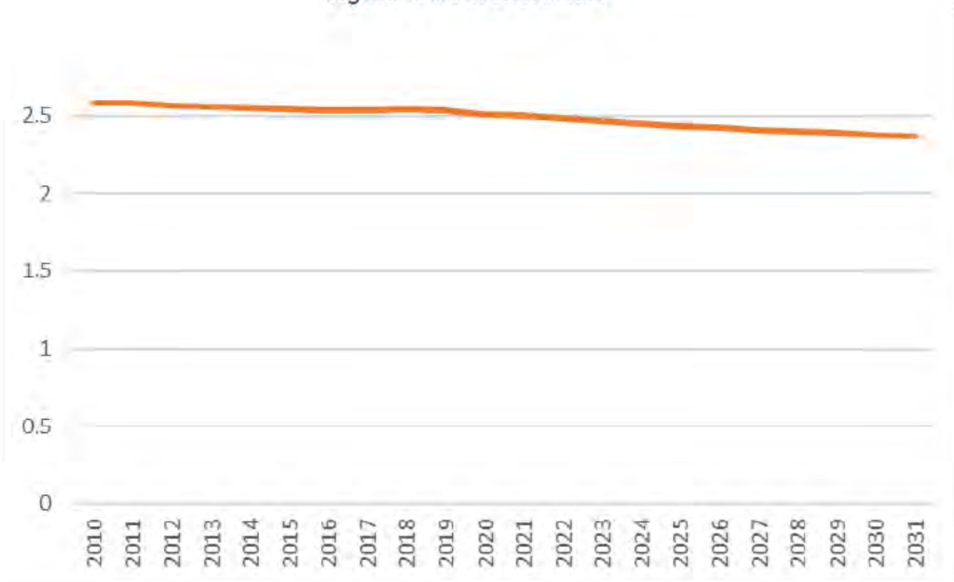


Figure 5 Indiana Real Median Household Income

Figure 6 Employment in Service Producing Industry

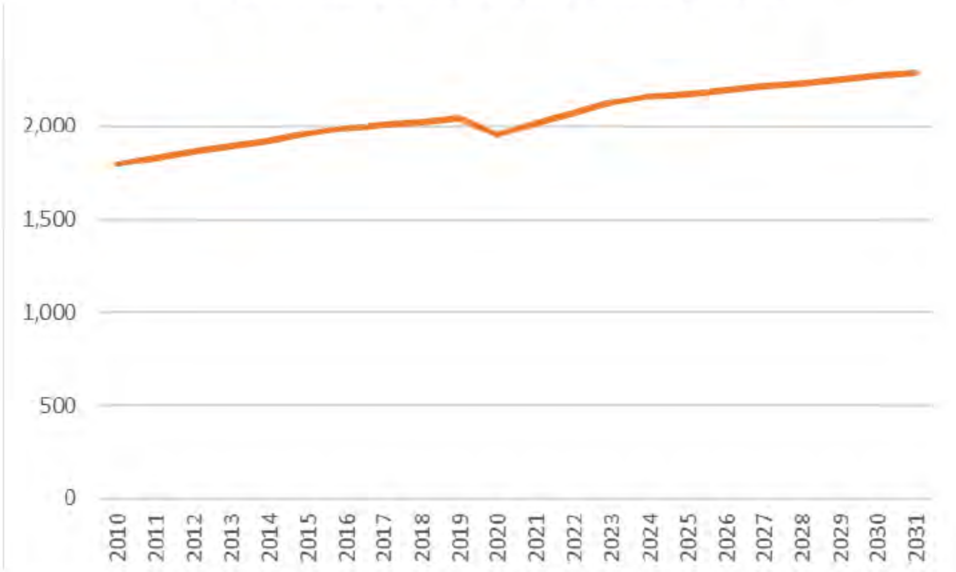


Figure 7 Retail Sales (in Millions of Dollars)

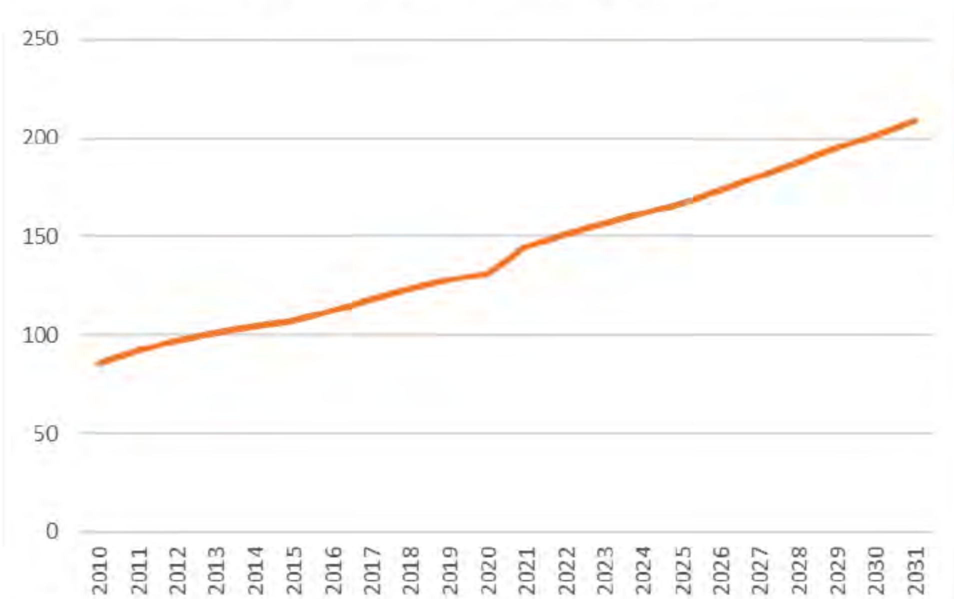


Figure 8 Real GDP Non-Manufacturing (in Millions of Dollars)

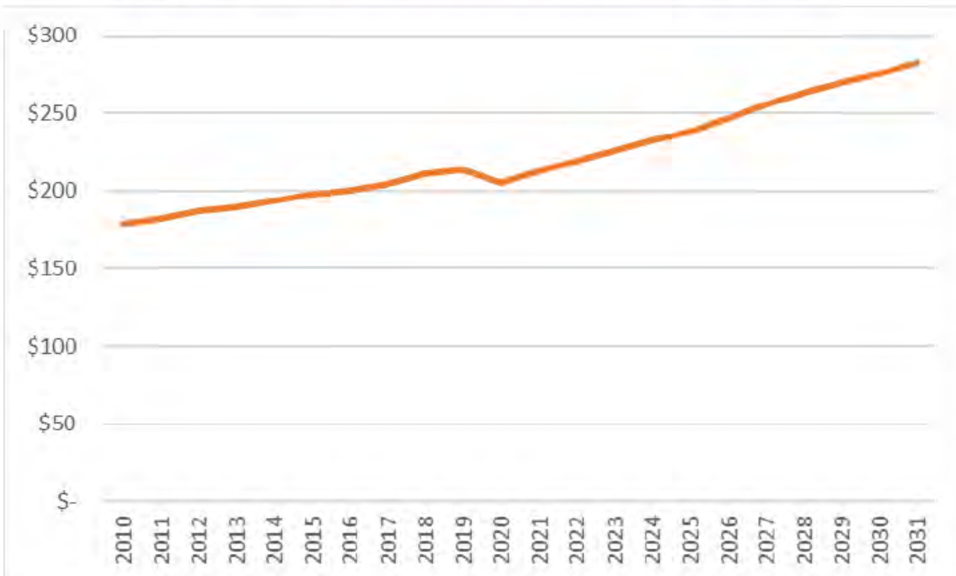


Figure 9 Manufacturing Employment in Thousands

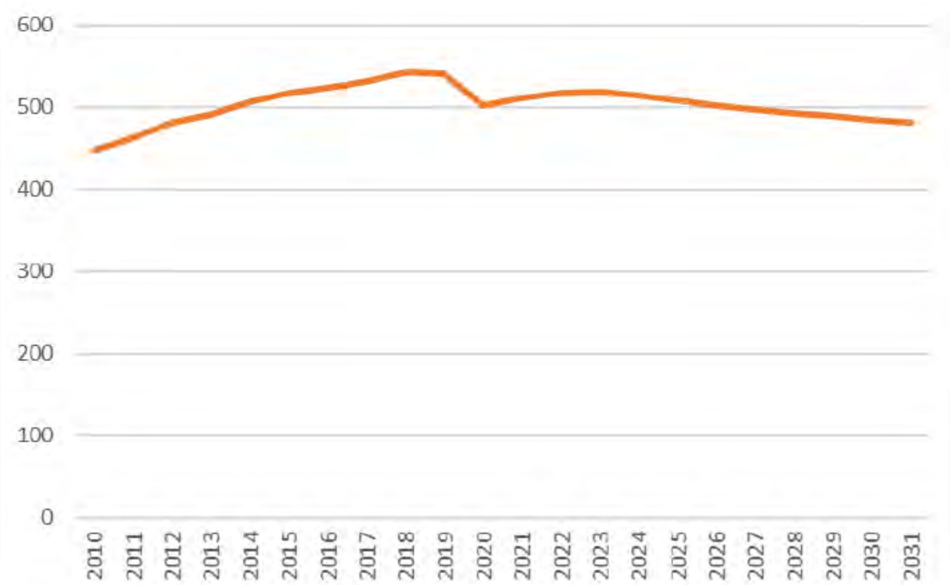
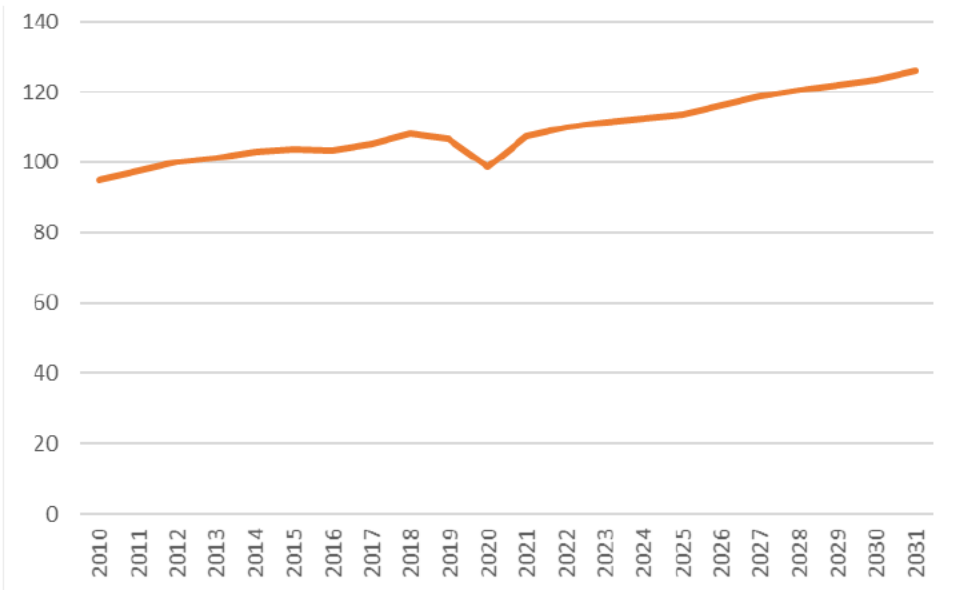


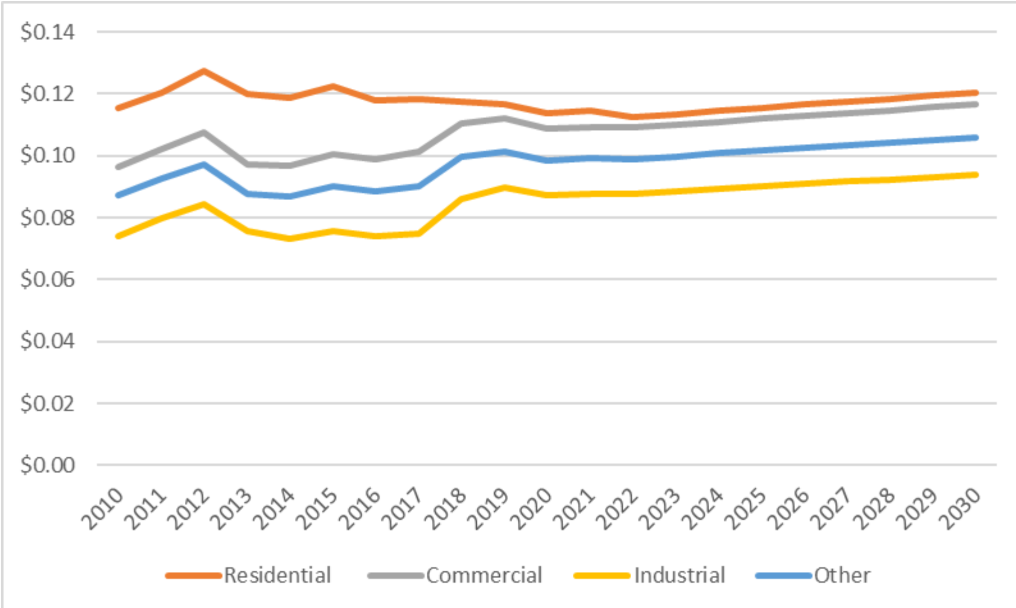
Figure 10 Production Index



Electric Rates

Historical rates and forecasted rates by class are provided through various means in the Company. The rates included in the forecast are defined as the 12-month average rate. Additionally, the rates were adjusted for inflation using 2019 constant dollar using Moody's projection of CPI deflator. As shown in Figure 10, most rate classes assume relatively modest increases compared to the current levels.

Figure 11 Electric Rates ($/kWH)



Intensities

The 2021 Duke Energy Indiana forecast utilizes end-use energy intensities developed by Energy Information Agency (EIA) for East North Central Region. The end-use intensities are separated by cooling, heating, and other use and integrated into the forecasting model for residential and commercial use. This approach captures the historical efficiency trends and accounts for the efficiency trends expected in the future such as UEE, improvements in technology and change in standards.

As shown in figure 11, the total end-use intensities utilized in the residential model is decreasing at the average annual rate of -0.4% over the forecast period. This trend is primarily driven by the heating load, which is decreasing at the rate of -0.8% annually over the forecast period. The cooling load is expected to increase at an annual rate of 0.2% over the forecast period. Lastly, the other load is decreasing at the annual rate of -0.2%.

On the commercial side, there are declines in all three types of end-use intensities. The heating intensities are decreasing at the rate of -2.0% a year, cooling intensities are decreasing at -0.2% a year, and other use is decreasing at the rate of -0.8% a year over the forecast period.

Figure 12 Residential Intensities

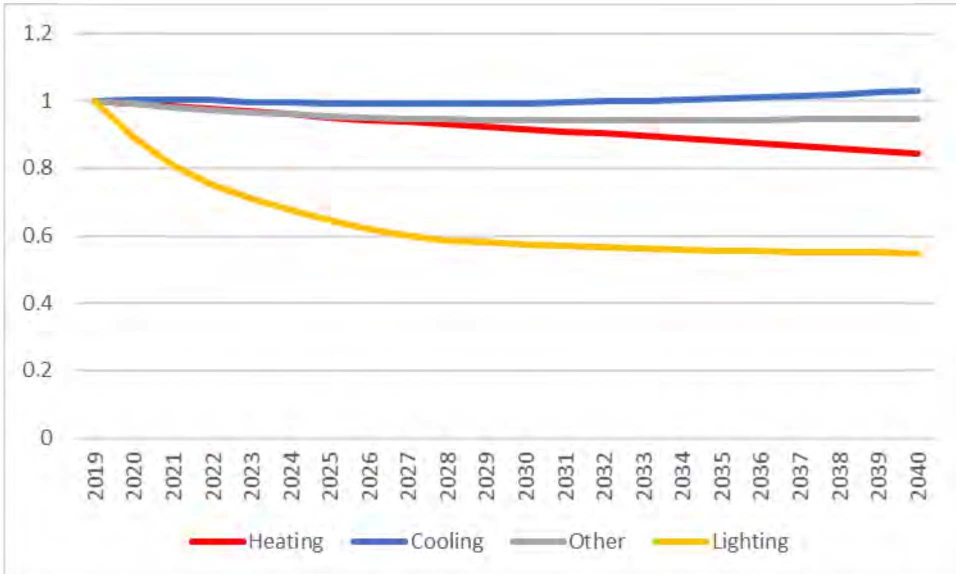
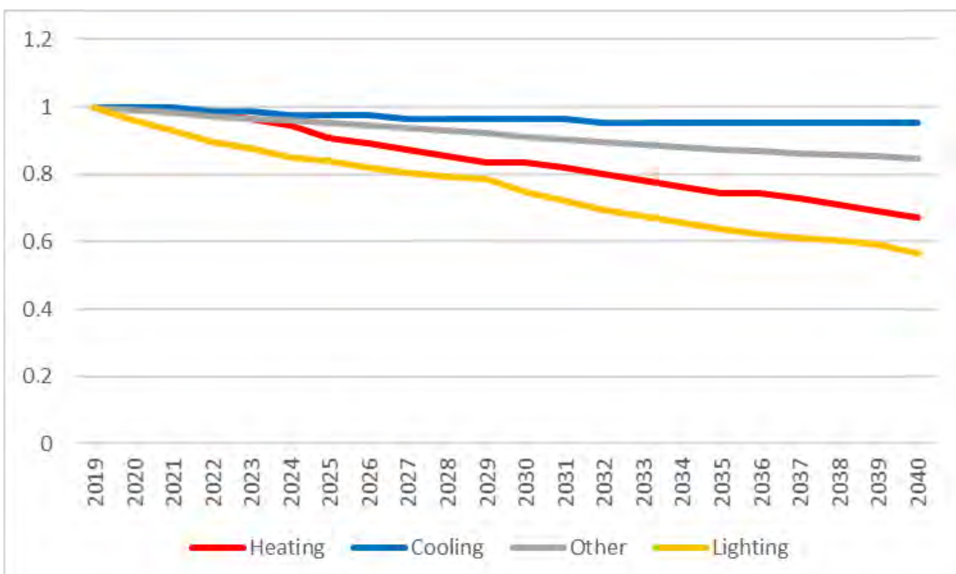


Figure 13 Commercial Intensities



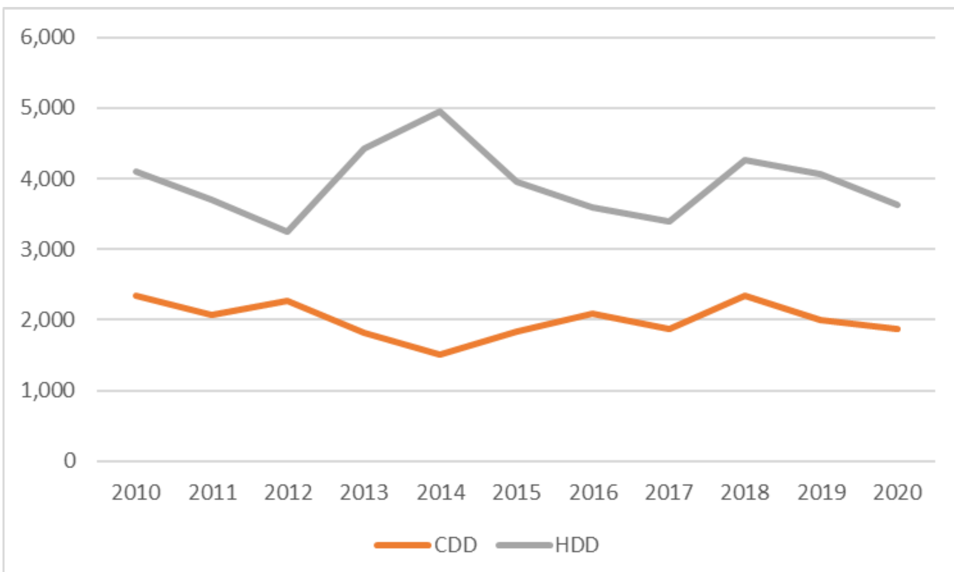
Weather

Temperature is one of the key drivers of the load. Heating and cooling indoor space account for a significant portion of the load. Demand for heating load increases as temperature falls below the desired temperature; conversely, the demand for cooling load increases when the temperature increases above a base temperature.

Historical daily temperature data was pulled from the Indianapolis Airport weather station. The daily temperature was transformed into degree days and rolled up to the monthly level for the sales model. For the peak model, maximum cooling or heating degree days were utilized to map the historical relationship.

As shown in Figure 13, the heating degree days (HDD) in the past 10 years fall in the range of 3,240 - 4,950-degree days. The cooling degree days fall in the range of 1,500 – 2,340-degree days in the past 10 years. The forecast assumes the previous 30-year average weather conditions in the forecast horizon. [3] As such the normal weather used in the forecasted period was 3,949 HDDs and 1,848 CDDs.

Figure 14 Cooling and Heating Degree Days



Energy Efficiency

Energy efficiency is reflected through energy savings from both UEE programs offered by Duke Energy Indiana and naturally occurring efficiency gains in end-use intensities as described above.

UEE programs serve to accelerate naturally occurring efficiency adoption rates described above; therefore, introducing UEE savings into the forecast in this manner requires a fine balancing act in order to avoid double counting the UEE efficiencies with the naturally occurring efficiencies. To ensure there

[3] The load forecasting staff continues to study the impact of climate change on the load forecast. Initial analyses have shown only a minor impact during the forecast horizon presented in this filing. See 2021 Duke Energy Indiana Integrated Resource Plan pg.29-30 for more details.

is not a double counting of the efficiencies, Duke Energy Indiana rolls off the savings generated by the UEE programs at the conclusion of the measure life, as the assumed savings from efficiency gains in end use intensities replaces the UEE savings.

Load Modifiers: Rooftop Solar and Electric Vehicles

Rooftop solar photovoltaic (PV) and electric vehicles (EVs) are considered load modifiers for the load forecast: behind-the-meter solar PV generation reduces the effective load that Duke Energy Indiana serves while plug-in EV charging increases the load that Duke Energy Indiana serves. Rooftop solar PV generation and EV load are independently forecasted and combined with the base load and EE impacts to produce the final electric load forecast. Because the impacts from existing rooftop solar PV generation and EVs are embedded in the historical data from which the base load forecast is derived, only incremental or “net new” rooftop solar PV generation and EV load are added within the planning horizon.

Rooftop Solar

Rooftop solar refers to behind-the-meter solar PV generation for residential, commercial, and industrial customers. Energy produced by rooftop solar is consumed by the customer and offsets their electric load consumption. Excess energy is exported to the grid and credited to the customer at rates specific to the net energy metering (NEM) policies in Indiana. As of the IRP filing, the current NEM rates are full retail rates but are expected to decrease to 125% of the marginal electricity price starting July 1, 2022. Despite this decrease in NEM rates and the corresponding increase in the payback period, forecasted rooftop solar adoptions are expected to increase over the planning horizon due to declining technology costs and an increase in customer preference for self-generation.

The rooftop solar generation forecast is created from the capacity forecasts and hourly production profiles for residential, commercial, and industrial customers.

The capacity forecast is developed as the product of a customer adoption forecast and an average capacity value. The customer adoption forecast is based on linear regression modeling in Itron MetrixND and relies on current adoption rates and both current and future payback periods (amount of time to recover the cost of installing rooftop solar) to generate a customer adoption forecast. Payback periods are a function of installation costs, regulatory incentives, and electric bill savings. Historical and projected technology costs are provided by Guidehouse, Inc., while projected incentives and bill savings are developed internally based on current regulatory policies and input from subject matter experts. The average capacity value, or size of the installed rooftop PV system, is derived using historical adoption trends and is shown in Table 3 below.

Table 3: Average Rooftop Solar Capacity (kW-AC)

Customer Class	Duke Energy Indiana
Residential	8
Non-residential	250

Hourly production profiles are developed using 20 years of historical irradiance data from Solar Anywhere and Solcast for 5 locations across Duke Energy Indiana's service territory. This data is modeled in PVsyst to develop capacity factors for all sites and years, which are combined on weighted average basis to produce '12x24' hourly production profiles (there is one 24-hour generation profile for each month).

The table 4 below shows the overall increase in rooftop solar customers, capacity, and energy increases from the beginning to the end of the IRP planning period. [4]

Table 4: Net New Rooftop Solar Adoption

Year	Number of Customers	Percent of Total Customers	Capacity (MW)	Energy (MWH/YEAR)
2021	490	0.3%	13	10,600
2035	6,375	0.8%	148	193,800

Tables 5 and 6 present the calculations for determining the Net New Energy for the Residential, Commercial, and Industrial classes for 2021 and 2035 based on the methodology as described above.

[4] The rooftop solar forecast presented in Table B-2 (page 159) of the 2021 Duke Energy Indiana IRP was from an earlier version that was not utilized in the forecast. This has no impact on the final sales, energy, and peak forecasts as the correct version of the rooftop solar forecast was used to prepare the 2021 IRP Forecast. Tables 4-6 provide an updated rooftop solar forecast.

Table 5 Monthly Rooftop Solar Calculations for 2035

DEI NEM Projections	Hours	Cumulative Net New Customers	Cumulative Net New Capacity (MWs)	Profile	Incremental Net New Energy (MWhs)	Cumulative Net New Energy (MWhs)
		Residential				
	(A)	(B)	(C)	(D)	(E)	(F)
					(C) x (A) x (D)	∑ (E)
Jan-21	744	49	0.4	7.78%	23	23
Feb-21	672	91	0.7	11.37%	56	78
Mar-21	744	130	1.0	14.77%	114	192
Apr-21	720	167	1.3	17.61%	169	362
May-21	744	203	1.6	19.15%	231	593
Jun-21	720	238	1.9	20.86%	285	878
Jul-21	744	273	2.2	21.30%	346	1,224
Aug-21	744	307	2.5	19.74%	360	1,584
Sep-21	720	341	2.7	17.24%	338	1,922
Oct-21	744	375	3.0	12.77%	284	2,206
Nov-21	720	409	3.3	8.86%	208	2,414
Dec-21	744	443	3.5	6.78%	178	2,592
		Commercial				
DEI NEM Projections	Hours	Cumulative Net New Customers	Cumulative Net New Capacity (MWs)	Profile	Incremental Net New Energy (MWhs)	Cumulative Net New Energy (MWhs)
	(A)	(B)	(C)	(D)	(E)	(F)
					(C) x (A) x (D)	∑ (E)
Jan-21	744	5	1.0	8.11%	60	60
Feb-21	672	11	2.2	11.68%	173	233
Mar-21	744	16	3.2	15.06%	358	591
Apr-21	720	20	4.0	18.16%	523	1,114
May-21	744	24	4.8	20.19%	720	1,834
Jun-21	720	27	5.4	21.78%	845	2,679
Jul-21	744	30	6.0	22.61%	1,007	3,687
Aug-21	744	33	6.6	21.11%	1,034	4,721
Sep-21	720	36	7.2	18.93%	979	5,700
Oct-21	744	39	7.8	14.18%	821	6,521
Nov-21	720	42	8.4	9.67%	583	7,104
Dec-21	744	45	9.0	7.34%	490	7,594
		Industrial				
DEI NEM Projections	Hours	Cumulative Net New Customers	Cumulative Net New Capacity (MWs)	Profile	Incremental Net New Energy (MWhs)	Cumulative Net New Energy (MWhs)
	(A)	(B)	(C)	(D)	(E)	(F)
					(C) x (A) x (D)	∑ (E)
Jan-21	744	0	0.0	8.11%	0	0
Feb-21	672	0	0.0	11.68%	0	0
Mar-21	744	0	0.0	15.06%	0	0
Apr-21	720	1	0.3	18.16%	39	39
May-21	744	1	0.3	20.19%	45	84
Jun-21	720	1	0.3	21.78%	47	131
Jul-21	744	1	0.3	22.61%	50	182
Aug-21	744	1	0.3	21.11%	47	229
Sep-21	720	2	0.6	18.93%	82	311
Oct-21	744	2	0.6	14.18%	63	374
Nov-21	720	2	0.6	9.67%	42	415
Dec-21	744	2	0.6	7.34%	33	448
		Totals				
DEI NEM Projections		Cumulative Net New Customers	Cumulative Net New Capacity (MWs)			Cumulative Net New Energy (MWhs)
2021 Totals		490	13.1			10,634

Table 6 Monthly Rooftop Solar Calculations for 2035

DEI NEM Projections	Hours	Cumulative Net New Customers	Cumulative Net New Capacity (MWs)	Profile	Incremental Net New Energy (MWhs)	Cumulative Net New Energy (MWhs)
		Residential				
	(A)	(B)	(C)	(D)	(E)	(F)
					(C) x (A) x (D)	∑ (E)
Jan-35	744	5,472	42.3	7.78%	2,448	2,448
Feb-35	672	5,507	42.5	11.37%	3,249	5,696
Mar-35	744	5,542	42.8	14.77%	4,702	10,398
Apr-35	720	5,577	43.1	17.61%	5,459	15,858
May-35	744	5,612	43.3	19.15%	6,172	22,030
Jun-35	720	5,647	43.6	20.86%	6,544	28,574
Jul-35	744	5,682	43.8	21.30%	6,949	35,523
Aug-35	744	5,717	44.1	19.74%	6,477	42,000
Sep-35	720	5,752	44.4	17.24%	5,507	47,508
Oct-35	744	5,787	44.6	12.77%	4,239	51,747
Nov-35	720	5,822	44.9	8.86%	2,864	54,610
Dec-35	744	5,858	45.2	6.78%	2,279	56,889
		Commercial				
DEI NEM Projections	Hours	Cumulative Net New Customers	Cumulative Net New Capacity (MWs)	Profile	Incremental Net New Energy (MWhs)	Cumulative Net New Energy (MWhs)
	(A)	(B)	(C)	(D)	(E)	(F)
					(C) x (A) x (D)	∑ (E)
Jan-35	744	454	87.7	8.11%	5,290	5,290
Feb-35	672	457	88.3	11.68%	6,930	12,221
Mar-35	744	460	88.8	15.06%	9,958	22,178
Apr-35	720	463	89.4	18.16%	11,692	33,870
May-35	744	466	90.0	20.19%	13,518	47,388
Jun-35	720	469	90.5	21.78%	14,197	61,585
Jul-35	744	472	91.1	22.61%	15,323	76,907
Aug-35	744	475	91.7	21.11%	14,392	91,300
Sep-35	720	478	92.2	18.93%	12,570	103,870
Oct-35	744	481	92.8	14.18%	9,788	113,658
Nov-35	720	484	93.3	9.67%	6,496	120,154
Dec-35	744	487	93.9	7.34%	5,126	125,280
		Industrial				
DEI NEM Projections	Hours	Cumulative Net New Customers	Cumulative Net New Capacity (MWs)	Profile	Incremental Net New Energy (MWhs)	Cumulative Net New Energy (MWhs)
	(A)	(B)	(C)	(D)	(E)	(F)
					(C) x (A) x (D)	∑ (E)
Jan-35	744	28	8.1	8.11%	489	489
Feb-35	672	28	8.1	11.68%	636	1,125
Mar-35	744	28	8.1	15.06%	909	2,034
Apr-35	720	29	8.4	18.16%	1,098	3,132
May-35	744	29	8.4	20.19%	1,262	4,394
Jun-35	720	29	8.4	21.78%	1,317	5,711
Jul-35	744	29	8.4	22.61%	1,412	7,123
Aug-35	744	29	8.4	21.11%	1,319	8,442
Sep-35	720	30	8.7	18.93%	1,183	9,625
Oct-35	744	30	8.7	14.18%	916	10,541
Nov-35	720	30	8.7	9.67%	604	11,145
Dec-35	744	30	8.7	7.34%	474	11,619
		Totals				
DEI NEM Projections		Cumulative Net New Customers	Cumulative Net New Capacity (MWs)			Cumulative Net New Energy (MWhs)
2035 Totals		6,375	147.7			193,788

Electric Vehicle

For the 2021 IRP, Duke Energy Indiana's EV load forecast was derived using an EV adoption forecast paired with load charging profiles to come up with energy and load impacts.

The Electric Power Research Institute (EPRI) provides EV forecasts specific to Duke Energy Indiana's service area using five vehicle types. Those five vehicle types are Battery Electric Vehicles (BEV) with a 100 or a 250 mile range and a Plug in Hybrid Electric Vehicles (PHEV) with a 10, 20, or 30 mile range. EPRI forecasts are based on a blend of published forecasts from others, and those forecasts use a range of assumptions and methodologies. In recent years Duke Energy has used EPRI's base adoption case with minor adjustments as needed for known or expected changes in the market. EPRI's base forecast uses current EV registration data for a benchmark, near-term expectations of growth, and a long-term expectation that the EV market will continue to expand steadily over time while still coexisting out in 2050 with a portfolio of other technologies (conventional and/or hybrid-electric, possibly some fuel cell). Confidential Table 7 below reflects EPRI's forecast for the 5 vehicle types described above.

CONFIDENTIAL Table 7 EPRI Electric Vehicle Forecast

Fleet Size (million vehicles)					
	BEV100	BEV250	PHEV10	PHEV20	PHEV40
2020	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2021	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2022	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2023	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2024	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2026	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2027	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2028	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2029	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2030	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2031	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2032	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2033	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2034	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2035	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Most of the success of EVs for the past 10 or so years has been due to excitement around the Tesla brand, combined with the California Zero Emissions Vehicles (ZEV) program, the federal tax credit, and other state and local incentives. Increased EV volume has enabled EV (primarily battery) cost reductions. The base forecast assumes EV costs continue to drop gradually and naturally and/or through incentives with no big bumps up or down.

Unique hourly load profiles (kWh per vehicle per day) are developed internally for each vehicle type, for weekdays and weekends, and for residential (or private) and public charging. These are developed using an internal program which monitors a select group of EV owners driving habits. This data is used to form an average daily load forecast and a charge profile for light duty vehicles as shown in Table 8 and Table 9 below respectively.

Table *8 Electric Vehicle Daily Load*

V_Type	ChargeType	DayType	DailyLoad, kWh
BEV	Public	Weekday	4.145
BEV	Public	Weekend	3.641
BEV	Residential	Weekday	7.521
BEV	Residential	Weekend	7.291
PHEV	Public	Weekday	1.234
PHEV	Public	Weekend	0.837
PHEV	Residential	Weekday	5.959
PHEV	Residential	Weekend	4.842
BEV100	Public	Weekday	2.327
BEV100	Public	Weekend	1.214
BEV100	Residential	Weekday	6.047
BEV100	Residential	Weekend	5.198
BEV250	Public	Weekday	5.203
BEV250	Public	Weekend	4.874
BEV250	Residential	Weekday	8.396
BEV250	Residential	Weekend	8.535
PHEV20	Public	Weekday	1.201
PHEV20	Public	Weekend	0.89
PHEV20	Residential	Weekday	4.01
PHEV20	Residential	Weekend	3.742
PHEV40	Public	Weekday	1.243
PHEV40	Public	Weekend	0.824
PHEV40	Residential	Weekday	6.473
PHEV40	Residential	Weekend	5.133

Table ***9 Electric Vehicle Daily Charge Profiles***

	BEV				PHEV			
	Public		Residential		Public		Residential	
Hour Ending	Weekday	Weekend	Weekday	Weekend	Weekday	Weekend	Weekday	Weekend
1	1.9%	3.8%	7.6%	8.1%	1.4%	3.2%	5.2%	6.6%
2	1.4%	2.5%	6.1%	6.7%	1.3%	2.5%	4.2%	5.4%
3	1.0%	1.9%	5.4%	6.1%	1.0%	2.0%	3.2%	4.3%
4	0.7%	1.3%	4.4%	4.9%	0.7%	1.5%	2.5%	3.4%
5	0.7%	1.3%	3.9%	3.8%	0.7%	1.3%	2.2%	2.8%
6	0.5%	1.0%	2.7%	2.7%	0.8%	1.2%	1.8%	2.3%
7	1.1%	1.0%	1.8%	2.1%	1.1%	1.4%	1.7%	1.7%
8	4.6%	1.7%	1.5%	1.8%	6.4%	2.7%	1.4%	1.6%
9	10.7%	2.6%	1.2%	1.8%	10.8%	3.6%	1.3%	1.3%
10	8.2%	3.8%	1.2%	1.9%	13.8%	5.6%	2.0%	1.5%
11	5.4%	4.9%	1.4%	1.9%	11.5%	6.4%	2.5%	1.8%
12	5.8%	5.6%	1.5%	2.1%	9.3%	7.6%	2.7%	2.3%
13	5.2%	6.5%	2.1%	2.6%	7.0%	6.9%	3.1%	3.3%
14	5.4%	7.0%	2.2%	3.1%	5.9%	6.6%	3.0%	4.2%
15	5.3%	7.6%	2.4%	3.5%	5.2%	6.6%	3.2%	4.4%
16	5.6%	6.2%	2.6%	3.9%	4.0%	5.7%	3.7%	4.9%
17	5.6%	7.1%	3.3%	3.8%	3.1%	5.8%	4.5%	5.2%
18	5.5%	5.6%	4.3%	4.1%	2.6%	6.1%	6.2%	5.3%
19	6.0%	5.5%	5.8%	5.0%	2.6%	5.2%	7.6%	5.5%
20	5.7%	6.3%	7.2%	5.7%	2.7%	5.3%	7.8%	6.0%
21	5.0%	5.5%	7.7%	6.1%	2.6%	3.9%	8.2%	6.4%
22	4.0%	4.3%	7.7%	6.1%	2.2%	3.0%	8.0%	6.9%
23	2.7%	3.7%	8.4%	6.3%	1.8%	3.0%	7.4%	6.8%
24	2.0%	3.3%	7.9%	6.2%	1.7%	3.0%	6.8%	6.1%

This process of using the vehicle load forecast and the unique hourly load profiles are used to develop jurisdictional hourly level load profiles that is an input to the Duke Energy Indiana load forecast used in the 2021 DEI IRP. These hourly load profiles are included in Workpaper 1 (provided on CD-ROM due to size).

Supplemental Data on Model Specification and Output Statistics

Figures 15 through 26 include the model specifications and model statistics utilized to generate sales forecast by class. Figures 27 through 28 includes the same for the peak model.

