PREPARED BY GDS

NIPSCO

NORTHERN INDIANA PUBLIC SERVICE COMPANY

Demand Side Management Market Potential Study

VOLUME I ELECTRIC ENERGY EFFICIENCY POTENTIAL

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GDS Associates, Inc.
ENGINEERS & CONSULTANTS

Demand Side Analytics
DATA DRIVEN RESEARCH AND INSIGHTS

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1 INTRODUCTION

1.1 BACKGROUND & STUDY SCOPE

This Market Potential Study ("MPS") was conducted to support the Integrated Resource Plan (IRP) and DSM planning for NIPSCO. The study included primary market research and a comprehensive review of current programs, historical savings, and projected energy savings opportunities to develop estimates of technical, economic, and achievable potential. This report discusses the analysis and results for the electric energy efficiency potential analysis. Estimates of gas energy efficiency and demand response potential were developed and are included in separate volumes. The effort was highly collaborative, as the GDS Team worked closely alongside the NIPSCO Oversight Board (OSB) to produce reliable estimates of future savings potential, using the best available information and best practices for developing market potential savings estimates.

1.2 TYPES OF POTENTIAL ESTIMATED

The scope of this study distinguishes three types of energy efficiency potential: (1) technical, (2) economic, and (3) achievable.

- *Technical Potential* is the theoretical maximum amount of energy use that could be displaced by efficiency, disregarding all non-engineering constraints such as cost-effectiveness and the willingness of end users to adopt the efficiency measures. Technical potential is constrained only by factors such as technical feasibility and applicability of measures.
- *Economic Potential* refers to the subset of the technical potential that is economically cost-effective as compared to conventional supply-side energy resources. Economic potential follows the same adoption rates as technical potential. Like technical potential, the economic scenario ignores market barriers to ensuring actual implementation of efficiency. Finally, economic potential only considers the costs of efficiency measures themselves, ignoring any programmatic costs (e.g., marketing, analysis, administration) that would be necessary to capture them. This study uses the Utility Cost Test (UCT) to assess cost-effectiveness.
- *Achievable Potential* is the amount of energy that can realistically be saved given various market barriers. Achievable potential considers real-world barriers to encouraging end users to adopt efficiency measures; the non-measure costs of delivering programs (for administration, marketing, analysis, and EM&V); and the capability of programs and administrators to boost program activity over time. Barriers include financial, customer awareness and willingness to participate in programs, technical constraints, and other barriers the "program intervention" is modeled to overcome. The potential study evaluated two achievable potential scenarios:
    - *Maximum Achievable Potential (MAP)* estimates achievable potential with NIPSCO paying incentives equal to 100% of measure incremental costs, while assuming strong adoption rates from aggressive customer education and program marketing.
    - *Realistic Achievable Potential (RAP)* estimates achievable potential with NIPSCO paying incentive levels (as a percent of incremental measure costs) closely calibrated to current levels but is not constrained by any previously determined spending levels.[1]

[1] An assessment of potential assuming current incentive levels provides a clear understanding of the remaining potential under present day conditions. NIPSCO's incentives are typically set to ensure cost-effectiveness under the Utility Cost Test. As part of ongoing EM&V efforts, NIPSCO monitors participant satisfaction and the influence of incentives on participation.

- *Enhanced RAP estimates* achievable potential by adjusting incentive levels to allow for more savings than in the RAP scenario. In some cases, incentives were lowered to improve cost-effectiveness and in others, incentives were increased to boost adoption rates if this did not change measure-level cost-effectiveness screening.

1.3 STUDY LIMITATIONS

As with any assessment of energy efficiency potential, this study necessarily builds on various assumptions and data sources, including the following:

- Energy efficiency measure lives, savings, and costs
- Projected penetration rates for energy efficiency measures
- Projections of electric avoided costs
- Future known changes to codes and standards
- NIPSCO load forecasts and assumptions on their disaggregation by sector, segment, and end use
- End-use saturations and fuel shares

While the GDS team has sought to use the best and most current available data (including the use of new primary market research in key market subsegments of interest based on stakeholder feedback) there are often reasonable alternative assumptions which would yield slightly different results. For instance, the analysis assumes that many existing measures, regardless of their current efficiency levels, can be eligible for future installation and savings opportunities. Other studies may select a narrower viewpoint, limiting the amount of potential from equipment that is already considered to be energy efficient. Additionally, the models used in this analysis must make several assumptions regarding program delivery and the timing of equipment replacement, which may ultimately occur more rapidly (or more slowly) than currently forecasted.

Furthermore, while the lists of energy efficiency measures examined in this analysis represent technologies available on the market today, as well as several emerging technologies not currently offered by NIPSCO, these measure lists may not be exhaustive. The GDS team acknowledges that new efficient technologies may become available, particularly over the course of a 20-year timeframe, which could produce efficiency gains and costs at different levels than those currently assumed.

Last, where possible, the GDS Team and NIPSCO collaborated to ensure consistency with assumptions and methodological considerations that are expected to be employed during the program planning process. However, final program designs and implementation strategies may need additional flexibility to target specific or underserved markets, address equity concerns, or react to changing customer preferences.

1.4 ORGANIZATION OF REPORT

The remainder of this volume is organized in four sections along with appendices as follows:

Chapter 2 MPS Methodology details the methodology used to develop the estimates of technical, economic, and achievable energy efficiency potential savings.

Chapter 3 MPS Market Characterization provides an overview of the NIPSCO service areas and a brief discussion of the forecasted energy sales by sector.

Chapter 4 Residential Energy Efficiency Potential provides a breakdown of the technical, economic, and achievable potential in the residential sector.

Chapter 5 Commercial and Industrial Energy Efficiency Potential provides a breakdown of the technical, economic, and achievable potential in the commercial and industrial (C&I) sectors.

Appendices for the DSM Market Potential Study are included in Volume IV of this report. MPS appendices include a discussion of sources used for the analysis, detailed measure level assumptions by customer segment, nonresidential sector potential savings (including opt-out customers), and detailed demand response results.

2 SALES FORECAST AND MARKET SEGMENTATION

Developing a market characterization in the context of utility electric consumption among each sector is a key foundational element to market potential studies. A market characterization describes how energy is used among the various end-uses and building types that are the subject of the potential study. This chapter provides a brief overview of the sales and customer forecasts for NIPSCO's electric customers. It also includes a more detailed breakdown of end-use and building type consumption, along with an overview of how these segmentations were developed.

2.1 NIPSCO COMPANY SERVICE AREA

This study assessed the electric energy efficiency potential for NIPSCO. Figure 2-1 identifies the overall NIPSCO territory relative to the geographic area of Indiana.

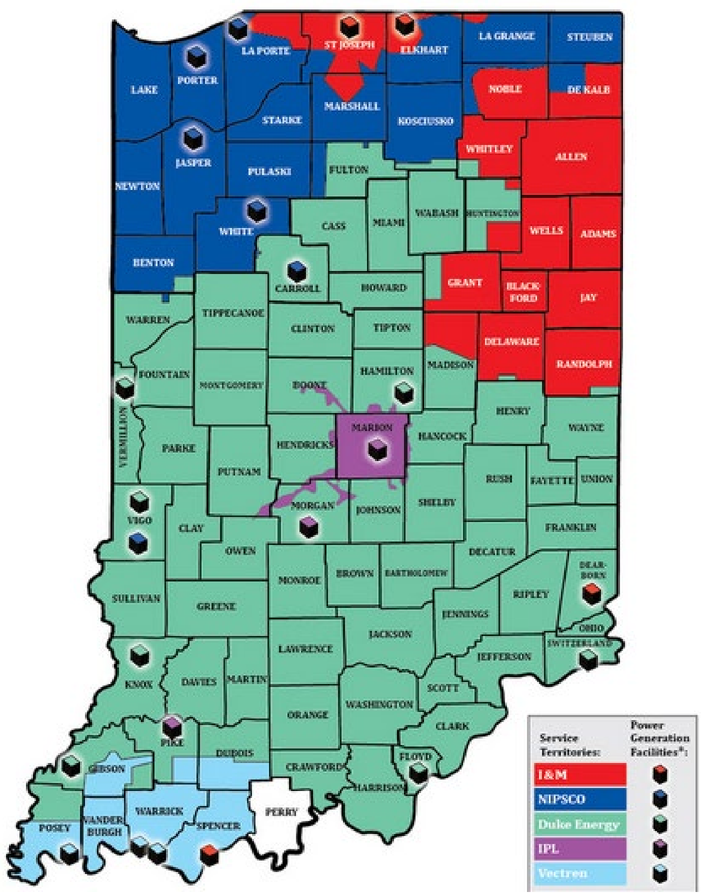

FIGURE 2-1 NIPSCO SERVICE TERRITORY MAP

2.2 LOAD FORECASTS

Figure 2-2 provides the electric sales by sector used in the MPS across the 2027-2046 timeframe. Sales are forecasted to gradually increase from 15.0 million MWh to 15.75 million MWh from 2027 to 2046. The figure also shows a breakdown of sales projections for C&I opt-out customers.