Figure 15 Residential Customer Growth Model

	A	B	C	D	E	F	G
1	Variable	Coefficient	StdErr	T-Stat	P-Value	Units	Definition
2	Econ_TForms.mHHoldsSA_MA2	0.750	0.051	14.632	0.00%		DEI 62 County Service Area Households
3	mCALENDAR.Jan	-217405.728	64177.541	-3.388	0.10%		
4	mCALENDAR.Feb	-219091.031	64147.442	-3.415	0.10%		
5	mCALENDAR.Mar	-220098.080	64124.347	-3.432	0.09%		
6	mCALENDAR.Apr	-220768.258	64107.615	-3.444	0.09%		
7	mCALENDAR.May	-223006.464	64096.904	-3.479	0.08%		
8	mCALENDAR.Jun	-223008.691	64090.976	-3.480	0.08%		
9	mCALENDAR.Jul	-223090.289	64090.066	-3.481	0.08%		
10	mCALENDAR.Aug	-227923.645	64094.794	-3.556	0.06%		
11	mCALENDAR.Sep	-221943.895	64104.765	-3.462	0.08%		
12	mCALENDAR.Oct	-222487.841	64118.336	-3.470	0.08%		
13	mCALENDAR.Nov	-221806.189	64135.181	-3.458	0.08%		
14	mCALENDAR.Dec	-217396.873	64154.081	-3.389	0.10%		
15	BINARIES.Y2015M05	-5401.260	1005.676	-5.371	0.00%		
16	BINARIES.Y2020M12	-1978.416	1006.129	-1.966	5.23%		
17	AR(1)	0.915	0.040	23.125	0.00%		

Figure 16 Residential Customer Growth Model Statistics

Regression Model: CUST_RES

	A	B	D	E
1	Model Statistics		Forecast Statistics	
2	Iterations	14	Forecast Observations	0
3	Adjusted Observations	108	Mean Abs. Dev. (MAD)	0.00
4	Deg. of Freedom for Error	92	Mean Abs. % Err. (MAPE)	0.00%
5	R-Squared	0.997	Avg. Forecast Error	0.00
6	Adjusted R-Squared	0.996	Mean % Error	0.00%
7	AIC	14.46	Root Mean-Square Error	0.00
8	BIC	14.86	Theil's Inequality Coefficient	0.0000
9	F-Statistic	#NA	-- Bias Proportion	0.00%
10	Prob (F-Statistic)	#NA	-- Variance Proportion	0.00%
11	Log-Likelihood	-918.28	-- Covariance Proportion	0.00%
12	Model Sum of Squares	45,487,590,384.64		
13	Sum of Squared Errors	153,537,236.36		
14	Mean Squared Error	1,668,883.00		
15	Std. Error of Regression	1,291.85		
16	Mean Abs. Dev. (MAD)	934.91		
17	Mean Abs. % Err. (MAPE)	0.13%		
18	Durbin-Watson Statistic	2.083		
19	Durbin-H Statistic	#NA		
20	Ljung-Box Statistic	35.46		
21	Prob (Ljung-Box)	0.0618		
22	Skewness	-0.522		
23	Kurtosis	3.078		
24	Jarque-Bera	4.926		
25	Prob (Jarque-Bera)	0.0852		

Figure 17: Residential Average Use Per Customer Model

Regression Model: UPC_B_Model

	A	B	C	D	E
1	Variable	Coefficient	StdErr	T-Stat	P-Value
2	mStruct_RES.XHeat1_B	0.002	0.000	51.470	0.00%
3	mStruct_RES.XCool1_B	0.002	0.000	48.194	0.00%
4	mStruct_RES.XOther_B	0.001	0.000	49.680	0.00%
5	BINARIES.Y2018M10	-0.091	0.027	-3.372	0.13%
6	BINARIES.Y2018M12	-0.344	0.028	-12.434	0.00%
7	AR(1)	0.187	0.124	1.504	13.74%
8					

Figure 18 Residential Average Use Per Customer Model Statistics

Regression Model: UPC_B_Model

	A	B	C	D	E
1	Model Statistics			Forecast Statistics	
2	Iterations	13		Forecast Observations	0
3	Adjusted Observations	72		Mean Abs. Dev. (MAD)	0.000
4	Deg. of Freedom for Error	66		Mean Abs. % Err. (MAPE)	0.00%
5	R-Squared	0.984		Avg. Forecast Error	0.000
6	Adjusted R-Squared	0.983		Mean % Error	0.00%
7	AIC	-7.1293		Root Mean-Square Error	0.000
8	BIC	-6.9396		Theil's Inequality Coefficient	0.0000
9	F-Statistic	#NA		-- Bias Proportion	0.00%
10	Prob (F-Statistic)	#NA		-- Variance Proportion	0.00%
11	Log-Likelihood	160.493		-- Covariance Proportion	0.00%
12	Model Sum of Squares	3.03			
13	Sum of Squared Errors	0.05			
14	Mean Squared Error	0.001			
15	Std. Error of Regression	0.027			
16	Mean Abs. Dev. (MAD)	0.021			
17	Mean Abs. % Err. (MAPE)	1.97%			
18	Durbin-Watson Statistic	1.949			
19	Durbin-H Statistic	#NA			
20	Ljung-Box Statistic	41.62			
21	Prob (Ljung-Box)	0.0142			
22	Skewness	0.083			
23	Kurtosis	3.474			
24	Jarque-Bera	0.756			
25	Prob (Jarque-Bera)	0.6851			

Figure 19 Commercial Sales Model

Regression Model: SALES_B_COM

	A	B	C	D	E
1	Variable	Coefficient	StdErr	T-Stat	P-Value
2	mStruct_COM.XHeat_B	661994.904	70197.859	9.430	0.00%
3	mStruct_COM.XCool_B	681037.959	32661.143	20.852	0.00%
4	mStruct_COM.XOther_B	30952.455	430.503	71.898	0.00%
5	BINARIES.Y2017M12	-22846.187	10193.759	-2.241	2.85%
6	BINARIES.Y2018M12	-134540.943	10422.872	-12.908	0.00%
7	BINARIES.Y2019M07	-37812.665	9308.262	-4.062	0.01%
8	BINARIES.Y2020M04	-21461.241	10503.731	-2.043	4.52%
9	BINARIES.Y2020M05	-22484.929	10496.177	-2.142	3.60%
10	BINARIES.Y2021M01	-27200.144	11107.679	-2.449	1.71%
11	SAR(1)	0.509	0.110	4.644	0.00%
12					

Figure 20 Commercial Sales Model Statistics

Regression Model: SALES_B_COM

	A	B	D	E
1	Model Statistics		Forecast Statistics	
2	Iterations	14	Forecast Observations	0
3	Adjusted Observations	73	Mean Abs. Dev. (MAD)	0.00
4	Deg. of Freedom for Error	63	Mean Abs. % Err. (MAPE)	0.00%
5	R-Squared	0.953	Avg. Forecast Error	0.00
6	Adjusted R-Squared	0.947	Mean % Error	0.00%
7	AIC	18.799	Root Mean-Square Error	0.00
8	BIC	19.113	Theil's Inequality Coefficient	0.0000
9	F-Statistic	#NA	-- Bias Proportion	0.00%
10	Prob (F-Statistic)	#NA	-- Variance Proportion	0.00%
11	Log-Likelihood	-779.74	-- Covariance Proportion	0.00%
12	Model Sum of Squares	165,160,581,823.45		
13	Sum of Squared Errors	8,101,879,821.86		
14	Mean Squared Error	128,601,267.01		
15	Std. Error of Regression	11,340.25		
16	Mean Abs. Dev. (MAD)	8,205.74		
17	Mean Abs. % Err. (MAPE)	1.57%		
18	Durbin-Watson Statistic	1.683		
19	Durbin-H Statistic	#NA		
20	Ljung-Box Statistic	12.75		
21	Prob (Ljung-Box)	0.9701		
22	Skewness	0.299		
23	Kurtosis	3.185		
24	Jarque-Bera	1.190		
25	Prob (Jarque-Bera)	0.5514		
26				

Figure 21 Industrial Sales Model

Regression Model: SALES_B_IND

	A	B	C	D	E
1	Variable	Coefficient	StdErr	T-Stat	P-Value
2	CONST	407208.794	56290.791	7.234	0.00%
3	MEcon_Base.EMan_IProd	4837.849	592.842	8.160	0.00%
4	Weather_MonthlyStats_B_Filled.CDD_B_60	73.423	12.964	5.664	0.00%
5	mCALENDAR.Jan	-9577.183	4739.101	-2.021	4.63%
6	mCALENDAR.Feb	-11575.602	5496.102	-2.106	3.80%
7	mCALENDAR.Mar	-25165.904	4521.466	-5.566	0.00%
8	mCALENDAR.Jun	17320.876	3581.836	4.836	0.00%
9	mCALENDAR.Aug	10879.363	4172.684	2.607	1.07%
10	mCALENDAR.Sep	24593.555	4285.848	5.738	0.00%
11	mCALENDAR.Nov	-10003.600	3956.476	-2.528	1.32%
12	BINARIES.Y2012M05	34532.968	10692.348	3.230	0.17%
13	BINARIES.Y2013M02	-33607.204	11322.235	-2.968	0.39%
14	BINARIES.Y2014M12	26421.471	11006.418	2.401	1.85%
15	BINARIES.Y2016M12	-24659.789	11023.471	-2.237	2.78%
16	BINARIES.Y2017M11	44758.645	11215.410	3.991	0.01%
17	BINARIES.Y2019M02	-24981.228	11322.116	-2.206	3.00%
18	BINARIES.Y2020M01	-31268.060	11404.599	-2.742	0.74%
19	BINARIES.Y2020M03	64168.991	12807.927	5.010	0.00%
20	BINARIES.Y2020M04	29085.596	12456.816	2.335	2.18%
21	AR(1)	0.903	0.042	21.663	0.00%

Figure 22 Industrial Sales Model Statistics

Regression Model: SALES_B_IND

	A	B	D	E
1	Model Statistics		Forecast Statistics	
2	Iterations	11	Forecast Observations	0
3	Adjusted Observations	108	Mean Abs. Dev. (MAD)	0.00
4	Deg. of Freedom for Error	88	Mean Abs. % Err. (MAPE)	0.00%
5	R-Squared	0.905	Avg. Forecast Error	0.00
6	Adjusted R-Squared	0.884	Mean % Error	0.00%
7	AIC	19.30	Root Mean-Square Error	0.00
8	BIC	19.79	Theil's Inequality Coefficient	0.0000
9	F-Statistic	44.040	-- Bias Proportion	0.00%
10	Prob (F-Statistic)	-0.0000	-- Variance Proportion	0.00%
11	Log-Likelihood	-1,175.20	-- Covariance Proportion	0.00%
12	Model Sum of Squares	170,056,895,234.18		
13	Sum of Squared Errors	17,884,610,105.68		
14	Mean Squared Error	203,234,205.75		
15	Std. Error of Regression	14,256.02		
16	Mean Abs. Dev. (MAD)	10,668.36		
17	Mean Abs. % Err. (MAPE)	1.24%		
18	Durbin-Watson Statistic	1.984		
19	Durbin-H Statistic	#NA		
20	Ljung-Box Statistic	35.89		
21	Prob (Ljung-Box)	0.0562		
22	Skewness	0.106		
23	Kurtosis	2.311		
24	Jarque-Bera	2.340		
25	Prob (Jarque-Bera)	0.3103		
26				

Figure 23 Other Public Authority Sales Model

Regression Model: SALES_B_OPA

	A	B	C	D	E
1	Variable	Coefficient	StdErr	T-Stat	P-Value
2	Econ_TForms.Emp_Gov_MA2	294.367	21.238	13.861	0.00%
3	OPA_B_Sales.Predicted	0.220	0.053	4.124	0.01%
4	Weather_MonthlyStats_B_Filled.CDD_B_65	113.205	8.813	12.845	0.00%
5	Weather_MonthlyStats_B_Filled.HDD_B_55	10.172	2.099	4.845	0.00%
6	mCALENDAR.Apr_BM	-5059.227	2149.483	-2.354	1.99%
7	mCALENDAR.Jul_BM	-10896.263	2316.168	-4.704	0.00%
8	mCALENDAR.Aug_BM	-18377.959	3120.703	-5.889	0.00%
9	mCALENDAR.Oct_BM	10259.033	2684.295	3.822	0.02%
10	BINARIES.Y2010M02	-13251.374	3822.223	-3.467	0.07%
11	BINARIES.Y2012M06	16737.477	4483.104	3.733	0.03%
12	BINARIES.Y2012M07	-11743.023	4594.596	-2.556	1.16%
13	BINARIES.Y2013M03	-12550.474	3829.462	-3.277	0.13%
14	BINARIES.Y2018M07	11472.246	3878.352	2.958	0.36%
15	BINARIES.Y2020M04	-8773.804	4398.356	-1.995	4.78%
16	BINARIES.Y2020M05	-10357.932	4436.950	-2.334	2.09%
17	AR(1)	0.813	0.050	16.209	0.00%
18					

Figure 24 Other Public Authority Model Statistics

Regression Model: SALES_B_OPA

	A	B	C	D	E
1	Model Statistics			Forecast Statistics	
2	Iterations	17		Forecast Observations	0
3	Adjusted Observations	168		Mean Abs. Dev. (MAD)	0.00
4	Deg. of Freedom for Error	152		Mean Abs. % Err. (MAPE)	0.00%
5	R-Squared	0.931		Avg. Forecast Error	0.00
6	Adjusted R-Squared	0.924		Mean % Error	0.00%
7	AIC	17.08		Root Mean-Square Error	0.00
8	BIC	17.38		Theil's Inequality Coefficient	0.0000
9	F-Statistic	#NA		-- Bias Proportion	0.00%
10	Prob (F-Statistic)	#NA		-- Variance Proportion	0.00%
11	Log-Likelihood	-1,657.14		-- Covariance Proportion	0.00%
12	Model Sum of Squares	49,240,503,784.58			
13	Sum of Squared Errors	3,635,405,592.41			
14	Mean Squared Error	23,917,142.06			
15	Std. Error of Regression	4,890.52			
16	Mean Abs. Dev. (MAD)	3,832.07			
17	Mean Abs. % Err. (MAPE)	2.15%			
18	Durbin-Watson Statistic	2.265			
19	Durbin-H Statistic	#NA			
20	Ljung-Box Statistic	46.21			
21	Prob (Ljung-Box)	0.0042			
22	Skewness	0.095			
23	Kurtosis	2.723			
24	Jarque-Bera	0.789			
25	Prob (Jarque-Bera)	0.6742			
26					

Figure 25 Street Light Model

Regression Model: SALES_B_SL

Variable	Coefficient	StdErr	T-Stat	P-Value
mCALENDAR.Jan	5440.703	123.384	44.096	0.00%
mCALENDAR.Feb	5330.335	123.023	43.328	0.00%
mCALENDAR.Mar	5301.407	122.775	43.180	0.00%
mCALENDAR.Apr	5273.107	122.621	43.003	0.00%
mCALENDAR.May	5239.622	122.542	42.758	0.00%
mCALENDAR.Jun	5216.465	122.525	42.575	0.00%
mCALENDAR.Jul	5213.485	122.558	42.539	0.00%
mCALENDAR.Aug	5206.097	122.625	42.455	0.00%
mCALENDAR.Sep	5258.092	122.757	42.833	0.00%
mCALENDAR.Oct	5289.330	122.864	43.050	0.00%
mCALENDAR.Nov	5335.797	123.046	43.364	0.00%
mCALENDAR.Dec	5419.719	123.208	43.988	0.00%
BINARIES.log_trend	-335.939	45.031	-7.460	0.00%
BINARIES.Y2010M09	125.010	16.833	7.426	0.00%
BINARIES.Y2012M12	-118.154	16.801	-7.033	0.00%
BINARIES.Y2016M11	-132.428	16.852	-7.858	0.00%
BINARIES.Y2018M08	-98.865	16.794	-5.887	0.00%
BINARIES.Y2019M10	-123.578	16.812	-7.350	0.00%
AR(1)	0.829	0.053	15.529	0.00%

Figure 26 Street Lighting Model Statistics

Regression Model: SALES_B_SL

	A	B	C	D	E
1	Model Statistics			Forecast Statistics	
2	Iterations	11		Forecast Observations	0
3	Adjusted Observations	144		Mean Abs. Dev. (MAD)	0.00
4	Deg. of Freedom for Error	125		Mean Abs. % Err. (MAPE)	0.00%
5	R-Squared	0.969		Avg. Forecast Error	0.00
6	Adjusted R-Squared	0.964		Mean % Error	0.00%
7	AIC	6.21		Root Mean-Square Error	0.00
8	BIC	6.60		Theil's Inequality Coefficient	0.0000
9	F-Statistic	#NA		-- Bias Proportion	0.00%
10	Prob (F-Statistic)	#NA		-- Variance Proportion	0.00%
11	Log-Likelihood	-632.18		-- Covariance Proportion	0.00%
12	Model Sum of Squares	1,706,334.39			
13	Sum of Squared Errors	54,845.60			
14	Mean Squared Error	438.76			
15	Std. Error of Regression	20.95			
16	Mean Abs. Dev. (MAD)	16.27			
17	Mean Abs. % Err. (MAPE)	0.37%			
18	Durbin-Watson Statistic	2.295			
19	Durbin-H Statistic	#NA			
20	Ljung-Box Statistic	46.52			
21	Prob (Ljung-Box)	0.0038			
22	Skewness	0.124			
23	Kurtosis	2.373			
24	Jarque-Bera	2.724			
25	Prob (Jarque-Bera)	0.2562			

Figure 27 System Peak Model

Regression Model: PEAK_SAE_ARO

Variable	Coefficient	StdErr	T-Stat	P-Value
mPkEndUse.CoolVar	70.392	11.712	6.010	0.00%
mPkEndUse.HeatVar	19.054	5.398	3.530	0.15%
mPkEndUse.BaseVar_ARO	15.765	0.727	21.681	0.00%
mCALENDAR.Apr	-278.327	148.790	-1.871	7.23%
mCALENDAR.Oct	-516.196	159.355	-3.239	0.32%
BINARIES.Y2019M01	455.392	280.163	1.625	11.57%
AR(1)	-0.077	0.674	-0.114	90.99%
MA(1)	0.179	0.690	0.260	79.67%

Figure 28 Peak Model Statistics

Regression Model: PEAK_SAE_ARO

Model Statistics		Forecast Statistics	
Iterations	14	Forecast Observations	0
Adjusted Observations	35	Mean Abs. Dev. (MAD)	0.00
Deg. of Freedom for Error	27	Mean Abs. % Err. (MAPE)	0.00%
R-Squared	0.845	Avg. Forecast Error	0.00
Adjusted R-Squared	0.805	Mean % Error	0.00%
AIC	11.217	Root Mean-Square Error	0.00
BIC	11.573	Theil's Inequality Coefficient	0.0000
F-Statistic	#NA	-- Bias Proportion	0.00%
Prob (F-Statistic)	#NA	-- Variance Proportion	0.00%
Log-Likelihood	-237.97	-- Covariance Proportion	0.00%
Model Sum of Squares	9,018,892.11		
Sum of Squared Errors	1,648,983.88		
Mean Squared Error	61,073.48		
Std. Error of Regression	247.13		
Mean Abs. Dev. (MAD)	173.72		
Mean Abs. % Err. (MAPE)	3.82%		
Durbin-Watson Statistic	1.999		
Durbin-H Statistic	#NA		
Ljung-Box Statistic	14.36		
Prob (Ljung-Box)	0.9382		
Skewness	-0.275		
Kurtosis	2.810		
Jarque-Bera	0.495		
Prob (Jarque-Bera)	0.7809		

Appendix B

REPORT

Nexant
Reimagine tomorrow.

Duke Energy Indiana DSM Market Potential Study

Submitted to Duke Energy

April 07, 2021

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1 Executive Summary

In October 2020, Duke Energy retained Nexant, Inc., to determine the potential energy and demand savings that could be achieved by demand-side management (DSM) programs[1] in the Duke Energy Indiana (DEI) service territory. DSM programs include both energy efficiency (EE) and demand response (DR) programs. This report describes the potential for DSM savings in the Indiana service territory. The time period covered in this analysis is 2021 – 2045, and the analysis is based on currently available data on the Duke Indiana service territory and DSM measure opportunities. As with Integrated Resources Planning, Nexant recommends updating this analysis periodically as new data are available. The main objectives of the study include:

- Providing a market potential study, which estimates the technical, economic and realistic achievable market potential energy savings over the short term (5-year projection), intermediate term (10-year projection), and long term (25-year projection).
- Estimating the potential savings of both energy and demand savings for Duke Energy's Indiana service territory.
- Developing potential savings with five scenarios, including a base scenario with all customers, a base scenario excluding customers currently opted-out[2], an enhanced scenario with expanded measures, an enhanced scenario with increased spending, and an avoided cost sensitivity aligned with enhanced scenario.
- Estimating program costs to acquire all the achievable potential for different scenarios, along with cost-effectiveness results. We recommend Duke Energy Indiana undertake detailed planning processes to extend or adjust these savings estimates prior to deploying specific program offerings and strategies.

1.1 Methodology

This study utilized Nexant's Microsoft Excel-based modeling tool, TEA-POT (Technical / Economic / Achievable POTential). This modeling tool was built on a platform that provides the ability to calculate multiple scenarios and recalculate potential savings based on variable inputs such as sales/load forecasts, electricity prices, discount rates, and actual program savings. The methodology for the energy efficiency potential assessment was based on a hybrid "top-down/bottom-up" approach. The assessment started with the current load Duke Energy forecasts for sales, demand, customer growth, end use intensities, and commercial segment shares; Nexant used data provided by Duke Energy Indiana and secondary data sources to disaggregate sales and loads into customer-class and end use components. The assessment then examined the effect of the range of

[1] In this report, the term "demand-side management", or "DSM", is used to describe energy savings and load management opportunities and programs that focus on the customer side of the meter, including both energy efficiency (EE) and demand response (DR).

[2] The base scenario excluding customers currently opted-out only exists for non-residential sector.

energy efficiency measures and practices on each end use, taking into account fuel shares, current market saturations, technical feasibility, commercial availability, and costs. These unique impacts were aggregated to produce estimates of potential at the end use, customer class, and system levels.

Opportunities for stakeholder engagement and feedback were also included throughout the course of the study. Nexant had an explicit goal of engagement and exchange with the Indiana Oversight Board (OSB). Details of the engagement activities and communication documents between Nexant and Duke Energy's Indiana OSB members are included in methodology section (Section 2.3) and Appendix E. Nexant received positive feedback from the OSB during a capstone session, held near the end of the study completion, in which we reviewed the correspondence and input provided by stakeholders over the course of the study preparation.

1.2 Savings Potential

DSM savings potential in the Duke Energy Indiana service territory reflects current conditions and trends as described with available data. Beyond measure cost research and measure impact parameters. Our analysis demonstrates the savings potential that can be expected considering current electricity consumption and demand trends in the DEI service territory. As with any static estimate made at a specific point in time, we recommend updating the analysis as new data or trends become evident. As with any model, our estimates are subject to uncertainty, and new data or trends may emerge that speak to the need to revise these estimates at some future date. We therefore avoid speculating on trends or market changes that may occur in the future and rely on what is currently known or observed for the DEI service territory.

1.2.1 DEI Energy Efficiency Potential

Energy efficiency potential is described using the industry-standard concepts of technical, economic, and achievable potential. Each scenario begins with the set of known and commercially available energy efficiency measures. The scenarios apply a set of screening criteria that accounts for technical feasibility, costs and benefits, and expected customer adoption via utility-sponsored program activities. The following section describe each scenario in detail.

Technical and Economic Potential

Energy efficiency technical and economic potential provide theoretical maximums for electricity savings from two perspectives. Technical potential estimates the savings potential when all technically feasible energy efficiency measures are fully implemented, ignoring all non-technical constraints on electricity savings, such as cost-effectiveness and customer willingness to adopt energy efficiency. Economic potential applies a cost-effectiveness screening to all technically feasible measures and includes full implementation of all measures that pass this screening. Based on the recommendation from the Indiana Utility Regulatory Commission (IURC) Oversight Board (OSB) and subsequent discussions with Duke Energy, the Utility Cost Test (UCT) test was used for the economic screening of energy efficiency measures in this study. Measure permutations were screened individually, and the economic potential represents the sum of the energy savings associated with all measure permutations passing the economic screening.

The estimated technical and economic potential results are summarized in Table 1-1. Nexant reported technical and economic potential as single numerical values for the DEI service territory over the 25-year study period, considering changes in energy sales forecast over the study horizon as well as equipment turnover rates.

Table 1-1: DEI Energy Efficiency Cumulative Technical and Economic Potential

	Cumulative Energy Efficiency Potential (2021-2045)			
	Energy (GWh)	% of 2042 Base Sales	Summer Demand (MW)	Winter Demand (MW)
Technical Potential	9,318	32%	1,362	1,308
Economic Potential	7,040	24%	1,020	1,000

Achievable Program Potential

Achievable program potential estimates the energy savings that can feasibly be achieved in the market with consideration of market barriers and customer adoption of DSM technologies, inclusive of the influence of utility-sponsored incentives on adoption rates. In terms of competing measures, customer adoption is distributed among technologies based on their payback periods. Like the economic potential analysis, cost-effectiveness screening was performed from the UCT perspective.

Achievable program potential was estimated for five scenarios, each with specific assumptions on the types of programs and eligible measures offered. The five scenarios were developed as follows:

- Base scenario with all customers – includes all the customers in Duke Energy's Indiana service territory and includes existing EE programs and measures currently offered by DEI.
- Base scenario excluding opt-outs – aligns with existing program portfolio excluding customers currently opted-out and includes existing EE programs and measures currently offered by DEI.
- Enhanced scenario with expanded measures – includes existing EE programs with measure bundles that include current and newly proposed measures, as well as new EE programs where measures included in the study did not logically fit into an existing offering.
- Enhanced scenario with increase spending – aligns with enhanced scenario with expanded measures but increases program spending via increasing incentives as approximation of higher program participation.
- Avoided cost sensitivity – aligns with enhanced scenario with expanded measures, with enhanced EE benefits that would occur if avoided energy costs were higher than current values. Measures are re-screened from UCT perspective with 50% increase in avoided energy costs.

Table 1-2 summarizes the short-term (5-year), medium term (10-year) and long-term (25-year) DEI portfolio EE program potential for the base scenario with all customers. Impacts are presented as both **cumulative impacts**, which represent the savings that occur in the respective year based on measures installed in that year and measures installed in prior years that have not reached the end of their useful life, and **the sum of annual impacts** which represents the total annual incremental savings achieved over the stated time horizon (5 years, 10 years, or 25 years).

Table 1-2: DEI Energy Efficiency Achievable Program Potential with All Customers[3]

	Cumulative Impacts			Sum of Annual Incremental Impacts			Average Annual % of Base Sales[4]
	Energy (GWh)	Demand (MW)		Energy (GWh)	Demand (MW)		
		Summer	Winter		Summer	Winter	
Achievable Program Potential – Base Scenario, All Customers							
5 Year (2025)	1,450	232	216	1,686	265	249	1.34%
10 Year (2030)	2,172	350	325	2,927	463	432	1.16%
25 Year (2045)	1,825	307	275	5,810	926	856	0.88%

Duke Energy's energy efficiency programs in Indiana include an "opt-out" provision approved by the Indiana Utility Regulatory Commission. This provision allows non-residential customers receiving electric service at a single site with at least one meter constituting more than 1 MW demand for any one billing period within the previous 12 months to opt out, which exempts the customer from cost recovery mechanism but also eliminates that customer's eligibility for participation in the program. For the achievable program potential analysis, Duke provided Nexant with current opt-out information in Indiana, which showed a 2020 opt-out rate of 37.4% of commercial kWh sales and 86.4% of industrial kWh sales in the DEI service territory. Nexant incorporated this opt-out rate as a modeling sensitivity.

Table 1-3 summarizes the short-term (5-year), medium term (10-year) and long-term (25-year) DEI portfolio EE program potential for the base and enhanced scenarios as well as avoided cost sensitivity, excluding the non-residential customers that are currently opted-out.

[3] Achievable program potential results listed in table include non-residential customer opt-outs

[4] Average annual energy savings as percentage of annual Base Sales per period.

Table 1-3: DEI Energy Efficiency Achievable Program Potential with Opt-Outs

	Cumulative Impacts			Sum of Annual Incremental Impacts			Average Annual % of Base Sales[5]
	Energy (GWh)	Demand (MW)		Energy (GWh)	Demand (MW)		
		Summer	Winter		Summer	Winter	
Achievable Program Potential – Base Scenario, Opt Outs							
5 Year (2025)	696	112	101	929	146	134	1.31%
10 Year (2030)	1,022	168	148	1,671	263	239	1.17%
25 Year (2045)	1,082	182	153	3,720	587	527	0.98%
Achievable Program Potential – Enhanced Scenario, Expanded Measures							
5 Year (2025)	741	118	107	966	150	139	1.36%
10 Year (2030)	1,133	182	164	1,784	277	255	1.25%
25 Year (2045)	1,326	212	188	4,120	636	581	1.09%
Achievable Program Potential – Enhanced Scenario, Increased Spending							
5 Year (2025)	784	121	114	1,010	152	145	1.42%
10 Year (2030)	1,244	189	182	1,910	284	274	1.34%
25 Year (2045)	1,481	220	218	4,419	652	626	1.17%
Achievable Program Potential – Avoided Cost Sensitivity							
5 Year (2025)	815	126	116	1,040	157	148	1.46%
10 Year (2030)	1,230	190	178	1,896	285	270	1.33%
25 Year (2045)	1,399	214	206	4,287	641	606	1.13%

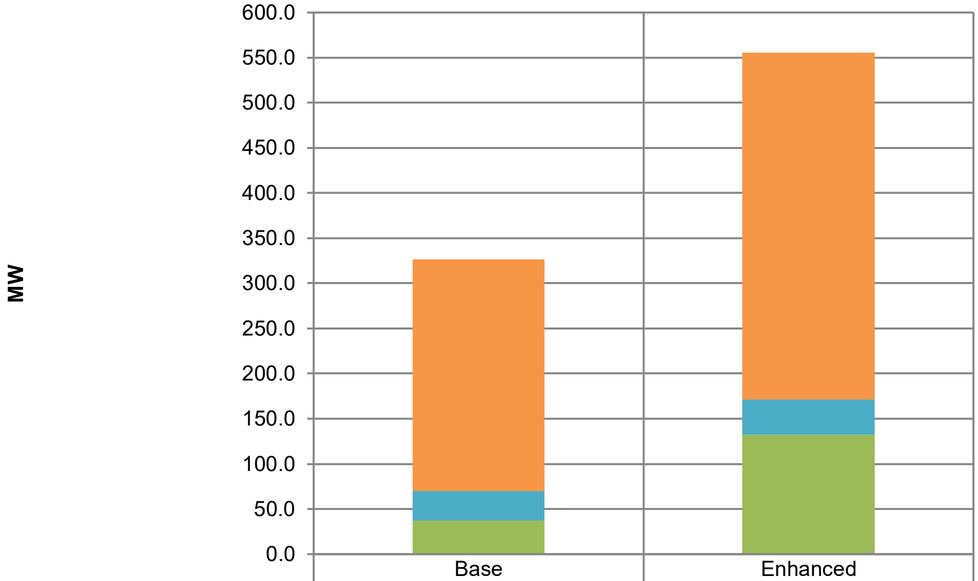
1.2.2 DEI Demand Response Potential

Demand response opportunities were analyzed for DEI's Indiana service territory to determine the amount of summer and winter peak capacity that could be reduced through DR initiatives from a technical, economic, and program potential perspective. While technical and economic potential are theoretical upper limits, participation rates are calculated as a function of the incentives offered to each customer group for program-based DR. For a given incentive level and participation rate, the cost-effectiveness of each customer segment is evaluated to determine whether the aggregate DSM potential from that segment should be included in the achievable potential.

[5] Average annual savings as percentage of annual non-opt out Base Sales per period.

Figure 1-1 and Figure 1-2 summarize the summer peak and winter peak DR potential estimated for the two program scenarios analyzed in the study (the avoided cost sensitivity scenario applies only to avoided energy costs).

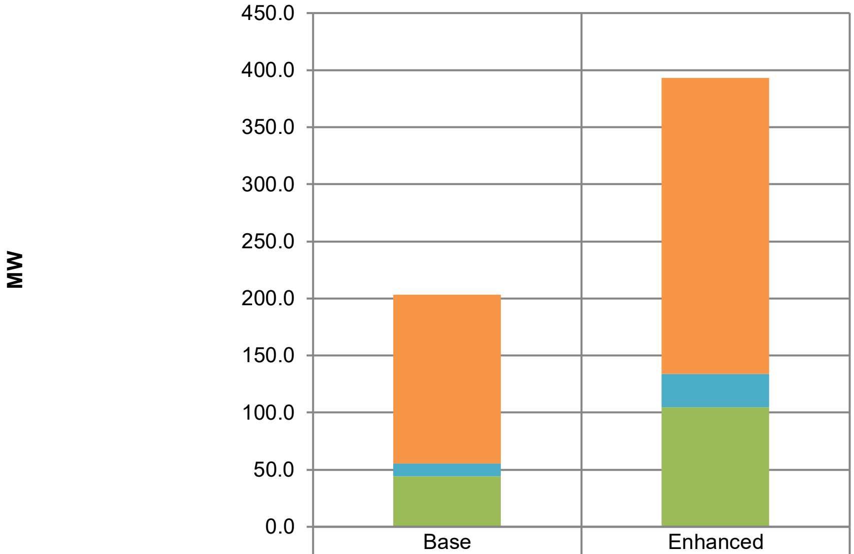
Figure 1-1 DEI DR Summer Peak Capacity Program Potential[6]



	Base	Enhanced
Large C&I	256.4	383.8
Small and Medium Business	32.4	38.9
Residential	37.4	132.6

[6] Results are incremental to current DR capacity provided by Power Manager and PowerShare programs

Figure 1-2 DEI DR Winter Peak Capacity Program Potential



	Base	Enhanced
Large C&I	147.6	259.1
Small and Medium Business	11.7	29.3
Residential	44.0	104.5

2 Introduction

2.1 Objectives and Deliverables

In October 2020, Duke Energy retained Nexant, Inc., to determine the potential energy and demand savings that could be achieved by demand-side management (DSM) programs[7] in the Duke Energy's Indiana service territory (DEI). DSM programs include both energy efficiency (EE) and demand response (DR) programs. The main objectives of the study included:

- Providing a market potential study, which estimates the technical, economic and realistic achievable market potential energy savings over the short term (5-year projection), intermediate term (10-year projection), and long term (25-year projection).
- Estimating the potential savings of both energy and demand savings for Duke Energy's Indiana service territory.
- Developing potential savings with five scenarios, including base scenario with all customers, base scenario excluding customers currently opted-out[8], enhanced scenario with expanded measures, enhanced scenario with increased spending, and avoided cost sensitivity aligned with enhanced scenario.
- Estimating program costs to acquire all the achievable potential, along with cost effectiveness results.

In developing the market potential for DEI, the following deliverables were developed by Nexant as part of the project and are addressed in this report:

- Project plan
- Measure list and detailed assumption workbooks
- Summary of major assumptions
- Disaggregated baseline by year, state, sector, end use, technology saturations, and energy and demand consumptions
- List of forward looking, DSM program concepts, along with the applicable markets, measures, and estimated delivery costs
- List of cost-effective energy efficiency measures and demand response technologies and products
- Market potential energy savings for technical, economic and realistic program achievable potential scenarios for short, intermediate and long-term periods

[7] In this report, the term "demand-side management", or "DSM", is used to describe energy savings and load management opportunities and programs that focus on the customer side of the meter, including both energy efficiency (EE) and demand response (DR).

[8] The base scenario excluding customers currently opted-out only exists for non-residential sector.

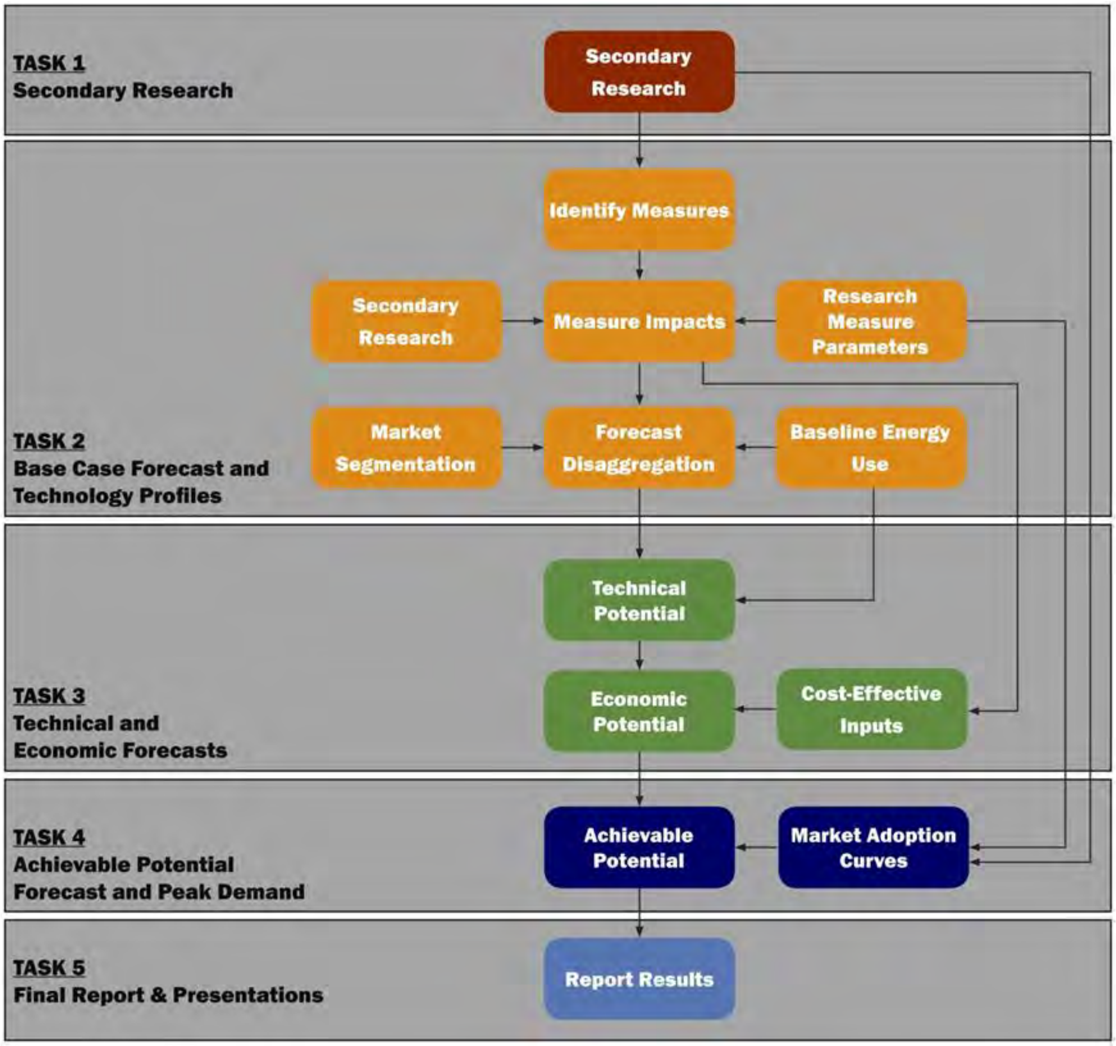
- Estimated program costs to acquire all the achievable potential
- Supporting calculation spreadsheets

2.2 Methodology

Energy efficiency and market potential studies involve several analytical steps to produce estimates of each type of energy efficiency potential: technical, economic, and achievable. A market potential study is an assessment of current market conditions and trends, as observed with available secondary data sources. All components of the study, such as baseline energy consumption, expected utility sales forecasts, and available EE and DR measures, among others, are determined on the basis of available data. A market potential study is therefore a discrete estimate of EE and DR potential based on current market conditions and savings opportunities. An MPS does not contemplate potential changes in utility rates, changes in technology costs, nor changes in underlying economic conditions that provide a context for current consumption trends. This study considers existing technology and market trends as observed with currently available data and does not speculate on the potential impact of unknown, emerging technologies that are not yet market ready.

This study utilized Nexant's Microsoft Excel-based modeling tool, TEA-POT (Technical / Economic / Achievable Potential). This modeling tool was built on a platform that provides the ability to calculate multiple scenarios and recalculate potential savings based on variable inputs such as sales/load forecasts, electricity prices, discount rates, and actual program savings. The model provides transparency into the assumptions and calculations for estimating market potential. TEA-POT has been consistently refined to accommodate and advance industry best practices, with the most recent upgrade occurring in 2020.The methodology for the energy efficiency potential assessment is based on a hybrid "top-down/bottom-up" approach.

Figure 2-1: Approach to Market Potential Modeling



As illustrated in Figure 2-1, the assessment started with the current load forecast, then disaggregated it into its constituent customer-class and end use components. Nexant examined the effect of energy efficiency measures and practices on each end use, taking into account fuel shares, current market saturations, technical feasibility, and costs. These unique impacts were aggregated to produce estimates of potential at the technology, end use, customer class, and system levels.

The market potential in Indiana territory can be characterized by levels of opportunity. The ceiling or theoretical maximum is based on commercialized and emerging technologies and behavior measures, whereas the realistic savings that may be achieved through DSM programs reflect real world market constraints such as utility budgets, customer perspectives and energy efficiency policy. This analysis defines these levels of energy efficiency potential according to the Environmental Protection Agency's (EPA) National Action Plan for Energy Efficiency (NAPEE), as follows:

- Technical Potential is the theoretical maximum amount of energy and capacity that could be displaced by efficiency, regardless of cost and other barriers that may prevent the installation or adoption of an energy efficiency measure. Technical potential is only constrained by factors such as technical feasibility and applicability of measures.

- Economic Potential is the amount of energy and capacity that could be reduced by efficiency measures that pass a cost-effectiveness test. This study applies the utility cost test (UCT) to determine whether measures are cost-effective[9].
- Achievable Potential is the energy savings that can feasibly be achieved in the market with consideration of market barriers and customer adoption of DSM technologies, and the influence of incentive levels on adoption rates. For this study, achievable potential is organized into specific utility program offerings, and therefore referred to as Achievable Program Potential.
- Program Potential delivered by programs is often less than achievable potential due to real-world constraints, such as utility program budgets, effectiveness of outreach, and market delays.

This study explored technical, economic, and achievable program potential over a 25-year period from January, 2021, to December, 2045. The quantification of these three levels of energy efficiency potential is an iterative process reflecting assumptions on cost effectiveness that drill down the opportunity from the theoretical maximum to realistic program savings. The California Standard Practice Manual (SPM) provides the methodology for estimating cost effectiveness of energy efficiency measures, bundles, programs, or portfolios based on a series of tests representing the perspectives of the utility, customers, and societal stakeholders. In this potential study, individual measures were screened for cost-effectiveness using the utility cost test (UCT) from the Standard Practice Manual.

Naturally occurring conservation is captured by this analysis in the load forecast. Effects of energy codes and equipment standards were considered by incorporating changes to codes and standards and marginal efficiency shares in the development of the base-case forecasts. Additionally, the model accounted for known or planned future federal code changes that will impact efficiencies, and therefore overall potential energy savings of specific measures and end uses such as residential HVAC.

Nexant estimated DSM program savings potential based on a combination of market research, analysis, and a review of Duke Energy's existing DSM programs, all in coordination with Duke Energy. Nexant examined both energy efficiency (EE) and demand-side management (DSM) programs; therefore, this report is organized to offer detail on both types of programs. The remainder of the report provides methodologies and results in the following sections: Market Characterization, DSM Measure List, Technical Potential, Economic Potential, Achievable Program Potential, and Appendices.

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[9] The total resource cost test (TRC test) is commonly applied to identify cost-effective DSM measures. The TRC considers avoided generation and capacity benefits of energy efficiency measures and compares them to the incremental costs of purchasing and installing the measure. The TRC test also includes utility administrative costs when estimating achievable potential. Utility-sponsored DSM programs typically provide an incentive to offset the incremental costs of installing energy efficiency measures, and this incentive is typically less than the incremental cost.

2.3 Stakeholder Engagement

Nexant understands how an open stakeholder engagement process can support the larger IRP process. This study included multiple feedback sessions to provide interim results and insight into our study approach and modeling process. The stakeholder engagement process also provided discussion and feedback on DSM modeling and program concepts, approaches, and best practices. Stakeholder engagement activities were included in all stages of the study and covered all project tasks, from the initial project work plan through project reporting (capstone). Through the review process, Nexant provided Duke Energy and Indiana OSB members with insights into methods, data, and assumptions used in the study, solicited stakeholder's feedback, and responded to stakeholder's comments. Communication documents that include OSB members' comments and Nexant's responses are provided in Appendix E.

3 End Use Market Characterization

The Duke Energy Indiana base year energy use and sales forecast provided the reference point to determine potential savings. The end use market characterization of the base year energy use and reference case forecast included customer segmentation and load forecast disaggregation. The characterization is described in this section, while the subsequent section addresses the measures and market potential energy savings scenarios.

3.1 Methodology

3.1.1 Customer Segmentation

In order to estimate energy efficiency (EE) and demand response (DR) potential, the sales forecast and peak load forecasts were segmented by customer characteristics. Assessing the savings potential required an understanding of how DSM measures are applied to the wide array of electricity customers. As electricity consumption patterns vary by customer type, Nexant segmented customers into homogenous groups to identify which customer groups are eligible to adopt specific energy efficiency technologies or to provide DSM grid services.

Customer segmentation also examined how the costs and benefits of utility-sponsored DSM may differ across the customer base. Significant cost efficiency can be achieved through strategic DSM program designs that recognize and address the similarities of DSM potential that exists within each customer group. Nexant segmented DEI customers according to the following:

1) **By Sector** – how much of the Duke Energy's energy sales, summer peak, and winter peak load forecast is attributable to the residential, commercial, and industrial sectors?
2) **By Customer** – how much electricity does each customer typically consume annually and during system peaking conditions? For the DR assessment, customer segmentation was done by customer size and heating type for residential customers, and by customer size and industry type for non-residential customers.
3) **By End Use** – within a home or business, what equipment is using electricity during the peak? How much energy does this end-use consume over the course of a year?

This analysis identified the segments of customers that may be ineligible for DSM, such as Opt Out commercial and industrial customers[10], as well as the share of the load forecast that is served by non-premises accounts (such as street lighting).

Table 3-1 summarizes the segmentation within each sector. The customer segmentation is discussed in Section 3.1.1. In addition to the segmentation described here for the EE analysis, the residential customer segments were further segmented by heating type (electric heat, gas heat, or

[10] Consideration of non-residential opt-out customers for the market potential study is described in Section 3.4.3.

unknown) and by annual consumption bins within each sub-segment for the DR analysis. The goal of this further segmentation was to understand which customer groups were most cost-effective to recruit and allow for more targeted marketing of DR programs.

Table 3-1: Customer Segments and Sub-Sectors

Residential	Commercial		Industrial	
Single Family	Assembly	Lodging/ Hospitality	Agriculture and Assembly	Lumber/Furniture/Pulp/Paper
Multi Family	College and University	Miscellaneous	Textiles and Lumber	Metal Products and Machinery
	Data Center	Offices	Transportation Equipment	Miscellaneous Manufacturing
	Grocery	Restaurant	Water and Wastewater	Primary Resources Industries
	Healthcare	Retail	Chemicals and Plastics	Stone/Glass/Clay/Concrete
	Hospitals	Schools K-12	Construction	
	Institutional	Warehouse	Electrical and Electronic Equipment	

From an equipment and energy use perspective, each segment has variation within each building type or sub-sector. For example, the energy consuming equipment in a convenience store will vary significantly from the equipment found in a supermarket. To account for variations of this sort, the selected end uses describe energy savings potential that are consistent with those typically studied in national or regional surveys. These end uses are listed in Table 3-2.

Table 3-2: End Uses

Residential End Uses	Commercial End Uses	Industrial End Uses
Space heating	Space heating	Process heating
Space cooling	Space cooling	Interior lighting high bay
Domestic hot water	Domestic hot water	Interior lighting linear fluorescent
Ventilation and circulation	Ventilation and circulation	Interior lighting other
Lighting	Interior lighting	Process cooling
Cooking	Exterior lighting	Compressed air
Refrigerators	Cooking	Motors, pumps
Freezers	Refrigeration	Motors, fans, blowers
Clothes washers	Office equipment	Process-specific
Clothes dryers	Miscellaneous	Exterior lighting
Dishwashers		HVAC
Plug load		Other
Miscellaneous		

For the DR assessment, the end uses targeted were limited to end-uses with controllable load for residential customers and small/medium businesses (SMB), but all load during peak hours for large commercial and industrial (large C&I) customers, who potentially would be willing to reduce electricity consumption for a limited time if offered a large enough incentive during temporary system peak demand conditions. For residential customers, AC/heating loads, as well as pool pumps and electric water heaters for certain program potential scenarios, were studied. For SMB customers, the analysis was limited to AC/heating loads.