The overall sales forecast, used in the MPS, was provided by NIPSCO's IRP consultant (Charles River Associates) and is consistent with the forecast developed for NIPSCO's 2024 IRP. GDS made two subsequent adjustments. First, a small number of commercial and industrial sales were redistributed across the sectors based on their industry codes and estimated building types, with total C&I sales remaining consistent. Second, GDS used NIPSCO's opt-out customer list (as of January 2023) to estimate the total commercial and industrial sales that were not eligible for future utility-driven efficiency savings in the MPS. The final sales forecast used in the MPS, including the contribution from opt-out customers is shown in Figure 2-2.

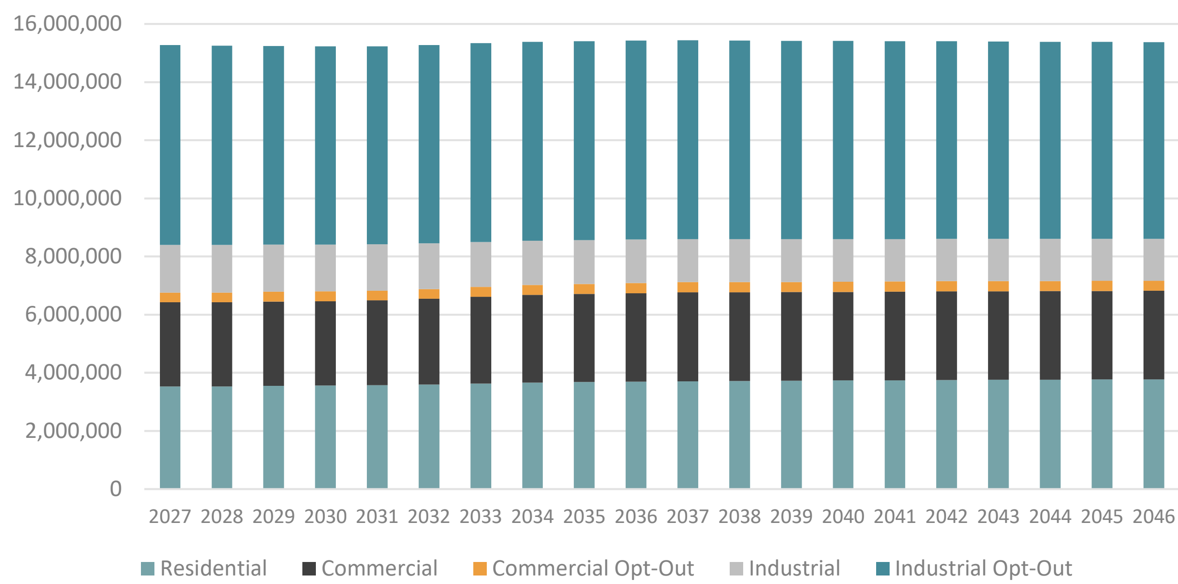

FIGURE 2-2 20-YEAR MPS ELECTRIC SALES (MWH) FORECAST BY SECTOR

2.3 SECTOR LOAD DETAIL

2.3.1 Residential Sector

The residential electric calibration effort led to an end-use intensity breakdown as shown below in Figure 2-3. Overall, GDS estimated per home consumption to be 8,177 kWh per year. The "Other" end use is the leading end-use, reflecting the increasing prominence of electronics and other plug-in load devices.[2]

[2] Other includes electronics, light appliances, and other miscellaneous and intermittent plug loads

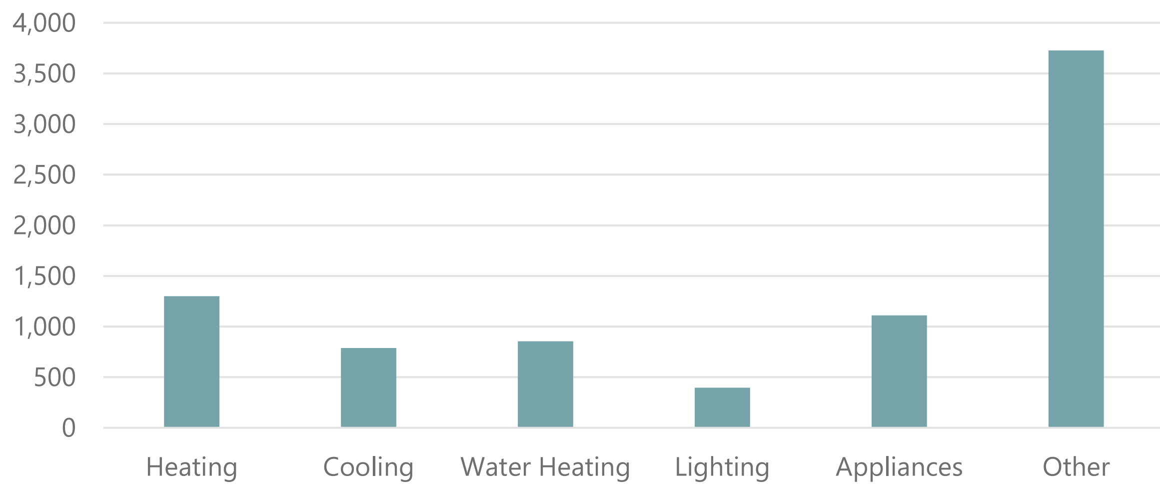

FIGURE 2-3 RESIDENTIAL ELECTRIC END-USE BREAKDOWN

2.3.2 Commercial & Industrial Sectors

In the C&I sector, disaggregated forecast data provides the foundation for the development of energy efficiency potential estimates. As noted above, GDS received an initial forecast from the NIPSCO IRP Team. Standard Industry Classification (SIC) information from NIPSCO, was then used to segment the forecast into end-uses by building type. Figure 2-4 provides a breakdown of commercial electric sales (excluding opt-outs) by building type. Office (27%), Retail (14%) and Education (13%) are the leading contributors of the stand-alone building types to total commercial electric sales.

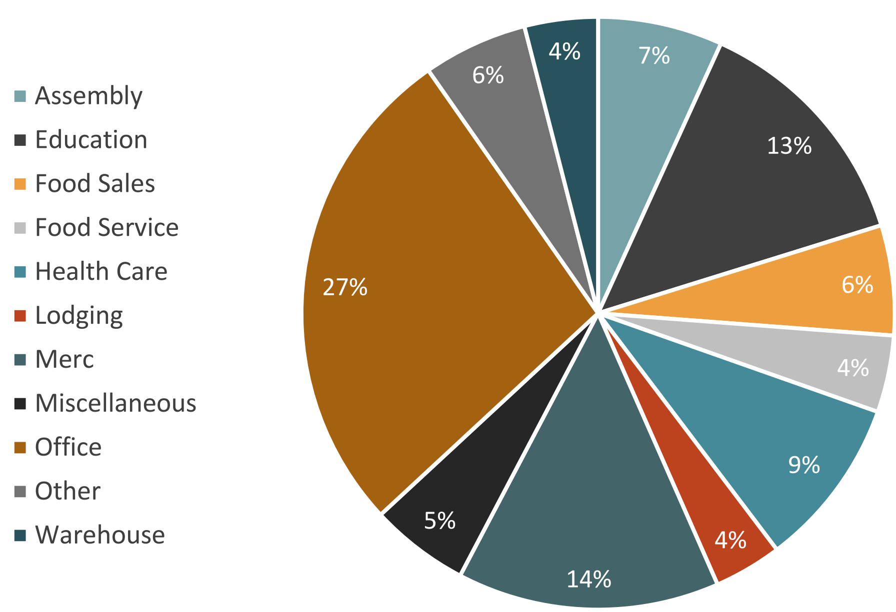

FIGURE 2-4 COMMERCIAL ELECTRIC SALES BREAKDOWN BY BUILDING TYPE

Figure 2-5 provides an illustration of the leading end-uses across all building types in the commercial sector. Lighting, Space Cooling, and Ventilation are the primary end-uses with a significant share of load across most building types. Shares of refrigeration and office/computing are often dependent on the type of building, with refrigeration loads greatest in food sales and food service, while office/computing loads are greatest in offices and education.

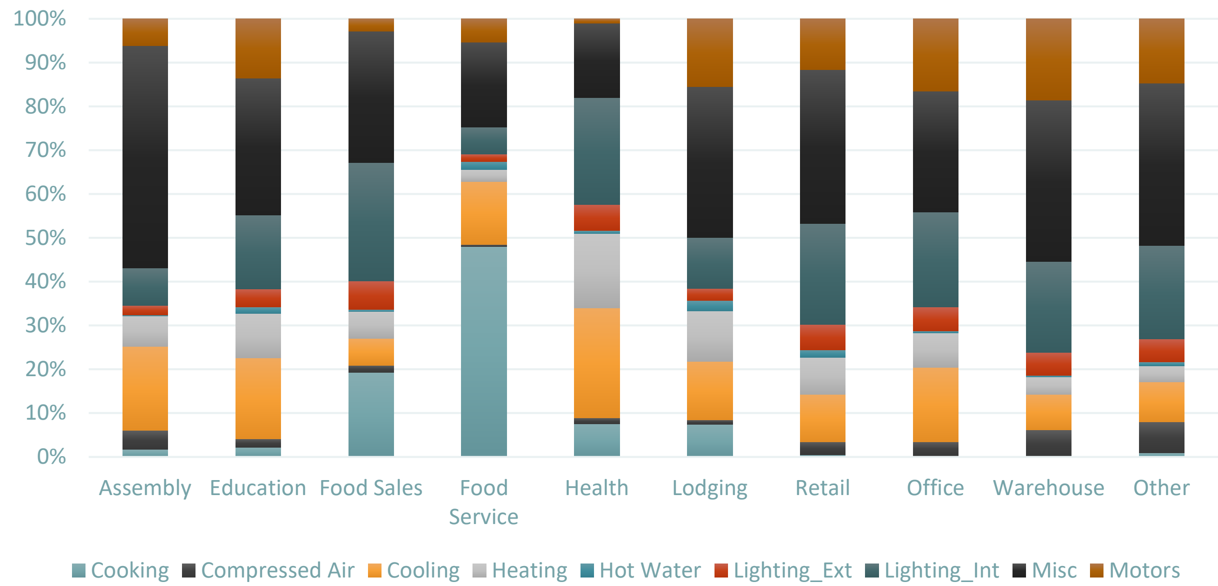

FIGURE 2-5 COMMERCIAL ELECTRIC END-USE BREAKDOWN BY BUILDING TYPE

Figure 2-6 depicts the industrial segment, excluding current opt-out customers, broken down by both industry type and end-use. General Industry, Miscellaneous, Machinery, and Transportation were the leading industry types according to SIC code. Industrial Machine Drive is the dominant share of industrial sales, followed by Process Heating and Facility HVAC. The industry type and end-use breakdowns are based on the industrial sales net of opt-out customers in the NIPSCO service area.

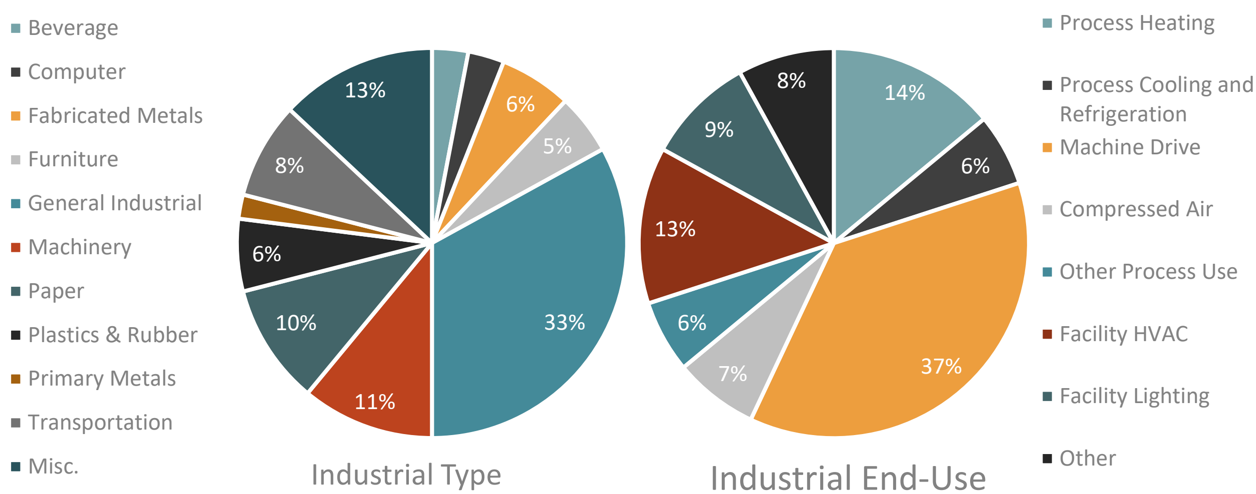

FIGURE 2-6 INDUSTRIAL SECTOR SALES BREAKDOWN BY INDUSTRY TYPE AND END-USE (EXCLUDES OPT-OUT CUSTOMERS)[3]

[3] Missing values reflect industry type/end-uses with < 5% of total industrial sales.

3 MARKET POTENTIAL STUDY METHODOLOGY

This chapter describes the overall methodology utilized to assess the electric energy efficiency potential in the NIPSCO service area. The main objectives of this Market Potential Study ("MPS") were to estimate the technical, economic, maximum achievable potential ("MAP"), and realistic achievable potential ("RAP") savings from energy efficiency in the NIPSCO service territory; and to quantify these estimates of potential in terms of MWh and MW savings, for each level of energy efficiency potential.

3.1 OVERVIEW OF APPROACH

For the residential sector, GDS utilized a bottom-up approach for the modeling of energy efficiency potential, whereby measure-level estimates of costs, savings, and useful lives were used as the basis for developing the technical, economic, and achievable potential estimates. The measure data was used to build-up the technical potential, by applying the data to each relevant market segment. The measure data allowed for benefit-cost screening to assess economic potential, which was in turn used as the basis for achievable potential, taking into consideration incentives and estimates of annual adoption rates. For the C&I sector, GDS employed a bottom-up modeling approach to first estimate measure-level savings, costs, and cost-effectiveness, and then applied measure savings to all applicable shares of energy load.

3.2 MARKET CHARACTERIZATION

The initial step in the analysis was to gather a clear understanding of the current market segments in the NIPSCO service area. The GDS team coordinated with NIPSCO to gather utility sales, customer data, and existing market research, in order to define appropriate market sectors, market segments, vintages, saturation data and end uses. This information served as the basis for completing a forecast disaggregation and market characterization of both the residential and nonresidential sectors.

3.2.1 Forecast Disaggregation

As noted in Chapter 2, through the development of the baseline forecasts, GDS produced disaggregated forecasts by sector and end-use. The produced baseline forecasts were disaggregated by sector and then further segmented as follows:

- *Residential.* The residential forecast was broken out by housing type between existing income qualified and market-rate customers, as well as new construction.
- *Commercial.* Typically based on major EIA Commercial Building Energy Consumption Survey (CBECS) business types: retail, warehouse, food sales, office, lodging, health, food service, education, and miscellaneous.
- *Industrial.* As determined by actual load consumption shares and major industry types, defined by EIA's Manufacturing Energy Consumption Survey (MECS) data.