3.1.2 Forecast Disaggregation

Although the primary focus of the EE potential study was the electricity consumption forecast and the primary focus of the DR potential study was the peak load forecasts, the accuracy of the demand impacts and cost-effectiveness screening in the EE potential study is enhanced by a detailed approach to peak load disaggregation. Therefore, during the development of all the baselines, the energy efficiency and demand response teams coordinated with each other, to ensure consistent assumptions and to avoid potential double counting of potential.

Additionally, a common understanding of the assumptions and granularity in the baseline load forecast was developed with input with Duke Energy. Key discussion topics reviewed with Duke Energy included:

- How are Duke Energy's current program offerings reflected in the energy and demand forecast?
- What are the assumed weather conditions and hour(s) of the day when the system is projected to peak?

- How much of the load forecast is attributable to accounts that are not eligible for DSM programs or have opted-out of the DSM rider?
- How are projections of population increase, changes in technological energy efficiency, and evolving distribution of end use load shares accounted for in the 25-year peak demand forecast?
- If separate forecasts are not developed by region or sector, are there trends in the load composition that Nexant should account for in the study?

3.1.2.1 Electricity Consumption (kWh) Forecast

Nexant segmented the DEI electricity consumption forecast into electricity consumption load shares by customer class and end use. The baseline customer segmentation represents the Indiana electricity market by describing how electricity was consumed within the service territory. Nexant developed these forecasts for the years 2021–2045 and based it on data provided by Duke Energy. The data addressed current baseline consumption, system load, and sales forecasts.

3.1.2.2 Peak Demand (kW) Forecast

A fundamental component of DR potential was establishing a baseline forecast of what loads or operational requirements would be absent existing dispatchable DR or time varying rates. This baseline was necessary to assess how DR can assist in meeting specific planning and operational requirements. Nexant utilized Duke's summer and winter peak demand forecast, which was developed for system planning purposes.

3.1.2.3 Estimating Consumption by End-Use Technology

As part of the forecast disaggregation, Nexant developed a list of electricity end uses by sector (Table 3-2). To develop this list, Nexant began with Duke Energy's estimates of average end-use consumption by customer and sector. Nexant combined these data with other information, such as 2019 Duke Energy's residential appliance saturation surveys, to develop estimates of customers' baseline consumption. Nexant augmented the Duke Energy data with data available from public sources, such as the Energy Information Agency's (EIA) recurring data-collection efforts that describe energy end-use consumption for the residential, commercial, and manufacturing sectors.

To develop estimates of end-use electricity consumption by customer segment and end use, Nexant applied estimates of end-use saturation, energy fuel share, and equipment-type saturation to the average energy consumption for each sector. The following data sources and adjustments were used in developing the base year 2020 sales by end use:

Residential sector:

- The disaggregation was based on DEI rate class load shares and intensities; adjustments were made for dwelling type.
- Adjustments were made to the baseline intensity to account for differences in end use saturation, fuel source, and equipment saturation as follows:
    - Duke Energy rate class load share is based on average per customer.

  - Outcome is designed to reflect customers' fuel-specific and equipment-specific savings opportunities.

Commercial sector:

- The disaggregation was based on DEI rate class load shares, intensities, and EIA Commercial Buildings Energy Consumption Survey (CBECS) data.
- Segment data from DEI, supplemented by EIA.
- Adjustments were made to the baseline intensity for end use saturation, fuel source, and equipment saturation as follows:
  - Duke Energy rate class load share is based on segments' shares of total consumption.
  - Nexant estimates of end use consumption calibrated to disaggregated Duke Energy segment shares and assigned using EIA CBECS segment consumption shares.
  - Outcome reflects customers' fuel-specific and equipment-specific savings opportunities.

Industrial sector:

- The disaggregation was based on DEI rate class load shares, intensities, and EIA Manufacturing Energy Consumption Survey (MECS) data.
- Segment data from EIA, and DEI.
- Adjustments were made to the baseline intensity for end use saturation, fuel source, and equipment saturation as follows:
  - Duke Energy rate class load share based on EIA MECS and end use forecasts from DEI.
  - Outcome reflects customers' fuel-specific and equipment-specific savings opportunities.

3.2 Analysis of Customer Segmentation

Customer segmentation allows an MPS to examine DSM savings potential in a manner that reflects the diversity of energy savings opportunities across Duke Energy's customer base. Nexant examined DEI customer data from multiple perspectives to identify customer segments. Nexant's approach to segmentation varied slightly for commercial and residential accounts, but the overall logic segments accounts in terms that were relevant to DSM opportunities. The following two sections describe the segmentation analysis and results for commercial and industrial C&I accounts (Section 3.2.1) and residential accounts (Section 3.2.2).

3.2.1 Commercial and Industrial Accounts

Nexant segmented C&I accounts according to two approaches: Standard Industrial Classification (SIC) codes and peak energy demand.

3.2.1.1 Standard Industrial Classification Codes

For the energy efficiency analysis, the approach to examining DEI's C&I accounts was based on the SIC codes, which Duke Energy provided as part of the customer data. Nexant further classified the customers in this group as *either* commercial or industrial, on the basis of DSM measures applicable to each. For example, agriculture and forestry DSM measures are more similar to industrial savings opportunities than commercial; therefore, small farms with relatively low energy demand were included in this group. The estimated sales distributions Nexant applied from Duke Energy's customer data are described below in Figure 3-1 and Figure 3-2.

Figure 3-1: Customer Segmentation by Commercial Segment

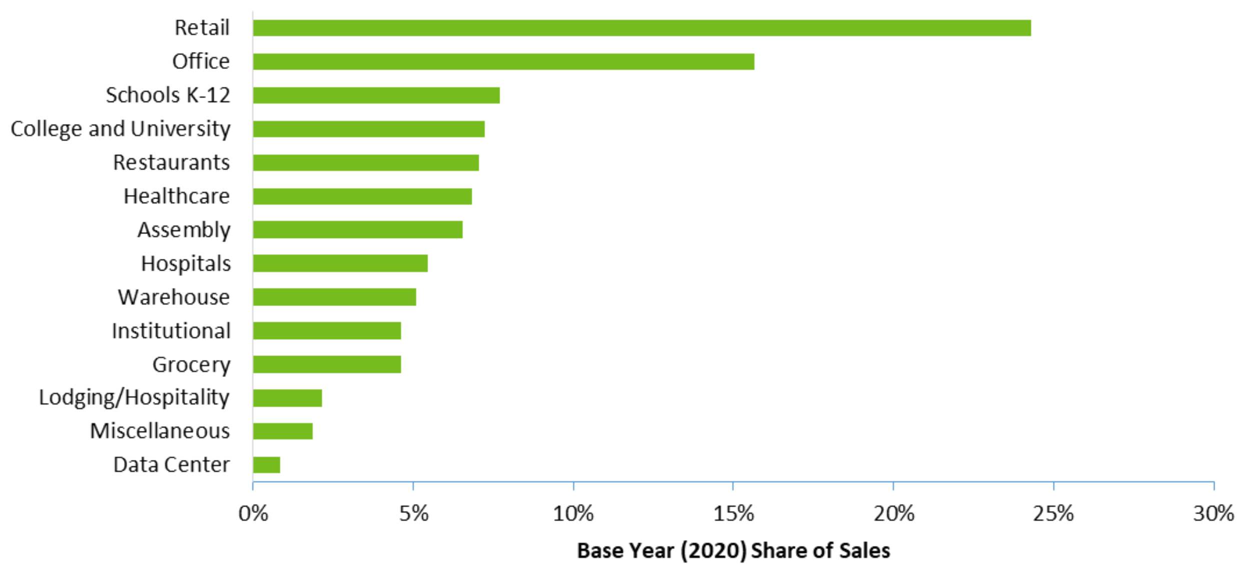
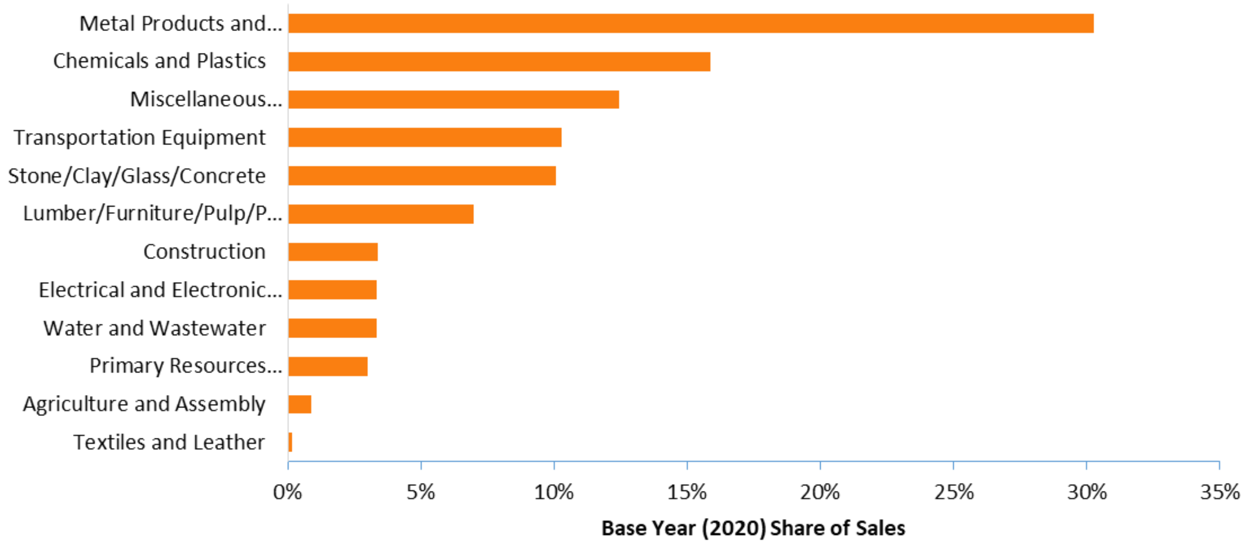


Figure 3-2: Customer Segmentation by Industrial Segment



3.2.1.2 Peak Energy Demand Categories

For the demand response analysis, Nexant divided the non-residential customers into the two customer classes of 'Small/Medium Business' (SMB) and 'Large C&I' using rate class and annual consumption. For the purposes of this analysis, 'SMB' customers are commercial accounts included in Duke Energy's load research sample.[11] Large C&I customers are all customers with a peak demand greater than 500 kW, for whom DEI has interval meter data (hourly).

Table 3-3 shows the account breakout between SMB and large C&I.

Table 3-3: Summary of DEI Customer Classes

Customer Class	Tariff	Peak kW	Number of Accounts
SMB	CS	All	70,832
	HLF	Primary, Tx, Secondary <=500kw	3,880
	LLF	Primary, Tx, Secondary <=500kw	29,291
	TEC	Primary, Tx, Secondary <=500kw	232
		Total	**104,235**
Large C&I	LLF	Primary, Tx, Secondary >500kw	396
	HLF	Primary, Tx, Secondary >500kw	408
	TEC	Primary, Tx, Secondary >500kw	23
		Total	**827**

[11] This level of consumption corresponded to the upper bound of the first usage stratum (out of 3) for the load research sample.

Nexant segmented both the SMB and Large C&I customer classes using Standard Industry Classification (SIC) codes, which Duke Energy provided as part of the customer data. Nexant aggregated the SMB segments into five overall segments, as shown in Table 3-4. This aggregation allowed for adequate sample sizes in each segment when modeling cooling and heating load. Aggregating was not necessary for the Large C&I segment and Table 3-5 shows the size of each segment by number of customer accounts.

Table 3-3: Summary of DEI SMB Segment

Segment	Number of Accounts
Healthcare/Hospitals	3,994
Offices	37,500
Retail Stores	9,470
Wholesale, Transportation & Utilities	18,997
Other	34,274
Total (unadjusted)	**104,235**
Total (adjusted for DR Participation)	**96,866**
“Other” Includes:	
Agriculture, Forestry & Fishing	1,385
Mining & Construction	4,180
Manufacturing	5,997
Schools	1,757
Institution / Government	3,752
Other or Unknown	5,804
Restaurants	4,158
Lodging (Hospitality)	857
Assembly	5,559
Grocery	825

Table 3-5: Summary of DEI Large C&I Segment

Segment	Summer Peak
Agriculture, Forestry & Fishing	5
Chemicals & Plastics	59
Colleges & Universities	20
Construction	19
Electrical & Electronic Equipment	17
Grocery Stores	9
Healthcare	26
Hospitals	36
Institution/Government	21
Large Public Assembly	2
Lodging (Hospitality)	5
Lumber, Furniture, Pulp & Paper	21
Metal Products & Machinery	101
Misc. Manufacturing	44
Retail	67
Misc (Offices, Other, Unk)	95
Primary Resource Industries	31
Schools K-12	91
Stone, Clay, Glass & Concrete	15
Textiles & Leather	2
Transportation Equipment	43
Warehouse, Transport & Other Utilities	81
Water & Wastewater	17
Total (Unadjusted)	**827**

3.2.2 Residential Accounts

Segmentation of residential customer accounts enabled Nexant to align DSM opportunities with appropriate DSM measures. Nexant segmented the residential sector according to two fields provided in the Duke Energy data: customer dwelling type (single family, multi-family or “unknown”), and space heat fuel source (electric, gas, and “other”). The resulting distribution of customers and total electricity consumption by each segment is presented below in Table 3-4 and Table 3-5. Figure 3-3 and Figure 3-4 present this information graphically.

Table 3-4: DEI Residential Customer Market Composition by Heating Fuel Source

Attribute	Electricity	Gas
Customer Count	18.88%	81.12%
Total kWh Consumption	21.75%	78.25%

Table 3-5: DEI: Residential Market Characteristics by Type of Dwelling Unit

Attribute	Single Family	Multi-Family
Customer Count	78.31%	21.69%
Total kWh Consumption	85.23%	14.77%

Figure 3-3: DEI Residential Market Segmentation by Space Heat Fuel Source

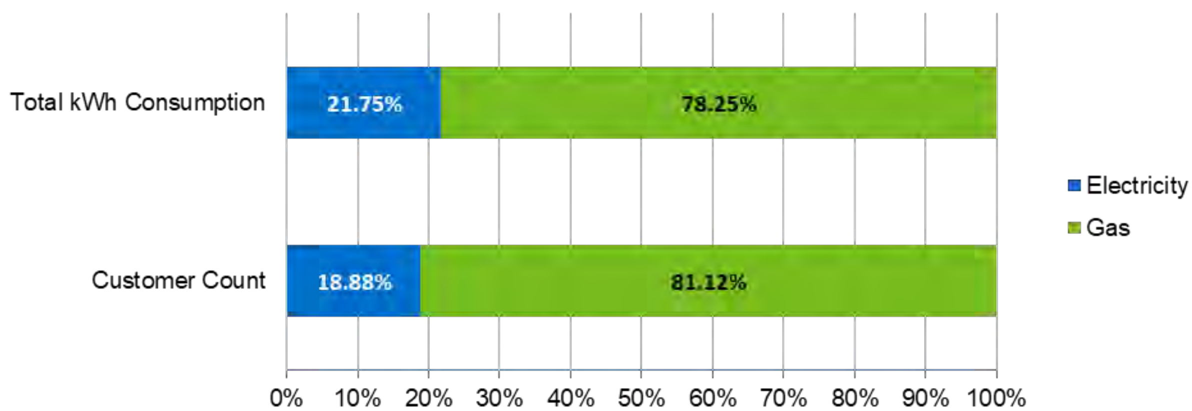
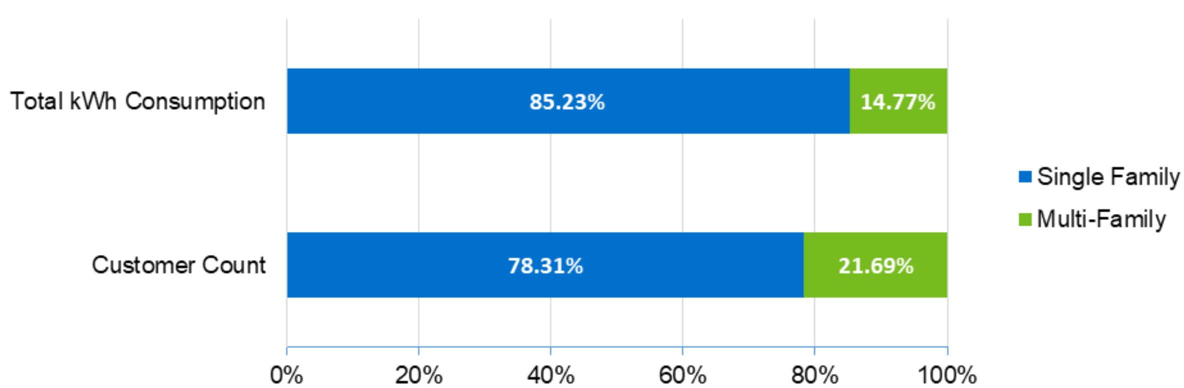


Figure 3-4: DEI Residential Market Segmentation by Space Heat Fuel Source



The DR assessment required the use of interval data to estimate the loads associated with space cooling, space heating, water heating, and pool pumps. For this study, interval data were available from DEI's load research sample, which included whole building data from a sample of 217 premises.

The residential sector was segmented into three different bins based on annual consumption. Within each of these customer segments, heating and cooling load profiles were estimated. The residential customer segments were further segmented between customers who had electric heating and gas heating (i.e., customers who do not have a controllable load during winter peaks), producing a total of six residential customer segments. Cooling loads for electric and gas heating customers were assumed to be identical for each of the corresponding consumption bins.

3.3 DEI Base Year 2020 Disaggregated Load

The DEI's disaggregated loads for the base year 2020 by sector and end use are summarized in Figure 3-5,

Figure 3-6 and

Figure 3-7. Load disaggregation is based on Duke Energy end use forecast data. The following supplemental data sources were used by Nexant to disaggregate each sector's loads:

- Residential load disaggregation is based on Duke Energy's estimates of residential end use load shares; this information in turn is derived from the EIA Residential End Use Consumption Survey (RECS), vintage 2015.
- Commercial load disaggregation is based on the Commercial Building Energy Consumption Survey (CBECS), vintage 2012.
- Industrial load disaggregation is based on Manufacturers' Energy Consumption Survey (MECS), vintage 2014.

The data provided by these products represents the best available secondary data sources for end use consumption within each economic sector.

Figure 3-5: DEI Residential Baseline (2020) Sales by End Use

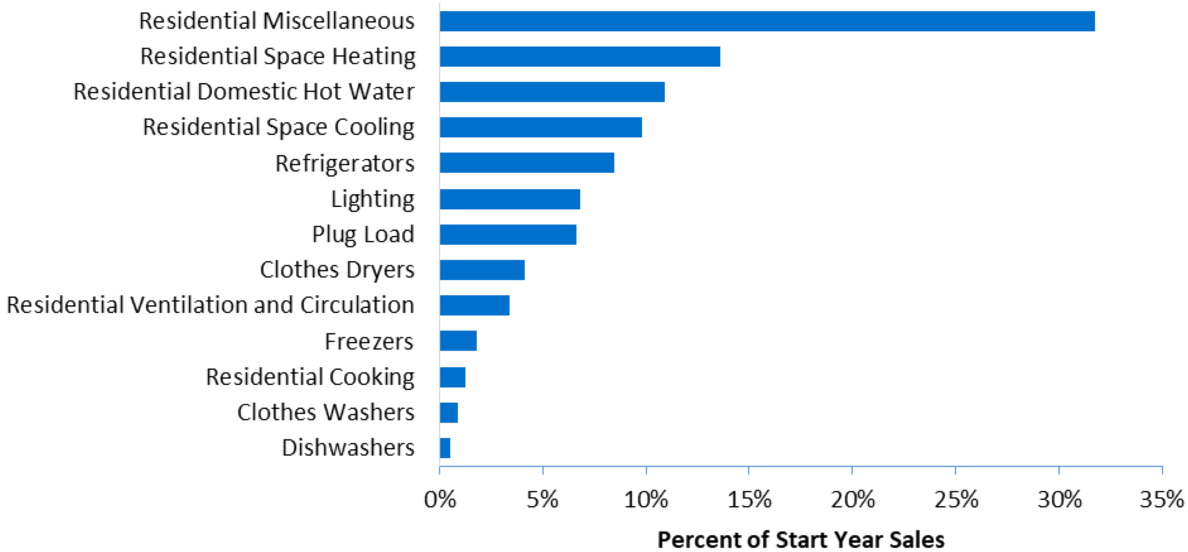


Figure 3-6: DEI Commercial Baseline (2020) Sales by End Use

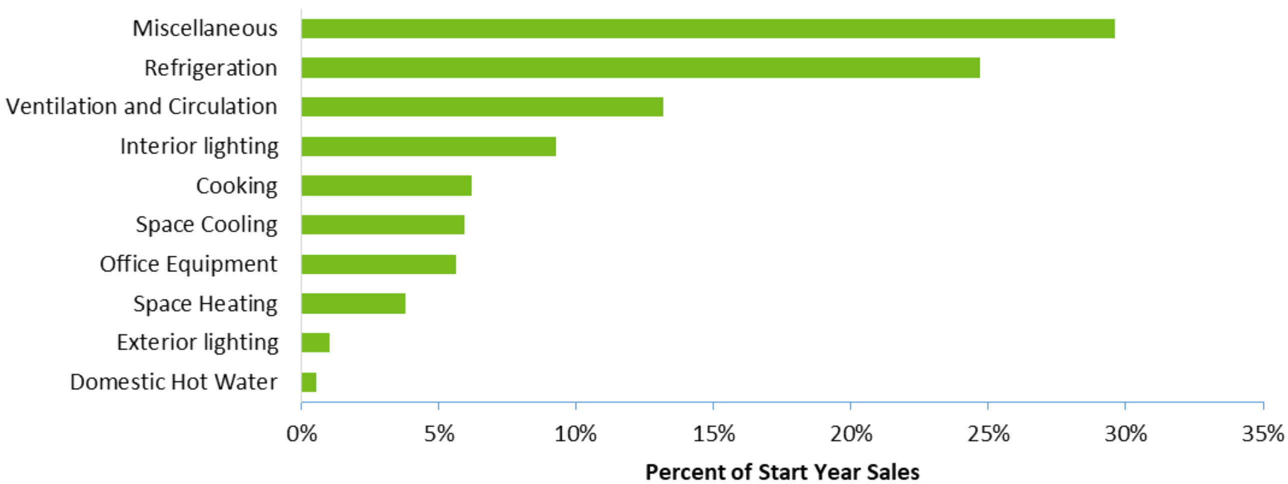
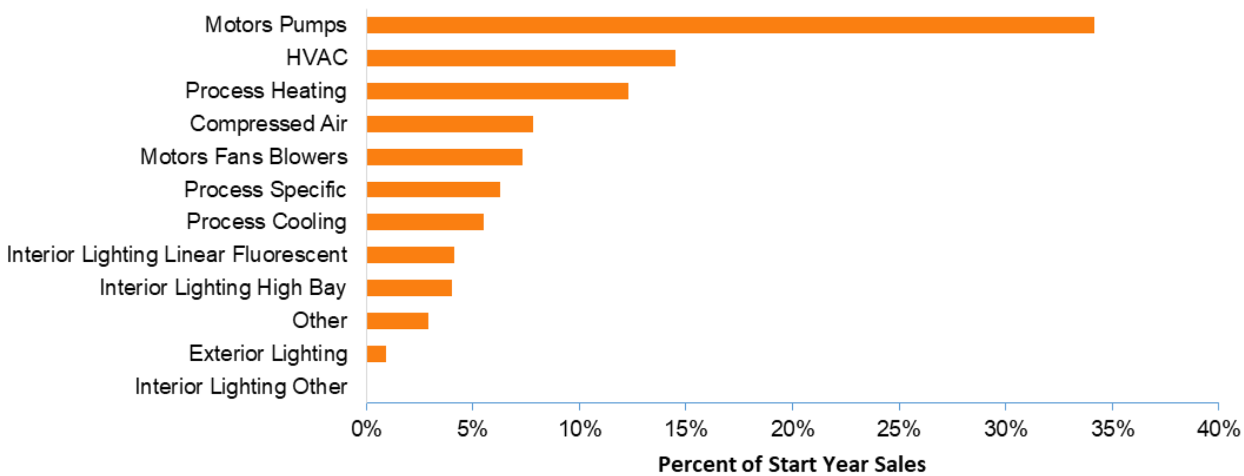


Figure 3-7: DEI Industrial Baseline (2020) Sales by End Use



In the base year 2020, the DEI top load share categories are:

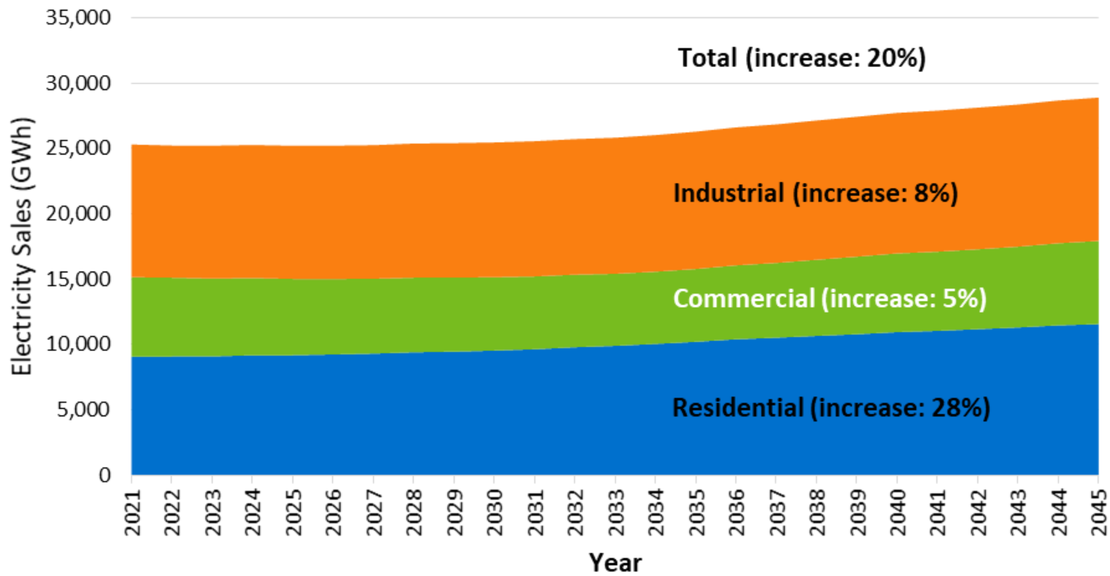
- ***Residential:*** miscellaneous, space heating and domestic hot water.
- ***Commercial:*** miscellaneous, refrigeration, and ventilation and circulation.
- ***Industrial:*** motors pumps, HVAC, and process heating.

3.4 DEI System Load Forecast 2021 - 2045

3.4.1 DEI System Energy Sales

DEI electricity use is forecasted to increase by 3,584 GWh (a change of 20%) from 2021 to 2045, to a total of 28,886 GWh in 2045 (see Figure 3-8). The residential sector is expected to account for the largest share of the increase, growing by 2,500 GWh to reach 11,560 GWh (an increase of 28%) over the 25-year period. The commercial sector is expected to increase by 276 GWh to reach 6,363 GWh (an increase of 5%) over the 25-year period. The industrial sector is forecasted to increase by 808 GWh to reach 10,963 GWh (an increase of 8%) in 2045. In 2045 the residential sector accounts for 40% (11,560 GWh) of total electricity sales, the industrial sector 38% (10,963 GWh) and the commercial sector 22% (6,363 GWh). These forecasts do not include the expected future impacts of planned EE and DSM technologies.

Figure 3-8: DEI Electricity Sales Forecast by Sector for 2021 - 2045[12]



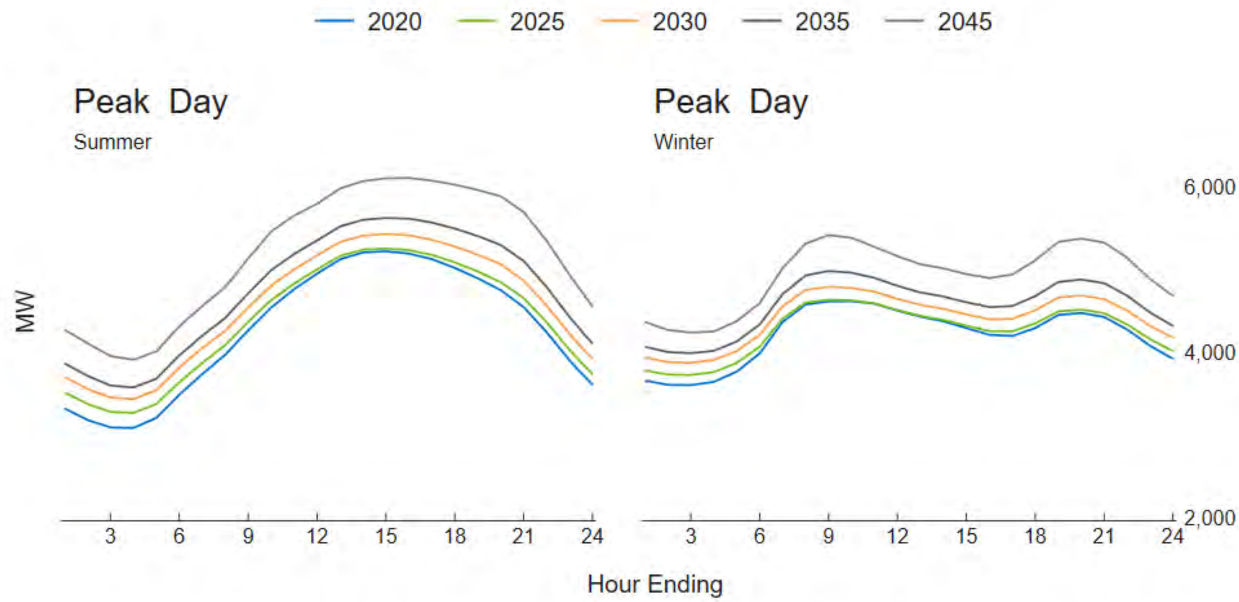
3.4.2 DEI System Demand

Estimating technical potential for demand response resources requires knowing how much load is available to be curtailed or shifted during system peak demand conditions. Demand response benefits accrue from avoiding costly investments to meet peak loads; load reductions will not have any value unless they occur during hours of peak system usage. Market potential for demand response is based on when load reductions will most likely be needed throughout the year.

The primary data source used to determine when demand response resources will be needed was the DEI system load forecast. This forecast contains forecasted loads for all 8,760 hours of each year in the study period (2020-2045). Figure 3-9 represents an initial inspection of the data. Each figure shows the expected average load profiles for two distinct types of days: peak summer days and peak winter days. Summer was defined as June-September and winter as November-February, while the peak days refer to the day with the maximum demand during the year and season.

[12] Sales forecast based on DEI Summer 2020 forecast—the current forecast at the time of Nexant's analysis. Forecasts represent expected energy sales before applying future energy efficiency reductions, but includes energy efficiency reductions from previous years' DSM programs.

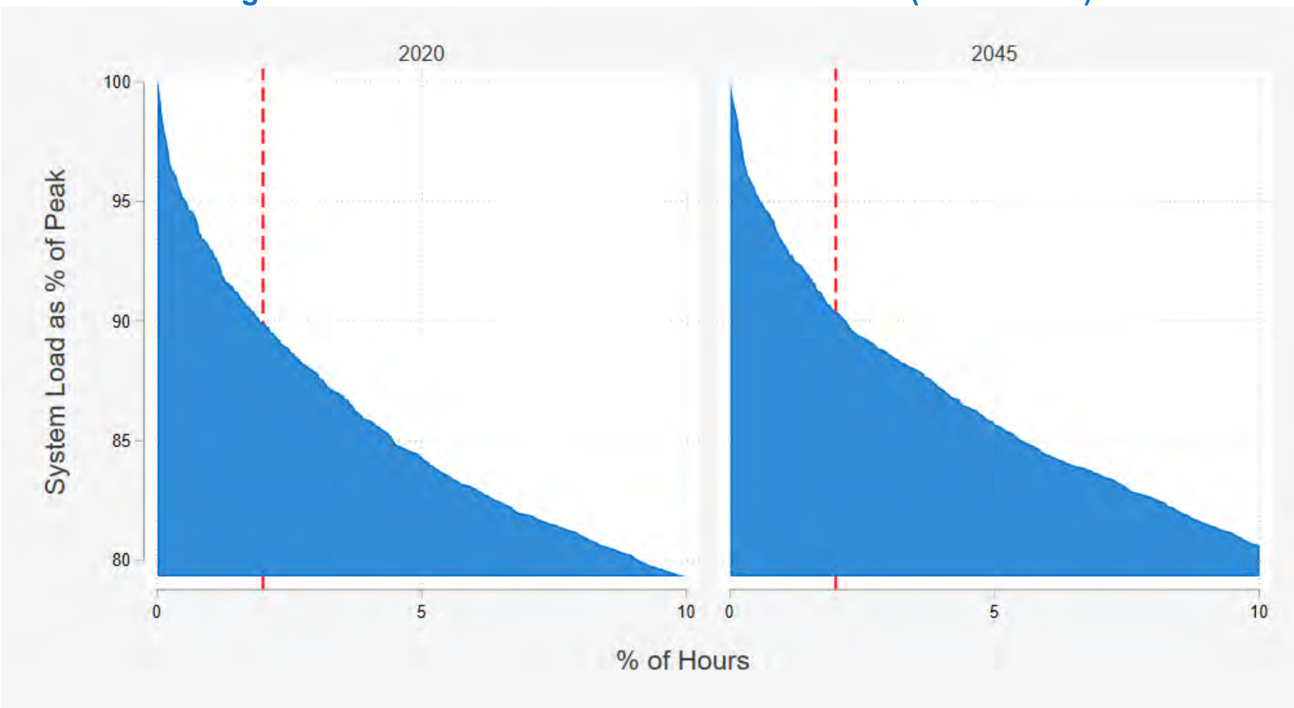
Figure 3-9: DEI System Load Forecast (2020 – 2045)



Several patterns are apparent from examining the figure above. As system load grows over time, the peak hour during winter is forecasted to change slightly from 9-10 am in 2020 to 7-8 pm by 2045. Summer loads are substantially higher than winter loads. However, the forecasted shifts have a high degree of uncertainty. Thus, the potential study focuses on the current summer peak hour, 3-4 pm, and the current winter peak hour, 9-10 am.

Though useful for assessing patterns in system loads, Figure 3-9 does not provide very much information about the concentration of peak loads. A useful tool to examine peak load concentration is a load duration curve, which is presented for 2020 and 2045 in Figure 3-10 . This curve shows the top 10% of hourly loads as a percentage of the system's peak hourly usage, sorted from highest to lowest.

Figure 3-10: DEI Forecasted Load Duration Curve (2020 v 2045)



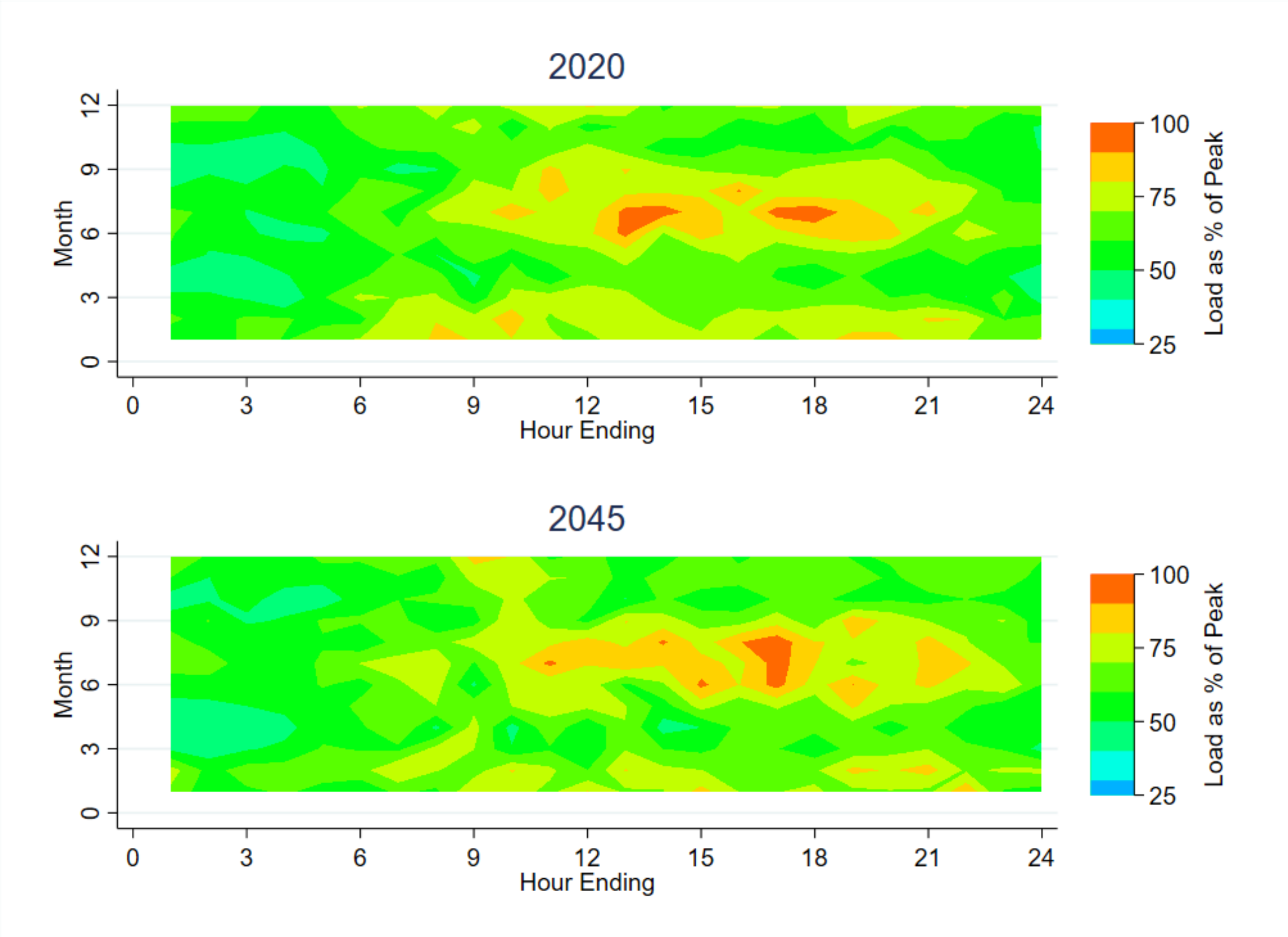
The x-axis in Figure 3-10 is depicted as the cumulative percentage of hours. The red line drawn at 2% serves as a helpful reference point for interpretation by showing the amount of peak capacity needed to serve the 2% of hours with the highest usage.[13] The DEI system currently uses 11% of peak capacity to serve only 2% of hours. Peak loads, however, are projected to become less concentrated by 2045 and use 8% of peak capacity to serve the top 2% of hours.

Another valuable tool for studying peak loads is a contour plot. Often referred to as "heat maps", these plots show frequencies or intensities of a variable for different combinations of two other variables. Figure 3-11 contains the same hourly data as a percentage of peak system load that is presented in Figure 3-10; however, it shows the months and hours when each hourly load occurs for all hours instead of only the top 10% of hours.

The results in Figure 3-11 show the highest hours of usage are concentrated in summer evening hours. Actual weather patterns reflect year to year variation in loads and depending on the extreme temperatures for a year, winter peaks can still be of concern. Another consideration is market prices, which can be high in winter if natural gas is used both for heating and electricity generation.

[13] Another interpretation of the load duration curve data would be the amount that peak load capacity could be reduced by shaving demand during 2% of the hours throughout the year.

Figure 3-11: Forecasted Patterns in DEI System Load (2020 vs 2045)



3.4.3 Customer Opt-Outs

Duke Energy's energy efficiency programs in Indiana include an "opt-out" provision approved by the Indiana Utility Regulatory Commission. This provision allows non-residential customers receiving electric service at a single site, with at least one meter constituting more than 1 megawatt of electric capacity to opt out, along with all accounts in contiguous property. This opt-out provision exempts the customer from cost recovery mechanism but also eliminates that customer's eligibility for participation in the program.

For this study, technical and economic potential did not consider the impacts of customer opt-outs. For the achievable program potential analysis, Duke provided Nexant with current opt-out information in Indiana, which showed an opt-out rate of approximately 37.4% of commercial kWh sales and 86.4% of industrial kWh sales in the DEI service territory. Nexant incorporated this opt-out rate into the model by reducing the non-residential sales estimates by the appropriate percentage and applying the applicable energy efficiency technologies and market adoption rates to the remaining sales forecast. As an additional sensitivity, the achievable program potential was calculated with the full sales forecast, inclusive of customers that are currently opted out. Results of these sensitivities are provided in Section 7.4.

4 DSM Measure List

Determining the list of demand-side management (DSM) measures to include in the MPS was a key effort in estimating the market potential. This section presents the methodology to develop the measure list and discusses the energy efficiency and demand response services and products.

Nexant maintains a database of energy efficiency measures for use in MPS studies. Measure data are developed and refined as new information on, or methods for, estimating measure impacts become available. The current list of savings opportunities, or “measures,” incorporated the measure list that used in the 2018 MPS study Nexant conducted on behalf of Duke Energy Indiana but removed old measures and added new measures where conditions changed. An example of measure list updates is that Nexant consolidated the lighting opportunities by excluding all CFLs and metal halides but keeping the LEDs to better reflect market trends. This section describes how the measure data is developed and applied in the study for energy efficiency and DSM services and products.

4.1 Methodology

Nexant identified measures for consideration in the MPS by initially reviewing the measure list used for three sectors in the 2018 Indiana MPS study, comparing it with measure lists that Nexant has used for other recent MPS, and then comparing it with the technologies listed in the 2015 Indiana Technical Reference Manual, to develop an initial qualitative screening for applicability in the DEI territory. Then Nexant compared the measure list with those in the other five regional Technical Reference Manuals (TRMs) (i.e. Illinois, Iowa, Michigan, Wisconsin, and Minnesota) to make sure the measure list covers comprehensive technologies in the region.

Nexant developed measure base and efficient case descriptions by researching other recent MPS, TRMs, codes and standards. Necessary updates were conducted to make sure that baseline descriptions are aligned with current codes and standards for Indiana. Measure end use intensities (EUIs) were developed by reviewing six states’ TRMs in the region, and other sources when a measure’s end use life (EUL) information could not be found in any of the six TRMs.

The final measure list covered a robust and comprehensive set of measures that included energy efficiency technologies and products that enable DSM opportunities. DSM initiatives that do not rely on installing a specific technology or measure (such as a voluntary curtailment program) are not reflected in the measure list. See Appendix A for the final measure list.

4.2 Energy Efficiency Measures

Nexant’s measure data represents savings opportunities for all electricity end uses and customer types. EE program measure offers are typically more specific than those required to assess EE potential. For example, Duke Energy programs have multiple instances of LED lamps with varying characteristics (candelabra base, globe base, A-line, etc.). Although these distinctions are important during program delivery, this level of granularity is not necessary to identify the market potential for EE savings.

Nexant used a qualitative screening approach to address the applicability of measures to the Indiana service territory. The qualitative screening criteria that Nexant used included: difficult to quantify savings, no longer current practice, better measure available, immature or unproven technology, limited applicability, poor customer acceptance, health and environmental concerns, and end-use service degradation.

Nexant updated its online measure database to support this study. Nexant's database contains the following information for each measure:

- Classification of measure by type, end use, and subsector
- Description of the base-case and the efficiency-case scenarios
- Measure life
- Savings algorithms and calculations per subsector, taking weather zones and subsectors into consideration
- Input values for variables used to calculate energy savings
- Measure costs
- References and supporting information
- Output to be used as input in Nexant's TEA-POT model.

Detailed measure assumptions in this database are provided to Duke Energy in supplemental electronic files, MS Excel format. As shown in Table 4-1, the study included 383 unique energy-efficiency measures. Expanding the measures to account for all appropriate combinations of segments, end uses, and construction types resulted in 10,698 measure permutations.

Table 4-1: EE Measure Counts by Sector

Sector	Unique Measures	Permutations
Residential	110	1,022
Commercial	160	6,358
Industrial	113	3,318

4.3 DR Services and Products

Nexant and Duke Energy worked together to determine which DR products and services were included in the MPS, and addressed the following:

- **Direct load control.** Customers receive incentive payments for allowing the utility a degree of control over equipment, such as air conditioners or water heaters
- **Emergency load response.** Customers receive payments for committing to reduce load if called upon to do so by the grid operator
- **Economic load response:** Utilities provide customers with incentives to reduce energy consumption when marginal generation costs are higher than the incentive amount required to achieve the needed energy reduction
- **Base interruptible DR**. Customers receive a discounted rate for agreeing to reduce load to a firm service level upon request
- **Automated DR.** Utility dispatched control of specific end-uses at customer facilities

5 Technical Potential

Technical potential is based on base year load shares and reference case load forecasts for 2021 to 2045. This information, along with data on measures available to capture savings opportunities provide inputs for estimating technical potential. The technical potential scenario estimates the savings potential when all technically feasible energy efficiency measures are fully implemented, while accounting for equipment turnover. This savings potential can be considered the maximum reduction attainable with available technology and current market conditions (e.g. currently available technology, building stock, customer preferences as reflected in Duke Energy forecasted sales). EE and DR potential scenarios that account for measures' costs and benefits and market adoption are discussed in subsequent report sections for economic potential and achievable potential, respectively.

5.1 Methodology

5.1.1 Energy Efficiency

Energy efficiency technical potential provides a theoretical maximum for electricity savings. Technical potential ignores all non-technical constraints on electricity savings, such as cost-effectiveness and customer willingness to adopt energy efficiency. For an electricity potential study, technical potential refers to delivering less electricity to achieve the same end uses. In other words, technical potential might be summarized as "doing the same thing with less energy, regardless of the cost."

The potential estimate applied DSM measures to the disaggregated DEI electricity sales forecasts to estimate technical potential. Specifically, this involved applying estimated energy savings from equipment or non-equipment measures to all electricity end uses and customers. Since technical potential does not consider the costs or time required to achieve these electricity savings, the estimates provide an upper limit on savings potential. Technical potential consists of the total electricity that can be saved in the market. Nexant reported technical potential as a single numerical value for the DEI service territory.

The core equation used in the residential sector energy efficiency technical potential analysis for each individual efficiency measure is shown in Equation 5-1 below, while the core equation used in the nonresidential sector technical potential analysis for each individual efficiency measure is shown in Equation 5-2 below.

Equation 5-1: Core Equation for Residential Sector Technical Potential

$$\text{Technical Potential of Efficient Measures} = \text{Total Number of Households} \times \text{Base Case Equipment Energy Use Intensity (kWh/unit)} \times \text{Saturation Share} \times \text{Remaining Factor} \times \text{Applicability Factor} \times \text{Savings Factor}$$

Where:

Base Case Equipment Energy Use Intensity = the electricity used per customer per year by each base-case technology in each market segment. In other words, the base case equipment energy-use intensity is the consumption of the electrical energy using equipment that the efficient technology replaces or affects.

Saturation Share = the fraction of the end-use electrical energy that is applicable for the efficient technology in a given market segment. For example, for residential water heating, the saturation share would be the fraction of all residential electric customers that have electric water heating in their household.

Remaining Factor = the fraction of equipment that is not considered to already be energy efficient. To extend the example above, the fraction of electric water heaters that is not already energy efficient.

Applicability Factor = the fraction of units that is technically feasible for conversion to the most efficient available technology from an engineering perspective (i.e., it may not be possible to install CFLs in all light sockets in a home because the CFLs may not fit in every socket).

Savings Factor = the percentage reduction in electricity consumption resulting from the application of the efficient technology.

Equation 5-2: Core Equation for Nonresidential Sector Technical Potential

$$\text{Technical Potential of Efficient Measures} = \text{Total Stock Sq. Footage by Building Type by EDC} \times \text{Base Case Equipment Energy Use Intensity (kWh/unit)} \times \text{Equipment Saturation Share} \times \text{Remaining Factor} \times \text{Applicability Factor} \times \text{Savings Factor}$$

Where:

Total Stock Square Footage by Building Type = the forecasted square footage level for a given building type (e.g., square feet of office buildings).

Base Case Equipment Energy Use Intensity = the electricity used per square foot per year by each base-case equipment type in each market segment. In other words, the base case equipment energy-use intensity is the consumption of the electrical energy using equipment that the efficient technology replaces or affects.

Equipment Saturation Share = the fraction of total end use energy consumption associated with the efficient technology in a given market segment. For example, for room air conditioners, the saturation share would be the fraction of all space cooling kWh in a given market segment that is associated with room air conditioner equipment.

Remaining Factor = the fraction of equipment that is not considered to already be energy efficient. For example, the fraction of electric water heaters that is not already energy efficient.

Applicability Factor = the fraction of the equipment or practice that is technically feasible for conversion to the efficient technology from an engineering perspective (i.e., it may not be possible to install VFDs on all motors in a given market segment).

Savings Factor = the percentage reduction in electricity consumption resulting from the application of the efficient technology.

It is important to note that the technical potential estimate represents electricity savings potential at a specific point in time. In other words, the technical potential estimate is based on data describing *status quo* customer electricity use and technologies known to exist today. As technology and electricity consumption patterns evolve over time, the baseline electricity consumption will also change accordingly. For this reason, technical potential is a discrete estimate of a dynamic market. Nexant reported technical potential at a given point in time, based on currently known DSM measures and observed electricity consumption patterns.

Addressing Naturally Occurring Energy Efficiency

Because the anticipated impacts of efficiency actions that may be taken even in the absence of utility intervention are included in the baseline forecast, savings due to naturally occurring efficiency were considered separately in the potential estimates. Nexant worked with Duke Energy's forecasting group to ensure that the sales forecasts incorporated two known sources of naturally occurring efficiency:

- **Codes and Standards:** The sales forecasts incorporated the impacts of known code changes. While some code changes have relatively little impact on overall sales, others—particularly other federal legislation such as code change on residential HVAC —will have noticeable influence.
- **Baseline Measure Adoption:** Sales forecasts typically exclude the projected impacts of future DSM efforts, but account for baseline efficiency penetration that is anticipated to occur outside of DSM program offerings (as reflected in historical trends)

By properly accounting for these factors, the potential study estimated savings that result from utility DSM efforts beyond the "business as usual" adoption rates absent DSM intervention. This is true even in the technical and economic scenarios, where adoption was assumed to be 100%, and was particularly important in the achievable potential analysis, where Nexant estimated the measure adoption and associated savings that can be expected to occur relative to the baseline forecast.

5.1.2 Demand Response

The concept of technical potential applies differently to demand response than for energy efficiency. Technical potential for demand response is effectively the magnitude of loads that can be managed during conditions when grid operators need peak capacity, ancillary services, or when wholesale energy prices are high. Which accounts are consuming electricity at those times? What end-uses are in play? Can those end use loads be managed? Large C&I accounts generally do not provide the utility with direct control over end-uses. However, businesses will forego virtually all electric demand temporarily if the financial incentive is large enough. For residential and small C&I accounts where DR generally takes the form of direct utility control, technical potential for demand response is limited by the loads that can be controlled remotely at scale.

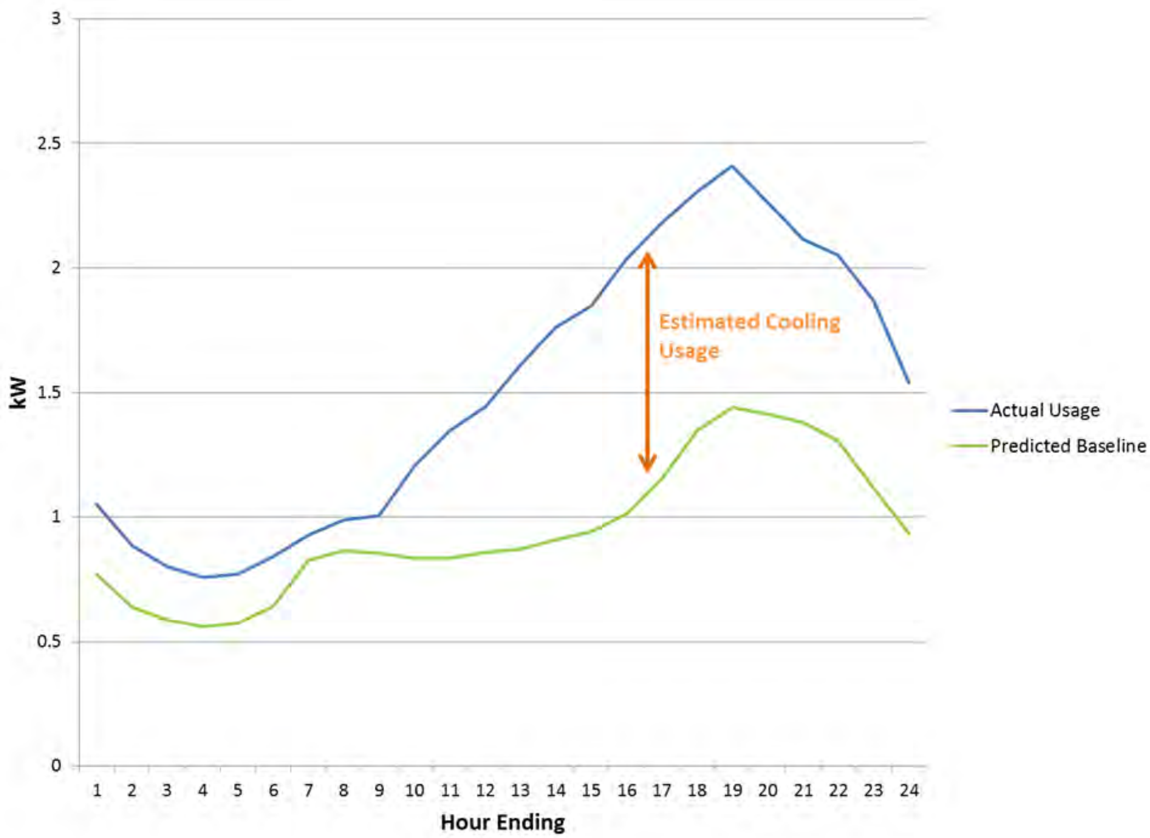
This framework makes end use disaggregation an important element for understanding DR potential, particularly in the residential and SMB sectors. As the technology to actively manage loads becomes more advanced over the study horizon, accurate end-use disaggregation will be increasingly important. When done properly, end-use disaggregation not only provides insights into which loads are on and off when specific grid services are needed, it also provides insight concerning how key loads and end-uses, such as air conditioning use, vary across customers. The approach used for load disaggregation is more advanced than what is used for most potential studies. Instead of disaggregating annual consumption or peak demand, Nexant produced end-use load disaggregation for all 8760 hours. This was needed because the loads available at times when different grid applications are needed can vary substantially. Instead of producing disaggregated loads for the average residential customers, the study was produced for several customer segments, thereby allowing the study to identify which customers were cost-effective to recruit and which were not.

Nexant used interval data for all large C&I customers, interval data from a load research sample for SMB and residential customers. Technical potential, in the context of DR, is defined as the total amount of load available for reduction that is coincident with the period of interest. In the context of this study, DR capacity is defined as the system peak hour for the summer and winter seasons. Thus, two sets of capacity values are estimated: a summer capacity and a winter capacity.

As previously mentioned, all large C&I load is considered dispatchable, while residential and SMB DR capacity is based on specific end uses. For this study, it was assumed that summer DR capacity for residential customers would be comprised of AC, pool pumps, and water heaters. For SMB customers, summer capacity would be based on AC load. For winter capacity, residential DR capacity would be based on electric heating loads and water heaters. For SMB customers, winter capacity would be based on heating load.

AC and heating load profiles were generated for residential and SMB customers using the load research sample provided by Duke Energy. The aggregate load profile for each customer class was combined with historical weather data and used to estimate hourly load as a function of weather conditions. AC and heating loads were estimated by first calculating the baseline load on days when cooling degree days (CDD) and heating degree days (HDD) were equal to zero, and then subtracting this baseline load. This methodology is illustrated by Figure 5-1 (a similar methodology was used to predict heating loads).

Figure 5-1: Methodology for Estimating Cooling Loads



This method was able to produce estimates for average AC/heating load profiles for several different customer segments within the residential and SMB sectors. Residential customers were segmented into three different groups based on annual energy consumption, while SMB customers were segmented into five segments based on industry NAICS codes. Profiles for residential water heater and pool pump loads were estimated by utilizing end use load data from DEI.

For all eligible loads, the technical potential was defined as the amount that was coincident with system peak hours for each season. System peak hours were identified using 2019 system load data. The 2019 summer peak for DEI territory occurred July 18th during hour ending 16. The 2019 winter peak for DEI territory occurred January 29th during hour ending 10.

5.2 DEI Energy Efficiency Technical Potential

This section provides the results of the DEI energy efficiency technical potential for each of the three segments.

5.2.1 Summary

Table 5-1 summarizes the energy efficiency technical potential by sector and levelized cost associated with the identified potential. Nexant calculated levelized cost as the discounted sum of incremental cost over the study period divided by the discounted sum of lifetime energy savings over the period:

Table 5-1: DEI Energy Efficiency Technical Potential by Sector

Sector	Technical Potential (2021-2045)				
	Energy (GWh)	% of 2044 Base Sales	Demand (MW)		Levelized Cost ($/kWh)
			Summer	Winter	
Residential	3,844	33%	581	580	$0.21
Commercial	2,156	34%	328	284	$0.23
Industrial	3,317	30%	452	444	$0.10
Total	**9,318**	**32%**	**1,362**	**1,308**	**$0.18**

5.2.2 Sector Details

Figure 5-2 summarizes the DEI residential sector energy efficiency cumulative technical potential by end use.

Figure 5-2: DEI Residential EE Technical Potential– Cumulative 2045 by End-Use

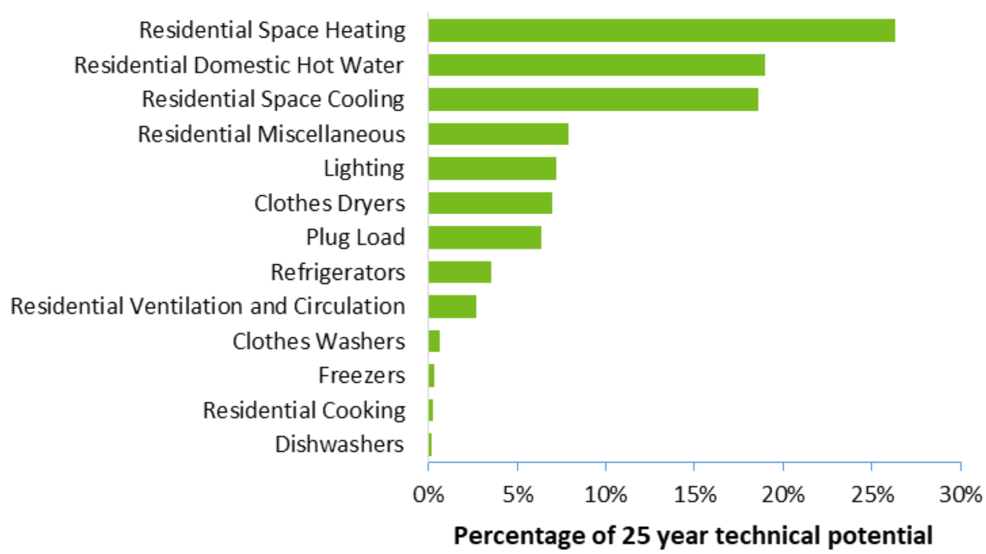


Figure 5-3 summarizes the DEI commercial sector energy efficiency cumulative technical potential by end use.

Figure 5-3: DEI Commercial EE Technical Potential – Cumulative 2045 by End-Use

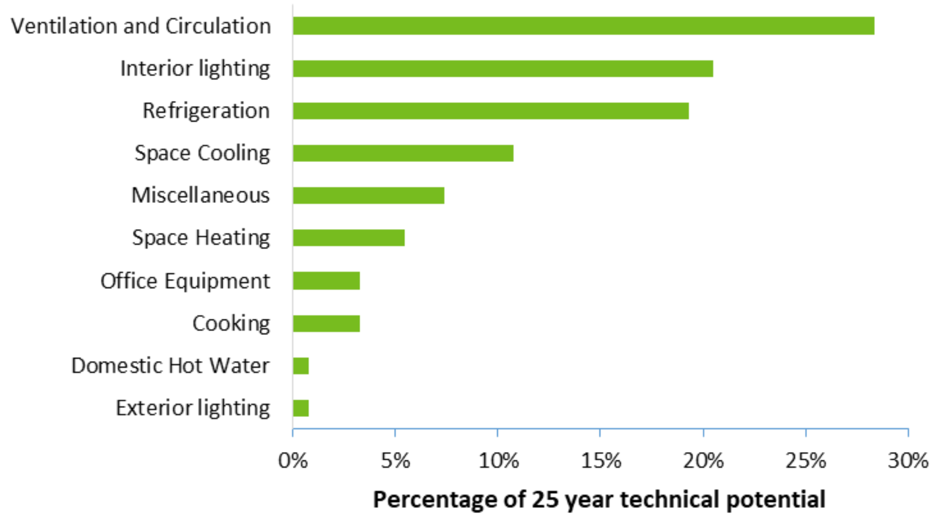


Figure 5-4 provides a summary of DEI energy efficiency technical potential contributions by commercial facility types analyzed in this study.

Figure 5-4: DEI Commercial EE Technical Potential Segment

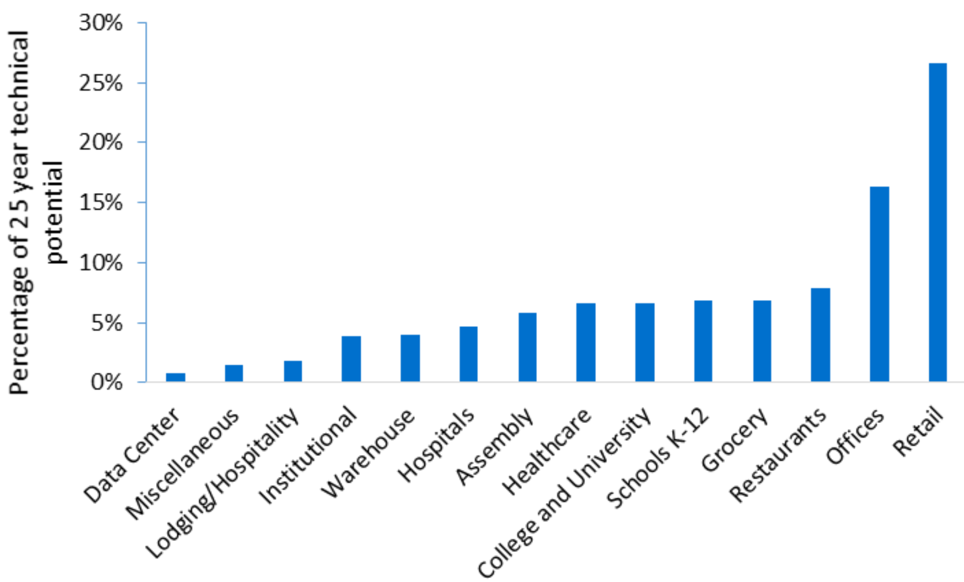


Figure 5-5 summarizes the DEI industrial sector energy efficiency cumulative technical potential by end use.

Figure 5-5: DEI Industrial EE Technical Potential – Cumulative 2045 by End-Use

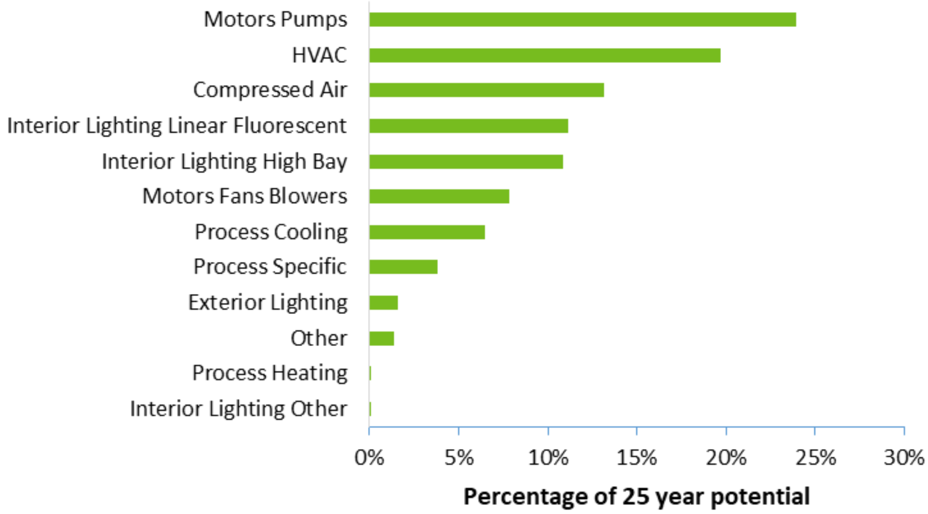
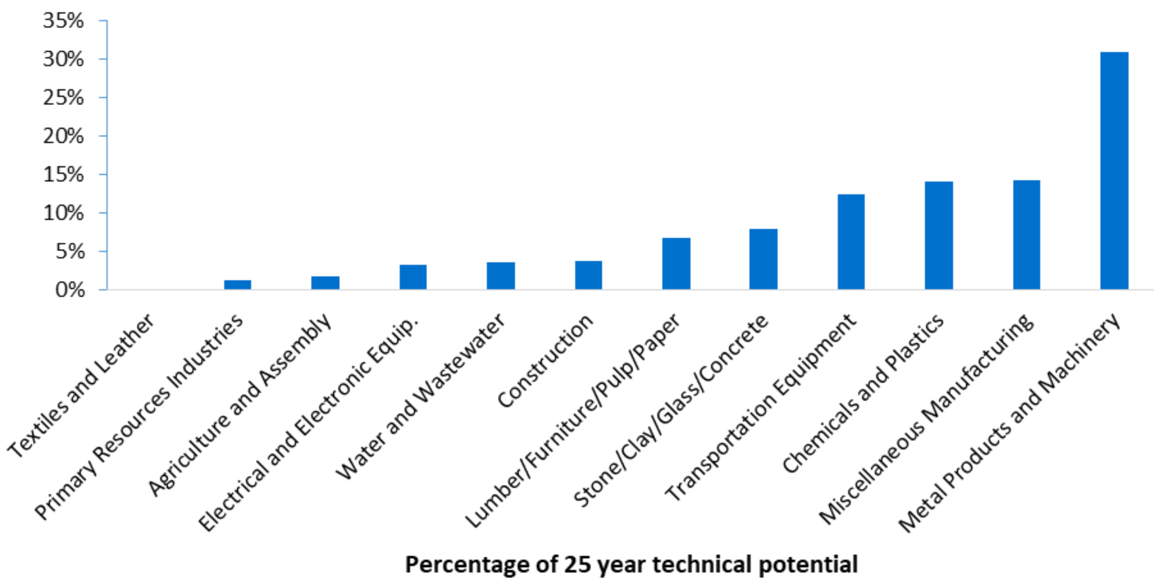


Figure 5-6 provides a summary of DEI energy efficiency technical potential contributions by industrial facility types analyzed in this study.

Figure 5-6: DEI Industrial EE Technical Potential Segment



5.3 DEI Controllable Peak Load, by Customer Type

Technical potential for demand response is defined for each class of customers as follows:

- **Residential & SMB customers** – Technical potential is equal to the aggregate load for all end uses that can participate in Duke Energy's current and planned demand response programs in which the utility uses specialized devices to control loads (i.e. direct load control programs). This includes AC/heating loads for residential and SMB customers, and water heater and pool pump load for residential customers. The magnitude of demand reductions from behavioral programs such as time varying pricing, peak time rebates and targeted notifications is linked to cooling and heating loads. While other end-uses may be curtailed, they are not well defined based on empirical studies.
- **Large C&I customers** – Technical potential is equal to the total amount of load for each customer segment. This reflects the contractual nature of most large C&I programs and the fact that for a large enough payment and small enough number of events, we assume large C&I customers would be willing to reduce their usage to zero.

Table 5-2 summarizes the seasonal demand response technical potential by sector:

Table 5-2: DR Technical Potential by Sector

Sector	Technical Potential (2020-2045)	
	Summer (Agg MW)	Winter (Agg MW)
Residential	1,510	742
SMB	354	252
Large C&I	1,038	825
Total	**2,902**	**1,819**

5.3.1 Residential and SMB Customers

Residential technical potential is summarized Table 5-3. The potential is broken down by end use and building type and excludes the existing 62.54 MW of DR capacity that is provided by the Power Manager program. A more detailed breakdown of the AC and heating loads by customer segment is provided in the economic potential section, along with the cost-effectiveness of each customer segment.

Table 5-3: Residential Demand Technical Potential (Incremental to Existing)

Customer Segment	Season	End Use	First Tertile Residential		Second Tertile Residential		Third Tertile Residential		Total (Adjusted)
			Avg. kw	Agg. MW	Avg. kw	Agg. MW	Avg. kw	Agg. MW	Agg. MW
Electric Heating	Summer	AC Cooling	1.14	53.3	1.92	90.3	2.52	118.2	**252.2**
	Winter	Heating	3.96	187.5	3.96	187.5	3.96	187.5	**562.5**
	Summer/Winter	Water Heater*	0.48	11.4	0.48	11.4	0.48	11.4	**34.1**
	Summer	Pool Pump**	1.11	1.5	1.11	1.5	1.11	1.5	**4.6**
Gas Heating	Summer	AC Cooling	1.14	225.5	1.92	382.1	2.52	500.0	**1,054.8**
	Winter	Heating	-	-	-	-	-	-	**-**
	Summer/Winter	Water Heater*	0.48	48.2	0.48	48.2	0.48	48.2	**144.5**
	Summer	Pool Pump**	1.11	6.5	1.11	6.5	1.11	6.5	**19.4**

*Based on public data from OpenEI

**Based on Duke Energy Pool Pump Load Shapes

Small business technical potential is provided in Table 5-4.

Table 5-4: SMB Demand Technical Potential

Segment	AC Cooling		Heating	
	Avg. kw	Agg. MW	Avg. kw	Agg. MW
Healthcare/Hospitals	8.93	31.02	193.09	41.52
Offices	4.01	93.91	55.42	63.24
Retail Stores	11.02	72.68	71.27	25.63
Wholesale, Transportation & Utilities	5.09	14.61	137.20	18.30
Other	16.88	149.41	414.16	103.52
Total		**353.99**		**252.20**

Overall, the bulk of the technical potential from these two sectors comes from residential cooling, space heating and water heating loads.

5.3.2 Large C&I Customers

Table 5-6 provides the technical potential for C&I customers, broken down by industry type. Most of the technical potential provided by large C&I customers comes from the largest class of customers.

The industries with the most technical potential are metal products and machinery, retail, chemicals and plastics, and warehouse, transport and non-water utilities.

Table 5-5: Large C&I Demand Technical Potential

Segment	Summer	Winter
Agriculture, Forestry & Fishing	2.0	2.2
Chemicals & Plastics	182.9	155.4
Colleges & Universities	75.4	48.7
Construction	15.0	14.2
Electrical & Electronic Equipment	41.0	38.5
Grocery Stores	5.5	3.3
Healthcare	17.0	14.8
Hospitals	50.4	31.2
Institution/Government	23.4	17.4
Large Public Assembly	0.7	0.5
Lodging (Hospitality)	1.0	1.1
Lumber, Furniture, Pulp & Paper	69.4	49.7
Metal Products & Machinery	310.3	314.3
Misc. Manufacturing	132.2	117.5
Retail	43.5	29.6
Misc (Offices, Other, Unk)	83.8	71.8
Primary Resource Industries	37.4	30.0
Schools K-12	43.1	38.2
Stone, Clay, Glass & Concrete	103.6	99.8
Textiles & Leather	2.2	2.2
Transportation Equipment	144.4	134.8
Warehouse, Transport & Non-Water Utilities	135.0	111.0
Water & Wastewater	8.8	8.6
Total	**1,038.3**	**825.5**

6 Economic Potential

Economic potential compares the expected costs and benefits of energy and demand savings provided by DSM measures and applies the Utility Cost Test (UCT) to determine whether measures meet the scenario screening criterion of a benefit-cost ratio greater than 1. The economic potential was the sum of the energy savings associated with all measure permutations passing the economic screening.

6.1 DSM Cost-Effective Screening Criteria

Based on the recommendation from the Indiana Utility Regulatory Commission (IURC) Oversight Board (OSB) and subsequent discussions with Duke Energy, the Utility Cost Test (UCT) test was used for the economic screening of energy efficiency measures in the MPS. The UCT is calculated by comparing the total avoided electricity production and delivery costs to the cost of utility-sponsored efforts to encourage the installation of that measure, inclusive of both incentive or customer rebate costs and non-incentive program costs, such as program management and administration, marketing and outreach, and evaluation costs.

Nexant used data provided by Duke Energy on the avoided cost benefits of energy efficiency measures or demand response services. Incentive and non-incentive (DSM program delivery and administrative costs) program costs were developed based on current Duke Energy program initiatives that align with the proposed MPS program offering. Nexant made assumptions about program incentive rates for measures that are not currently part of Duke Energy's portfolio of DSM offerings. Nexant used incentive rates for current programs to assign incentive rates for non-program measures and applied the UCT screening criterion.

For EE screening, the UCT test is applied to each energy efficiency measure based on installation of the measure in Year 1 of the study (i.e. avoided cost benefits begin in Year 1 and extend through the useful life of the measure; and estimated DEI incentive and administrative costs are also incurred in Year 1). By using DSMore outputs for lifetime avoided cost benefits, the screening aligns with Duke Energy's avoided cost forecast and allows for a direct comparison of measure costs with these avoided cost benefits. The screening included measures with a UCT ratio of 1.0 or higher for determining economic potential.

For DR screening, Nexant also used the UCT perspective, with the assumption that all technology costs and associated installation costs are borne by the utility rather than the customer. However, cost-effectiveness screening for DR potential is inherently of limited usefulness. Economic potential only answers the question, "Is a customer segment worth pursuing based on the marginal net benefits they provide?" Because DR capacity is determined by participation levels, which is in turn a function of the incentive level, a full cost-effectiveness screening cannot be performed without considering incentive levels, which is a key variable for the various scenarios of the program potential. As such, cost-effectiveness screening for the economic potential only considers non-incentive costs. In other words, customer segments are screened based on whether the marginal cost-effectiveness of enrolling a customer of that segment provides positive net benefits when only considering marketing, equipment, installation, and program operation costs.

For this analysis, the non-incentive costs for each sector is detailed in Table 6-1. These values are based on the costs assumed for a similar DR potential study conducted for SMUD and represent reasonable cost estimates in today's dollars with current technology. Economic potential screening is conducted using today's technology costs.

Table 6-1: Demand Response Non-Incentive Costs

	One-Time				Recurring (per year)
	Equipment	Installation	Acquisition Marketing	Other	Maintenance Marketing
Residential ($/customer)	$ 250.00	$ 200.00	$ 2.50	$ 4.50	$ 1.20
SMB ($/customer)	$ 300.00	$ 300.00	$ 20.00	$ 4.50	$ 1.20
Large C&I ($/MW)	$ 150.00		$ 10.00		

The cost of enrolling customers from each customer segment is compared to the marginal benefits provided by enrolling customers in that segment. Because DR programs are called relatively infrequently, very little benefit is derived from avoided energy costs, to the point where they are insignificant. Instead, DR derives its value from avoided generation capacity and avoided transmission and distribution capacity.

Forecasts of these values were provided by Duke Energy and formed the basis for the benefit calculations. Because these values were given as annual values, while this study aims to evaluate DR capacity for summer and winter separately, the annual avoided capacity values were allocated between summer and winter. To that end, capacity values were allocated between summer and winter seasons based on weighted percentage of top load hours (i.e. hours when load was within 20% of peak load) that occurred in summer and winter of 2016. Based on this analysis, 71.5% of the avoided capacity is associated with the summer season, with the remaining 28.5% allocated to winter.

6.2 DEI Energy Efficiency Economic Potential

This section provides the results of the DEI energy efficiency economic potential for each of the three segments.

6.2.1 Summary

Table 6-2 summarizes the DEI's energy efficiency economic potential by sector:

Table 6-2: DEI EE Economic Potential by Sector

Sector	Economic Potential (2020-2044)				
	Energy (GWh)	% of 2044 Base Sales	Demand (MW)		Levelized Cost ($/kWh)
			Summer	Winter	
Residential	2,672	23%	384	401	$0.04
Commercial	1,574	25%	249	217	$0.03
Industrial	2793	25%	386	382	$0.02
Total	**7,040**	**24%**	**1,020**	**1,000**	**$0.03**

While the UCT was utilized in this study for economic screening, the more common cost-effectiveness perspective used for economic potential in market potential studies is the Total Resource Cost (TRC) test. The TRC test incorporates the utility avoided cost benefits as well as the incremental cost to install the technology, capturing economics from both the customer and utility perspectives, rather than only considering the utility's perspective. As a sensitivity, Nexant also analyzed the economic potential using the TRC test for measure screening, which resulted in 5,501 GWh of economic potential for the DEI service territory.

6.2.2 Sector Details

Figure 6-1 summarizes the DEI residential sector energy efficiency cumulative economic potential by end use.

Figure 6-1: DEI Residential EE Economic Potential – Cumulative 2045 by End-Use

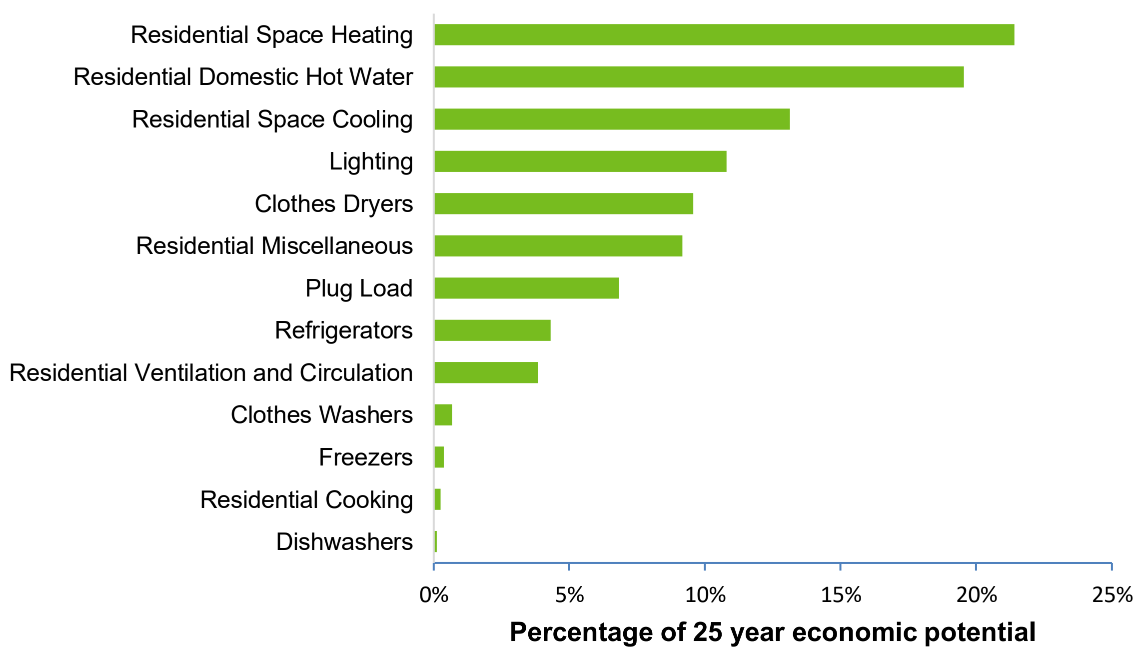


Figure 6-2 summarizes the DEI commercial sector energy efficiency cumulative economic potential by end use.

Figure 6-2: DEI Commercial EE Economic Potential – Cumulative 2045 by End-Use

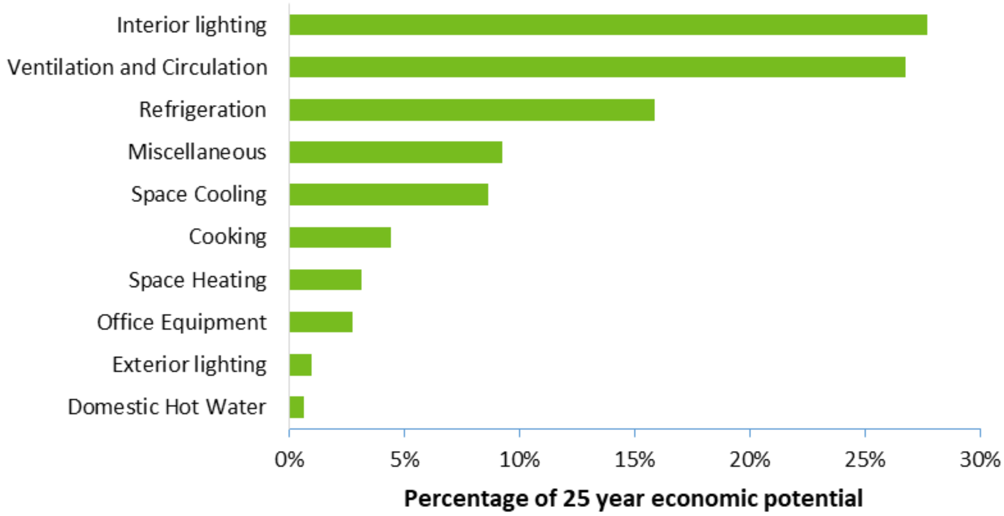


Figure 6-3 provides a summary of DEI energy efficiency economic potential contributions by commercial facility types analyzed in this study.

Figure 6-3: DEI Commercial EE Economic Potential by Segment

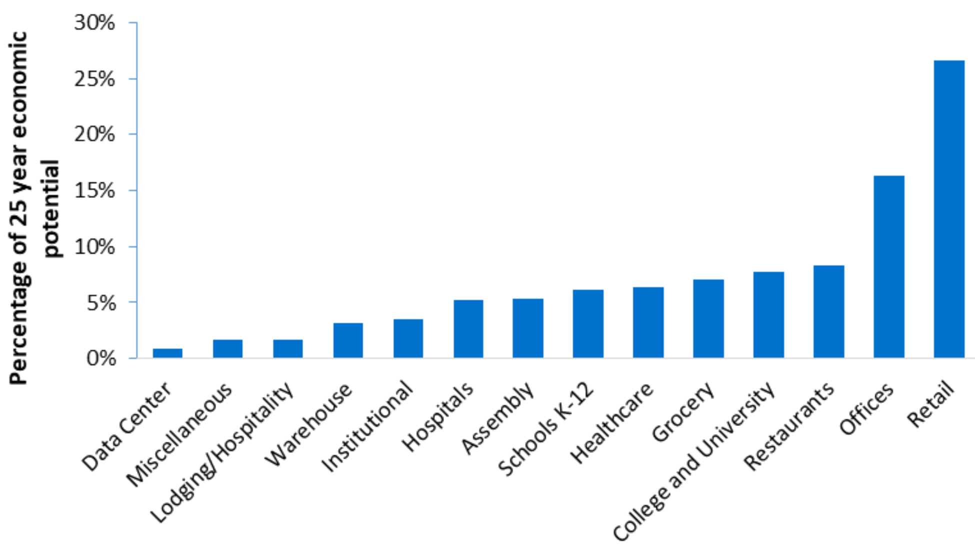


Figure 6-4 summarizes the DEI industrial sector energy efficiency cumulative economic potential by end use.

Figure 6-4: DEI Industrial EE Economic Potential – Cumulative 2045 by End-Use

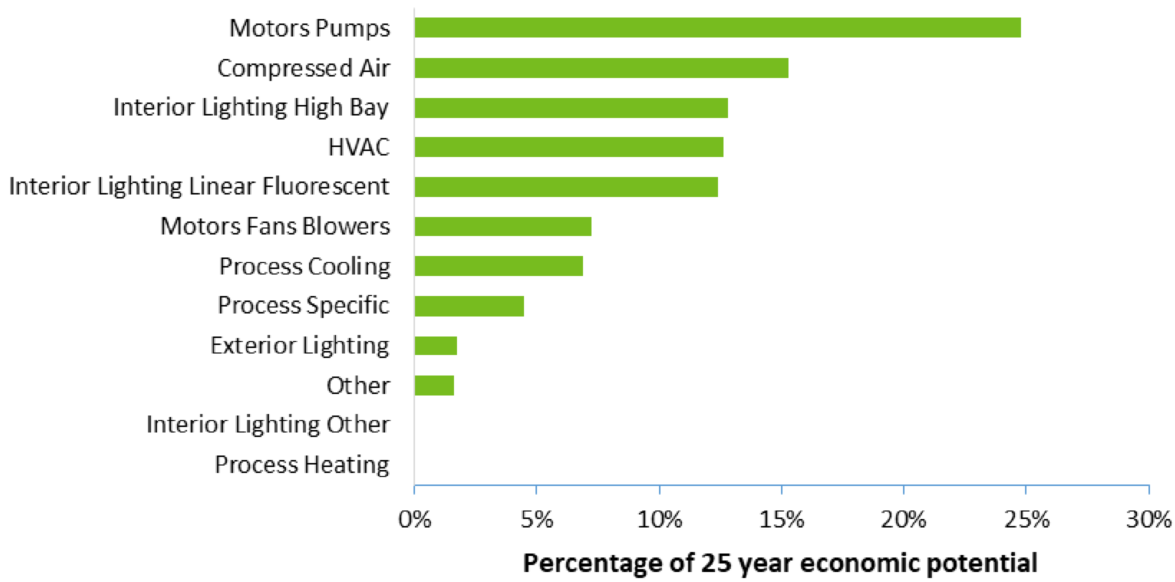
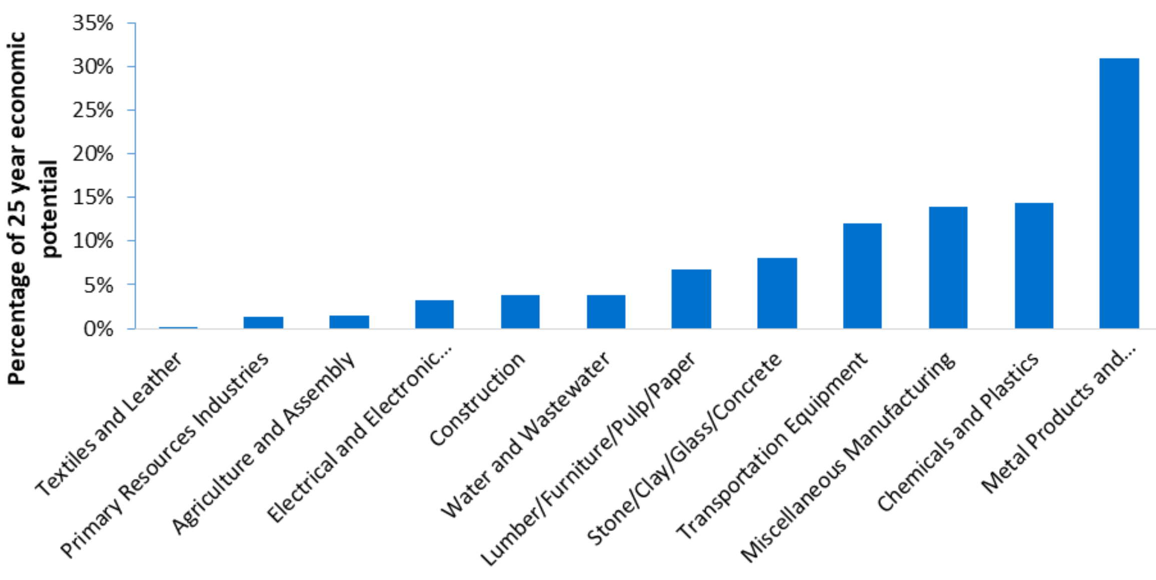


Figure 6-5 provides a summary of DEI energy efficiency economic potential contributions by industrial facility types analyzed in this study.