The segmentation analysis was performed by applying NIPSCO-specific segment and end-use consumption shares, derived from NISPCO's customer database and SIC code analysis (building segmentation), and by EIA CBECS and MECS data (end-use segmentation), to forecast year sales. Within the residential, commercial, and industrial market segments, the forecasts were segmented by the major end uses shown in Table 3-1.

TABLE 3-1 ELECTRIC END-USE LOADS

Residential	C&I	
	Commercial	Industrial
Appliances	Compressed Air	Compressed Air
Behavioral	Cooking	HVAC
Consumer Electronics	Cooling	Lighting
Electric Vehicle Charging	Lighting	Motors
HVAC Equipment	Hot Water	Process Heat
Lighting	Miscellaneous	Process Refrigeration
New Construction	Motors	Process Other
Pools/Pumps	Plug Office	Whole Building
Shell	Refrigeration	Water / Wastewater
Water Heating	Ventilation	
	Whole Building	

3.2.2 Eligible Opt-Out Customers

In Indiana, individual commercial or industrial customer sites with a peak load greater than 1MW are eligible to opt out of utility-funded electric energy efficiency programs. Approximately 10% of NIPSCO's total retail commercial sales have opted out of utility-funded electric energy efficiency programs, while roughly 81% of NIPSCO's total retail industrial sales have opted out.[4]

Figure 3-1 shows the total sales for the C&I sectors, as well as the sales, by sector, that have currently opted out of paying the charge levied to support utility-administered energy efficiency programs. The portion of sales that have not opted out include both ineligible load (i.e., does not meet the 1 MW monthly peak requirement) as well as eligible load that has not yet opted out.

[4] These percentages were calculated based on 2022 NIPSCO non-residential customer data and 2022 billing history. Note, the total nonresidential sales were adjusted to shift select industrial sales into the commercial sector based on the identified building type and more applicable mapping to the commercial sector models for the MPS.

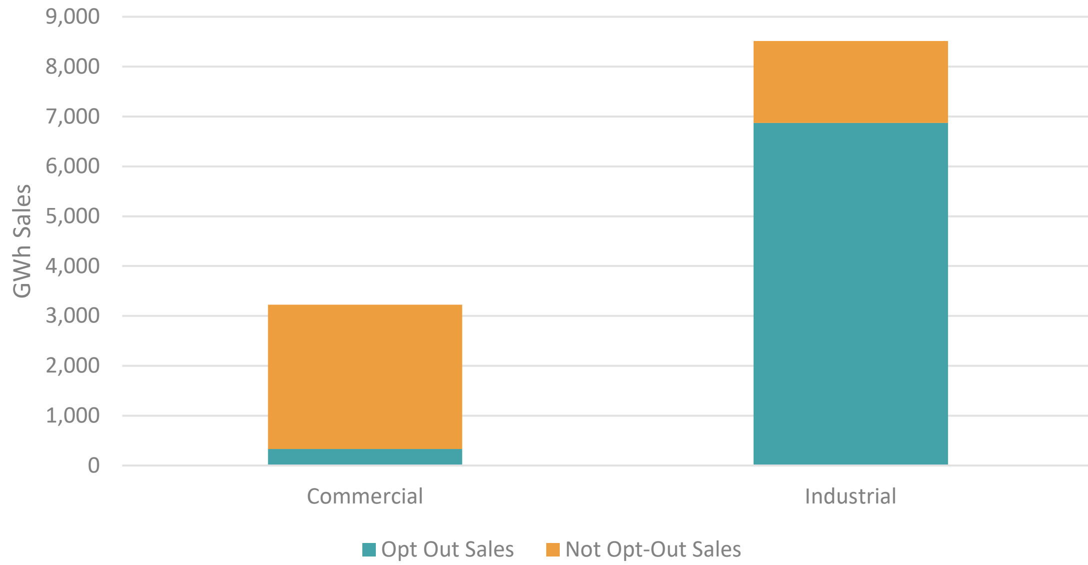

FIGURE 3-1 OPT-OUT SALES BY C&I SECTOR

The main body of this report focuses on the electric energy efficiency potential savings in the C&I sectors, excluding sales from opt-out customers. Results of C&I sector potential in a scenario that includes savings from NIPSCO's opt-out customers are provided in an appendix to this report.

3.2.3 Building Stock/Equipment Saturation

To assess the potential electric energy efficiency savings available, estimates of the current saturation of baseline equipment and energy efficiency measures are necessary.

3.2.3.1 Residential Sector

For the residential sector, GDS relied primary on the market research that was used to develop the 2020 MPS. The most important effort was a 2019 online/mail survey of NIPSCO customers conducted by the GDS Team as part of the prior study. GDS also relied on the onsite survey of NIPSCO customers conducted by the GDS Team in 2019. This study helped fill in data gaps and confirm the results of the online survey.

Other data sources included ENERGY STAR unit shipment data, NIPSCO evaluation reports, EIA Residential Energy Consumption Survey data from 2020 and baseline studies from other states. The ENERGY STAR unit shipment data filled data gaps related to the increased saturation of energy efficient equipment across the U.S. in the last decade.

3.2.3.2 C&I Sector

For the commercial and industrial sectors, GDS did not collect any primary market research for the current market potential study. GDS relied on the primary data collection collected for the 2020 MPS, EIA regional data, and other regional data. For example, a recent baseline study conducted in Pennsylvania was utilized to ascertain estimates of updated LED lighting stock in commercial businesses. National studies on commercial energy consumption and equipment stock were also used to inform consumption in the remaining end-uses where data from the primary market research was even more limited.[5] These sources typically informed estimates of base equipment saturation for cooking, refrigeration, water heating, plug loads, and other miscellaneous end-uses.

3.2.4 Remaining Factor

The remaining factor is the proportion of a given market segment that is not yet efficient and can still be converted to an efficient alternative. It is the inverse of the saturation of an energy efficient measure, prior to any adjustments. For this study we made two key adjustments to recognize that the energy efficient saturation does not necessarily always fully represent the state of market transformation. First, while a percentage of installed measures may already be efficient, some customers may backslide (i.e. revert to standard technologies, or otherwise less efficient alternatives in the future, based on considerations like measure cost and availability and customer preferences). For example, some customers have disliked the water pressure associated with low flow showerheads and have removed them in favor of standard flow showerheads. These situations represent an opportunity to regain those savings with the installation of higher quality low flow showerhead measures.

For measures categorized as market opportunity (i.e., replace-on-burnout), we assumed that 50% of the instances in which an efficient measure is already installed, the burnout or failure of those measures would be eligible for inclusion in the estimate of future savings potential. Essentially, this adjustment implies that we are assuming that 50% of the market is transformed, and no future savings potential exists, whereas the remaining 50% of the market is not transformed and could backslide without the intervention of a NIPSCO program and an incentive. Similarly, for retrofit measures, we assumed that in only 10% of the instances in which an efficient measure is already installed, the burnout or failure of those measures would be eligible for inclusion in the estimate of future savings potential. This recognizes the more proactive nature of retrofit measures, as the implementation of these measures are more likely to be elective in nature, compared to market opportunity measures, which are more likely to be needs-based. We recognize the uncertainty in these assumptions, but we believe these are appropriate assumptions, as they recognize a key component of the nature of customer decision making.

3.3 MEASURE CHARACTERIZATION

3.3.1 Measure Lists

The study's sector-level energy efficiency measure lists were informed by a range of sources including the Indiana TRM, the Illinois TRM, the MEMD, current NIPSCO program offerings, and commercially viable emerging technologies, among others. Measure list development was a collaborative effort in which GDS developed draft lists that were shared with NIPSCO and stakeholders. The final measure lists ultimately included in the study reflect the informed comments and considerations from the parties that participated in the measure list review process.

In total, GDS analyzed 379 measure types for NIPSCO. Many measures were included in the study as multiple permutations to account for different specific market segments, such as different building types, efficiency levels, and replacement options. GDS developed a total of 2,711 measure permutations

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[5] Examples of secondary research includes Energy Savings Potential, RD&D Opportunities for Commercial Building Appliances (DOE 2016) and Energy Star Shipment Data.

for this study. Each permutation was screened for cost-effectiveness according to the UCT. The parameters for cost-effectiveness under the UCT are discussed in detail later in Section 3.4.3. Table 3-2 below shows the number of measures by sector and in total.

TABLE 3-2 NUMBER OF ELECTRIC MEASURES EVALUATED

	# of Measures	Total # of Measure Permutations
NIPSCO – Electric		
Residential	196	1,276
Nonresidential	183	1,435
Total	379	2,711

3.3.2 Emerging Technologies

GDS considered several specific emerging technologies as part of analyzing future potential. In the residential sector, these technologies include high performance windows, energy recovery ventilators, integrated HVAC controls, and several smart technologies. In the nonresidential sector, specific emerging technologies that were considered as part of the analysis include energy recovery ventilators, strategic energy management, building integrated energy management systems, and triple pane windows, among other things. While this is likely not an exhaustive list of possible emerging technologies over the next twenty years it does consider many of the known technologies that are available today but may not yet have widespread market acceptance and/or product availability.

In addition to these specific technologies, GDS acknowledges that there could be future opportunities for new technologies as equipment standards improve and market trends occur. To address this consideration, GDS also included a set of measures characterized in this study as “innovative”, which are anticipated to potentially become commercially available during the study timeframe. These measures were phased into the study after six years, using the best available estimates of costs and savings to project long-term potential. While these may also be considered emerging technologies, the lack of commercial availability in the near-term necessitates a more long-term view of their potential, which is why GDS determined it was appropriate to include these measures but assume any savings would not accrue until 2032.

3.3.3 Assumptions & Sources

A significant amount of data is needed to estimate the electric savings potential for individual energy efficiency measures or programs across the residential and nonresidential customer sectors. GDS utilized data specific to NIPSCO, when it was available and current. GDS used the Indiana TRM, the Illinois TRM, the most recent I&M Indiana evaluation report findings (as well as I&M Indiana program planning documents), and the Michigan Energy Measures Database (“MEMD”) for a large amount of the data requirements. Evaluation report findings and NIPSCO program planning assumptions were leveraged to the extent feasible. The National Renewable Energy Laboratory (NREL) Energy Measures Database also served as a key data source in developing measure cost estimates. Additional source documents included American Council for an Energy-Efficient Economy (ACEEE) research reports, covering topics like emerging technologies.

Measure Savings: GDS relied on the Illinois TRM, the Indiana TRM, and the MEMD to inform calculations supporting estimates of annual measure savings as a percentage of base equipment usage. For custom measures and measures not included in the MEMD, GDS estimated savings from a variety of sources, including:

- Existing NIPSCO evaluation report findings
- Other regional/state TRMs
- Secondary sources such as the ACEEE, Department of Energy (DOE), EIA, ENERGY STAR, and other technical potential studies

Measure Costs: Measure costs represent either incremental or full costs. These costs typically include the incremental cost of measure installation, when appropriate, based on the measure definition. For purposes of this study, nominal measure costs held constant over time.

GDS obtained measure cost estimates primarily from the Indiana TRM, the Illinois TRM and the MEMD. GDS also used the following supplementary data sources:

- Other regional/state TRMs
- Secondary sources such as the ACEEE, ENERGY STAR, and NREL

Costs and savings for new construction and replace on burnout measures were calculated as the incremental difference between the code minimum equipment and the energy efficiency measure. This approach was utilized because the consumer must select an efficiency level that is at least the code minimum equipment when purchasing new equipment. The incremental cost is calculated as the difference between the cost of high efficiency and standard efficiency (code compliant) equipment. However, for retrofit or direct install measures, the measure cost was the "full" cost of the measure, as the baseline scenario assumes the consumer would not make energy efficiency improvements in the absence of a program. In general, the savings for retrofit measures are calculated as the difference between the energy use of the removed equipment and the energy use of the new high efficiency equipment (until the removed equipment would have reached the end of its useful life).

Measure Life: Measure life represents the number of years that energy using equipment is expected to operate. GDS obtained measure life estimates from the Indiana TRM, the Illinois TRM and the MEMD: Other sources reviewed include:

- Other regional/state TRMs
- Manufacturer data
- Savings calculators and life-cycle cost analyses

All measure savings, costs, and useful life assumption sources are documented in the Appendices volume of this report.

3.3.4 Treatment of Codes & Standards

Although this analysis does not attempt to predict how energy codes and standards will change over time, the analysis does attempt to reflect the latest legislated improvements to federal codes and standards. Where possible, improvements to baseline equipment standards can typically be met with incremental improvements to efficient equipment standards.

3.3.5 Net to Gross (NTG)

All estimates of technical, economic, and achievable potential, as well as measure level cost-effectiveness screening were conducted in terms of gross savings to reflect the absence of program design considerations in these phases of the analysis. The impacts of free-riders (participants who would have installed the high efficiency option in the absence of the program) and spillover customers (participants who install efficiency measures due to program activities, but never receive a program incentive) were considered in the development of subsequent inputs for integrated resource planning and preliminary program savings estimates.

3.4 ENERGY EFFICIENCY POTENTIAL

This section reviews the types of potential analyzed in this report, as well as some key methodological considerations in the development of technical, economic, and achievable potential.

3.4.1 Types of Potential

Potential studies often distinguish between several types of energy efficiency potential: technical, economic, and achievable. However, because there are often important definitional issues between studies, it is important to understand the definition and scope of each potential estimate as it applies to this analysis.

The first two types of potential, technical and economic, provide a theoretical upper bound for energy savings from energy efficiency measures. Still, even the best-designed portfolio of programs is unlikely to capture 100% of the technical or economic potential. Therefore, achievable potential attempts to estimate what savings may realistically be achieved through market interventions, when it can be captured, and how much it would cost to do so. Figure 3-2 illustrates the types of energy efficiency potential considered in this analysis.

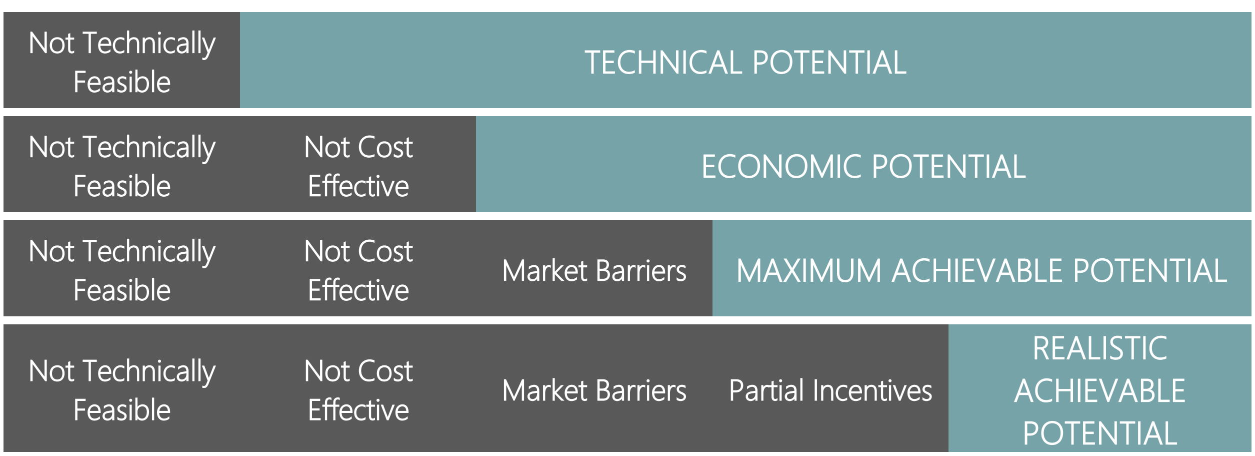

FIGURE 3-2 TYPE OF ENERGY EFFICIENCY POTENTIAL

3.4.2 Technical Potential

Technical potential is the theoretical maximum amount of energy use that could be displaced by efficiency, disregarding all non-engineering constraints such as cost-effectiveness and the willingness of end users to adopt the efficiency measures. Technical potential is only constrained by factors such as technical feasibility and applicability of measures. Under technical potential, GDS assumed that 100% of new construction and market opportunity measures are adopted as those opportunities become available (e.g., as new buildings are constructed, they immediately adopt efficiency measures, or as existing measures reach the end of their useful life). For retrofit measures, implementation was assumed to be resource constrained and that it was not possible to install retrofit measures all at once. Rather, retrofit opportunities were assumed to be replaced incrementally until 100% of stock was converted to the efficient measure over a period of no more than 20 years (study timeframe).