Figure 6-5: DEI Industrial EE Economic Potential Segment



6.3 DEI Demand Response Economic Potential

Demand response cost-effectiveness screening for economic potential determines whether the benefits of enrolling a marginal customer for a given customer segment into a demand response program will outweigh the costs, while ignoring the costs associated with sign-up incentives. The reason for excluding the sign-up incentive is that it can be set at any level and is mainly used to achieve a desired participation rate for the program. Since economic potential ignores the participation rate in the program (this is taken into account when determining the achievable potential), cost-effectiveness screening at this point only considers whether a marginal customer for a given customer segment is worth pursuing for participation in the program.

Cost effectiveness screening for economic potential revealed that the vast majority of the technical potential presented in the prior chapter is cost-effective on a marginal basis. Results for residential customer segments are presented in Table 6-3. Note that each of the three residential customer segments has a positive marginal net benefit, indicating that customers of each segment provide more benefit in the form of generation, transmission, and distribution capacity than they cost to enroll in the program and enable for load reduction.

This table presents the aggregate capacity each customer segment would be able to provide during summer and winter peaks, along with the benefits associated with that capacity, based on avoided generation and T&D costs. The total cost of enrolling customers in that segment is also presented. The net benefits and net benefits per customer are presented on the right side of the table.

Table 6-3: Residential Economic Potential Results

Segmentation	Residential			Summer		Winter		Total Aggregate Net Benefit	Total Net Benefit per Customer
	Usage_bin	# of accounts	Total Cost	Agg. MW	Total Benefit	Agg. MW	Total Benefit		
Electric Heating	1	46,911	$22,849,849	53.3	$35,012,344	187.5	$53,858,219	$66,020,714	$1,407
	2	46,911	$22,849,849	90.3	$59,320,700	187.5	$53,858,219	$90,329,070	$1,926
	3	46,911	$22,849,849	118.2	$77,631,616	187.5	$53,858,219	$108,639,986	$2,316
Gas Heating	1	198,486	$96,679,472	225.5	$148,139,927	0.0	$-	$51,460,455	$259
	2	198,486	$96,679,472	382.1	$250,990,457	0.00	$-	$154,310,985	$777
	3	198,486	$96,679,472	500.0	$328,465,353	0.00	$-	$231,785,881	$1,168
Total AC/Heating Economic Potential (only included if economic)				1,369		563			
Additional Potential from WH and PP				203		179			
Total Potential (Unadjusted)				**1,572**		**741**			
Total Potential (Adjusted for Existing DR)				**1,510**		**741**			

Similar tables are presented for SMB and large C&I customers. All customer segments evaluated produced a positive marginal net benefit, indicating that there is substantial untapped DR potential available in DEI's territory, without considering incentive costs and expected participation rates.

Table 6-4: SMB Economic Potential Results

SMB			Summer		Winter			Total Net Benefit per Customer
Segment	**# of Accounts**	**Total Cost**	**Agg. MW**	**Total Benefit**	**Agg. MW**	**Total Benefit**	**Total Aggregate Net Benefit**	
Healthcare/ Hospitals	3,994	$2,477,912	31.0	$19,902,018	41.5	$11,650,582	$29,074,687	$7,280
Offices	37,500	$23,265,326	93.9	$60,257,806	63.2	$17,743,600	$54,736,080	$1,460
Retail Stores	9,470	$5,875,270	72.7	$46,631,019	25.6	$7,190,547	$47,946,296	$5,063
Wholesale, Transportation & Utilities	18,997	$11,785,904	14.6	$9,374,778	18.3	$5,134,191	$2,723,065	$143
Other	34,274	$21,263,887	149.4	$95,866,461	103.5	$29,048,028	$103,650,601	$3,024
Total (Unadjusted)	**104,235**	**$64,668,300**	**362**		**252**			
Total (Adjusted)	**96,866**	**-**	**354**		**252**			

Table 6-5: Large C&I Economic Potential Results

Large C&I			Summer		Winter			
Segment	MW of Tech Potential for cost calc (max of winter and summer)	Total Cost	Agg. MW	Total Benefit	Agg. MW	Total Benefit	Total Aggregate Net Benefit	Total Net Benefit per MW
Agriculture, Forestry & Fishing	2.2	$353,933	2.0	$1,275,342	2.2	$620,700	$1,542,109	$697,131
Chemicals & Plastics	182.9	$29,256,768	182.9	$117,326,278	155.4	$43,610,330	$131,679,840	$720,133
Colleges & Universities	75.4	$12,067,706	75.4	$48,394,238	48.7	$13,657,388	$49,983,920	$662,713
Construction	15.0	$2,398,749	15.0	$ 9,619,527	14.2	$3,998,201	$11,218,979	$748,322
Electrical & Electronic Equipment	41.0	$6,558,094	41.0	$26,299,447	38.5	$10,793,810	$30,535,162	$744,976
Grocery Stores	5.5	$877,555	5.5	$3,519,195	3.3	$912,328	$3,553,969	$647,976
Healthcare	17.0	$2,717,200	17.0	$10,896,589	14.8	$4,156,804	$12,336,193	$726,406
Hospitals	50.4	$8,064,693	50.4	$32,341,248	31.2	$8,762,466	$33,039,021	$655,480
Institution/Government	23.4	$3,739,133	23.4	$14,994,771	17.4	$4,895,497	$16,151,136	$691,118
Large Public Assembly	0.7	$112,496	0.7	$451,134	0.5	$141,112	$479,750	$682,335
Lodging (Hospitality)	1.1	$177,405	1.0	$661,450	1.1	$311,119	$795,164	$717,152
Lumber, Furniture, Pulp & Paper	69.4	$11,107,091	69.4	$44,541,956	49.7	$13,954,522	$47,389,387	$682,654
Metal Products & Machinery	314.3	$50,283,568	310.3	$199,084,988	314.3	$88,183,412	$236,984,831	$754,075
Misc. Manufacturing	132.2	$21,155,600	132.2	$84,838,756	117.5	$32,974,103	$96,657,259	$731,020
Retail	43.5	$6,964,634	43.5	$27,929,761	29.6	$8,305,575	$29,270,703	$672,442
Misc (Offices, Other, Unk)	83.8	$13,400,784	83.8	$53,740,185	71.8	$20,142,333	$60,481,734	$722,128
Primary Resource Industries	37.4	$5,982,394	37.4	$23,990,756	30.0	$8,416,382	$26,424,745	$706,734
Schools K-12	43.1	$6,899,054	43.1	$27,666,774	38.2	$10,725,513	$31,493,232	$730,378
Stone, Clay, Glass & Concrete	103.6	$16,583,840	103.6	$66,504,961	99.8	$28,009,554	$77,930,675	$751,871
Textiles & Leather	2.2	$358,464	2.2	$1,397,484	2.2	$628,646	$1,667,666	$744,361
Transportation Equipment	144.4	$23,101,216	144.4	$92,641,118	134.8	$37,820,325	$107,360,227	$743,581
Warehouse, Transport & Non-Water Utilities	135.0	$21,605,824	135.0	$86,644,257	111.0	$31,154,076	$96,192,509	$712,345
Water & Wastewater	8.8	$1,404,115	8.8	$5,630,821	8.6	$2,406,163	$6,632,868	$755,820
Total (Unadjusted)	**1,532**		**1,528**		**1,335**			
Total (Adjusted)	**1,023**		**1,038**		**825**			

7 Achievable Program Potential

Nexant incorporated realistic assumptions about program delivery when estimating achievable market potential. For this reason, Nexant prefers the term DSM Program Potential, because the estimated energy savings reflect the proposed program concepts, Duke Energy revenue requirements, and the expected costs that incur for the program offerings. Nexant estimated the cost-effective savings realistically achievable by utility-sponsored DSM programs in the DEI jurisdiction, subject to economic constraints and market demand for DSM services in Indiana. Nexant populated the DSM program concepts with cost-effective DSM measures or service and generated annual estimates of the energy savings potential for each program concept. These achievable program savings estimates considered the historic demand for energy efficient measures in major end uses, where data were available.

Program potential is based on estimating the share of customers that may choose to participate in utility-sponsored programs. As such, Nexant also examined past program performance as an indicator of future program adoption and expected performance. Nexant drew on experience in other jurisdictions and markets to create defensible estimates of market potential, making the best use of available data on local DEI market conditions, but supplementing Duke Energy data resources with suitable secondary data.

7.1 DSM Program Assessment and Screening

7.1.1 Review of current and proposed programs

Nexant's development of achievable program potential estimates began with a review of existing Duke Energy DSM programs to identify the objectives, target markets, existing measures, and delivery mechanisms of each. Program information reviewed included program regulatory filings, recent program evaluation reports, and publicly available program information on Duke's website or in program marketing literature. After completing the initial program data review, Nexant coordinated multiple meetings with Duke Energy product development and DSM program staff to assist in our understanding of current and proposed DSM initiatives, details of Indiana-specific market conditions, and the suitability of certain efficiency measures, groups of measures, and programs for the given customer base.

7.1.2 Development of proposed offerings

Based on existing programs and measure list developed for the study, Nexant worked with Duke Energy to identify and develop proposed program offerings to be considered in this study that may address identified gaps. Nexant leveraged the best practices and successes achieved in other markets to guide the development of new or enhanced program opportunities.

New offerings may include programs that focus on electricity end uses that are not currently addressed by programs; new program delivery approaches to address market barriers; or, offerings that focus on individual customer segments. Additionally, Nexant used the measure list developed for the study and aligned measures that were not included in existing Duke Energy programs with either existing offerings where they may logically fit, or as part of new offerings. Each eligible EE measure was mapped to one or more program offering across the Residential, Commercial, and Industrial customer segments, and DR opportunities were classified into specific offerings across the customer segments. The following tables describe the final EE and DR program offerings included in the study.

Table 7-1: Proposed Residential EE Program Offerings

Program	Description	Targeted Segments	Delivery Approach
Smart $aver	Contractor-driven program addressing need for HVAC equipment, water heating equipment, building envelope, appliances, and pool measures Also includes retail component for EE products and lighting that includes buy-downs, retail partnerships, and online store	All residential building types	*Marketing strategy:* target customer segment *Customer experience:* technical assistance *Incentive type:* customer rebate
Audits and EE Kits	Focuses on energy efficiency education for customers and installation of highly cost-effective measures.	All residential building types; note: decision-maker varies by building type	*Marketing strategy:* mass marketing *Customer experience:* direct install & behavior *Incentive type:* customer rebate
Income Qualified	Addresses the approach of centralized management and existing resources for low income community to support energy efficiency.	All residential building types, demographic limitations	*Marketing strategy:* target customer segment *Customer experience:* technical assistance & direct install *Incentive type:* customer rebate
New Construction	Targets energy efficiency whole building measures and individual high cost-effective measures for new homes.	All residential building types (new construction)	*Marketing strategy:* joint marketing *Customer experience:* technical assistance *Incentive type:* customer rebate

Behavioral	Provides customers with increased information on their home energy consumption and tips to reduce energy use. Information provided through periodic usage reports as well as direct feedback with real-time usage information for their home.	All residential building types	*Marketing strategy:* target customer segment *Customer experience:* behavioral *Incentive type:* N/A
Energy Efficiency Lighting	Provides highly cost-effective lighting measures.	All residential building types; note: decision-maker varies by building type	*Marketing strategy:* mass marketing *Customer experience:* direct install *Incentive type:* customer rebate
Multi-Family	Target property managers at multi-family residences to support energy efficiency.	Residential multi-family	*Marketing strategy:* target customer segment *Customer experience:* technical assistance & direct install *Incentive type:* customer rebate
Appliance Recycling	Focuses on recycling appliances to support energy efficiency.	All residential building types	*Marketing strategy:* target customer segment *Customer experience:* technical assistance *Incentive type:* customer rebate
Energy Efficiency Education	A third party contractor delivers energy efficiency education with measure kit to students in K-12 enrolled in public and private schools in the DEI service territory.	All residential building types	*Marketing strategy:* joint marketing *Customer experience:* direct install & behavior *Incentive type:* social & giveaway

Table 7-2: Proposed Non-Residential EE Program Offerings

Program	Description	Targeted Segments	Delivery Approach
Smart $aver-Prescriptive	Addresses need to overcome cost barriers and increase efficiency of commercial and industrial equipment. Offers incentives to businesses for installing energy efficiency equipment.	All non-residential building types	*Marketing strategy:* target customer segment *Customer experience:* multiple participation channels (midstream, technical assistance, online store, education) *Incentive type:* customer rebate
Smart $aver – Custom	Measures outside the Smart $aver prescriptive incentive program measure list. Offers incentives to businesses for installing energy efficiency equipment.	All non-residential building types	*Marketing strategy:* target customer segment *Customer experience:* technical assistance *Incentive type:* customer rebate
Small Business Energy Saver	Focuses on installing highly-cost effective measures while minimizing customers' participation burden with a direct install approach.	Non-residential small business customers (less than 180 kW demand)	*Marketing strategy:* target customer segment *Customer experience:* direct install *Incentive type:* upstream incentive/mark-down
New Construction	Influences the design and construction phase of the commercial real estate market. Offers design assistance and cash incentives for a package of whole-building energy opportunities.	All non-residential building types	*Marketing strategy:* target customer segment *Customer experience:* technical assistance *Incentive type:* customer rebate
Pay-for-Performance	Offering measures are similar to Smart $aver-Custom Program with part of the incentives paid a year later to customers.	All non-residential building types	*Marketing strategy:* target customer segment *Customer experience:* technical assistance *Incentive type:* customer rebate

Table 7-3: Proposed Demand Response Program Offerings

Type of DR	Sector	Technology	Existing Program?
Utility controlled loads	Residential	▪ Central AC switches	Y
		▪ Smart thermostat	Y
		▪ Water heater switches	Y
		▪ Home gateway (control HVAC, water heater, pool pumps, power strips	N
		▪ Pool pumps	N
	Non-Residential	▪ Lighting controls (EMS or lighting ballasts)	N
		▪ HVAC controls (EMS)	Y
		▪ Pump loads	N
		▪ Auto DR for process loads	N
		▪ Battery storage	N
		▪ Backup generation	Y
Contractual	Non-Residential	▪ Interruptible rates – Firm service levels	Y
		▪ Guaranteed Load Drop	Y
		▪ Emergency Load Response	Y
Voluntary	Non-Residential	▪ Economic Load Response	Y

7.2 EE Achievable Program Potential Methodology

7.2.1 Market Adoption Rates

Utility-sponsored DSM programs offer incentives for energy efficiency measures that are designed to lower customers' costs and increase the rate at which the market adopts energy efficiency technologies. To estimate the adoption rate of energy efficiency based on the proposed program offerings described above, Nexant incorporated Duke DSM program data as well as secondary data from other utility sponsored DSM initiatives.

Nexant used Duke Energy's most recent program year prior to the MPS (2020) is taken as the baseline cumulative program saturation, which describes that share of customers that have previously participated in Duke Energy programs. We developed estimates of future program adoption using secondary research and standard economic theories on product diffusion. Forecasting future market penetration beyond the most recent program participation rate requires assumptions about the ultimate market penetration for a given program or set of measures, and information on the expected rate of market diffusion or uptake.

Nexant considered on a number of secondary data sources to develop market adoption parameters. These sources include EPA Energy Star data on qualified product shipments, empirically derived market penetration curves from other utility-sponsored programs, and primary research conducted in other markets. The use of secondary data for estimating market penetration is based on aligning energy efficiency measures with program concepts designed to address specific market segments and the varieties of DSM measures widely available in and suitable for the Indiana market.

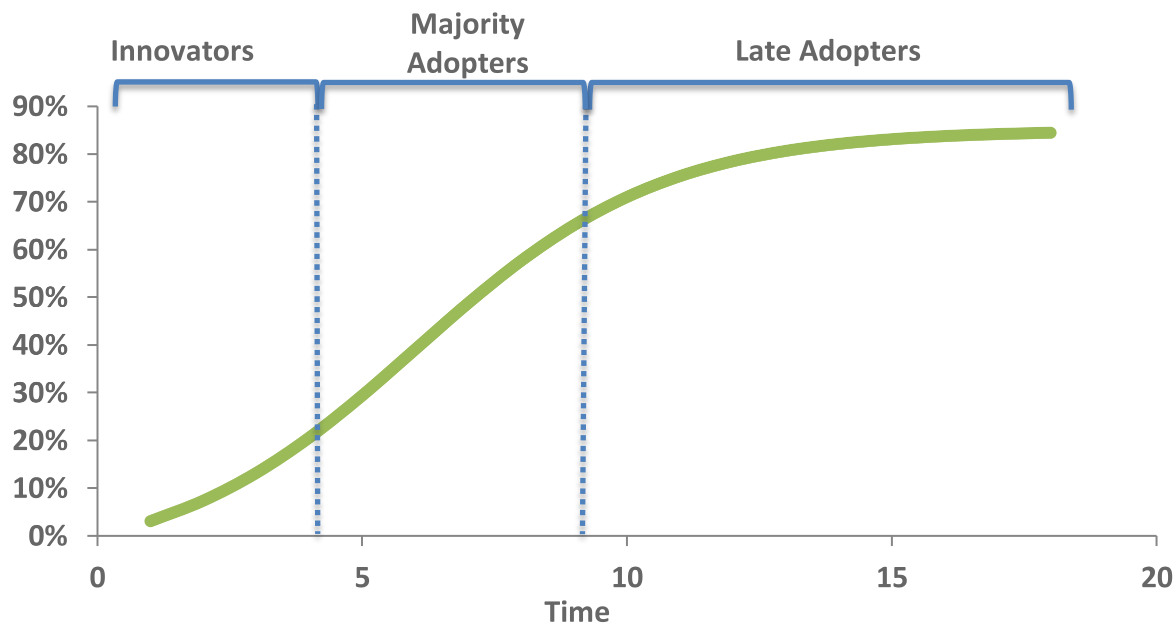
We apply a structured model of market adoption, referred to as the Bass Diffusion Model. The Bass model is a widely accepted mathematical description of how new products and innovations spread through an economy over time. It was originally published in 1969, and in 2004 was voted one of the top 10 most influential papers published in the 50-year history of the peer-reviewed publication *Management Science*[14]. More recent publications by Lawrence Berkeley National Laboratories have illustrated the application of this model to demand-side management in the energy industry[15]. Nexant applied the secondary data and research collected to develop and apply Bass Model diffusion parameters in the Indiana jurisdiction.

According to product diffusion theory, the rate of market adoption for a product changes over time. When the product is introduced, there is a slow rate of adoption while customers become familiar with the product. When the market accepts a product, the adoption rate accelerates to relative stability in the middle of the product cycle. The end of the product cycle is characterized by a low adoption rate because fewer customers remain that have yet to adopt the product. This concept is illustrated in Figure 7-1.

[14] Bass, F. 2004. Comments on “A New Product Growth for Model Consumer Durables the Bass Model” (sic). *Management Science* 50 (12_supplement): 1833-1840. http://pubsonline.informs.org/doi/abs/10.1287/mnsc.1040.0300. Accessed 01/08/2016.

[15] Buskirk, R. 2014. Estimating Energy Efficiency Technology Adoption Curve Elasticity with Respect to Government and Utility Deployment Program Indicators. LBNL Paper 6542E. Sustainable Energy Systems Group, Environmental Energy Technologies Division. Ernest Orlando Lawrence Berkeley National Laboratory. http://escholarship.org/uc/item/2vp2b7cm#page-1. Accessed 01/14/2016.

Figure 7-1: Bass Model Market Penetration with Respect to Time



The Bass Diffusion model is a mathematical description of how the rate of new product diffusion in a market changes over time. Figure 1 depicts the cumulative market adoption with respect to time, $S(t)$. The rate of adoption in a discrete time period is determined by external influences on the market, internal market conditions, and the number of previous adopters. The following equation describes this relationship:

$$\frac{dS(t)}{dt} = \left(p + \frac{q}{m} * S(t-1)\right) * (m - S(t-1))$$

Where:

$\frac{dS(t)}{dt}$ = the rate of adoption for any discrete time period, t

p = external influences on market adoption

q = internal influences on market adoption

m = the maximum market share for the product

$S(t-1)$ = the cumulative market share of the product, from product introduction to time period *t-1*

Marketing is the quintessential external influence. The internal influences are characteristics of the product and market; for example: the underlying market demand for the product, word of mouth, product features, market structure, and other factors that determine the product's market performance. Nexant's approach applied literature reviews and analysis of secondary data sources to estimate the Bass model parameters. We then extrapolated the model to future years; the historic participation and predicted future market evolution serve as the program adoption curve applied to each proposed offering.

7.2.2 Scenario Analysis

The achievable program potential for the proposed energy efficiency program offerings was developed based on five scenarios, each with specific assumptions presented as follows:

- **Base Scenario - All Customers:** includes measures passing UCT screen currently in DEI program offerings, aligns with existing program portfolio with assumptions of similar program delivery structure and incentive level, and considers all customers in DEI's service territory.
- **Base Scenario - Opt Outs:** same with Base Scenario All Customers but excludes customers currently opted-out.
- **Enhanced Scenario - Expanded Measures:** includes all measures passing UCT screen, assumes comparable incentive rates to existing programs for new measures, and excludes customers currently opted-out of DEI programs.
- **Enhanced Scenario - Increased Spending:** aligns with pervious scenario adding new measures, increases program spending via increasing incentives as approximation of higher program participation.
- **Avoided Cost Sensitivity:** aligns with Enhanced - Expanded Measures scenario, with enhanced EE benefits that would occur if avoided energy costs were higher than current values. In other words, measures are re-screened from UCT perspective with 50% increase in avoided energy costs.

Table 7-4 summarizes the programs and measures considered in each scenario:

Table 7-4: EE Programs by Scenario

	Program	Included in Base Scenarios?	Included in Enhanced Scenarios?	Included in Avoided Cost Sensitivity?
Residential	Smart $aver	Yes, Existing measures only	Yes, Existing + new measures	Yes, Existing + new measures
	Audits and EE Kits	Yes, Existing measures only	Yes, Existing + new measures	Yes, Existing + new measures
	Income Qualified	Yes, Existing measures only	Yes, Existing + new measures	Yes, Existing + new measures
	New Construction	Yes, Existing measures only	Yes, Existing + new measures	Yes, Existing + new measures
	Behavioral	Yes, Existing measures only	Yes, Existing + new measures	Yes, Existing + new measures
	Energy Efficiency Lighting	Yes, Existing measures only	Yes, Existing + new measures	Yes, Existing + new measures
	Multi-Family	Yes, Existing measures only	Yes, Existing + new measures	Yes, Existing + new measures
	Appliance Recycling	Yes, Historic measures only	Yes, Existing + new measures	Yes, Existing + new measures
	Energy Efficiency Education	Yes, Existing measures only	Yes, Existing + new measures	Yes, Existing + new measures
Non-Residential	Smart $aver - Prescriptive	Yes, Existing measures only	Yes, Existing + new measures	Yes, Existing + new measures
	Smart $aver - Custom	Yes, Existing measures only	Yes, Existing + new measures	Yes, Existing + new measures
	Pay-For-Performance	Yes, Existing measures only	Yes, Existing + new measures	Yes, Existing + new measures
	Small Business	Yes, Existing measures only	Yes, Existing + new measures	Yes, Existing + new measures
	New Construction	Yes, Existing measures only	Yes, Existing + new measures	Yes, Existing + new measures
	Behavioral	Yes, Existing measures only	Yes, Existing + new measures	Yes, Existing + new measures

Program Variations by Scenario

The new measures included in the Enhanced Scenario are described in Table 7-10 and Table 7-14 below. The sole basis for including these new measures in the Enhanced Scenario, while excluding from the Base Scenario, was whether the measures were offered in DEI's current program portfolio. Therefore, the additional measures analyzed in the Enhanced Scenario may include measures that are more or less cost-effective than measures in the Base Scenario. As detailed in the following sections, the overall energy and demand savings of the Enhanced Scenario is larger than the Base Scenario; however because of the variation in costs and benefits in the new Enhanced Scenario measures, some program-specific impacts may be lower for the Enhanced Scenario than the Base Scenario, including the following:

- *KWh or kW savings slightly lower for Enhanced Scenario than Base Scenario:* this situation occurs when the measure mix in the Base and Enhanced Scenarios are very similar; however due to the introduction of additional measures that apply to the same end-use (even if they are included in other programs), the savings for a particular measure may be slightly reduced. If the new measures have a higher cost-effectiveness, the savings for these measures are applied to the baseline consumption first, and the Base Scenario measures are then applied to a rolling, reduced baseline, resulting in slightly lower savings for the particular measure.
- *Levelized cost slightly lower for Enhanced Scenario than Base Scenario:* this situation occurs when the new measures incorporated into the Enhanced Scenario for a program have a lower average levelized cost than the Base Scenario measures. As described above, the Enhanced Scenario measures are not excluded from the Base Scenario on an economic basis, but based on current DEI programs; therefore, they may have lower costs or greater lifetime benefits than the Base Scenario measures.
- *Net Benefits lower for Enhanced Scenario than Base Scenario:* net benefits are based on the difference in total benefits and total costs from each test perspective. Enhanced Scenario net benefits may be lower than the Base Scenario when the additional cost added to a program exceeds the additional benefits added by the new measures.

7.3 DR Achievable Program Potential Methodology

7.3.1 Estimation of Participation Rates for DR Programs

While economic potential merely considers whether a given customer segment is worth pursuing based on the marginal net benefits provided by those customers, achievable program potential takes into account the estimated participation rate and how that affects the overall cost-effectiveness of the customer segment.

The magnitude of DR resources that can be acquired is fundamentally the result of customer preferences, program or offer characteristics (including incentive levels), and how programs are marketed. How predisposed are specific customers to participate in DR? What are details of specific offers and how do they influence enrollment rates? What is the level of marketing intensity and what marketing tactics are employed?

For program-based DR, participation rates are calculated as a function of the incentives offered to each customer group. For a given incentive level and participation rate, the cost-effectiveness of each customer segment is evaluated to determine whether the aggregate DR potential from that segment should be included in the achievable program potential.

The following subsections describe how marketing/incentive level, participation rates, and technology costs are handled by this study.

7.3.2 Marketing and Incentive Levels for Programs

Several underlying assumptions are used to define three different marketing levels. The number of marketing attempts and the method of outreach are varied by marketing level, as described in Table 7-5. The enhanced case assumes a high marketing level for program-based DR, while the base case assumes a medium marketing level (the low marketing level was not utilized for this study). Within each marketing level, the participation rate for each customer segment is a function of the incentive level.

The specific tactics included in the low, medium, and high marketing scenarios are not prescriptive but are instead designed to provide concrete details about the assumptions used in the study. There is a wide range of strategies and tactics that can attain the same enrollment levels and the best approach for a jurisdiction is best developed through testing and optimizing the mix of marketing tactics and incentives.

Table 7-5: Marketing Inputs for Residential Program Enrollment Model

Input	Marketing Level			
	No Marketing	Low	Medium	High
Number of marketing attempts (Direct mail)	0	5	5	8
Outreach mode	No marketing	Direct Mail	DM + Phone	DM + Phone
Installation required (%)	0%	100%	100%	100%
Attrition Rate	7.5%	7.5%	7.5%	7.5%

The incentive level and marketing inputs for each scenario determine the participation rate, assuming that the incentive is uniform across all customer segments within a given customer class.

7.3.3 Participation Rates

The participation models for the residential and nonresidential customer segments use a bottom up approach to estimate participation rates. These estimates have been crosschecked with mature programs in other jurisdictions to ensure that the estimated participation rates are reasonable.

Many DR potential studies rely on top down approaches which benchmark programs against enrollment rates that have been attained by mature programs. However, aggregated program results often do not provide enough detail to calibrate achievable program potential. In many cases, programs are not marketed to all customers, either because it is not cost-effective to market to all customers or budgets are capped by regulators. Enrollment rates are a function of specific offers and the extensiveness of marketing over many years. They also vary based on the degree to which DR resources are utilized and tend to be higher when payments are high but actual events are infrequent, particularly among large C&I customers.

For residential customers, the Nexant approach to estimate participation rates involves five steps. The initial step required some modification due to the data provided (or lack thereof).

1) Estimate an econometric choice model based on who has and has not enrolled in DR programs. The goal is to estimate the pre-disposition or propensity of different customers to participate in DR based on their characteristics. Because micro-level acquisition marketing data were not provided, we relied on differences in participation rates by usage level and electric heating. This information is based on prior micro-level analysis of program participation by Nexant and supplemented by outbound acquisition marketing that Nexant implements for load control programs.

2) Incorporate information about how different offer characteristics influence enrollment likelihood. What is the incremental effect of incentives? How do requirements for on-site installation affect enrollment rates? The two questions above have been analyzed using mature market specific data for residential customers. In each case, regression coefficients describe the incremental effect of each of the above factors on participation rates. It is important to note that while this element of the participation model was derived using non-Duke Energy specific data, it is only being used to determine the incremental impact of additional incentives on participation (i.e., how does increasing the sign-up incentive increase participation in DR programs). The underlying assumption is that customers' response to incremental financial incentives is similar across various geographic regions. Finally, as will be described in subsequent steps, the final participation model is calibrated to reflect the DEI territory.

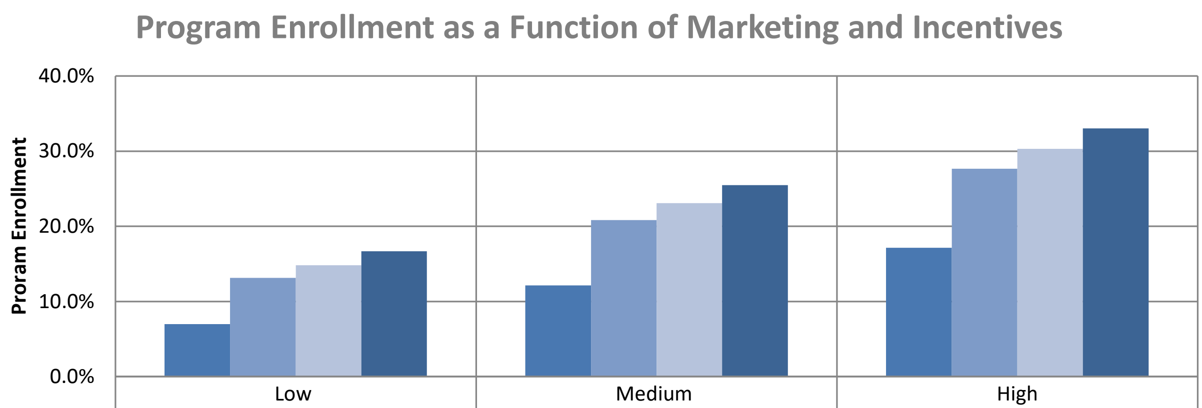
3) Incorporate information about how marketing tactics and intensity of marketing influence participation rates. What is the effect of incremental acquisition attempts? Is there a bump in enrollment rates when phone and/or door-to-door recruitment is added to direct mail recruitment? This relies on data from side-by-side testing designed to explicitly quantify the effect of marketing tactics on enrollment rates.

4) Calibrate the models to reflect actual enrollment rates attained with mature programs. To calibrate the models, the constant is adjusted so that the model produces exactly the enrollment rates observed by mature programs in DEI's territory used for benchmarking.

5) Predict participation rates using specific tactics and incentive levels for programs with and without installation requirements. The enrollment estimates were produced for low, medium, and high marketing levels, where specific marketing tactics are specified for each scenario. All estimates reflect enrollment rates for eligible customers.

As a demonstration of how marketing level and incentive affects participation in DR programs, Figure 7-2 shows the range of participation rates for each marketing level for a given residential customer segment at several different incentive levels.

Figure 7-2: Program Enrollment for Residential Customer Segments Under Different Marketing and Incentive Levels



	Low	Medium	High
$0	7.0%	12.1%	17.2%
$25	13.1%	20.8%	27.7%
$50	14.8%	23.1%	30.3%
$100	16.7%	25.5%	33.0%

For SMB customers, a similar approach was used to estimate participation levels. However, these customers tend to have lower enrollments than larger nonresidential customers and were scaled accordingly. SMB customers tend to exhibit roughly 40% of the uptake of residential customers, based on data from other utilities, which have extensively marketed these programs.

For large nonresidential customers, enrollment levels were predicted as a function of load rather than the number of customers, since large customers tend to have relatively high participation rates and commit to relatively large demand reductions on a percentage basis. For these customers, publicly available data on DR programs offered by other utilities were used to model program participation rates. Participation data were combined with data from the utilities on customer size and industry to generate a breakdown of participation rates, which is summarized in Table 7-6.

Table 7-6: Large Nonresidential Participation Rates by Size and Industry

Industry	Annual Max Demand (Non-coincident)				Total
	100kw - 300kW*	300 - 500kW	500kW - 1MW	1 MW or more	
Agriculture, Mining & Construction	19.8%	43.2%	57.9%	60.7%	**44.6%**
Manufacturing	24.2%	44.8%	52.3%	74.0%	**64.6%**
Wholesale, Transport & Other Utilities	27.9%	50.1%	55.7%	60.8%	**49.7%**
Retail Stores	28.1%	53.0%	53.8%	48.0%	**42.7%**
Offices, Hotels, Finance, Services	13.0%	26.9%	34.3%	40.2%	**30.0%**
Schools	15.0%	30.5%	40.3%	52.5%	**35.7%**
Institutional/Government	13.7%	34.1%	42.8%	62.3%	**40.4%**
Other or Unknown	9.4%	25.3%	29.6%	29.5%	**18.6%**
Total	**19.7%**	**40.8%**	**45.6%**	**60.8%**	**45.4%**

These programs have been marketed to every large nonresidential customer in a mature market, which reflect a saturated market and a good representation of the total potential. For each large nonresidential customer segment, participation was estimated as a function of incentive level and number of dispatch hours, based on publicly available information on program capacity, dispatch events, and incentive budgets. Finally, these models were calibrated to reflect actual enrollment from DEI marketing initiatives for the Power Manager® (residential) and PowerShare® (nonresidential) programs.

7.3.4 Scenario Analysis

Base and Enhanced scenarios were constructed for the DR potential analysis, which align with the assumptions for the EE scenarios (notably, the penetration of smart thermostats and the incremental energy savings associated with behavioral demand response). The Base Scenario assumes a modest increase in DR scope from current DEI offerings, while the Enhanced Scenario assumes more aggressive expansion. Major assumptions for both scenarios are listed below:

Program Potential - Base

- Assume residential load control will only target AC/heating loads and water heating
- Offer incentives for smart thermostats (50% penetration by 2045)
- Medium marketing level for DR programs
- Target only customer segments who are cost-effective on their own

Program Potential - Enhanced

- 50% higher sign-up incentives for residential and nonresidential DR programs compared to current levels

- Target pool pumps in addition to AC/heating and water heating for residential customers
- Aggressively increase program marketing and outreach budgets (high marketing level)
- Target all customer segments that can be included without making the program cost-prohibitive (UCT<1.0)

7.4 DEI Energy Efficiency Achievable Program Potential

This section provides the results of the DEI EE achievable program potential for each of the three segments.

7.4.1 Summary

Table 7-7 summarizes the short-term (5-year), medium term (10-year) and long-term (25-year) DEI portfolio EE achievable program potential for the base scenario includes all customers across the residential, commercial, and industrial sectors without regard for current opt-out rates. Table 7-8 summarizes the EE program potential excluding opt-out customer for the base scenario, enhanced - expanded measures scenario, enhanced - increased spending scenario, and avoided cost sensitivity.

Impacts are presented as both **cumulative impacts**, which represent the savings that occur in the respective year based on measures installed in that year and measures installed in prior years that have not reached the end of their useful life and **the sum of annual impacts**, which represent the total annual incremental savings achieved over the stated time horizon (5 years, 10 years, or 25 years).

Table 7-7: DEI EE Achievable Program Potential (All Customers)

	Cumulative Impacts			Sum of Annual Incremental Impacts			Average Annual % of Base Sales[16]
	Energy (GWh)	Demand (MW)		Energy (GWh)	Demand (MW)		
		Summer	Winter		Summer	Winter	
Achievable Program Potential – Base Scenario, All Customers							
5 Year (2025)	1,450	232	216	1,686	265	249	1.34%
10 Year (2030)	2,172	350	325	2,927	463	432	1.16%
25 Year (2045)	1,825	307	275	5,810	926	856	0.88%

Table 7-8: DEI EE Achievable Program Potential (Opt Outs)

	Cumulative Impacts			Sum of Annual Incremental Impacts			Average Annual % of Base Sales[17]
	Energy (GWh)	Demand (MW)		Energy (GWh)	Demand (MW)		
		Summer	Winter		Summer	Winter	
Achievable Program Potential – Base Scenario, Opt Outs							
5 Year (2025)	696	112	101	929	146	134	1.31%
10 Year (2030)	1,022	168	148	1,671	263	239	1.17%
25 Year (2045)	1,082	182	153	3,720	587	527	0.98%
Achievable Program Potential – Enhanced Scenario, Expanded Measures							
5 Year (2025)	741	118	107	966	150	139	1.36%
10 Year (2030)	1,133	182	164	1,784	277	255	1.25%
25 Year (2045)	1,326	212	188	4,120	636	581	1.09%
Achievable Program Potential – Enhanced Scenario, Increased Spending							
5 Year (2025)	784	121	114	1,010	152	145	1.42%
10 Year (2030)	1,244	189	182	1,910	284	274	1.34%
25 Year (2045)	1,481	220	218	4,419	652	626	1.17%
Achievable Program Potential – Avoided Cost Sensitivity							
5 Year (2025)	815	126	116	1,040	157	148	1.46%
10 Year (2030)	1,230	190	178	1,896	285	270	1.33%
25 Year (2045)	1,399	214	206	4,287	641	606	1.13%

Figure 7-3, Figure 7-4, Figure 7-5, Figure 7-6, and Figure 7-7 show DEI achievable energy savings potential by sector for each scenario.

[16] Average annual energy savings as percentage of annual Base Sales per period.

[17] Average annual energy savings as percentage of non-opt out annual Base Sales per period. Appropriate opt-out rates were applied into the model to reduce the non-residential sales estimates.

Figure 7-3: DEI Achievable Program Potential by Sector, Base Scenario – All Customers

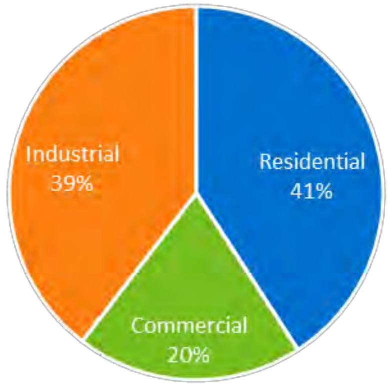


Figure 7-4: DEI Achievable Program Potential by Sector, Base Scenario – Opt Outs

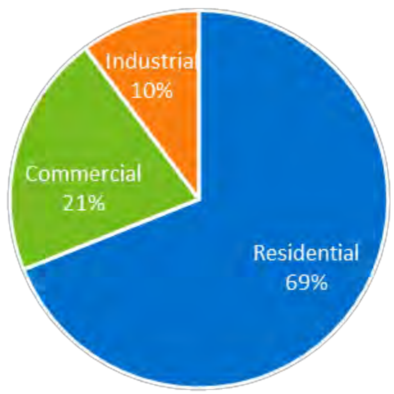


Figure 7-5: DEI Achievable Program Potential by Sector, Enhanced Scenario – Expanded Measures

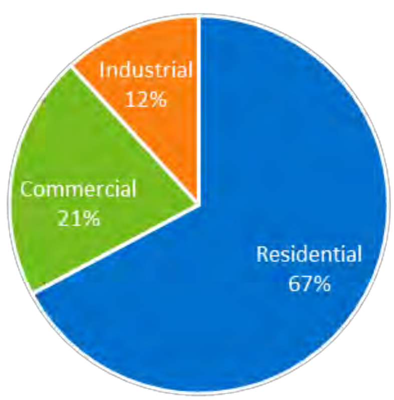


Figure 7-6: DEI Achievable Program Potential by Sector, Enhanced Scenario – Increased Spending

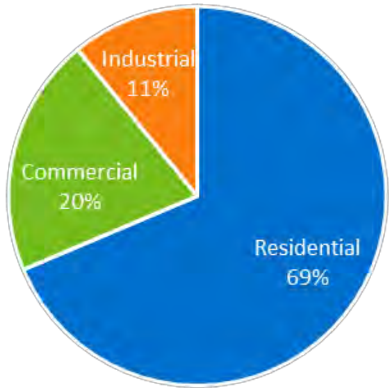
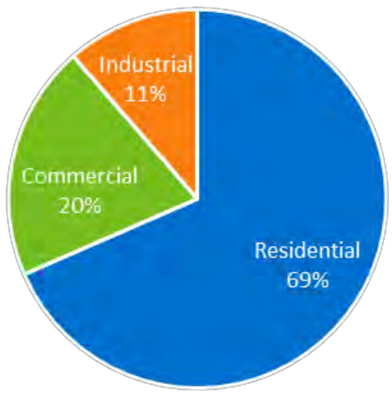


Figure 7-7: DEI Achievable Program Potential by Sector, Avoided Cost Sensitivity



Participant and program costs associated with achievable program potential scenarios include the following:

- **Program incentives:** Financial incentives paid by energy-efficiency programs to subsidize purchases of energy-efficiency measures.
- **Program administration costs:** Administrative, marketing, promotional, and other costs associated with managing programs designed to achieve energy-efficiency savings.
- **Total program acquisition costs:** Total incentive and non-incentive program costs per sum of annual incremental energy savings achieved.
- **Participant costs:** Incremental costs to purchase, install, and maintain energy-efficiency measures.

Table 7-9 lists estimated participant and program costs associated with the theoretically achievable scenarios over the first 5 program years.