The core equation used in the residential sector energy efficiency technical potential analysis for each individual efficiency measure is shown in Equation 3-1 below. The business (C&I) sector employs a similar analytical approach.

EQUATION 3-1 CORE EQUATION FOR RESIDENTIAL SECTOR TECHNICAL POTENTIAL

TECHNICAL POTENTIAL OF EFFICIENT MEASURES = *Total Number of Households* X *Base Case End Use Intensity (kWh/unit)* X *Saturation Share* X *Remaining Factor* X *Feasibility Factor* X *Savings Factor*

Where…

Total Number of Households = number of households by housing type in the NIPSCO service area

Base Case Equipment End-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 end-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.

Feasibility Factor = (also functions as the applicability factor) the fraction of the applicable units that is technically feasible for conversion to the most efficient available technology from an engineering perspective (e.g., it may not be possible to install heat pump water heaters in all homes because of space limitations).

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

3.4.2.1 Competing Measures & Interactive Effects Adjustments

GDS prevents double-counting of savings, and accounts for competing measures and interactive savings effects, through three primary adjustment factors:

Baseline Saturation Adjustment. Competing measure shares are factored into the baseline saturation estimates. For example, nearly all homes can receive insulation, but the analysis creates multiple measure permutations to account for varying impacts of different heating equipment types and have applied baseline saturations to reflect proportions of households with each heating equipment type.

Applicability Factor Adjustment. Combined measures into measure groups, where total applicability factor across measures is set to 100%. In instances where there are two (or more) competing technologies for the same electrical end use, such as central air conditioners with different tiers of efficiency, an applicability factor aids in determining the proportion of the available population assigned to each measure. In general, measure applicability was assigned based on cost-effectiveness screening results. For example, if one competing measure had a TRC benefit-cost ratio of 2.0, and another competing measure had a UCT ratio of 1.0, the measure with the higher TRC score would receive 66% applicability, with the secondary competing measure receiving the remaining 34% applicability.

Interactive Savings Adjustment. As savings are introduced from select measures, the per-unit savings from other measures need to be adjusted (downward) to avoid over-counting. For example, the savings from installing high efficiency space heating equipment in the residential sector would impact the baseline consumption that remaining building shell efficiency measures could affect.

3.4.3 Economic Potential

Economic potential refers to the subset of the technical potential that is economically cost-effective (based on screening with the UCT) as compared to conventional supply-side energy resources.

3.4.3.1 Utility Cost Test & Incentive Levels

The economic potential assessment included a screen for cost-effectiveness using the UCT at the measure level. In the NIPSCO territory, the UCT considers electric energy, capacity, and transmission & distribution (T&D) savings as benefits, and utility incentives and direct install equipment expenses as costs. Consistent with application of economic potential, according to the National Action Plan for Energy Efficiency, the measure level economic screening does not consider non-incentive/measure delivery costs (e.g., admin, marketing, evaluation, etc.) in determining cost-effectiveness.[6]

Apart from the low-income segment of the residential sector, all measures were required to have a UCT benefit-cost ratio greater than 1.0 to be included in economic potential and all subsequent estimates of energy efficiency potential. Low-income measures were not required to be cost-effective.

For both the calculation of the measure-level UCT, as well as the determination of RAP, historical incentive levels (as a % of incremental measure cost) were calculated for current measure offerings. GDS relied on NIPSCO’s DSM Portfolio Summary to map current measure offerings to their historical incentive levels.

- In the residential sector, incentives ranged from 3% to 100% and averaged 51% of measure cost. If measures are not currently assigned to a program, the incentive level was generally set to 25% of measure cost.
- In the non-residential sector, incentives averaged 40% of measure cost.

[6] National Action Plan for Energy Efficiency: Understanding Cost-Effectiveness of Energy Efficiency Programs. *Note: Non-incentive delivery costs are included in the assessment of achievable potential.*

- In the MAP scenario, incentives were increased up to 100% of the incremental measure cost.[7]

3.4.3.2 Avoided Costs

Avoided energy supply costs are used to assess the value of energy savings. Avoided cost values for electric energy, electric capacity, and avoided T&D were provided by NIPSCO as part of an initial data request. Electric energy is based on an annual system marginal cost. For years outside of the avoided cost forecast timeframe, future year avoided costs are escalated by the rate of inflation.

3.4.4 Achievable Potential

Achievable potential is the amount of energy that can realistically be saved given various market barriers. Achievable potential considers real-world barriers to encouraging end users to adopt efficiency measures; the non-measure costs of delivering programs (for administration, marketing, analysis, and EM&V); and the capability of programs and administrators to boost program activity over time. Barriers include financial, customer awareness and willingness-to-participate (WTP) in programs, technical constraints, and other barriers the "program intervention" is modeled to overcome. Additional considerations include political and/or regulatory constraints. The potential study evaluated three achievable potential scenarios:

- *MAP* estimates achievable potential for paying incentives equal to up to 100% of measure incremental costs and aggressive adoption rates.
- *RAP*, or realistic achievable potential, estimates achievable potential with NIPSCO paying incentive levels (as a percentage of incremental measure costs) closely calibrated to historical levels but is not constrained by any previously determined spending levels.
- *Enhanced RAP estimates* achievable potential by adjusting incentive levels to more savings than in the RAP scenario. In some cases, incentives were lowered to improve cost-effectiveness and in others, incentives were increased to boost adoption rates as long as this did not change measure-level cost-effectiveness screening.

3.4.4.1 Market Adoption Rates

GDS assessed achievable potential on a measure-by-measure basis. In addition to accounting for the natural replacement cycle of equipment in the achievable potential scenario, GDS estimated measure specific maximum adoption rates that reflect the presence of possible market barriers and associated difficulties in achieving the 100% market adoption assumed in the technical and economic scenarios.

The initial step was to assess the long-term market adoption potential for energy efficiency technologies. Due to the wide variety of measures across multiple end-uses, GDS employed varied measure and end-use-specific ultimate adoption rates versus a singular universal market adoption curve. These long-term market adoption estimates were based on either NIPSCO-specific WTP market research or publicly available DSM research, including market adoption rate surveys and other utility program benchmarking. These surveys included questions to residential homeowners and

[7] The GDS team lowered MAP incentives to less than 100% of measure incremental cost in some cases if 100% incentives would preclude the measure from being cost-effective. MAP incentives were lowered to either 75% or 50% of the incremental measure cost if either of those incentive levels would allow for a measure to remain cost-effective.

nonresidential facility managers regarding their perceived willingness to purchase and install energy efficient technologies across various end uses and incentive levels.

One caveat to this approach is that the WTP adoption score is generally a simple function of incentive levels and payback. There are other factors that may influence a customer's willingness to purchase an energy efficiency measure. For example, increased marketing and education programs can have a critical impact on the success of energy efficiency programs. The adoption rate was based on the WTP survey research as well as other market research conducted by NIPSCO related to customer engagement and awareness of energy efficiency programs. Although we recognize this approach does not capture every possible factor in determining appropriate long-term adoption levels, it does assign some weight to non-financial considerations in the assessment of long-term energy efficiency potential.

Table 3-3 presents the long-term market adoption rates at varied incentive levels used for the residential sector.[8] Most end-uses are based on the WTP primary market research. Modifications include lighting adoption levels to reflect additional WTP conducted in other jurisdictions (and observed high levels of market acceptance) and behavior. Behavior was set to 100% to reflect that the program design is typically opt-out and participation levels are dictated by the utility.[9]

TABLE 3-3 RESIDENTIAL LONG-TERM MARKET ADOPTION RATES AT DISCRETE INCENTIVE LEVELS

End Use	0% Incentive	25% Incentive	50% Incentive	75% Incentive	100% Incentive
Appliances / Hot Water / Plug Load / Pools	25.3%	43.1%	61.1%	78.8%	97.5%
Insulation / New Construction	14.4%	28.6%	48.3%	72.0%	96.4%
HVAC	23.0%	39.9%	57.4%	76.8%	96.6%
Lighting	48.9%	59.3%	69.7%	78.5%	88.2%
Behavior	100%	100%	100%	100%	100%

Table 3-4 presents the long-term market adoption rates used in the nonresidential sector. Again, the adoption scores were primarily informed by NIPSCO-specific WTP research. To reflect differences in delivery strategy, varying awareness factors were created for different C&I program offerings based on available market data collected by NIPSCO and assumptions about trade ally involvement and impact on future adoption rates.