Table 7-9: DEI Participation and Program Costs by Scenario (cumulative through 2025)

Program Sector	Program Incentives ($M)	Program Admin ($M)	Participant Costs ($M)
Base Scenario – All Customers			
Residential	$34.40	$47.69	$43.18
Non-Residential	$140.94	$54.79	$179.97
Total	$175.33	$102.47	$223.16
Base Scenario – Opt Outs			
Residential	$34.40	$47.69	$43.18
Non-Residential	$58.78	$19.89	$72.53
Total	$93.18	$67.58	$115.71
Enhanced Scenario – Expanded Measures			
Residential	$34.40	$46.20	$49.21
Non-Residential	$58.99	$19.96	$72.77
Total	$93.39	$66.16	$121.99
Enhanced Scenario – Increased Spending			
Residential	$51.32	$52.17	$16.78
Non-Residential	$105.79	$21.44	$35.26
Total	$157.11	$73.61	$52.04
Avoided Cost Sensitivity			
Residential	$28.68	$45.62	$51.38
Non-Residential	$83.48	$22.27	$102.38
Total	$112.16	$67.89	$153.75

7.4.2 Residential Program Details

As described in Section 7.2.2 above, the Enhanced Scenarios considered additional measures for existing program offerings, as well as new programs not currently in Duke Energy's portfolio. Table 7-10 summarizes the additional measure categories and programs contributing to the achievable program potential identified in the Enhanced scenarios:

Table 7-10: Enhanced Scenario Additional EE Measures - Residential

Program	Enhanced Scenario Measures
Smart $aver	• Lighting controls (interior, exterior), including motion sensors, photocells, and timers • Additional HVAC equipment rebates, including variable refrigerant flow (VRF) systems, room air conditioners and targeted rebates for air source heat pumps replacing homes with electric resistance heating • Additional building envelope improvement measures, including window film, ENERGY STAR windows and doors, wall insulation, and higher levels of ceiling insulation (up to R-49) • High efficiency (ENERGY STAR, where applicable) appliances and consumer products for the home, including clothes washers and dryers, ceiling fans, bathroom exhaust fan, dehumidifiers, air purifiers, holiday lights • Additional high efficiency products for residential pools, including heat pump pool heaters, and dual speed pool pump motors • Additional water heater rebates, including drain water heat recovery systems and solar electric water heaters • Dehumidifier recycling
Audits and EE Kits	• Additional kit items, such as specialty LED night lights
Income Qualified	• Lighting controls (interior, exterior), including motion sensors, photocells, and timers • HVAC equipment rebates, including room air conditioners • Additional building envelope improvement measures, including window film, ENERGY STAR windows and doors, wall insulation, and higher levels of ceiling insulation (up to R-49) • Miscellaneous high efficiency consumer products for the home, including ENERGY STAR ceiling fans and efficient bathroom exhaust fans • Additional water heater rebates, including drain water heat recovery systems, water heater insulating blankets, water heater pipe insulation, and thermostatic shower restriction valves
New Construction	• Whole home performance measures, targeting specific reductions in energy consumption for the home • Individual efficiency upgrades for new homes, including: o Building envelope upgrades o Energy efficient appliances and products for the home o Energy efficient lighting equipment and controls o ENERGY STAR HVAC equipment and controls o Energy efficient water heating equipment o Energy efficient residential pool equipment
Behavioral	• Interactive Home Energy Reports with online access • Real-time information on energy use, provided online or through home energy management system • Pre-pay customer billing, which provides real-time energy use information

Table 7-11 summarizes the short-term (5-year), medium term (10-year) and long-term (25-year) cumulative residential energy efficiency achievable program potential for the base scenario, enhanced scenarios as well as avoided cost sensitivity. Impacts are presented as both **cumulative impacts**, which represent the savings that occur in the respective year based on measures installed in that year and measures installed in prior years that have not reached the end of their useful life and **the sum of annual impacts**, which represent the total annual incremental savings achieved over the stated time horizon (5 years, 10 years, or 25 years):

Table 7-11: EE Residential Achievable Program Potential

	Cumulative Impacts			Sum of Annual Incremental Impacts			Average Annual % of Base Sales[18]
	Energy (GWh)	Demand (MW)		Energy (GWh)	Demand (MW)		
		Summer	Winter		Summer	Winter	
Achievable Program Potential – Base Scenario							
5 Year (2025)	268	44	36	498	77	69	1.09%
10 Year (2030)	417	70	56	983	153	135	1.06%
25 Year (2045)	746	125	99	2,632	409	360	1.04%
Achievable Program Potential – Enhanced Scenario, Expanded Measures							
5 Year (2025)	311	50	42	533	82	74	1.17%
10 Year (2030)	495	80	67	1,063	163	147	1.15%
25 Year (2045)	892	142	123	2,876	438	396	1.14%
Achievable Program Potential – Enhanced Scenario, Increased Spending							
5 Year (2025)	322	48	45	545	79	76	1.19%
10 Year (2030)	571	82	82	1,140	162	160	1.23%
25 Year (2045)	1,018	147	150	3,090	443	432	1.23%
Achievable Program Potential – Avoided Cost Sensitivity							
5 Year (2025)	334	51	46	556	82	77	1.22%
10 Year (2030)	538	81	75	1,108	162	154	1.20%
25 Year (2045)	959	144	141	2,966	433	413	1.18%

Figure 7-8,

Figure 7-9, Figure 7-10, and

[18] Average annual energy savings as percentage of annual Base Sales per period.

Figure 7-11 illustrate the relative contributions to the overall residential program potential by program for the base scenario, enhanced scenarios as well as avoided cost sensitivity.

Figure 7-8: DEI Residential 5-Yr Cumulative Potential by Program – Base Scenario

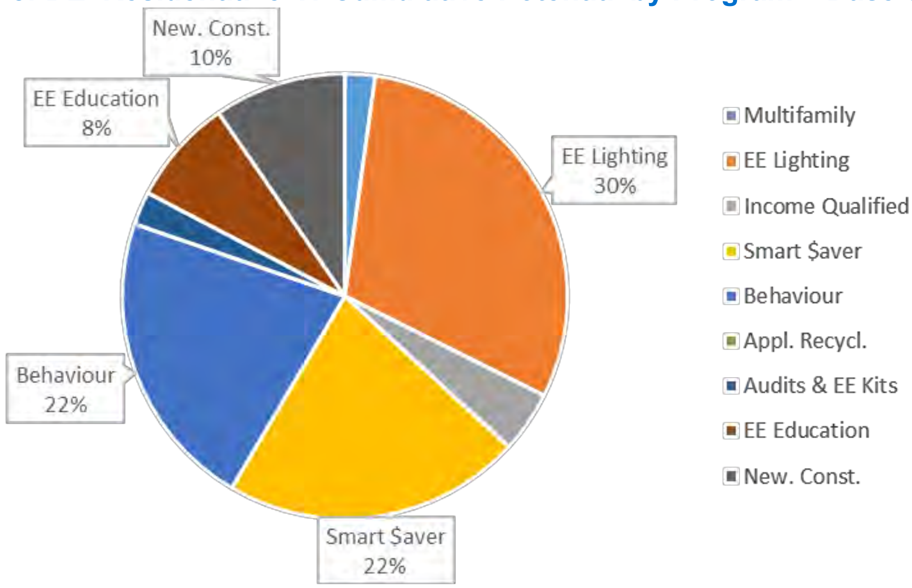


Figure 7-9: DEI Residential 5-Yr Cumulative Potential by Program – Enhanced Scenario, Expanded Measure

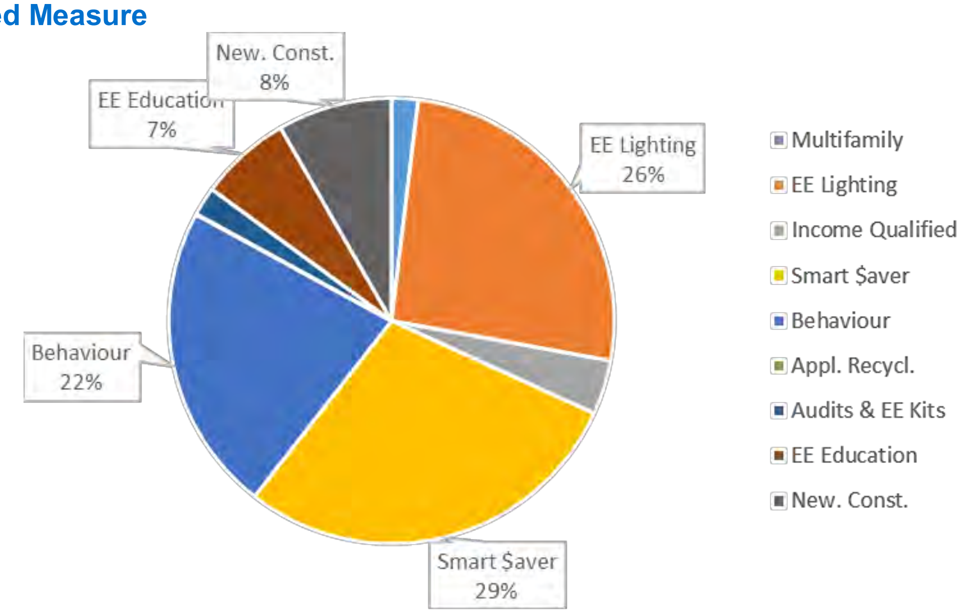


Figure 7-10: DEI Residential 5-Yr Cumulative Potential by Program – Enhanced Scenario, Increased Spending

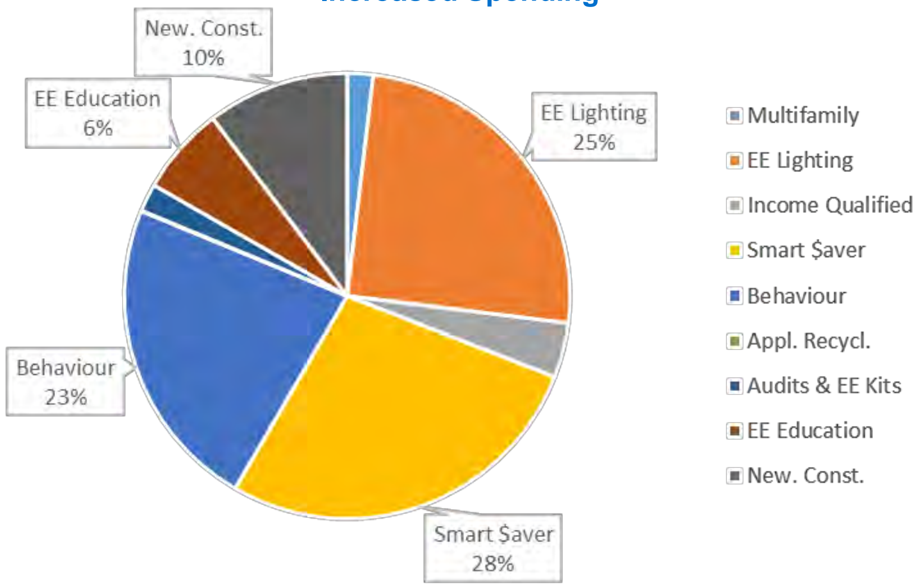
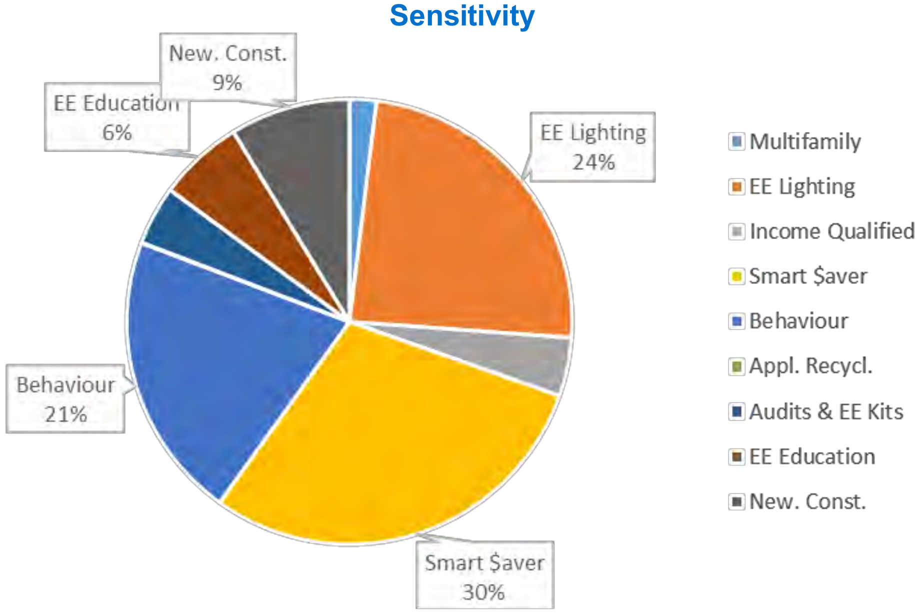


Figure 7-11: DEI Residential 5-Yr Cumulative Potential by Program – Avoided Cost Sensitivity



Detailed program results for the short-term residential EE programs are provided in Table 7-12:

Table 7-12: DEI Residential Achievable Program Potential (cumulative through 2025)

	Multifamily	EE Lighting	Income Qualified	Smart $aver	Behavior	Appl. Recycl.	Audits & EE Kits	EE Education	New. Const.
5-yr (2025) impacts – Base Scenario									
MWh savings (cumulative)	5,849	80,717	11,950	57,960	58,319	0	6,455	20,627	25,660
Summer MW savings (cumulative)	0.87	11.99	1.89	12.87	8.40	0.00	0.96	2.94	4.07
Winter MW savings (cumulative)	0.89	12.23	1.79	5.68	8.27	0.00	0.98	3.07	3.46
Program costs (cumulative) ($M)	$0.33	$4.18	$13.92	$20.46	$12.90	$0.00	$4.21	$4.57	$21.51
Levelized Cost ($/kWh)	$0.01	$0.01	$0.18	$0.13	$0.05	N/A	$0.10	$0.05	$0.14
5-yr (2025) impacts – Enhanced Scenario, Expanded Measures									
MWh savings (cumulative)	5,963	80,716	12,279	89,339	69,622	135	6,508	20,620	25,817
Summer MW savings (cumulative)	0.88	11.99	1.90	16.91	10.02	0.04	0.96	2.94	4.00
Winter MW savings (cumulative)	0.91	12.23	1.85	9.95	9.88	0.00	0.99	3.07	3.48
Program costs (cumulative) ($M)	$0.24	$4.18	$13.08	$27.22	$12.90	$0.04	$3.60	$4.57	$14.77
Levelized Cost ($/kWh)	$0.01	$0.01	$0.18	$0.12	$0.04	$0.06	$0.10	$0.05	$0.14
5-yr (2025) impacts – Enhanced Scenario, Increased Spending									
MWh savings (cumulative)	6,057	80,824	12,822	88,444	73,635	113	6,521	20,616	33,219
Summer MW savings (cumulative)	0.85	12.00	1.81	14.36	10.19	0.03	0.97	2.94	4.66
Winter MW savings (cumulative)	0.91	12.24	1.99	11.02	10.29	0.00	0.99	3.06	4.67
Program costs (cumulative) ($M)	$0.34	$4.19	$14.89	$31.57	$13.06	$0.03	$4.26	$4.57	$30.58
Levelized Cost ($/kWh)	$0.01	$0.01	$0.18	$0.08	$0.04	$0.05	$0.10	$0.05	$0.13

	Multifamily	EE Lighting	Income Qualified	Smart $aver	Behavior	Appl. Recycl.	Audits & EE Kits	EE Education	New. Const.
5-yr (2025) impacts – Avoided Cost Sensitivity									
MWh savings (cumulative)	6,518	80,738	14,181	98,471	69,609	135	14,287	20,619	29,121
Summer MW savings (cumulative)	0.93	11.99	2.04	16.94	9.68	0.04	2.13	2.94	4.41
Winter MW savings (cumulative)	0.98	12.23	2.19	11.79	9.77	0.00	2.09	3.06	3.90
Program costs (cumulative) ($M)	$0.01	$4.19	$12.77	$32.71	$12.90	$0.04	$7.03	$4.57	$0.09
Levelized Cost ($/kWh)	$0.01	$0.01	$0.18	$0.13	$0.04	$0.06	$0.10	$0.05	$0.06

To analyze the costs and benefits of the achievable program potential scenarios, Nexant used several common test perspectives in the MPS, consistent with the California Standard Practice Manual.[19]:

- Total resource cost (TRC): Calculated by comparing the total avoided electricity production and the avoided delivery costs from installing a measure, to that measure's incremental cost. The incremental cost is relative to the cost of the measure's appropriate baseline technology.
- Utility cost test (UCT): Calculated by comparing total avoided electricity production and avoided delivery costs from installing a measure, to the utility's cost of delivering a program containing that measure. Costs include incentive and non-incentive costs.
- Participant cost test (PCT): Calculated by dividing electricity bill savings for each installed measure, by the incremental cost of that measure. The incremental cost is relative to the cost of the measure's appropriate baseline technology.
- Ratepayer Impact Measure (RIM): Calculated by comparing the total avoided electricity production and the avoided delivery costs from installing a measure, to the utility's revenue impacts from lost sales and program delivery.

Table 7-13 provides the net benefits and benefit-to-cost ratios by sector for each scenario:

[19] California Standard Practice Manual: Economic Analysis of Demand-Side Program and Projects. California Public Utilities Commission. San Francisco, CA. October 2001.

Table 7-13: Cost-Benefit Results – Residential Programs (cumulative through 2025)

	Multifamily	EE Lighting	Income Qualified	Smart $aver	Behavior	Appl. Recycl.	Audits & EE Kits	EE Education	New. Const.
5-yr (2025) impacts – Base Scenario									
UCT – Net Benefits ($M)	$2.14	$25.22	-$8.30	$18.43	$1.00	$0.00	-$1.63	$1.54	$0.61
UCT – B/C ratio	7.45	7.03	0.40	1.90	1.08	N/A	0.61	1.34	1.03
TRC – Net Benefits($M)	$2.48	$28.43	$5.62	-$11.29	$13.90	$0.00	$2.59	$6.11	-$4.31
TRC – B/C ratio	N/A	29.91	N/A	0.77	N/A	N/A	N/A	N/A	0.84
PCT – Net Benefits ($M)	$3.82	$47.25	$7.85	$12.06	$22.33	$0.00	$4.11	$9.77	$17.01
PCT – B/C ratio	N/A	N/A	N/A	1.37	N/A	N/A	N/A	N/A	2.61
RIM – Net Benefits ($M)	-$1.67	-$22.03	-$16.15	-$26.25	-$21.33	$0.00	-$5.74	-$8.23	-$26.97
RIM – B/C ratio	0.60	0.57	0.26	0.60	0.39	N/A	0.31	0.43	0.45
5-yr (2025) impacts – Enhanced Scenario, Expanded Measures									
UCT – Net Benefits ($M)	$1.45	$25.22	-$7.69	$23.13	$6.80	$0.02	-$1.39	$1.54	$0.22
UCT – B/C ratio	7.04	7.03	0.41	1.85	1.53	1.57	0.61	1.34	1.01
TRC – Net Benefits($M)	$1.69	$28.43	$5.38	-$14.29	$19.70	$0.04	$2.21	$6.10	-$2.98
TRC – B/C ratio	N/A	29.91	N/A	0.78	N/A	4.83	N/A	N/A	0.83
PCT – Net Benefits ($M)	$2.67	$47.25	$7.42	$19.88	$30.68	$0.06	$3.52	$9.77	$11.40
PCT – B/C ratio	N/A	N/A	N/A	1.47	N/A	11.22	N/A	N/A	2.59
RIM – Net Benefits ($M)	-$1.23	-$22.03	-$15.11	-$38.76	-$23.88	-$0.05	-$4.91	-$8.23	-$18.37
RIM – B/C ratio	0.58	0.57	0.26	0.57	0.45	0.56	0.31	0.43	0.45
5-yr (2025) impacts – Enhanced Scenario, Increased Spending									
UCT – Net Benefits ($M)	$2.27	$25.24	-$8.88	$12.93	$8.51	$0.02	-$1.64	$1.54	-$1.85
UCT – B/C ratio	7.60	7.02	0.40	1.41	1.65	1.74	0.62	1.34	0.94
TRC – Net Benefits($M)	$2.62	$28.45	$6.01	$8.40	$21.57	$0.04	$2.62	$6.10	-$2.27
TRC – B/C ratio	N/A	29.80	N/A	1.23	N/A	9.58	N/A	N/A	0.93
PCT – Net Benefits ($M)	$4.00	$47.30	$8.49	$49.68	$33.40	$0.05	$4.16	$9.76	$28.95

	Multifamily	EE Lighting	Income Qualified	Smart $aver	Behavior	Appl. Recycl.	Audits & EE Kits	EE Education	New. Const.
PCT – B/C ratio	N/A	N/A	N/A	6.50	N/A	45.35	N/A	N/A	4.73
RIM – Net Benefits ($M)	-$1.72	-$22.06	-$17.38	-$45.78	-$24.89	-$0.04	-$5.80	-$8.23	-$38.55
RIM – B/C ratio	0.60	0.57	0.26	0.49	0.46	0.57	0.31	0.43	0.43
5-yr (2025) impacts – Avoided Cost Sensitivity									
UCT – Net Benefits ($M)	$0.07	$34.23	-$5.36	$41.06	$12.55	$0.03	-$0.93	$3.40	$0.07
UCT – B/C ratio	10.32	9.17	0.58	2.26	1.97	1.90	0.87	1.74	1.85
TRC – Net Benefits($M)	$0.08	$37.43	$7.42	-$5.23	$25.45	$0.06	$6.09	$7.97	$0.11
TRC – B/C ratio	N/A	38.91	N/A	0.93	N/A	5.88	N/A	N/A	3.10
PCT – Net Benefits ($M)	$0.09	$47.26	$7.60	$19.01	$30.68	$0.06	$7.13	$9.77	$0.16
PCT – B/C ratio	N/A	N/A	N/A	1.37	N/A	11.22	N/A	N/A	8.50
RIM – Net Benefits ($M)	-$0.01	-$13.03	-$12.96	-$29.30	-$18.13	-$0.03	-$8.06	-$6.37	-$0.10
RIM – B/C ratio	0.85	0.75	0.36	0.72	0.58	0.68	0.43	0.56	0.61

7.4.3 Non-Residential Program Details

Like the residential sector the Enhanced Scenario for the Non-Residential sector considered additional measures for existing program offerings, as well as new programs not currently in Duke Energy's portfolio. Table 7-14 summarizes the additional measure categories and programs contributing to the achievable potential identified in the Enhanced scenario:

Table 7-14: Enhanced Scenario Additional EE Measures – Non-Residential

Program	Enhanced Scenario Measures
Smart $aver-Prescriptive	• Additional HVAC and building envelope improvements, including economizers, and ENERGY STAR building products • Additional office equipment, including ENERGY STAR servers, computers, and monitors • Additional commercial ENERGY STAR products, including vending machines, water coolers, and commercial clothes washers • Water heating equipment, including solar water heaters, heat pump water heaters, and insulating jackets • Additional food service equipment, including solid state hood controls • Additional refrigeration equipment, including high efficiency refrigeration compressors, suction pipe insulation, and strip curtains
Smart $aver – Custom	Custom program focuses on energy savings that can be delivered by a wide range of measures and technologies. The enhanced scenario for Smart $aver Custom included measures that may be eligible for the current offering, but may be less common or target a specific customer segment or industry, including: • Data center improvements, including service consolidation and high efficiency computer room air conditioning (CRAC) units • Compressed air improvements, including additional storage capacity, system optimization, and controls • Other process equipment and facility improvements, including high efficiency welders, cogged belts on motors, high volume-low speed fans
Small Business Energy Saver	• Commercial ENERGY STAR products, including vending machines, water coolers, and commercial clothes washers • Water heating equipment, including heat pump water heaters and insulating jackets • Refrigeration equipment, including suction pipe insulation, and strip curtains
New Construction	• Energy efficient building design and certification • Energy efficient lighting design

7.4.3.1 All Customers Scenario

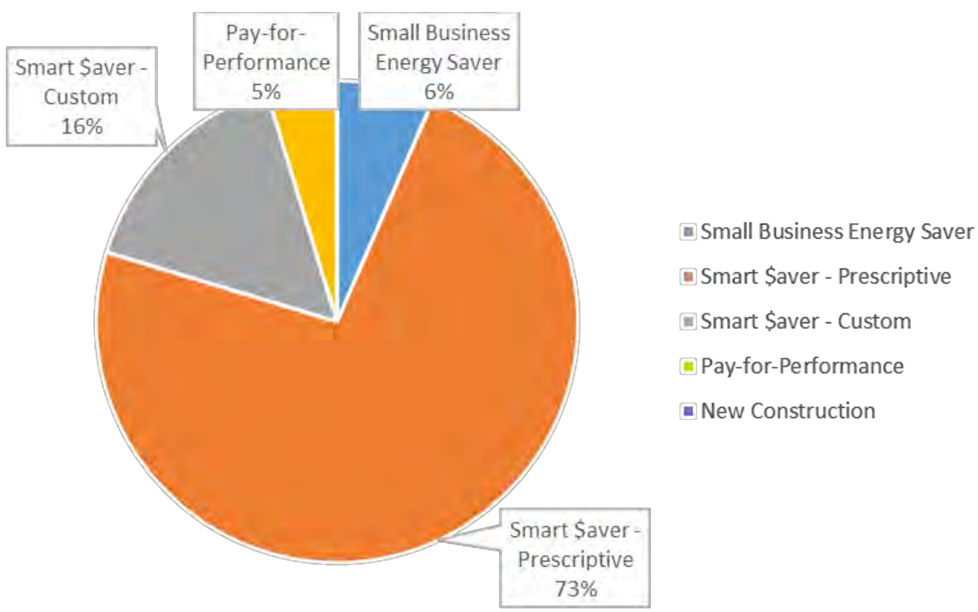
Table 7-15 summarizes the short-term (5-year), medium term (10-year) and long-term (25-year) cumulative non-residential energy efficiency achievable program potential for the base scenario, based on the full commercial and industrial customer population, **without consideration of current opt-out status**. Savings are presented as both cumulative and sum of annual impacts:

Table 7-15: DEI EE Non-Residential Achievable Program Potential (All Customers)

	Cumulative Impacts			Sum of Annual Incremental Impacts			Average Annual % of Base Sales[20]
	Energy (GWh)	Demand (MW)		Energy (GWh)	Demand (MW)		
		Summer	Winter		Summer	Winter	
Achievable Program Potential – Base Scenario, All Customers							
5 Year (2025)	1,183	188	179	1,187	188	180	1.47%
10 Year (2030)	1,755	279	269	1,944	310	297	1.21%
25 Year (2045)	1,079	182	175	3,177	518	496	0.78%

Figure 7-12 illustrates the relative contributions to the overall non-residential achievable program potential by program for the base scenario.

Figure 7-12: Non-Residential 5-Yr Cumulative Potential by Program – Base Scenario, All Customers



Detailed program results for the short-term non-residential EE programs are provided in Table 7-16:

[20] Average annual savings as percentage of annual Base Sales per period.

Table 7-16: DEI Non-Residential Achievable Program Potential (cumulative through 2025) (All Customers)

	Small Business Energy Saver	Smart $aver - Prescriptive	Smart $aver - Custom	Pay-for-Performance	New Construction
5-yr (2025) impacts – Base scenario, All Customers					
MWh savings (cumulative)	77,021	865,102	184,620	55,689	212
Summer MW savings (cumulative)	13.93	140.02	25.83	7.81	0.04
Winter MW savings (cumulative)	13.03	135.28	24.73	6.17	0.02
Program costs (cumulative) ($M)	$19.50	$137.19	$28.73	$10.21	$0.10
Levelized Cost ($/kWh)	$0.06	$0.05	$0.04	$0.09	$0.12

Table 7-17 provides the net benefits and benefit-to-cost ratios by sector for each scenario:

Table 7-17: Cost-Benefit Results – Non-Residential Programs (cumulative through 2025) (All Customers)

	Small Business Energy Saver	Smart $aver - Prescriptive	Smart $aver - Custom	Pay-for-Performance	New Construction
5-yr (2022) impacts – Base scenario, All Customers					
UCT – Net Benefits ($M)	$13.75	$328.78	$45.39	$4.32	$0.04
UCT – B/C ratio	1.71	3.40	2.58	1.42	1.42
TRC – Net Benefits($M)	$9.78	$223.83	$33.94	-$0.43	-$0.03
TRC – B/C ratio	1.42	1.92	1.84	0.97	0.83
PCT – Net Benefits ($M)	$36.24	$497.80	$94.04	$10.99	$0.07
PCT – B/C ratio	6.15	4.43	5.68	2.47	1.82
RIM – Net Benefits ($M)	-$29.53	-$314.30	-$68.74	-$14.15	-$0.11
RIM – B/C ratio	0.53	0.60	0.52	0.51	0.55

7.4.3.2 Opt Out Scenarios

Table 7-18 summarizes the short-term (5-year), medium term (10-year) and long-term (25-year) cumulative non-residential energy efficiency achievable program potential for the base scenario, enhanced scenarios as well as avoided cost sensitivity, **including the impact of current customer opt-out**. Savings are presented as both cumulative and sum of annual impacts:

Table 7-18: DEI EE Non-Residential Achievable Program Potential (with Opt-Outs)

	Cumulative Impacts			Sum of Annual Incremental Impacts			Average Annual % of Base Sales[21]
	Energy (GWh)	Demand (MW)		Energy (GWh)	Demand (MW)		
		Summer	Winter		Summer	Winter	
Achievable Program Potential – Base Scenario, Opt Outs							
5 Year (2025)	429	68	64	431	68	65	1.69%
10 Year (2030)	605	98	92	688	110	104	1.37%
25 Year (2045)	335	57	54	1,088	179	167	0.86%
Achievable Program Potential – Enhanced Scenario, Expanded Measures							
5 Year (2025)	430	68	64	433	69	65	1.69%
10 Year (2030)	637	102	96	720	114	108	1.43%
25 Year (2045)	435	70	64	1,244	198	185	0.98%
Achievable Program Potential – Expanded Measures, Increased Spending							
5 Year (2025)	462	73	68	465	73	69	1.82%
10 Year (2030)	673	107	101	770	121	114	1.53%
25 Year (2045)	464	74	68	1,329	209	195	1.05%
Achievable Program Potential – Avoided Cost Sensitivity							
5 Year (2025)	481	75	70	484	75	71	1.89%
10 Year (2030)	692	108	103	788	123	116	1.57%
25 Year (2045)	440	71	65	1,321	208	193	1.04%

Figure 7-13, Figure 7-14, Figure 7-15 and Figure 7-16 illustrate the relative contributions to the overall non-residential achievable program potential by program for the base scenario, enhanced scenarios as well as avoided cost sensitivity.

[21] Average annual energy savings as percentage of non-opt out annual Base Sales per period. Appropriate opt-out rates were applied into the model to reduce the non-residential sales estimates.

Figure 7-13: Non-Residential 5-Yr Cumulative Potential by Program – Base Scenario, Opt Out

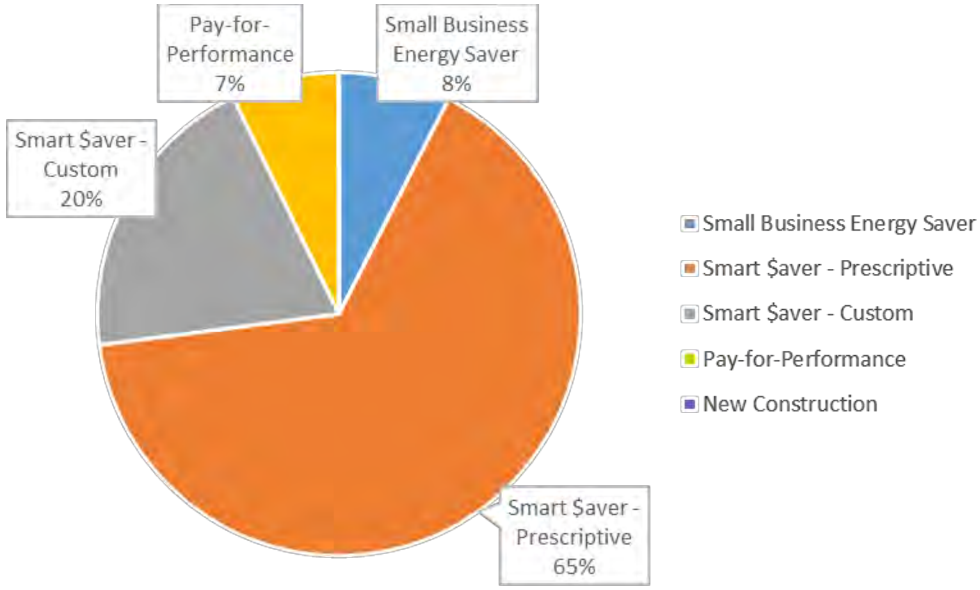


Figure 7-14: Non-Residential 5-Yr Cumulative Potential by Program – Enhanced Scenario, Expanded Measures

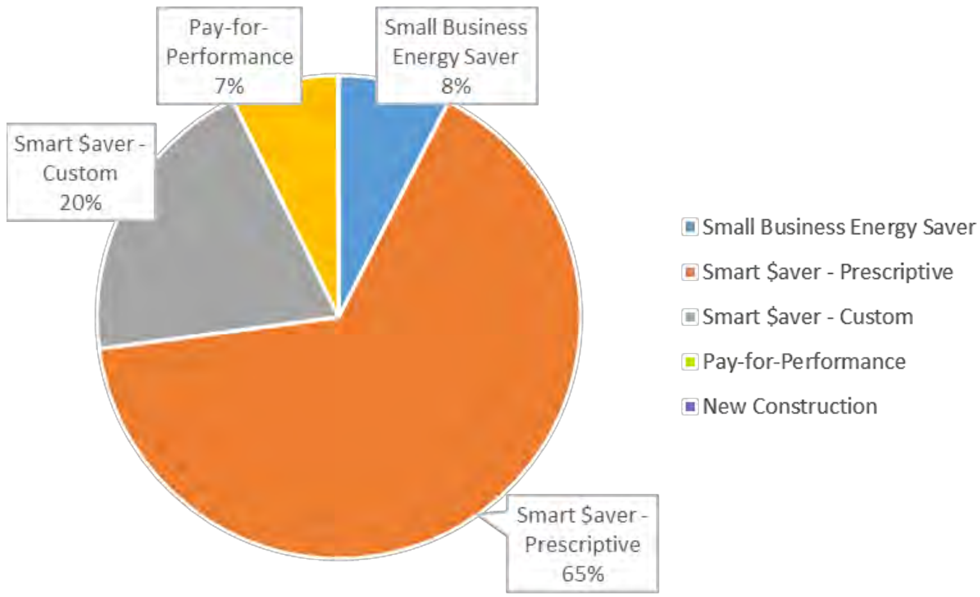


Figure 7-15: Non-Residential 5-Yr Cumulative Potential by Program – Enhanced Scenario, Increased Spending

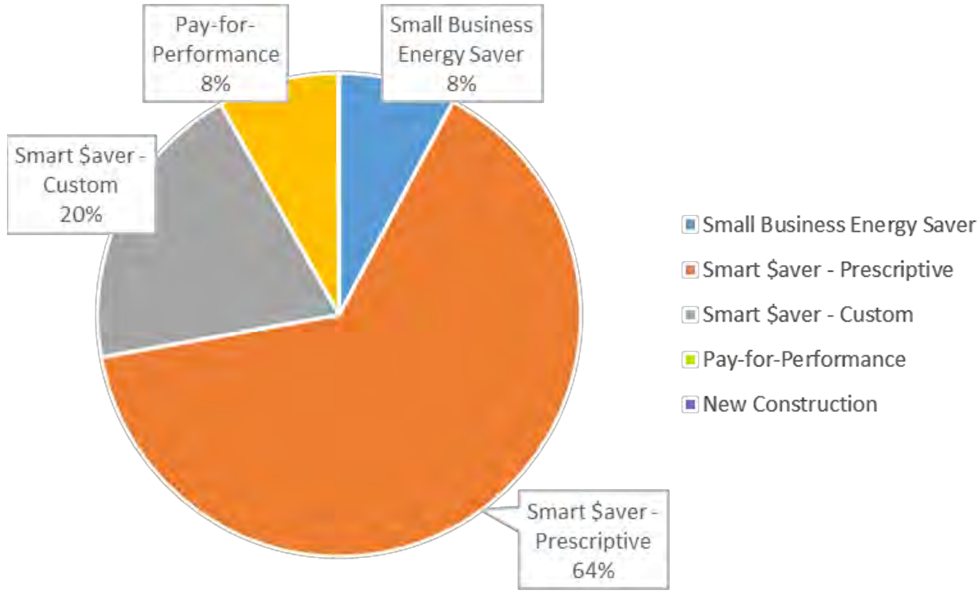
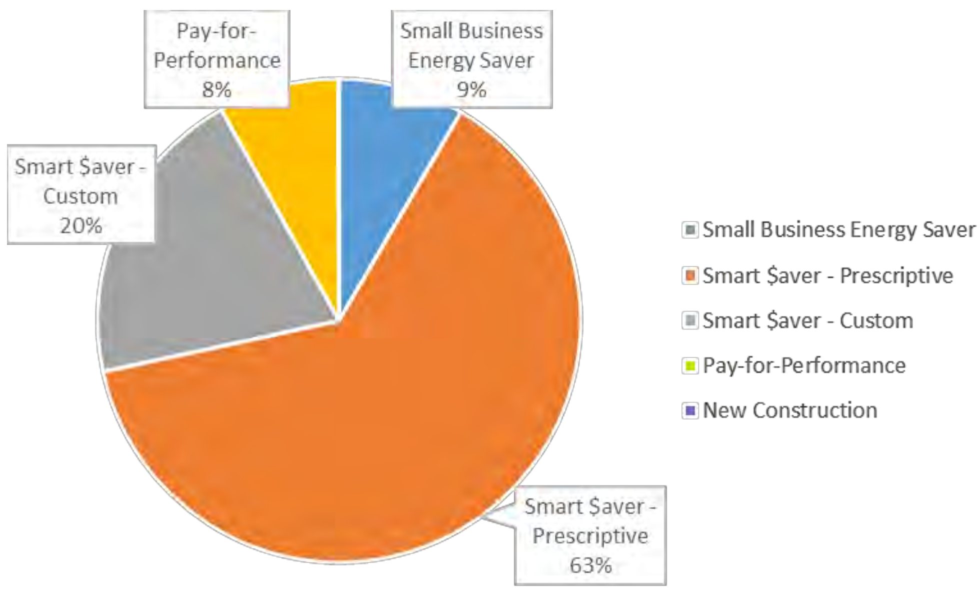


Figure 7-16: Non-Residential 5-Yr Cumulative Potential by Program – Avoided Cost Sensitivity



Detailed program results for the short-term non-residential EE programs are provided in Table 7-19:

Table 7-19: DEI Non-Residential Achievable Program Potential (cumulative through 2025) (with Opt-Outs)

	Small Business Energy Saver	Smart $aver - Prescriptive	Smart $aver - Custom	Pay-for-Performance	New Construction
5-yr (2025) impacts – Base Scenario, Opt Outs					
MWh savings (cumulative)	32,227	280,511	84,907	30,904	111
Summer MW savings (cumulative)	5.56	46.59	11.71	4.29	0.02
Winter MW savings (cumulative)	5.25	44.38	11.07	3.52	0.01
Program costs (cumulative) ($M)	$8.65	$49.03	$15.03	$5.91	$0.05
Levelized Cost ($/kWh)	$0.07	$0.05	$0.05	$0.09	$0.12
5-yr (2025) impacts – Enhanced Scenario, Expanded Measures					
MWh savings (cumulative)	32,309	281,361	85,453	30,903	226
Summer MW savings (cumulative)	5.57	46.70	11.77	4.29	0.03
Winter MW savings (cumulative)	5.25	44.48	11.14	3.52	0.02
Program costs (cumulative) ($M)	$8.68	$49.16	$15.11	$5.91	$0.11
Levelized Cost ($/kWh)	$0.07	$0.05	$0.05	$0.09	$0.12
5-yr (2025) impacts – Enhanced Scenario, Increased Spending					
MWh savings (cumulative)	36,141	297,329	90,745	37,419	264
Summer MW savings (cumulative)	6.13	49.05	12.46	5.16	0.04
Winter MW savings (cumulative)	5.75	46.59	11.82	4.29	0.03
Program costs (cumulative) ($M)	$10.18	$85.42	$21.60	$9.85	$0.18
Levelized Cost ($/kWh)	$0.07	$0.05	$0.05	$0.09	$0.12
5-yr (2025) impacts – Avoided Cost Sensitivity					

	Small Business Energy Saver	Smart $aver - Prescriptive	Smart $aver - Custom	Pay-for-Performance	New Construction
MWh savings (cumulative)	40,559	303,851	97,511	38,712	280
Summer MW savings (cumulative)	6.74	49.32	13.35	5.43	0.04
Winter MW savings (cumulative)	6.25	47.08	12.54	4.44	0.03
Program costs (cumulative) ($M)	$11.47	$63.22	$20.24	$10.68	$0.14
Levelized Cost ($/kWh)	$0.08	$0.06	$0.06	$0.12	$0.13

Table 7-20 provides the net benefits and benefit-to-cost ratios by sector for each scenario:

Table 7-20: Cost-Benefit Results – Non-Residential Programs (cumulative through 2025) (with opt outs)

	Small Business Energy Saver	Smart $aver - Prescriptive	Smart $aver - Custom	Pay-for-Performance	New Construction
5-yr (2025) impacts – Base Scenario, Opt Outs					
UCT – Net Benefits ($M)	$4.90	$107.95	$18.40	$2.62	$0.02
UCT – B/C ratio	1.57	3.20	2.22	1.44	1.38
TRC – Net Benefits($M)	$3.02	$67.17	$11.28	-$0.21	-$0.02
TRC – B/C ratio	1.29	1.75	1.51	0.98	0.80
PCT – Net Benefits ($M)	$14.11	$154.33	$40.68	$5.92	$0.03
PCT – B/C ratio	5.47	3.86	4.67	2.36	1.68
RIM – Net Benefits ($M)	-$12.36	-$100.27	-$33.35	-$7.67	-$0.05
RIM – B/C ratio	0.52	0.61	0.50	0.53	0.56
5-yr (2025) impacts – Enhanced Scenario, Expanded Measures					
UCT – Net Benefits ($M)	$4.91	$108.17	$18.61	$2.62	$0.07
UCT – B/C ratio	1.57	3.20	2.23	1.44	1.64
TRC – Net Benefits($M)	$3.03	$67.30	$11.46	-$0.21	-$0.01

	Small Business Energy Saver	Smart $aver - Prescriptive	Smart $aver - Custom	Pay-for-Performance	New Construction
TRC – B/C ratio	1.29	1.75	1.52	0.98	0.94
PCT – Net Benefits ($M)	$14.16	$154.73	$41.06	$5.92	$0.08
PCT – B/C ratio	5.47	3.86	4.69	2.36	1.86
RIM – Net Benefits ($M)	-$12.41	-$100.57	-$33.57	-$7.67	-$0.10
RIM – B/C ratio	0.52	0.61	0.50	0.53	0.63
5-yr (2025) impacts – Enhanced Scenario, Increased Spending					
UCT – Net Benefits ($M)	$4.67	$78.90	$14.22	$0.40	$0.03
UCT – B/C ratio	1.46	1.92	1.66	1.04	1.15
TRC – Net Benefits($M)	$3.20	$68.96	$12.66	-$0.40	-$0.01
TRC – B/C ratio	1.27	1.72	1.55	0.96	0.95
PCT – Net Benefits ($M)	$15.96	$195.14	$49.71	$9.73	$0.15
PCT – B/C ratio	6.48	9.18	9.58	4.66	3.76
RIM – Net Benefits ($M)	-$14.20	-$140.08	-$41.28	-$11.99	-$0.18
RIM – B/C ratio	0.51	0.54	0.46	0.46	0.54
5-yr (2025) impacts – Avoided Cost Sensitivity					
UCT – Net Benefits ($M)	$8.49	$152.53	$30.19	$4.11	$0.11
UCT – B/C ratio	1.74	3.41	2.49	1.39	1.78
TRC – Net Benefits($M)	$5.88	$93.14	$19.02	-$2.72	$0.00
TRC – B/C ratio	1.42	1.76	1.61	0.84	1.01
PCT – Net Benefits ($M)	$15.71	$150.37	$43.52	$5.44	$0.08
PCT – B/C ratio	4.72	3.04	3.77	1.62	1.62
RIM – Net Benefits ($M)	-$11.44	-$71.41	-$29.04	-$10.08	-$0.09
RIM – B/C ratio	0.64	0.75	0.63	0.59	0.73

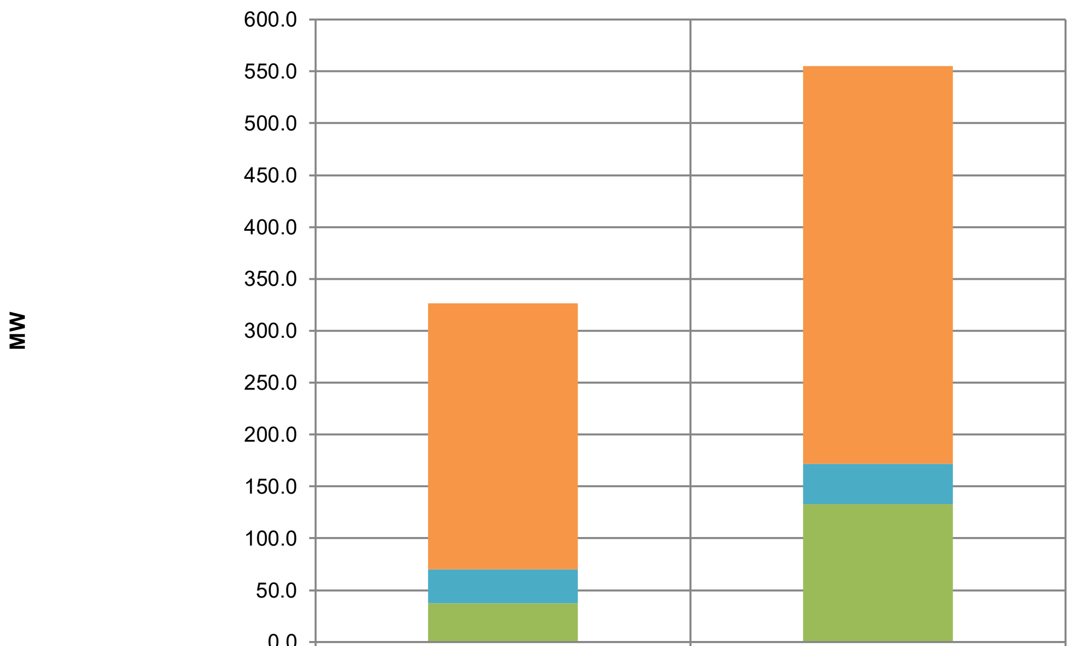
7.5 DEI Demand Response Achievable Program Potential

This section presents the estimated overall achievable program potential for the base and enhance scenarios. The results are provided separately for summer and winter peaking capacity. The results are further broken down by customer segment and presented in the form of supply curves. All results presented reflect the projected achievable DR potential by 2045.

7.5.1 Summer Peaking Capacity

Figure 7-17 presents the overall summer peak capacity results for both scenarios, broken down by sector. The capacity is what is expected to be available during the peak hour of system demand. Overall, the estimated magnitude of peak capacity comes out to 326 MW in the Base Scenario and 555 MW in the Enhanced Scenario. This equates to 6.5% of Duke Indiana's peak load in the Base Scenario and 11.0% in the Enhanced Scenario. Most of the peak capacity potential comes from the large C&I sector, which is not surprising given that it makes up a large portion of the overall system demand. Variation in the peak capacity between the two scenarios can be attributed to differences in incentive levels, the degree of marketing, and technology cost forecasts.

Figure 7-17 DR Summer Peak Capacity Program Potential[22]



	Base	Enhanced
Large C&I	256.4	383.8
Small and Medium Business	32.4	38.9
Residential	37.4	132.6

[22] Results are incremental to current DR capacity provided by Power Manager and PowerShare programs

Because the achievable program potential is driven by marketing intensity, incentive levels, and technology costs, it is possible to yield non-linear changes in participation level. This can be seen in the program participation results in Table 7-21. Note that this table shows the overall participation rate for each sector, including existing participation in the Power Manager program.

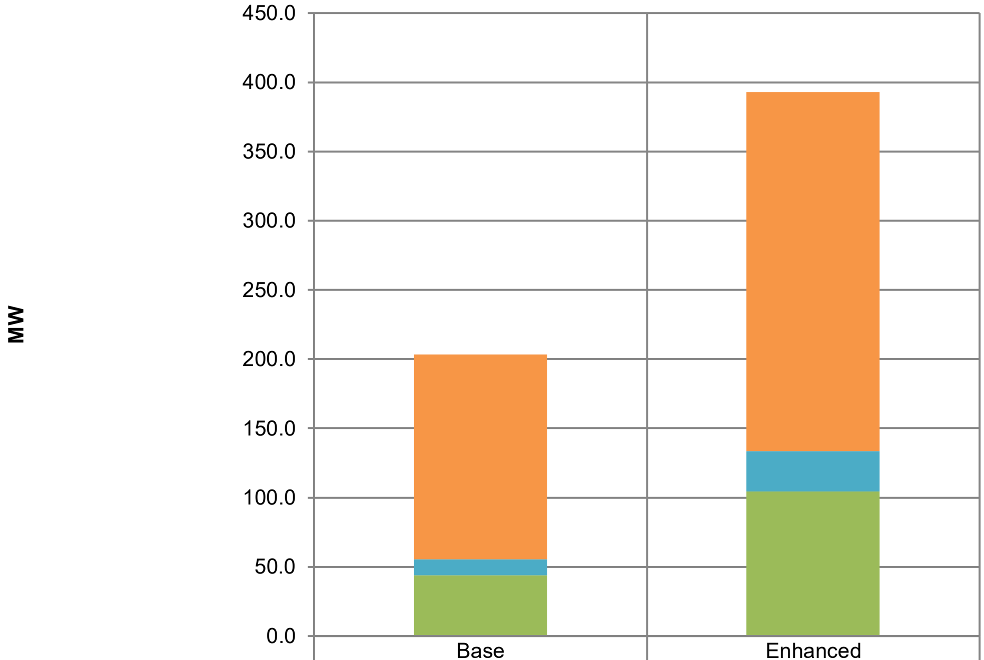
Table 7-21 DR Program Participation Rates by Scenario and Customer Class (Including Existing DR Capacity)

Customer Class	Base	Enhanced	Units
Residential Electric Heating	8.4%	19.7%	% of Customers
Small and Medium Business	20.2%	23.6%	% of Customers
Large C&I	47.8%	56.1%	% of Load

7.5.2 Winter Peaking Capacity

Figure 7-18 presents the overall winter peak capacity results for both scenarios, broken down by sector. The capacity is what is expected to be available during the peak hour of system demand. Overall, the estimated magnitude of peak capacity is 203 MW in the Base Scenario and 393 MW in the Enhanced Scenario. This equates to 4.4% of Duke Indiana's winter peak load in the Base Scenario and 8.4% of the winter peak in the Enhance Scenario. Most of the peak capacity potential comes from the large C&I sector, which is not surprising given that it makes up a large portion of the overall system demand. Variation in the peak capacity across the various scenarios can be attributed to differences in incentive levels, the degree of marketing, and technology cost forecasts.

Figure 7-18 DR Winter Peak Capacity Program Potential



	Base	Enhanced
Large C&I	147.6	259.1
Small and Medium Business	11.7	29.3
Residential	44.0	104.5

7.5.3 Segment specific results

A total of 34 different customer segments were individually analyzed. This includes 3 segments each for gas and electric heated residential customers (6), 5 industry types for SMB customers, and 23 industries for large commercial and industrial customers. This section presents the segment-level results, focusing on the customer segments that are most attractive to pursue, allowing for prioritization and targeted marketing of those customer segments.

These results are fairly similar across the two scenarios that were studied, with the main difference being the magnitude of the overall resources being larger for the Enhanced Scenario due to higher participation rates across all sectors and the inclusion of additional residential end uses dramatically increasing the residential DR capacity. For the sake of simplicity, only the results for the Base Scenario are presented in this section.

Table 7-22 shows the cost/benefit details for residential customer segments. All customer segments are cost-effective under the base case assumptions to pursue for DR enrollment. However, these customers do not provide much DR capacity (the aggregate results are reported with existing DR capacity from Power Manager removed). Because the Base Scenario does not consider pool pumps, there is not much incremental DR capacity. Inclusion of pool pumps in the Enhanced Scenario provides 21.4 MW of summer capacity.

SMB customers similarly do not provide much DR capacity, due to their being a relatively small portion of the overall system load and having relatively low participation rates. In fact, the “wholesale, transportation, and utilities” customer segments do not provide positive net benefits once participation rates are taken into account in the achievable program potential analysis.

The vast majority of the DR potential comes from the large C&I sector. These customers comprise a large portion of the overall system load, and are expected to have considerably high participation rates. The participation rate presented here represents the percentage of the overall peak period load from each customer segment that would be available for curtailment if DR programs are properly incentivized and marketed. They reflect a saturated market (i.e., all customers are properly informed of the program and given the opportunity to enroll).

Table 7-23 and Table 7-24 show the segment specific program potential results for each non-residential sector.

Table 7-22: Residential Single Family Segment Specific Achievable Program Potential

	Residential				Summer				Winter					
	Usage bin	# of accounts	Participation	Total Cost	Agg. MW	NPV of Avoided Gen Capacity Benefits	NPV of Avoided Dist Capacity Benefits	Total Benefit	Agg. MW	NPV of Avoided Gen Capacity Benefits ($/kW)	NPV of Avoided Dist Capacity Benefits ($/kW)	Total Benefit	Total Aggregate Net Benefit	Total Net Benefit per Enrolle
Electric	1	46,911	7.42%	$1,444,520	2.6	$ 323.74	$ 333.19	$ 1,692,452	9.1	$ 142.16	$ 145.06	$ 2,603,437	$ 2,851,369	$819
	2	46,911	6.60%	$1,284,270	3.9	$ 323.74	$ 333.19	$ 2,549,379	8.1	$ 142.16	$ 145.06	$ 2,314,622	$3,579,730	$1,157
	3	46,911	8.59%	$1,671,494	6.6	$ 323.74	$ 333.19	$ 4,342,252	10.5	$ 142.16	$ 145.06	$ 3,012,509	$5,683,267	$1,411
Gas	1	198,486	10.18%	$8,381,749	14.9	$ 323.74	$ 333.19	$ 9,820,361	-	$ 142.16	$ 145.06	$ -	$1,438,612	$71
	2	198,486	7.24%	$5,961,423	18.0	$ 323.74	$ 333.19	$ 11,833,898	-	$ 142.16	$ 145.06	$ -	$5,872,475	$409
	3	198,486	11.49%	$9,463,889	37.4	$ 323.74	$ 333.19	$ 24,585,546	-	$ 142.16	$ 145.06	$ -	$15,121,658	$663
Total AC/Heating Program Potential					83.5				27.6					
Additional Potential from WH and PP					16.5				16.5					
Total Potential (Unadjusted)					100.0				44.1					
Total Potential (Adjusted)					**37.4**				**44.0**					

Table 7-23: SMB Segment Specific Achievable Program Potential

Small/Medium C&I				Summer				Winter					
Segment	# Accounts	Participation	Total Cost	Agg. MW	NPV of Avoided Gen Capacity Benefits ($/kW)	NPV of Avoided Dist Capacity Benefits ($/kW)	Total Benefit	Agg. MW	NPV of Avoided Gen Capacity Benefits ($/kW)	NPV of Avoided Dist Capacity Benefits ($/kW)	Total Benefit	Total Aggregate Net Benefit	Total Net Benefit per Enrollee
Healthcare/Hospitals	3,994	16.43%	$572,676	2.9	$ 315.84	$ 325.79	$ 1,842,993	3.8	$ 138.69	$ 141.90	$ 1,078,883	$ 2,349,199	$3,580
Offices	37,500	17.19%	$5,624,349	9.1	$ 315.84	$ 325.79	$ 5,836,866	2.4	$ 138.69	$ 141.90	$ 659,706	$872,223	$135
Retail Stores	9,470	33.69%	$2,784,028	13.8	$ 315.84	$ 325.79	$ 8,853,683	1.2	$ 138.69	$ 141.90	$ 347,952	$6,417,607	$2,012
Wholesale, Transportation & Utilities	18,997	28.91%	$4,792,386	2.4	$ 315.84	$ 325.79	$ 1,527,402	1.0	$ 138.69	$ 141.90	$ 294,448	($2,970,537)	($541)
Other	34,274	16.94%	$5,066,367	14.3	$ 315.84	$ 325.79	$ 9,152,168	4.2	$ 138.69	$ 141.90	$ 1,184,863	$5,270,664	$908
Total (Unadjusted)				40.0				11.7					
Total (Adjusted)				**32.4**				**11.7**					

Table 7-24: Large C&I Segment Specific Achievable Program Potential

Large C&I - 300 kW and Up				Summer				Winter					
Segment	MW of Tech Potential for cost calc (max of winter and summer)	Participation	Total Cost	Agg. MW	NPV of Avoided Gen Capacity Benefits ($/kW)	NPV of Avoided Dist Capacity Benefits ($/kW)	Total Benefit	Agg. MW	NPV of Avoided Gen Capacity Benefits ($/kW)	NPV of Avoided Dist Capacity Benefits ($/kW)	Total Benefit	Total Aggregate Net Benefit	Total Net Benefit per Enrolled MW
Agriculture & Forestry	2.2	59.22%	$ 465,161	1.2	$ 315.84	$ 325.79	$ 755,284	1.3	$ 138.69	$ 141.90	$ 367,591	$657,714	$502,057
Chemicals & Plastics	182.9	52.93%	$ 34,366,668	96.8	$ 315.84	$ 325.79	$ 62,102,264	82.3	$ 138.69	$ 141.90	$ 23,083,492	$50,819,088	$525,059
Colleges & Universities	75.4	33.67%	$ 9,017,000	25.4	$ 315.84	$ 325.79	$ 16,294,163	16.4	$ 138.69	$ 141.90	$ 4,598,393	$11,875,556	$467,639
Construction	15.0	53.36%	$ 2,840,409	8.0	$ 315.84	$ 325.79	$ 5,132,759	7.6	$ 138.69	$ 141.90	$ 2,133,348	$4,425,698	$553,248
Electrical & Electronic Equipment	41.0	52.93%	$ 7,703,512	21.7	$ 315.84	$ 325.79	$ 13,920,625	20.4	$ 138.69	$ 141.90	$ 5,713,298	$11,930,412	$549,902
Grocery stores / Convenience chains	5.5	66.10%	$ 1,287,371	3.6	$ 315.84	$ 325.79	$ 2,326,343	2.1	$ 138.69	$ 141.90	$ 603,089	$1,642,061	$452,902
Healthcare	17.0	36.29%	$ 2,188,440	6.2	$ 315.84	$ 325.79	$ 3,954,620	5.4	$ 138.69	$ 141.90	$ 1,508,599	$3,274,778	$531,332
Hospitals	50.4	33.67%	$ 6,025,945	17.0	$ 315.84	$ 325.79	$ 10,889,180	10.5	$ 138.69	$ 141.90	$ 2,950,290	$7,813,525	$460,406
Institutional	23.4	33.67%	$ 2,793,883	7.9	$ 315.84	$ 325.79	$ 5,048,685	5.9	$ 138.69	$ 141.90	$ 1,648,296	$3,903,098	$496,044
Large Public Assembly (Churches, Stadiums, Arena, & Sports Venues)	0.7	33.67%	$ 84,057	0.2	$ 315.84	$ 325.79	$ 151,895	0.2	$ 138.69	$ 141.90	$ 47,512	$115,350	$487,261
Lodging (Hospitality)	1.1	36.29%	$ 142,882	0.4	$ 315.84	$ 325.79	$ 240,055	0.4	$ 138.69	$ 141.90	$ 112,912	$210,085	$522,078
Lumber, Furniture, Pulp & Paper	69.4	52.93%	$ 13,047,023	36.7	$ 315.84	$ 325.79	$ 23,576,613	26.3	$ 138.69	$ 141.90	$ 7,386,303	$17,915,894	$487,580
Metal Products & Machinery	314.3	52.93%	$ 59,065,947	164.2	$ 315.84	$ 325.79	$ 105,378,170	166.3	$ 138.69	$ 141.90	$ 46,676,581	$92,988,804	$559,001
Misc. Manufacturing	132.2	52.93%	$ 24,850,574	70.0	$ 315.84	$ 325.79	$ 44,906,213	62.2	$ 138.69	$ 141.90	$ 17,453,604	$37,509,243	$535,946
Retail	43.5	66.10%	$ 10,217,097	28.8	$ 315.84	$ 325.79	$ 18,462,798	19.6	$ 138.69	$ 141.90	$ 5,490,350	$13,736,051	$477,368
Miscellaneous	83.8	17.87%	$ 5,313,795	15.0	$ 315.84	$ 325.79	$ 9,602,289	12.8	$ 138.69	$ 141.90	$ 3,599,029	$7,887,524	$527,054
Primary Resource Industries	37.4	59.22%	$ 7,862,440	22.1	$ 315.84	$ 325.79	$ 14,207,817	17.8	$ 138.69	$ 141.90	$ 4,984,354	$11,329,731	$511,660
Schools K-12	43.1	25.69%	$ 3,932,577	11.1	$ 315.84	$ 325.79	$ 7,106,360	9.8	$ 138.69	$ 141.90	$ 2,754,906	$5,928,689	$535,304
Stone, Clay, Glass & Concrete	103.6	52.93%	$ 19,480,324	54.9	$ 315.84	$ 325.79	$ 35,201,906	52.8	$ 138.69	$ 141.90	$ 14,825,807	$30,547,389	$556,797
Textiles & Leather	2.2	52.93%	$ 421,072	1.2	$ 315.84	$ 325.79	$ 739,706	1.2	$ 138.69	$ 141.90	$ 332,750	$651,384	$549,287
Transportation Equipment	144.4	53.36%	$ 27,354,635	77.0	$ 315.84	$ 325.79	$ 49,431,174	71.9	$ 138.69	$ 141.90	$ 20,180,057	$42,256,597	$548,507
Warehouse	135.0	53.36%	$ 25,583,910	72.1	$ 315.84	$ 325.79	$ 46,231,387	59.2	$ 138.69	$ 141.90	$ 16,623,100	$37,270,577	$517,271
Water & Wastewater	8.8	53.36%	$ 1,662,642	4.7	$ 315.84	$ 325.79	$ 3,004,477	4.6	$ 138.69	$ 141.90	$ 1,283,873	$2,625,708	$560,746
Total (Unadjusted)				**746.0**				**657.0**					
Total (Adjusted)				**256.4**				**147.6**					

7.5.4 Key Findings

The overall DR potential is estimated to be 326 MW of peak summer capacity in the Base Scenario and 555 MW under the assumption of aggressive marketing. These estimates are based on an in-depth, bottom-up assessment of load reduction potential of all customer segments, and includes an analysis of pricing and program-based DR.

The extent to whether these potential figures can be attained in a cost-effective manner by 2045 depends on the ability to implement programs that target all possible end-uses and cost-effective customer segments. These estimates rely upon assumptions around the future value of capacity.

The customer segment-level analysis of the program- and pricing-based DR potential sheds light on which customer segments can provide the greatest magnitude of capacity, as well as which customer segments are most cost-effective to pursue. Unsurprisingly, the most attractive customer segments from a benefit/cost perspective are customers who have more load available for reduction during peak hours: large C&I customers, particularly metal products and machinery, retail, chemicals and plastics, and warehouses. In general, these customers are more capable of shifting load with little inconvenience/cost, and therefore tend to have higher participation levels in DR programs as well as greater willingness to shed a higher percentage of their load.

8 Appendices

Appendix A MPS Measure Algorithms and Parameters

For information on how Nexant developed this list, please see Section 4.

A.1 Residential Measure Algorithms and Parameters

Residential Measure
Algorithms and Paran

A.2 Commercial Measure Algorithms and Parameters

Commercial Measure
Algorithms and Paran

A.3 Industrial Measure Algorithms and Parameters

Industial Measure
Algorithms and Paran

Appendix B Measure Impacts

B.1 Residential Measure Impacts

DEI Measure Impacts_Res.xlsx

B.2 Commercial Measure Impacts

DEI Measure Impacts_Com.xlsx

B.3 Industrial Measure Impacts

DEI Measure Impacts_Ind.xlsx

Appendix C Measure Cost-Benefit Test Results

C.1 Residential Measure UCT & TRC Results

Residential Measures
UCT_TRC Screening R

C.2 Commercial Measure UCT & TRC Results

Commercial
Measures UCT_TRC S

C.3 Industrial Measure UCT & TRC Results

Industrial Measures
UCT_TRC Screening R

Appendix D Customer Demand Characteristics

Customer demand on peak days was analyzed by rate classes within each sector. Outputs presentation includes load shapes on peak days and average days, along with the estimates of technical potential by end uses. The two end uses, Air Conditioning and Heating, were studied for both residential and large C&I customers; however, in residential sector, another two end uses were also incorporated into the analyses, which are Water Heaters and Pool Pumps.

Residential

Air Conditioning

The cooling load shapes on the summer peak weekday and average weekdays were generated from hourly load research sample in DEI territory for 2019. A regression model was built to estimate relationship between load values and cooling degree days (CDD) (shown as *Equation (1)*). The p-values of the model and coefficient are both less than 0.05, which means that they are of statistically significance. The product of actual hourly CDD values and coefficient would be used as cooling load during that hour in terms of per customer.

Equation (1):

$$Load_t = CDD_t * \beta_1 + i.month + \varepsilon$$

Where:

t	Hours in each day in year 2013 and 2014
$Load_t$	Load occurred in each hour
CDD_t	Cooling Degree Day value associated with each hour
β_1	Change in average load per CDD
$i.month$	Nominal variable, month
ε	The error term

To study the peak technical potential, a peak day was selected if it has the hour with system peak load during summer period (among May to September). Technical potential for residential customers was then calculated as the aggregate consumption during that summer peak hour.

Space Heating

Similar to the analyses for air conditioning, the heating load shapes on peak day and average days were obtained from the same hourly load research profile in 2013 and 2014, and the peak day was defined as the day with system peak load during winter period. The regression model was modified to evaluate relationship between energy consumption and heating degree days (HDD) (shown as Equation (2)), but the technical potential was calculated in the same way as illustrated earlier.

Equation (2):

$$Load_t = HDD_t * \beta_1 + i.month + \varepsilon$$

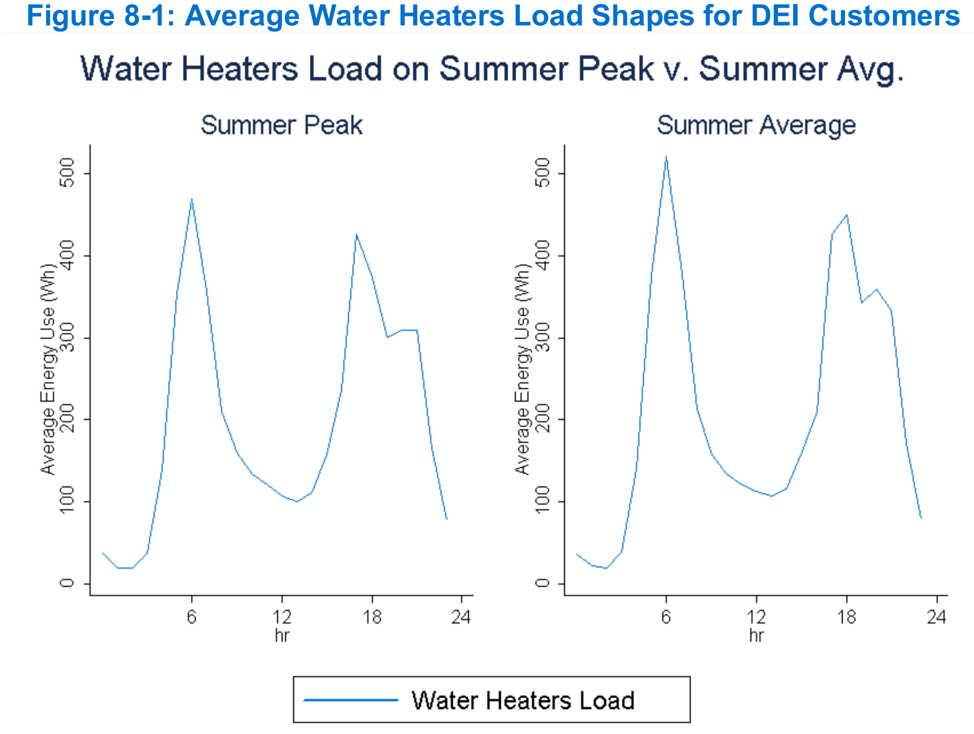
Where:

t	Hours in each day in year 2013 and 2014
$Load_t$	Load occurred in each hour
HDD_t	Heating Degree Day value associated with each hour
β_1	Change in average load per HDD
$i.month$	Nominal variable, month
ε	The error term

Water Heaters

Interval load data by end-use are not available for individual customers in Duke territory, so the analyses of water heaters was completed based on end-use metered data from DEI.

Figure 8-1: Average Water Heaters Load Shapes for DEI Customers

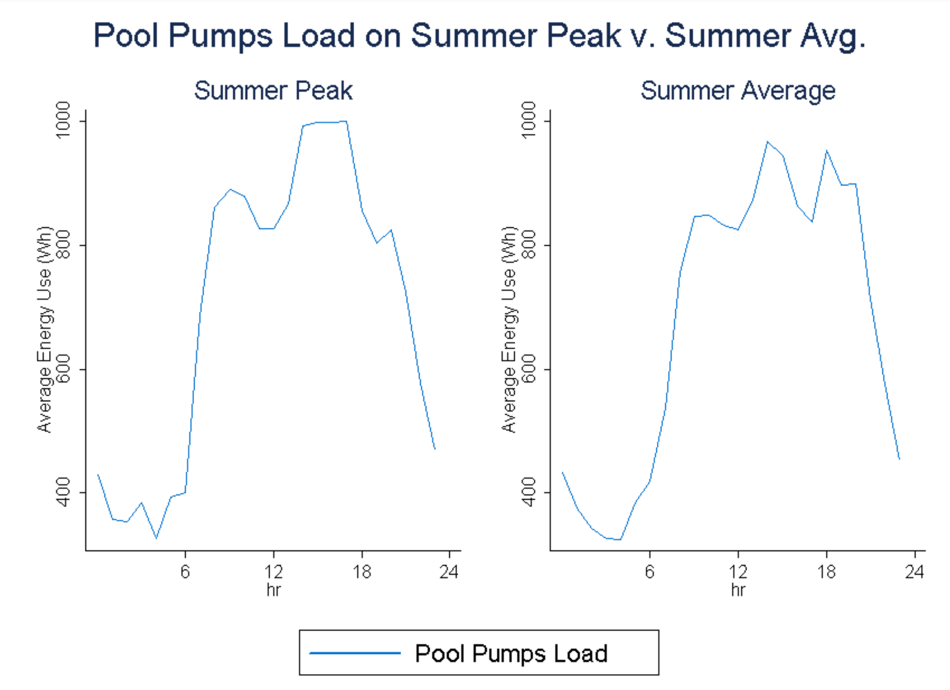


It is apparent from the Figure 8-3 that there is not much difference from peak usage and average usage, which proves that water heater loads has low sensitivity to weather. There are two spikes in a day, indicating two shifts when people would be likely to take showers. The time periods with highest consumption are 5:00 am – 7:00 am and 5:00 pm – 8:00 pm.

Pool Pumps

Pool pump load shapes were based on data provided by DEI.

Figure 8-2: Average Pool Pumps Load Shapes for DEI Customers



According to the Figure 8-4, the peak hours for pool pumps are 3:00 pm to 6:00 pm, and there is minor sensitivity with weather observed by comparing peak loads and average loads.

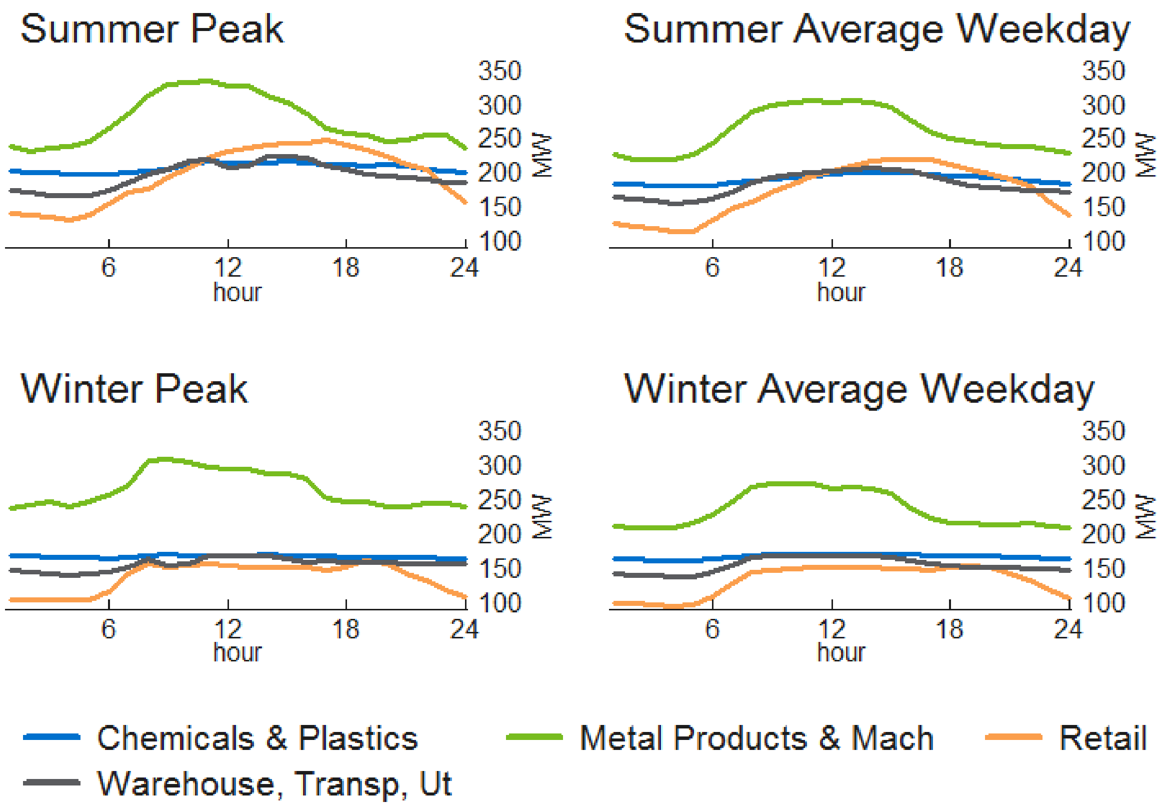
Large C&I Customers

Estimates of technical potential were based on one year of interval data (2016) for all customers in the TEC and HLF rate classes and all customers in the LLF rate class with annual consumption greater than 94,000 kWh. Customers were categorized into one of 23 industry segments for the purpose of analysis. Technical potential for these customers was defined as the aggregate usage within each segment during summer and winter peak system hours.

Visual presentations of the results are shown below. These graphs are useful to identify the segments with the highest potential as well as examine the weather-sensitivity of each segment by comparing peak usage to the average usage in each season. For example, the segments with the highest technical potential are the metal products & machinery, chemicals & plastics, retail, and warehouse, transportation & non-water utility segments. In contrast to the metal products &

machinery and retail segments that show a modest amount of weather sensitivity year-around, the other two segments show almost no weather sensitivity in either season.

Figure 8-3: Aggregate Load Shapes for DEI Large C&I Customers



Appendix E Stakeholder Engagement Documents

E.1 20200901_Nexant Response to OSB Work Plan Comments

Nexant Response to
OSB Work Plan Comm

E.2 20200908_Measure Development Process_draft

20200908_Measure
Development Process

E.3 20201019_Response to OSB Comments on Draft Measure List

20201019_Response
to OSB Comments on

E.4 20201030_Response to OSB Comments on Disaggregated Forecast

20201030_Response
to OSB Comments on

E.5 20201103_Follow up on Measure List Comments from OSB

20201103_Follow Up
on Measure List Comı

E.6 20201216_Response to OSB Comments on Res Measure Impacts

20201216_Response
to OSB Comments on

E.7 20201216_Response to OSB Comments on Com Measure Impacts

20201216_Response
to OSB Comments on

E.8 20201216_Response to OSB Comments on Ind Measure Impacts

20201216_Response
to OSB Comments on

E.9 20201216_DEI MPS Tech Potential_DRAFT

20201216_DEI MPS
Tech Potential_DRAFT

E.10 20201216_DEI MPS Econ Potential_DRAFT

20201216_DEI MPS
Econ Potential_DRAFT

E.11 20210119_DEI MPS Econ_Ach Base_DRAFT

20210119_DEI MPS
Econ_Ach Base_DRAF

E.12 20210119_Response to OSB Comments on TP_EP_Measure Impacts

20210119_Response
to OSB Comments on

E.13 20210219_Program Cost Slides_Res_DRAFT

20210219_Program
Cost Slides_Res_DRAF

E.14 20210219_Program Cost Slides_NonRes_DRAFT

20210219_Program
Cost Slides_NonRes_[

E.15 DEI MPS - Program Planning - 102120

DEI MPS - Program
Planning - 102120.pd

E.16 DEI MPS – Interim Results

Presentations of interim results were made on several occasions. The Capstone presentation (below) includes a list of these occasions. Presentations of interim results are not included here, only final results.

E.17 DEI MPS – Capstone Presentation

The capstone presentation includes interim draft results of our analysis, which are superseded by the results contained in the main body of this report.

20210308_DEI
MPS_Report Capstone

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DEI Expanded Measures	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Residential											
Non-Behavioral Net	46,779,019	47,964,582	49,499,512	51,238,986	52,916,843	52,848,945	53,603,341	54,665,979	55,712,454	56,257,801	56,819,146
Net to Gross Ratio	85.5%	85.7%	86.3%	86.3%	86.3%	86.3%	86.3%	86.3%	86.3%	86.3%	86.3%
Gross	54,717,236	55,935,488	57,378,944	59,395,311	61,340,253	61,261,547	62,136,029	63,367,819	64,580,874	65,213,031	65,863,732
Behavioral *	60,066,574	60,220,380	60,698,478	61,228,632	61,973,636	62,384,029	63,007,943	63,743,224	64,866,185	65,679,093	66,775,808
Gross Residential KWh	**114,783,810**	**116,155,868**	**118,077,423**	**120,623,942**	**123,313,889**	**123,645,576**	**125,143,972**	**127,111,044**	**129,447,059**	**130,892,123**	**132,639,540**
Non-Residential											
Non-Behavioral Net	98,554,909	86,422,755	74,544,801	65,976,087	60,803,486	56,225,604	51,075,156	45,432,830	39,932,973	38,314,854	37,355,251
Net to Gross Ratio	84.7%	84.7%	85.2%	85.2%	85.2%	85.2%	85.2%	85.2%	85.2%	85.2%	85.2%
Gross	116,289,577	102,086,440	87,500,877	77,442,898	71,371,287	65,997,756	59,952,147	53,329,172	46,873,425	44,974,073	43,847,688
Behavioral *	965,936	957,669	951,216	944,265	942,951	935,648	927,569	921,747	919,262	912,897	914,303
Gross Non-Residential KWh	**117,255,513**	**103,044,108**	**88,452,093**	**78,387,164**	**72,314,237**	**66,933,405**	**60,879,716**	**54,250,919**	**47,792,688**	**45,886,970**	**44,761,991**
Total Incremental Gross KWh Impacts at Generation	**232,039,322**	**219,199,976**	**206,529,516**	**199,011,106**	**195,628,126**	**190,578,981**	**186,023,689**	**181,361,963**	**177,239,746**	**176,779,094**	**177,401,531**
Total Cumulative Gross MWh Impacts at Generation	**867,338**	**1,086,538**	**1,293,067**	**1,492,079**	**1,687,707**	**1,878,286**	**2,064,309**	**2,245,671**	**2,422,911**	**2,599,690**	**2,777,092**

DEI Expanded Measures	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Residential											
Non-Behavioral Net	57,763,143	58,646,472	58,827,632	59,130,313	59,568,330	60,346,849	60,442,797	60,431,224	61,178,133	62,005,959	62,909,158
Net to Gross Ratio	86.3%	86.3%	86.3%	86.3%	86.3%	86.3%	86.3%	86.3%	86.3%	86.3%	86.3%
Gross	66,957,996	67,981,935	68,191,933	68,542,795	69,050,536	69,952,982	70,064,203	70,050,788	70,916,591	71,876,192	72,923,164
Behavioral *	67,942,119	69,322,097	70,194,256	71,178,478	72,121,126	73,294,251	74,002,413	74,791,638	75,590,414	76,398,900	77,217,258
Gross Residential KWh	**134,900,115**	**137,304,032**	**138,386,189**	**139,721,272**	**141,171,662**	**143,247,233**	**144,066,616**	**144,842,426**	**146,507,005**	**148,275,093**	**150,140,422**
Non-Residential											
Non-Behavioral Net	36,895,453	36,621,510	36,406,412	36,538,764	36,579,794	36,551,689	36,277,065	36,319,113	36,373,904	36,439,393	36,514,057
Net to Gross Ratio	85.2%	85.2%	85.2%	85.2%	85.2%	85.2%	85.2%	85.2%	85.2%	85.2%	85.2%
Gross	43,307,977	42,986,422	42,733,939	42,889,294	42,937,455	42,904,465	42,582,111	42,631,467	42,695,781	42,772,652	42,860,293
Behavioral *	922,086	936,504	948,043	966,472	983,767	998,140	1,004,501	1,016,215	1,028,073	1,040,077	1,052,228
Gross Non-Residential KWh	**44,230,063**	**43,922,926**	**43,681,982**	**43,855,766**	**43,921,221**	**43,902,605**	**43,586,612**	**43,647,682**	**43,723,854**	**43,812,729**	**43,912,520**
Total Incremental Gross KWh Impacts at Generation	**179,130,178**	**181,226,957**	**182,068,171**	**183,577,038**	**185,092,883**	**187,149,838**	**187,653,228**	**188,490,108**	**190,230,859**	**192,087,822**	**194,052,942**
Total Cumulative Gross MWh Impacts at Generation	**2,956,222**	**3,137,449**	**3,319,517**	**3,503,094**	**3,688,187**	**3,875,337**	**4,062,990**	**4,251,480**	**4,441,711**	**4,633,799**	**4,827,852**

*** Behavioral NTG equals 1.**

Response Comments of Duke Energy Indiana, LLC
To Stakeholder Comments to DEI's 2021 Integrated Resource Plan
Submitted: July 22, 2022

I. Introduction

On December 15, 2021, Duke Energy Indiana, LLC ("DEI") submitted its 2021 Integrated Resource Plan ("IRP") to the Indiana Utility Regulatory Commission ("Commission" or "IURC"). Comments to DEI's IRP were submitted by the Indiana Office of Utility Consumer Counselor ("OUCC"); jointly by Citizens Action Coalition of Indiana, Inc., Earthjustice, and Vote Solar (collectively "CAC"); Energy Matters Community Coalition, Incorporated ("EMCC"); Hoosier Environmental Council, Inc. ("HEC"); Advanced Energy Economy, Inc. dba Indiana Advanced Energy Economy ("AEE"); Indiana State Conference of the National Association for the Advancement of Colored People ("NAACP"); Duke Energy Indiana Industrial Group ("Duke IG"); Reliable Energy, Inc. ("Reliable Energy"); and Sierra Club. CAC and EMCC also performed and provided independent modeling analysis, results, and conclusions regarding the DEI portfolio; AEE utilized a third party to conduct analysis on its behalf.

DEI appreciates the constructive feedback and observations that its customers and stakeholders provided in their comments to the Commission. Recognizing that the IRP process is a point-in-time forecast of the next 20 years, which is always evolving, DEI is continuously looking for ways to improve the development, organization, analysis, description, and transparency of its IRP. DEI will take the stakeholders' comments and suggestions into account when preparing the next IRP and refining the stakeholder process. DEI will also consider core issues and challenges in any new analysis that may support related filings at the Commission, such as requests for Certificates of Public Convenience and Necessity (CPCN).

There are also items included in the stakeholders' comments with which DEI respectfully disagrees and/or would like to provide clarification to the Commission. Specifically, DEI would like to address comments or concerns raised regarding the IRP modeling, including access to modeling inputs/outputs, the modeling approach and assumptions, cost assumptions, and compliance with the IRP rule. DEI will also respond to the independent modeling performed by CAC and EMCC and address stakeholders' challenges to the DEI selected preferred portfolio.[1]

[1] In these response comments, DEI focuses on providing clarifying input to the Commission's staff on the various stakeholder comments on DEI's 2021 IRP. DEI's silence on any comment submitted by a stakeholder should not be interpreted as DEI's agreement with the stakeholder's position.

II. Comments Summary

1) **IRP Modeling** – There was some stakeholder concern about various assumptions related to the cost of new generation, fuel forecasts, incremental amounts of energy efficiency (EE) and demand response (DR), and the decision not to model MISO's proposed seasonal resource adequacy construct.

   DEI collects cost of new generation and fuel forecast assumptions from industry leading firms that specialize in those activities. DEI recognizes that those are forecasts and supplements its analysis by considering other scenarios and sensitivity analysis.

   EE and DR assumptions were built upon the data from DEI's Market Potential Study performed by a third-party expert consultant, and DEI completes a comprehensive review of program offerings for consideration to add to the portfolio of offerings for customers each year.

   At the time of the modeling of the IRP (mid-2021), there were too many unknowns to base the modeling on MISO's proposed seasonal resource adequacy construct. Even as of July 2022, there are still outstanding issues that DEI will not receive clarity on until later this year, but sufficient information has been learned such that DEI will be using some assumptions of the seasonal construct in the evaluation of its RFP bids.

2) **Overall IRP Process** – One stakeholder expressed the opinion that the IRP process is broken. DEI disagrees with this assertion and believes that the best interests of the state, customers, and all utilities are served within the construct of:

   a. Development of long-term resource plans every three years;

   b. Concurrent stakeholder processes; and

   c. Execution of resource plans through the well-established CPCN filing process.