TABLE 3-4 NONRESIDENTIAL LONG-TERM MARKET ADOPTION RATES BY PAYBACK PERFORMANCE

[8] For the MAP Scenario, the long-term adoption rate was reached by Year15 (or earlier) and annual participation remained flat in the final five years of the analysis. In the RAP scenario, the analysis assumes the maximum adoption rate is reached over a period of 20-years or less.

[9] GDS also applied a tax credit multiplier for measures that were eligible for Inflation Reduction Act or other tax credits to the adoption rate estimates.

	10 Year Payback Period	5 Year Payback Period	3 Year Payback Period	1 Year Payback Period	0 Year Payback Period
Major Investment	42.8%	58.1%	67.6%	74.6%	81.2%
Minor Investment	41.0%	56.1%	65.7%	73.1%	80.8%

In the maximum achievable potential scenario, incentives were assumed to represent 100% of the measure cost (0-year payback). GDS then estimated initial year adoption rates by reviewing the current saturation levels of efficient technologies and (if necessary) calibrating the estimates of 2027 annual potential to recent historical levels achieved by NIPSCO's current DSM portfolio. This calibration effort ensures that the forecasted achievable potential in 2027 is realistic and attainable. GDS then assumed a non-linear ramp rate from the initial year market adoption rate to the various long-term market adoption rates for each specific end-use.

3.4.4.2 Non-Incentive Costs

Consistent with National Action Plan for Energy Efficiency (NAPEE) guidelines[10], utility non-incentive costs were included in the overall assessment of cost-effectiveness in the RAP scenario. 2024 direct measure/program non-incentive costs were calibrated to recent projected levels (using NIPSCO's 2022-2023 DSM Plan) and set at the levels shown in Table 3-7 below.

TABLE 3-5 NON-INCENTIVE COST ASSUMPTIONS – BY PROGRAM

Program	Cost per kWh
Home Rebates	$0.130
Retail Products	$0.087
Home Energy Analysis	$0.135
Appliance Recycling	$0.106
School Education	$0.109
Multifamily Direct Install	$0.190
Home Energy Report	$0.069
Income Qualified Home Energy Report	$0.069
Residential New Construction	$0.132
HomeLife EE Calculator	$0.119
Income Qualified Weatherization	$0.192

[10] National Action Plan for Energy Efficiency (2007). Guide for Conducting Energy Efficiency Potential Studies. Prepared by Optimal Energy. This study notes that economic potential only considers the cost of efficiency measures themselves, ignoring programmatic costs. Conversely, achievable potential should consider the non-measures costs of delivering programs. Pg. 2-4.

Program	Cost per kWh
Income Qualified HEAR[11]	$0.192
Residential Online Marketplace	$0.089
Emerging Technology	$0.087
No Program	$0.087
Nonresidential – all programs	$0.053

Non-incentive costs were then escalated annually at the rate of inflation.

[11] The Income Qualified HEAR program heading (formerly referred to as Home Electrification and Appliance Rebates associated with legislation passed by Congress in 2022 known as the Inflation Reduction Act) is associated with savings that are included in RAP but are removed from subsequent assumptions about what can be achieved through NIPSCO programs because these savings are assumed to be tied to incentives associated with federal funds.

4 RESIDENTIAL ENERGY EFFICIENCY POTENTIAL

This chapter provides the potential results for technical, economic, MAP and RAP for the residential sector. The cost-effectiveness results and budgets for the RAP scenario are also provided.

4.1 SCOPE OF MEASURES & END USES ANALYZED

There were 196 total unique electric measures included in the analysis. Table 4-1 provides the number of measures by end-use and fuel type (the full list of residential measures is provided in Appendix B). The measure list was developed based on a review of current NIPSCO programs, the Indiana TRM, other regional TRMs, and industry documents related to emerging technologies. Data collection activities to characterize measures formed the basis of the assessment of incremental costs, electric energy and demand savings, and measure life.

TABLE 4-1 RESIDENTIAL ENERGY EFFICIENCY MEASURES – BY END USE

End-Use	Number of Unique Measures
Appliances	22
Audit	6
Behavioral	3
Consumer Electronics	4
Electric Vehicle Charging	1
HVAC Equipment	57
Lighting	19
New Construction	15
Pools/Pumps	4
Shell	48
Water Heating	17

4.2 RESIDENTIAL ELECTRIC POTENTIAL SAVINGS

Figure 4-1 provides the technical, economic, MAP and RAP results for the 5-year, 10-year, and 20-year timeframes. The cumulative annual 5-year technical potential is 18.8% of forecasted sales, and the economic potential is 16.3% of forecasted sales. The cumulative annual 5-year MAP is 6.8% and the RAP is 4.6%, as a percentage of forecasted sales. Over the duration of the study timeframe the technical and economic potential rise to 39% and 33% of forecasted sales, respectively. This indicates that a large portion of the technical potential is cost-effective. The MAP and RAP rise respectively to 24% and 18% of forecasted sales over the study timeframe. The gap between economic potential and MAP/RAP represents market barriers to prospective program participants, both financial and non-financial, to achieving the full amount of economic potential.

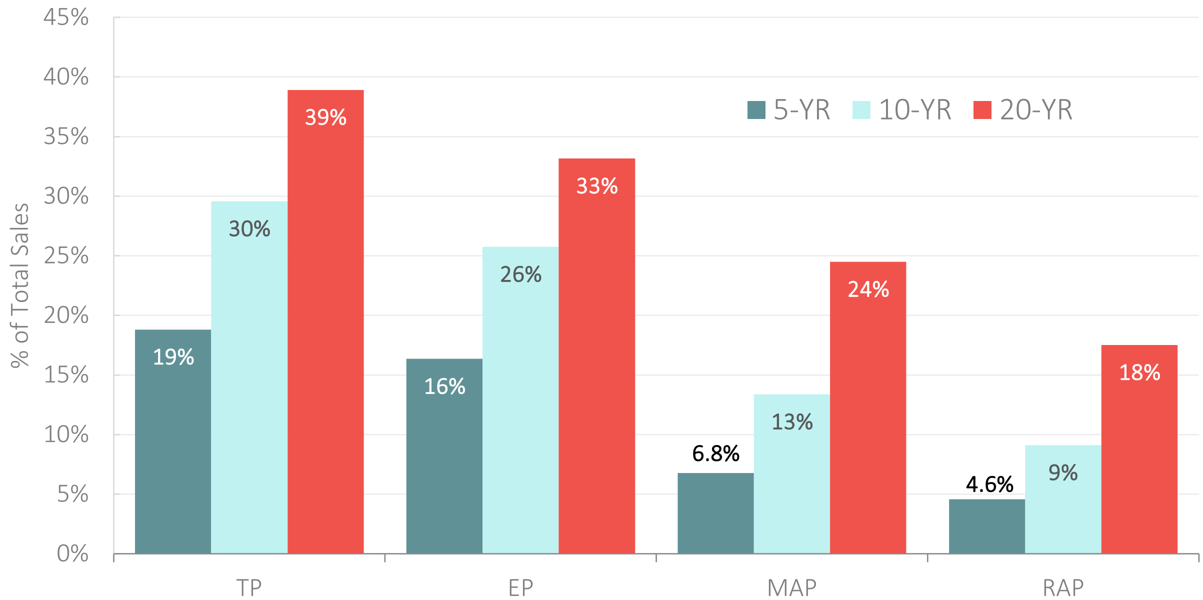

FIGURE 4-1 OVERVIEW OF RESIDENTIAL POTENTIAL

Table 4-2 provides additional details of the long-term residential potential, showing the cumulative annual MWh and MW associated with technical, economic and achievable potential. The 20-yr cumulative annual MAP and RAP are over 924,000 MWh and over 661,000 MWh, respectively, with an additional 314 MW and 174 MW savings from energy efficiency in the MAP and RAP scenarios.