3) **Stakeholder Engagement Process** – Some stakeholders expressed appreciation for DEI's inclusiveness, welcoming atmosphere, engagement, collaboration, and the ability to contribute, while other stakeholders expressed frustration with access to modeling files and critiqued information flow. During the IRP stakeholder process, DEI held eight daytime meetings and, for those who could not participate during the day, two evening sessions. Additionally, DEI worked extensively with some stakeholders to develop portfolios that reflect their perspectives and priorities. However, DEI will strive to streamline the data access process in future stakeholder engagements.

4) **Preferred Portfolio** – Opinions on the IRP's preferred portfolio ranged from retiring coal assets too soon to not retiring coal assets soon enough. Polarized opinions were also conveyed regarding renewables that were consistent with the stakeholders' view on the timing of coal and replacement preferences. The preferred portfolio lands between these two views and transitions the generation fleet in a responsible way, while being mindful of diversification, customer costs, and reliability.

5) **IRP Rule Compliance** – Despite comments to the contrary, DEI did comply with all the IRP rules. The IRP includes an appendix that cross-references the IRP rule requirements to the location within the IRP where the requirement is satisfied. Complete consensus among stakeholders is not expected, but, consistent with the IRP rule, DEI will continue to answer stakeholder questions and consider their input.

6) **Conclusion** – DEI actively seeks to learn and improve with each cycle of the IRPs and stakeholder processes. This will continue and be a part of future IRPs, stakeholder engagement processes, and CPCN filings.

III. IRP Modeling

Stakeholders commented on the methods and assumptions used in DEI's IRP modeling. To the extent that additional explanations around modeling are desired, DEI is willing, as demonstrated during the IRP process, to provide modeling inputs and outputs to all stakeholders, with appropriate confidentiality agreements in place, as well as to have additional conversations to build understanding with its stakeholders.

A. Core Modeling Assumptions – Overall Context

Certain commentors note perceived discrepancies in some baseline fundamental modeling assumptions that DEI used for its analysis. For example, OUCC notes that as of the date of its comments, the baseline crude oil price for 2022 is about double what DEI's assumption was in the IRP. Other comments relate to the cost and/or availability of solar panels, new natural gas combined cycle units, higher gas and power prices, or to the fact that Midcontinent Independent System Operator's (MISO) 2022-2023 annual Planning Resource Auction (PRA) cleared at the Cost of New Entry ("CONE") price in April 2022. Such observations must be taken in context. For example, the crude oil price assumption for the 2021 DEI IRP was set in the spring of 2021, well before any inclination of the war in Ukraine and its potential impact on global supply and commodity prices. As noted above, every IRP is a snapshot in time and may not be able to be updated for radical changes in world economics in such a short timeframe. Hopefully, the impact of current events will subside, and markets will eventually revert to a more fundamental nature. In the meantime, this emphasizes that an IRP truly is a point-in-time analysis, as everything is always changing. DEI creates scenarios and performs sensitivities to stress the bounds, but the entire range of potential futures cannot be practically predicted and modeled. Ultimately, a set of assumptions must be selected and firmed for any analysis to be executed and completed, even though many of those assumptions may be stale by the time the analysis is complete and newer information may be available. That is just one of the realities that must be accepted when undertaking a process that takes a year to perform. Critics always have the benefit of what is known today, but it is more appropriate to consider what was known and reasonably assumed at the time of the actual modeling.

B. New Resource Cost and Performance Estimates

Sierra Club and CAC commented that DEI's cost assumptions for new gas resources were too low. However, this comment ignores the meaningful differences in gas turbine technologies. DEI uses the generic unit study report for all resource costs. This generic unit study report is developed using internal market research, combined with expert third-party consultant input, and has been used throughout the different jurisdictions of Duke Energy Corporation.

DEI's combined-cycle cost is based on 2x1 GE J Class turbine with duct firing. CAC provided a list of combined-cycle plants in an attempt to challenge DEI's cost assumption. However, the projects listed utilize different turbine class and/or provider, and it was not noted if those comparable projects include duct firing in their heat recovery steam generator process, which will decrease the cost of the project on a per kW basis. In addition, the use of the summer or winter ratings in the cost per kW can also cause a difference in the comparison. DEI used the winter rating in the IRP. DEI has also noted that the project list from CAC does not indicate if the costs also assume transmission costs and other adders that the DEI assumption does not include. DEI continues to monitor the market and cost forecasts for all current and future IRPs.

The economics of renewables was also called into question by stakeholders. Between the cost assumptions, hourly dispatch, the inclusion of the tax credits, and the assumption of a tax equity arrangement, DEI's assumptions provide for a reasonable and robust analysis of the value proposition of renewables. As always, DEI actively welcomes opportunities to improve the quality of the analysis.

DEI's battery and storage assumptions were also commented on. DEI recognizes the difficulty in fully evaluating all the value streams that storage can provide. Improving the evaluation of storage is an ongoing effort, and DEI will consider and continue to work with stakeholders and others in the industry to improve upon this challenging aspect of the analysis. CAC commented the effective load carrying capability ("ELCC") used for storage by DEI, 80%, was lower than other IRPs filed by utilities operating in the MISO footprint, ranging 90-100%. DEI has confirmed with MISO that the ELCC for batteries is 96% for a 6-hour battery. However, DEI modeled a 4-hour battery due to lower capital costs for better selection opportunity, thus the reason for the 80% ELCC value, which is based on a PJM study.

On a specific technical note, Reliable Energy commented that "from confidential information confirmed directly with DEI, Reliable Energy was told that DEI assumed that the capacity price would be DEI's carrying cost of the new combustion turbines. The MISO auction results were significantly higher than the cost assumed by DEI." Reliable Energy Comments at 11. Reliable Energy is referring to MISO's 2022-2023 PRA clearing at CONE and interprets that DEI is assuming a cost much less than that for market capacity purchases. However, the value of CONE in MISO is founded on the carrying cost of a new simple cycle combustion turbine, just as DEI described its assumption. Therefore, Reliable Energy's interpretation of DEI's response is incorrect.

Sierra Club also claimed that DEI's assumptions skewed in favor fossil resources. DEI uses data from industry-leading firms and if one finds data points showing higher cost fossil resources and lower cost renewable resources, a conclusion could be made that DEI's assumptions are skewed in favor fossil resources. Using the exact same logic, a statement could be made that the stakeholders with views of higher cost gas resources and lower cost renewables are skewed in favor of renewables. DEI stands by the quality of its cost inputs during the planning process and has been clear that when it comes time for resource selection and execution of projects, DEI intends to use actual RFP bid data in the analysis and selection of new resource additions.

C. 2021-2023 Demand Response "Power Manager" Assumptions

The OUCC notes an apparent discrepancy in the quantity of capacity assumed in the IRP for the Power Manager demand response ("DR") program for the period 2021-2023, relative to amounts forecasted in Cause No. 43955 DSM-8. In that cause, DEI projected 86.75, 91.34, and 96.90 MW of demand response for 2021, 2022, and 2023, respectively. These amounts include Power Manager for Residential and Business. Table D-2 on page 226 of the IRP shows 35 MW, 35 MW, and 36 MW for years 2021-2023, respectively. The OUCC in concerned that "this discrepancy could result in an understatement of DR potential in DEI's IRP modeling and lead to selecting more resources than necessary." DEI notes that this is a voluntary customer DR program and, therefore, DEI must make some assumptions when registering the DR program with MISO for annual capacity auction purposes. The first few years noted use a discounted amount, while later years assume a higher amount more in line with the DSM proceeding amounts. Additionally, the capability registered with MISO is reflective of the amount supported through testing using MISO's baseline methodology, which differs from that used in DEI's DSM portfolio. While the approach used for the DSM portfolio tends to target highest system loads and temperatures at a local level on a single day, the MISO peak may not always align with such local conditions and its baseline methodology blends loads from the most recent ten business days, which may include periods with much reduced air conditioning load. In short, the theoretical maximum capability of Power Manager program(s) cannot be fully supported when registering associated load modifying resources (LMR) with MISO. In any event, the concern is effectively moot. For the period in question, 2021 through 2023, minimal to no new-build resources are available to be selected by the model due to minimum build lead times (incremental energy efficiency, demand response, and 100MW of solar are selected in this timeframe). In each of these years, a MISO capacity purchase is included in the portfolio to fill in the capacity position. By 2024, that MISO capacity purchase placeholder is gone, and the IRP model has started adding sufficient new resources to cover the capacity position. At most, the discrepancy in the DR quantities would result in minor adjustments to the placeholder MISO capacity purchases, which are just rough estimates, and will play out in the auction regardless. It would not have any bearing on the model's selection of long-term resources past 2023 in the portfolio.

D. Incremental Energy Efficiency (EE) and Demand Response (DR)

DEI completes a comprehensive review of program offerings for consideration to add to the portfolio of offerings for customers each year. DEI has always worked closely with its Oversight Board (OSB) to manage EE/DSM programs and has consistently requested more funding for programs when opportunities have arisen in the marketplace to extend the reach of these programs. Often, this will be in the form of new measures, new program offerings, or new marketing channels. Although a budget is set through the DSM portfolio process, DEI continues to entertain other openings in the market.

DEI appreciates AEE's suggestions regarding methods of modeling EE and DR resources but remains firm in its position that use of a comprehensive Market Potential Study (MPS) performed by third-party expert consultants to develop a detailed, bottoms-up assessment of energy savings potential is a more rigorous and quantitatively sound approach. It is important to recognize that customer adoption of EE/DR measures is not something that can be forced, only encouraged through marketing, outreach, and incentives. The purpose of developing the Achievable Potential estimates in the multiple scenarios of the MPS is to identify the range of EE/DR savings that can reasonably be included in system planning where reliability is a fundamental requirement.

In 2020, DEI retained Resource Innovations (formerly Nexant, Inc.) to conduct a comprehensive assessment of EE/DR market potential for DEI. Resource Innovation's methods are industry-leading, its analysis relies on the best data available at the time to support the study, and its results were specific to the customers and characteristics of the DEI service territory. The MPS includes all currently known technologies, estimated costs, and energy and demand reduction impacts for these EE and DR measures and determines the Technical, Economic, and Achievable Potential of these programs applicable to DEI customers. Resource Innovations collaborated extensively with the OSB to ensure the list of measures, their impacts, and their applicability to energy end uses was vetted by all applicable parties, and their comments were incorporated in the final study results.

Direct comparisons of EE savings as a percentage of load are of limited value across disparate utilities due to significant differences in factors influencing the cost effectiveness and adoption of EE programs, including climate, age, and type of housing stock, fuel types for space and water heat, as well as other energy end uses, retail energy prices, avoided energy costs, EE program maturity, opt-out rules, and average usage per retail customer. Additionally, DEI's EE achievements in recent years have exceeded the national average, thereby eroding the remaining achievable potential of existing technologies by "pulling forward" adoption from future years. Furthermore, recent performance across different utilities cannot always be maintained at a given level as much recent success has been driven by implementing lighting and other highly cost-effective measures. This is another reason why it is imperative to consider program maturity and past successes when comparing future potential projections across disparate utilities. Finally, it is important to incorporate the impact of rising baseline efficiency standards applicable to lighting and other programs, which reduce the opportunity for incremental future savings driven by utility-sponsored programs.

As noted in the IRP and explained in the stakeholder meetings, the two MPS scenarios used to develop the EE bundles were selected collaboratively with OSB members and represented the most cost effective Achievable Potential scenarios on a levelized, cost-per kWh basis. The IRP optimization models were permitted to select either of the two available EE bundles in each time window or no bundle. As would be expected, in modeling scenarios with higher avoided energy costs (resulting from higher fuel costs or a carbon price), the model often selected the larger, more expensive bundles as they were a lower cost resource than other supply side options. DEI maintains that this approach maximized the opportunity for the IRP models to select the most cost-effective combination of EE resources that are realistically achievable based on a comprehensive potential assessment.

The DR forecast in the preferred portfolio is based upon DEI's internal program forecasts and takes into account current program saturation, customer adoption trends, and verified program performance metrics. As noted in the AEE comments, this forecast grows from 497MW to 613MW by 2026 and remains at that level for the remainder of the planning horizon, reflecting the maturity of the programs in the forecast.

The additional DR included in the Biden 90 portfolio included three (3) 100 MW tranches of additional DR (grossed up for losses) reaching a total of 937MW. While these additional tranches of DR were chosen by the model, they did not have the detailed technical basis used to determine the internal program forecast. These additional tranches of DR were priced using a rough price curve extrapolation from existing programs but were not underpinned by detailed analysis from a potential study. The MPS from Resource Innovations does estimate incremental DR potential of 326MW by 2045 in their Base scenario and 555MW under a high scenario representing aggressive marketing. These incremental reductions are from the starting baseline of 497MW resulting in a 2045 reduction potential of 823MW – 1052MW. Thus, the Biden 90 portfolio achieving 937MW of DR capability by 2026 is not directly supported by the detailed MPS analysis and would require a range of programs not yet in existence in order to become potentially achievable. Additionally, emerging technologies, new government mandates or standards, carbon pricing, or other drivers could increase the ultimate savings potential, but those are not yet sufficiently known to support a more aggressive DR target.

DEI appreciates AEE's comments as to the potential additional load flexibility, which may be enabled through development, and deployment rate designs, which enhance the price signals and incentives for responsive customer load management. Duke Energy is committed to studying modern pricing opportunities to encourage customer behaviors that support the affordable transition to a more flexible, lower-carbon electricity system, while maintaining reliable service. DEI will leverage input from stakeholder engagement efforts to identify potential rate design approaches with this future in mind. It will likely be necessary to pilot multiple rate options to identify and address unintended consequences and develop a well-tested set of rate approaches before including significant impacts from these programs in future IRP modeling.

Modern pricing can provide meaningful system benefits if appropriately designed, well-marketed, and supported with advanced digital technologies. While adoption rates for time of use and other dynamic pricing structures have historically been low, subscription rates and enabling products and services may be able to sway customers to experiment with new options if there are reasonable expectations of cost savings and environmental benefits. Understanding customer preferences and attitudes toward new potential time-varying rates will be critical to achieve sufficient adoption and enable the desired system impacts.

E. Seasonal Capacity Construct

In stakeholder comments to its IRP, DEI was criticized for not attempting to more formally model what was, at the time, a proposed new seasonal capacity construct that was still in the design phase at the MISO Resource Adequacy Sub-Committee (“RASC”). Such criticism is unfounded, as in the end, it was a darned if you do, darned if you don’t situation. At the time DEI was developing its modeling assumptions and conducting its modeling for the IRP, the new MISO capacity construct (now known as Seasonal Accredited Capacity, or “SAC”) was still being designed. There were numerous uncertainties about the design itself and almost no specific characteristic data about the presumptive behavior of the SAC construct upon which to form any reasonable foundation of a modeling assumption. At best, it was known that the capacity auction would be seasonalized, but the rest was still vague and subject to change during the RASC stakeholder process. Notably, RASC stakeholders overwhelmingly voted numerous times to have MISO delay its FERC filing to allow more time to the design phase, which MISO rejected; such sentiment only added to the ongoing uncertainty of the outcome. DEI anticipates that any future CPCN coming out of DEI’s request for proposal (RFP) (discussed further below in subsection F) would involve an updated IRP analysis that takes into account additional information about SAC that has been learned or will be learned.

As a result of above-described uncertainties, DEI performed its modeling using existing unforced capacity ratings (“UCAP”) for summer, while seasonalizing installed capacity ratings (“ICAP”) and renewables’ contribution to peak (“CTP”) values and adding a separate winter planning season to the modeling. Again, at the time, there was no data available from MISO as to what seasonal planning reserve margins ("PRM") could look like, coordinated with the new capacity accreditation options, so DEI applied the same PRM to the summer and winter seasons. These assumptions were founded in a definitive lack of sufficient details about the SAC construct from MISO but put DEI in the crosshairs of the darned if you don't criticism.

Breaking the SAC construct down, there are three core elements to consider: PRM, thermal resource accreditation, and the "31-Day Rule." As discussed above, hindsight gives clearer knowledge of these elements today, but that knowledge was not available at the time assumptions were developed for the IRP modeling.

Beginning with the PRM, early in the design phase of the SAC construct at the RASC, thermal resource SAC capacity accreditation values were poised to decrease relative to UCAP. As a result, to maintain parity with the demand curve, PRM was also poised to decrease (the more loss of resource risk is imbedded in capacity accreditation, the less reserves are needed to be carried). However, near the end of the design phase at the RASC, the SAC capacity accreditation calculation was modified with a Total-System-UCAP to Total-System-ISAC gross-up ratio ("UCAP-to-ISAC" ratio).[2] The UCAP-to-ISAC ratio grosses up all intermediate calculation SAC ("ISAC") capacity values so that the total MISO system UCAP remains essentially unchanged from before the application of the SAC construct. Ultimately, what the SAC construct does is "redistribute the wealth" of capacity: better relative performing units will receive SAC values that exceed their traditional UCAP, whereas poorer relative performing units will receive less SAC value than their traditional UCAP. SAC for any individual unit can be below, at, or above its UCAP value, and in fact, SAC can even exceed a generator's ICAP value. This means, statistically, any well diverse set of resources will have varying SAC values unit-to-unit and season-to-season (some greater than UCAP and some less), but the total system SAC will be very similar to total system UCAP. As MISO started providing more example data later in the design phase, that is exactly what was observed.

The RASC design decision to apply the UCAP-to-ISAC ratio was driven by the desire to maintain parity between thermal capacity accreditation and the PRM. By grossing the thermal resource pool back up to an equivalent UCAP basis, MISO was able to

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[2] The MISO Independent Market Monitor first presented on the UCAP-to-ISAC ratio concept at the October 6, 2021 RASC. It was further discussed at the October 20, 2021 RASC Workshop, and November 3, 2021 RASC. https://cdn.misoenergy.org/20211006%20RASC%20Item%2003a%20IMM%20Presentation%20on%20Converting%20UCAP%20Requirement%20under%20Seasonal%20Accredited%20Capacity595120.pdf

demonstrate that the current PRM basis could stand. However, it still needed to be seasonalized. It was not until the November 2021 timeframe that MISO first published seasonal UCAP-to-ISAC gross-up ratios,[3] and not until December 2021 that MISO published an associated set of initial seasonal PRM, both based on analysis of a historic plan year.[4] Again, this was far too late to have informed DEI's modeling assumptions.

Next, turning to thermal resource accreditation, CAC commented that "Because the proposed changes in thermal accreditation will have the largest deleterious impact on poorly performing thermal units, we are concerned that by not using MISO's proposed SAC methodology that the model would retain poorly performing thermal units, since their contribution to the winter reserve margin is overstated." CAC Comments at 19. Also as discussed in depth at the RASC, the SAC construct will result in a greater level of by-unit, by-season volatility in ISAC values due to the random and unpredictable nature of the occurrence of Tier 2 Resource Adequacy Hours (which weigh 80% of capacity accreditation to 3% of hours per season), and their alignment with random and unpredictable outages or derates on the generators. The design of the SAC construct breaks any presumptive correlation between traditional historical reliability measures (equivalent forced outage rate metrics ("XEFORd")) for converting ICAP to UCAP, and ISAC for an individual unit. Using the bookends for example, a generator could have a very low 3% XEFORd resulting in a strong UCAP value, but if that 3% of unavailability just happened to occur in the 3% of hours that were Tier 2, then that generator's ISAC value would be substantially penalized. Conversely, a generator could also have a very high 97% XEFORd resulting in a very poor UCAP value, but if the 3% of time the generator was available just happened to occur in the Tier 2 Resource Adequacy Hours when it was needed the most, then the generator would still have a very high ISAC value. Further, by MISO's stated intent, Tier 2 Resource Adequacy Hours cannot be predicted in advance, not a day, let alone years ahead for IRP modeling purposes. Lastly, the complex outage exemption rules and Tier 1 and Tier 2 hours weighting phase-in considerations that progress from plan year 2023-2024 through plan year 2026-2027 further complicate the estimation of the ISAC values in the initial years of the program (CAC made no reference to such phase-in considerations in its analysis). These

[3] See https://cdn.misoenergy.org/20211103%20RASC%20Item%2004a%20Resource%20Adequacy%20Reforms%20Q%20and%20A%20Document600864.pdf

[4] See https://cdn.misoenergy.org/20211201%20RASC%20Supplemental%20Q%20and%20A%20Document613071.pdf

complexities make it impractical, if not completely impossible, to forecast unit-level ISAC for any timeframe into the future.

Putting these two SAC construct realities together (that for a diverse set of resources the total system SAC may be expected to be similar to total system UCAP and that by-unit by-season ISAC values may be expected to be volatile and cannot be reasonably forecasted), at least for now, market participants have little recourse but to revert to something that looks more like a traditional UCAP approach to capacity accreditation for long-term IRP modeling. That can be reasonably done by using seasonal ICAP and seasonal EFORd to determine representative seasonal UCAP values for individual units. Shifting from XEFORd to EFORd in this context, as able, is warranted as outages out of management control will no longer be subject to exclusion from consideration in the capacity value and is otherwise conservative. Again, this approach does not and cannot (and no approach could) imply that such by-unit, by-season UCAP value is predicting such individual unit's SAC values into the future, but rather that the sum across a diverse set of resources is representative of the total system SAC for purposes of determining capacity need, which is certainly the most important goal of the IRP modeling overall. This is not only a DEI level assumption; this must be simulated <u>at the entire MISO footprint level</u> for every existing and possible new generator to develop the MISO power prices that are used in the DEI level modeling. As it stands, the first actual true set of data for SAC calculated as per the proposed tariff is not expected to be provided by MISO until the December 2022 timeframe, for the 2023-2024 plan year. And even that will be just one data point. Over the longer term as the SAC construct is implemented and market participants develop a history of behavior with time, such behavior will certainly help to inform and improve SAC construct modeling assumptions, but it will take time.

Besides the thermal capacity accreditation methodology and the seasonalization of the PRM, the third core element of the MISO SAC construct proposal is the "31-Day Rule." This element specifies that generators on planned outage/derate greater than 31 days in a season must either withhold such unit's capacity/derate from that season's auction in its entirety, replace the capacity/derate in excess of 31 days with uncleared capacity, or pay a financial charge. This is a very difficult element of the SAC construct to incorporate into an IRP model. First and foremost, planned outage schedules (frequency, timing, and duration) for existing units (let alone all possible new units which could be dynamically selected by the IRP model) are actively managed and constantly changing. Currently, most planned outages are typically scheduled in the spring or the fall. DEI expects its spring and fall capacity position under the SAC construct may be predominantly governed by the need for such greater than 31-day planned outages. However, active outage scheduling management will ultimately dictate the strategy of greater than 31-day planned outages taken in a season, and which of the three consequences ensue for a given resource.

For modeling purposes, is it even possible to structure the IRP model to predict the frequency, timing, and duration of planned outage needs for all resources (existing and new selected by the model) over the entire planning horizon, under varying scenarios and portfolios that may drive varying levels of predicted operation of any unit (hence dictating the amount of maintenance needed)? Not just for DEI units, but for the entire MISO footprint? Even if the IRP model could be programmed with assumptions and algorithms to achieve this, could it optimize on the placement of those outages across the entire unit set, decide what units' capacity value should be excluded from that season, what should be replaced (and at what cost), and what should presumptively pay the capacity charge value? In the worst-case modeling behavior, the IRP model may select new resource additions in the event just one season in one year may fall short. This is not the desired outcome in modeling, knowing that human intervention with active outage management (such as choosing to accelerate or defer maintenance despite a deterministic schedule of maintenance need) would happen in real time and negate the need for such new resource.

While the 31-Day Rule is without a doubt an important characteristic of the SAC construct to consider, like predicting by-unit by-season ISAC values, it is virtually impossible to simulate and optimize over the long term. DEI has no immediate solution or recommendation for a detailed representation or treatment of the 31-Day Rule in IRP modeling, other than its position that active planned outage scheduling management should presumptively negate the need for new resource additions that may be driven solely by a single occurrence of capacity shortage. In that effect, the 31-Day Rule should be recognized, but perhaps ignored for long-term planning purposes, and we should allow the summer and winter peak seasons to govern the overall resource need and selection, at least until we gain more experience operating under the SAC construct over time.

Considering these elements altogether, CAC performed modeling of its own, attempting to represent the SAC construct. In Table 3 (page 12) in their Confidential Modeling Report, CAC shows its estimates of SAC accreditation values for some of DEI's thermal resources, compared to their summer UCAP values for year 2023, and concludes that DEI's thermal SAC accreditation is much lower than its UCAP. CAC makes no reference to the 31-Day Rule in its analysis, nor does it provide its estimates of SAC for the non-summer seasons, nor with time, nor for potential new generation resources. DEI disagrees with CAC's analysis and conclusions. CAC's result is not supported by example SAC calculation estimates provided by MISO during the stakeholder process, nor is it supported by DEI's own internal attempts to calculate SAC values.

Over the course of the design phase, MISO provided detailed SAC accreditation calculation examples for a subset of thermal resources to requesting market participants, as well as some higher-level system summary information comparing UCAP to estimated calculated SAC values.[5] CAC's SAC calculations are not in reasonable agreement with MISO's estimates. For example, CAC's estimates of Wheatland CT's and Vermillion CT's summer SAC values are substantially lower than MISO's estimates. While CAC's and MISO's estimates for the Gibson summer SAC value are similar, MISO's estimates for Gibson's SAC values for fall and winter are much higher than its summer value. Lastly, though omitted by CAC in its summary Table 3, MISO's estimated summer SAC value for the Cayuga coal units is much higher that Cayuga's current summer UCAP value, again demonstrating that SAC should not presumptively be less than UCAP for a given unit. Estimates of SAC calculated internally by DEI using MISO's provided methodology and example calculations also do not support CAC's determinations. Further, it should be noted that while CAC provides a SAC value for Madison CT, Madison CT is an external resource to MISO and therefore the SAC thermal accreditation methodology does not apply to it, per the proposed MISO tariff.

Such discrepancies between CAC's and MISO's estimates, CAC's lack of recognition of substantially varying SAC values by season, and the lack of understanding of what resources are a part of the program, diminish the credibility of CAC's overall modeling analysis and conclusions. As described above, the challenges in determining by-unit by-season SAC values once using actual historical data, let alone purporting to forecast them into the future, are enormous. The fact remains that we won't know (and can't know) for sure until MISO releases the actual first complete data set for the SAC construct in the December 2022 timeframe. As a final note on the issue, EMCC also performed and submitted its own modeling report in its comments to the Commission. Though EMCC's modeling report is relatively brief, it makes no reference at all to the MISO SAC construct or the effects of seasonal capacity requirements in MISO. To the

[5] The last set of data calculated by MISO that estimated SAC for DEI resources was provided on November 18, 2021. While DEI may not necessarily agree completely with MISO's estimated calculation of SAC values, DEI's and MISO's estimates are still much closer together than CAC's estimates.

extent EMCC's Deep Decarbonization and Rapid Electrification portfolio relies heavily on intermittent resources for supply, those may have dramatically different capacity contributions across the four seasons of the SAC construct. Similarly, AEE's independent review makes no mention of the MISO SAC construct.

In the end, the capacity construct approach DEI utilized in its IRP was as robust as could have been assumed at the time. Moving forward, DEI will use seasonal PRM characteristics informed by analysis now published by MISO (which was not available at the time of the IRP) and will add further granularity to representative unit-level seasonal UCAP by moving from an annual historical XEFORd to a seasonal historical EFORd, again under the premise that total system UCAP is similar to total system SAC. As experience is gained over time operating under the SAC construct, that experience will further inform and improve the modeling approach. While DEI may be darned if it didn't in stakeholders' eyes, stakeholders could not have made any better assumption with the information available at the time, and in comparing to MISO's own estimates of SAC, they did not.

F. Process Criticisms

Sierra Club recommended that "Duke should conduct an All-Source [request for proposal] at the beginning of the IRP process, to inform its modeling and resource selection, rather than after it has decided which resource types to procure." CAC comments at Section II.

As was discussed at length in the stakeholder process and included in the IRP, DEI has issued an RFP for resource needs that were identified in the IRP. Bids have been received and analysis of those bids are underway. The intent is to update the analysis and select resources that will ultimately be included in a CPCN filing. Although DEI already performed an RFI prior to its 2021 modeling effort, DEI will take the recommendation of Sierra Club to perform an RFP under advisement. DEI will take the lessons learned from its current RFP/CPCN process and make that determination prior to the commencement of the 2024 DEI IRP stakeholder process.

As discussed in Section III.E above, DEI was criticized for not modeling SAC in the IRP. At the time of the modeling (mid-2021), there were still too many unknowns for DEI to reasonably model the SAC. As of July 2021, there are still key unknowns about the administration of the SAC that will not be known until later this year. However, the information learned since mid-2021 does give DEI the clarity it needs to model some elements of the SAC in its analysis of the RFP bids.

IV. Overall IRP Process

Reliable Energy cites flaws in the IURC's IRP process in general, including lack of standard metrics, the timing of the IRP Director's Report and how it may not be able to be considered in the CPCN process, and lack of a formal proceeding on the IRP.

As to the requested metrics, DEI notes that it provides almost all the very metrics cited by Reliable Energy, including customer rate impact, present value of revenue requirements, carbon emissions data, capacity and energy by resource, and potential PPAs. As to stranded capital costs due to retirements, those costs are sunk, and therefore should not be included an economic analysis. However, they can be considered in future CPCN or rate cases, when they are actually at issue. Upstream, or scope 2 and 3, carbon emissions are more challenging to quantify, but DEI and other utilities are making continued progress in that area.

Reliable Energy also suggests certain assumptions, like fossil generation retirement dates, and sensitivity analyses.[6] DEI responds that these assumptions and sensitivities should be determined by what is relevant to the utility and its stakeholders, not a preset list of items that may have little value.

Reliable Energy's recommendation for a formal IRP proceeding, claiming that the CPCN process is too little, too late, rings false. The CPCN order is required *before* a utility can begin construction or enter into a lease; it is by definition not too late. It is that individual resource decision that the IURC must approve under Indiana law, with the IRP being key evidence of the reasonableness. Reliable Energy is correct that the IRP is reviewed in the CPCN process, which is one of the main reasons that a separate formal IRP proceeding is unnecessary, duplicative, and offers no additional value. All the issues Reliable Energy proposes could be accomplished in a formal IRP proceeding can and are accomplished in CPCN proceedings. For many years, the IRP could result in no need for additional resources. In such cases, having a heavily litigated, contested, and time-consuming formal IRP proceeding would provide no value. The CPCN process is the best way for the IURC to decide resource matters and is the method dictated by Indiana law.

Reliable Energy states in its comments: "[I]t is important to note that that changes to DEI's IRP appear to be primarily driven by its parent company's announcement of its intent to be off coal by 2035." DEI notes that Reliably Energy has the events backwards. The announcement of Duke Energy being out of coal by 2035 did not come until February 2022, well after DEI chose

[6] DEI notes that it does perform sensitivity analysis as Reliable Energy requests, as opposed to stochastic modeling.

its preferred portfolio in this IRP which was submitted in December 2021. So, it was the DEI IRP that informed that announcement, not the other way around. Reliable Energy also incorrectly comments that Duke Energy's goals are only around reducing coal, which ignores the long-standing carbon reduction goals of the Duke Energy enterprise of 50% by 2030 and net zero by 2050. DEI considers coal retirements in a responsible, orderly fashion and in a manner that prioritizes continued reliable and affordable service for its customers.

The IRP process is a work in progress, and it does a relatively good job today of examining the uncertainty attendant in future resource decisions. DEI sees improvements in each IRP round and seeks to use best practices as the markets and resource decisions evolve.

V. Stakeholder Engagement Process

While some stakeholders expressed an appreciation of DEI's inclusiveness, welcoming atmosphere, engagement, collaboration, and the ability to contribute, other stakeholders expressed frustration with access to modeling files and critiqued information flow. During the IRP stakeholder process, DEI held eight daytime meetings and, for those who could not participate during the day, two evening sessions. Additionally, DEI worked extensively with stakeholders that expressed interest to develop portfolios that reflect their perspectives and priorities. DEI will strive to streamline the data access process in future stakeholder engagements.

During the IRP process, there were times DEI did not meet the timing requirements for distributing information prior to stakeholder meetings. DEI regrets this lapse in timeliness and is committed to improving its performance going forward.

VI. Preferred Portfolio

A. Characterization of the Preferred Portfolio

Numerous commenters attempt to mischaracterize the IRP preferred portfolio from a preferred policy perspective. For example, the NAACP asserted in its comments that "Duke Energy Indiana opted for a preferred portfolio that continues to rely on a combination of coal, natural gas, and makes minimal progress toward increasing their renewable energy portfolio." Sierra Club referred to the preferred portfolio as "fossil heavy." Conversely, Reliable Energy argued that new natural gas combined cycle units face development hurdles, have too uncertain of a future life cycle, and should therefore not be pursued in favor of continued operation of existing coal units. Others similarly argue against a new natural gas combined cycle unit but in favor of resources other than the existing coal fleet. Further, EMCC, while "express[ing] their sincere and deep appreciation to DEI and its most talented IRP modeling staff for their engagement in this extensive collaboration," chose to forego comment on DEI's preferred portfolio altogether, and instead submitted its own modeling scenario and selected portfolio which it stresses DEI should adopt. Such competing views clearly demonstrate the challenge of developing a preferred portfolio that satisfies everyone.

DEI disagrees with statements that mischaracterize the balance of the selected preferred portfolio. The IRP preferred portfolio constitutes a balanced resource plan, adding over 7 GW of renewables over the 20-year horizon, while moderately further accelerating the retirement of coal units relative to the 2018 IRP preferred portfolio (and recall that the 2018 IRP preferred portfolio presented an initial significant acceleration of coal retirements in the portfolio from prior plans). The preferred portfolio adds dispatchable generation to replace some of the retired coal unit capacity, which provides for enhanced reliability. However, compared to some optimized portfolios that identified the need for 2,400 MW or more new natural gas combined cycle plant to replace retiring coal units, the selected preferred portfolio contains just 1,200 MW of natural gas combined cycle, with a balance of energy efficiency, demand response, renewable resources, and other future carbon-free technology options, such as hydrogen-fired combustion turbines. To the extent new technologies continue to develop, so will the flexible out-year makeup of the portfolio over time. Technologies like hydrogen, carbon capture storage and utilization, and advanced nuclear are all potential future options. Stakeholders seemingly interpret that the entire 20-year horizon of the preferred portfolio is "set in stone." DEI recognizes that nothing could be further from the truth. The portfolio forecast has changed in the last six years – this illustrates why resource planning is updated every three years, if not more frequently as needed.

B. Continued Operation of Edwardsport IGCC Gasifiers

The IG, Sierra Club, and AEE take issue with DEI's decision to reflect ongoing operation of the gasifiers at Edwardsport in the IRP preferred portfolio, citing cost and insufficiency of qualitative considerations. The issue of the cost of Edwardsport versus portfolio diversity and system reliability has already been litigated at length before the Commission through a long-running course of Edwardsport IGCC rider proceedings, concluding in the 2019 Duke Energy Indiana rate case.[7] The Commission has routinely and plainly found that maintaining capacity and fuel supply diversity in a generation

[7] See *Order of the Commission*, Cause No. 45253 (IURC June 29, 2020) (the "Order").

portfolio is important to overall system reliability and is a wholly valid qualitative consideration in developing a preferred portfolio. In fact, just this past winter, DEI took advantage of the fuel flexibility available at Edwardsport to help conserve coal needed for its other coal plants. The Commission has also found, regarding IRP analysis, “that models only inform us and do not themselves make reasoned recommendations or decisions. Rather, the Company does that through a review of various scenarios, sensitivities, and portfolios.[8]” Further, the Commission has found:

> Edwardsport is the newest coal unit on the DEI system and continues to be a valuable asset for the Company’s generating system, especially as the Company moves, as many utilities are, to retire older and less efficient coal plants. We also understand the many complexities and issues associated with primarily operating the plant on natural gas pointed out by Mr. Gurganus, not least of which is the requirement for new air permitting, elimination of tax incentives, and losing the optionality and diversity that operation primarily on coal provides.[9]
>
> and
>
> We believe it is premature to make a decision to retire Edwardsport when the asset is relatively early in its life cycle. As Mr. Gurganus noted, the Edwardsport plant will provide diversity in the future as the Company moves to retire its older coal-fired units. We must consider that, as DEI and other Indiana utilities retire thousands of megawatts of coal-fired baseload generation, the remaining baseload units – such as Edwardsport -- may become critical from a grid reliability perspective. The Edwardsport IGCC is the Company’s youngest and most advanced coal-fired unit and is equipped with advanced emission controls that will position it for continued operation for years to come. As older coal fired units reach the end of their useful lives and are largely replaced by non-coal-fired units, Edwardsport will remain in a position to be a meaningful contributor to maintaining a diverse generation portfolio that will benefit customers and the grid as a reliable and non-intermittent energy source.[10]

The execution of the IRP comes just one year on the heels of the Order, and the Commission’s opinions regarding ongoing operation of Edwardsport and its value to

[8] Order at 74.

[9] Id.

[10] Id. at 96.

system diversity and reliability "for years to come" remain valid. As the Commission found and DEI agrees, it is simply too early in the life cycle of the plant to make a retirement decision. That said, the IRP preferred portfolio still sought balance by reflecting a potential retirement of the Edwardsport gasifiers in 2035, pending future considerations around possible carbon capture and sequestration technology development and application. That is a full ten years ahead of the current depreciation retirement date of 2045 and is a fair and reasonable representation of the headwinds that coal-fired generation resources are expected to face in the future. DEI stands by its selected preferred portfolio, including the ongoing operation of the Edwardsport gasifiers for the foreseeable future, and believes that it is supported by the facts and assumptions of the overall process, as well as the Commission's consistent and clear findings.

C. Cayuga Steam Service

The Sierra Club provided comment implying that DEI had not considered the separation of retail electric service to all customers and the steam service demand to International Paper at Cayuga Station in the selection of a new natural gas combined cycle unit to replace the two Cayuga Coal units. That is not correct. The preferred portfolio includes a new dedicated combined heat and power unit ("CHP"), separate from the new natural gas combined cycle unit, that would serve electric retail customers while efficiently and economically continuing to provide steam service to International Paper. This is identified in the "CT+CHP" line of the preferred portfolio on page 133 of the IRP. A 21MW CHP enters service coincident with the new natural gas combined cycle unit in 2027. Contrary to Sierra Club's claim, DEI has contemplated the best way to continue service of steam to International Paper post-retirement of the Cayuga coal units. Including a dedicated CHP unit breaks the bond between the steam service and the operation of the new larger combined cycle unit for electric service, eliminating potential problems such as must-run and over-subsidization of the combined cycle. The IRP model was free to select that resource, or any other, without being tied to the Cayuga steam customer.

D. Waste Management

HEC "urges the Utility Regulatory Commission to do all it can to phase out Duke's use of coal as rapidly as possible," because "if Duke stops burning coal sooner, the disposal structures will contain less coal ash and the eventual burden to society will be less." HEC comments at 9-11. Further HEC states that "In Duke's response to HEC's data requests during the IRP process, they stated that their modeling included their variable operations and maintenance costs for CCR management including handling, transportation and placement expenses, and their fixed operations and maintenance costs, which include inspections, monitoring, and maintenance of landfills. Duke's response did not specifically mention the costs of corrective measures for groundwater contamination, leaving the inference that they are not accounted for in Duke's modeling." HEC comments at 7.

HEC is correct that DEI's coal unit economic retirement analysis cost assumptions do not include costs for corrective measures, and it should not. Existing asset retirement obligations and asset retirement costs, including corrective measures for any existing conditions, were not included in the coal unit economic retirement analysis because, to the extent such cost obligations already exist, they are not differential. Adding mass from ongoing operations into existing or new future lined landfills that meet design requirements does not change or worsen any existing condition. DEI is already working with stakeholders and regulators to close ash impoundments using science and engineering in ways that are safe and protective of the environment.

However, as DEI further details in its discovery response to HEC, the analysis would include any new incremental asset retirement obligations for closure of any new (not existing) landfill area that was determined to be needed to be "built" over the remaining life of a unit or facility. If additional landfill area was determined to be needed in any particular portfolio for any particular unit or facility (based on forecasted operation, waste generation, and consumption of existing landfill space), then an incremental closure cost was calculated based on the additional landfill area added. Incremental post-closure costs would also be calculated and included for the additional landfill area. Therefore, DEI's analysis did appropriately include future avoidable costs for incremental waste disposal volume, closure, and post-closure, which is reasonable.

E. CAC, EMCC, and AEE Independent Modeling

AEE commented that many IRP models, including the one used by DEI, fail to recognize the full value of storage for three reasons: 1) generally, under-represent both the frequency and size of hourly price variation; 2) ignore intra-hour price variation; and 3) typically use reserve margins instead of modelling all ancillary service values. DEI appreciates these comments and understands there are some limitations to modeling storage resources. DEI uses the EnCompass model to develop hourly pricing for MISO; however, DEI does not model in smaller time increments. DEI lets the model select battery storage and hybrid projects as an option and does not constrain potential selections. As the uses of energy storage continue to develop as the technology is becoming more commercially mature, DEI acknowledges the potential for future modifications to how energy storage may be modeled to capture the agility of storage resources.

In its comments, EMCC presented a Deep Decarbonization and Rapid Electrification ("DDRE") scenario for DEI. This scenario focused on rapid decarbonization in power, transportation, building, and industrial sectors. DEI appreciates the thoughtful scenario proposed by EMCC in its DDRE scenario. While worthy of future consideration and analysis, the implications of the DDRE scenario would upend many of the systems in the economy that make modeling it difficult. For example, the scenario included several assumptions about electric vehicle growth, electrification of the industrial sector and the availability of new technology. For these reasons, the DDRE scenario represents more of an aspirational scenario than plausible in the timeframe presented.

CAC and EMCC both commented on DEI's inclusion of 4-hour batteries as the storage option. CAC developed 8- and 10-hour options for its model, and EMCC's model included the use of 50-hour batteries by 2030. However, since the lower-cost 4-hour battery was not generally selected economically in the optimized model runs, the likelihood of longer duration batteries being selected would be even less likely. For comparison purposes, longer duration batteries (>=8 Hours), whether lithium-ion, flow or compressed air storage are well over 50% more expensive than 4-hour batteries. Nonetheless, DEI recognizes the value batteries can bring to the portfolio and did include solar plus storage resources in its preferred portfolio. DEI continuously monitors the market for potential new technology breakthroughs in energy storage and updated cost assumptions.

VII. Compliance with the IRP Rule

The CAC reviewed whether DEI met, partially met, or did not meet the requirements of each part of the IRP rule. Prior to submitting the document, DEI reviewed the IRP rule to ensure compliance and provided supplemental material to CAC on model inputs and outputs and load forecast details in areas where more information was requested. DEI will not address each of the areas in turn where the CAC indicated they believed DEI's IRP only partially or did not meet the requirements in the IRP rule. Rather, DEI simply confirms it met all requirements of the IRP rule as outlined in Appendix G of the IRP.

VIII. Conclusion

DEI offers the above clarifications, additional circumstantial and technical details, and response comments in an effort to help alleviate any concerns, confusion, or misinterpretation that the Commission or the stakeholders may have about DEI's IRP process and results. DEI incorporated continuous improvement efforts and stakeholder feedback into the IRP analysis and will continue this practice into future IRPs, as well any analysis that may support related filings at the Commission, such as CPCN requests. DEI is always available to meet with the Commission and the other stakeholders for further discussions of its IRP. DEI appreciates the participation of its stakeholders and the Commission in its ongoing IRP stakeholder process.