TABLE 4-2 LONG-TERM TECHNICAL, ECONOMIC, ACHIEVABLE POTENTIAL SAVINGS (MWH, % SAVINGS, MW)

	5-YR	10-YR	20-YR
Energy (MWh)			
Technical	673,297	1,093,194	1,469,556
Economic	585,061	951,931	1,252,021
MAP	242,779	494,310	924,753
RAP	163,391	336,693	661,253
Energy Savings (as % of Forecast)			
Technical	18.8%	29.6%	38.9%
Economic	16.3%	25.7%	33.2%
MAP	6.8%	13.4%	24.5%
RAP	4.6%	9.1%	17.5%
MW			
Technical	232	360	459
Economic	208	328	415
MAP	85	177	314
RAP	45	93	174

Table 4-3 provides additional details of the short-term residential potential, showing the incremental annual MWh and MW associated with technical, economic and achievable potential. The RAP rises from just over 50,000 MWh in 2027 to more than 63,000 MWh by 2032, representing 1.4% up to 1.8% of sector-sales.

TABLE 4-3 SHORT-TERM TECHNICAL, ECONOMIC, ACHIEVABLE POTENTIAL SAVINGS (MWH, % SAVINGS, MW)

	2027	2028	2029	2030	2031	2032
Energy (MWh)						
Technical	192,376	189,001	185,168	181,574	179,262	176,514
Economic	168,844	166,386	163,830	161,334	159,481	157,454
MAP	64,672	71,356	74,367	76,488	78,355	82,317
RAP	50,575	54,882	57,037	58,813	60,376	63,277
Energy Savings (as % of Forecast)						
Technical	5.4%	5.4%	5.2%	5.1%	5.0%	4.9%
Economic	4.8%	4.7%	4.6%	4.5%	4.5%	4.4%
MAP	1.8%	2.0%	2.1%	2.1%	2.2%	2.3%
RAP	1.4%	1.6%	1.6%	1.6%	1.7%	1.8%
MW						
Technical	62	61	59	58	58	57
Economic	53	52	51	50	50	49
MAP	19	22	24	25	26	28
RAP	13	14	15	15	16	17

4.2.1 Technical/Economic Potential

Figure 4-2 provides additional annual savings data for the technical and economic potential. The technical potential starts off at more than 192,000 MWh in 2027 and rises to almost 1.5 million MWh by 2046. The economic potential starts off at nearly 169,000 MWh in 2027 and rises to more than 1.2 million MWh by 2046.

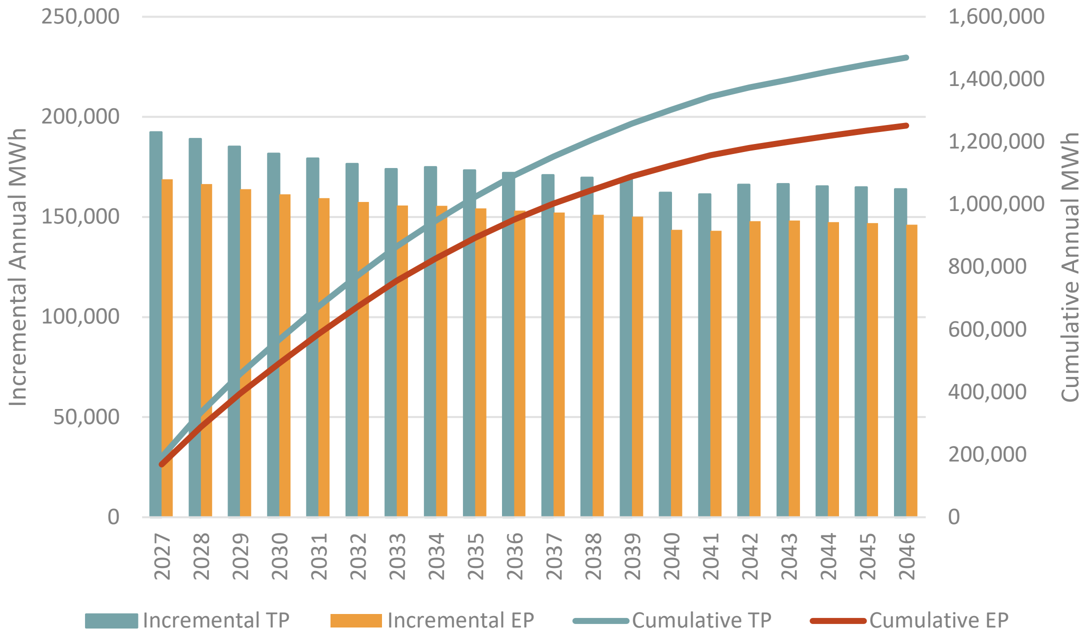

FIGURE 4-2 RESIDENTIAL TECHNICAL AND ECONOMIC POTENTIAL

4.2.2 Achievable Potential

Figure 4-3 provides the MAP and RAP across the 20-yr timeframe of the study. The green and red bars provide the respective incremental annual MAP and RAP in MWh per year energy savings. The green and orange lines provide the corresponding cumulative annual MAP and RAP as a percentage of forecasted annual sales. The MAP rises to 24% by 2046, and the RAP rises to 18%.

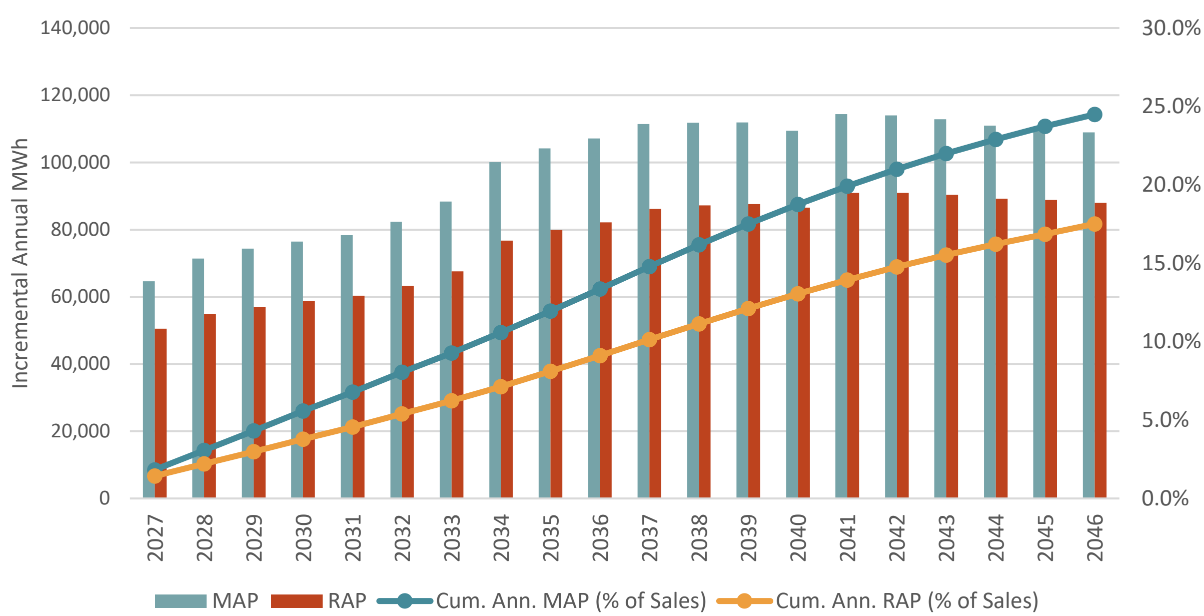

FIGURE 4-3 RESIDENTIAL MAXIMUM AND REALISTIC ACHIEVABLE POTENTIAL

Figure 4-4 provides a breakdown of the RAP potential in 2046 across end-uses and building type market segments. The end-use pie chart shows the savings potential from existing measures by end use, as well as among measures classified as emerging and innovative as described in Section 3.2 above. Among existing measures, the leading end uses are HVAC Equipment at 19%, Shell is at 16%, and Water Heating at 14% of RAP. Emerging and innovative measures account for 28% of the long-term RAP. Among income and home type classifications, the single-family market rate housing segment represents 64% of the potential, with another 20% from single-family low-income homes. The multifamily segment represents 6% of the potential across market rate and low-income customers. The new construction segment accounts for 11% of potential.

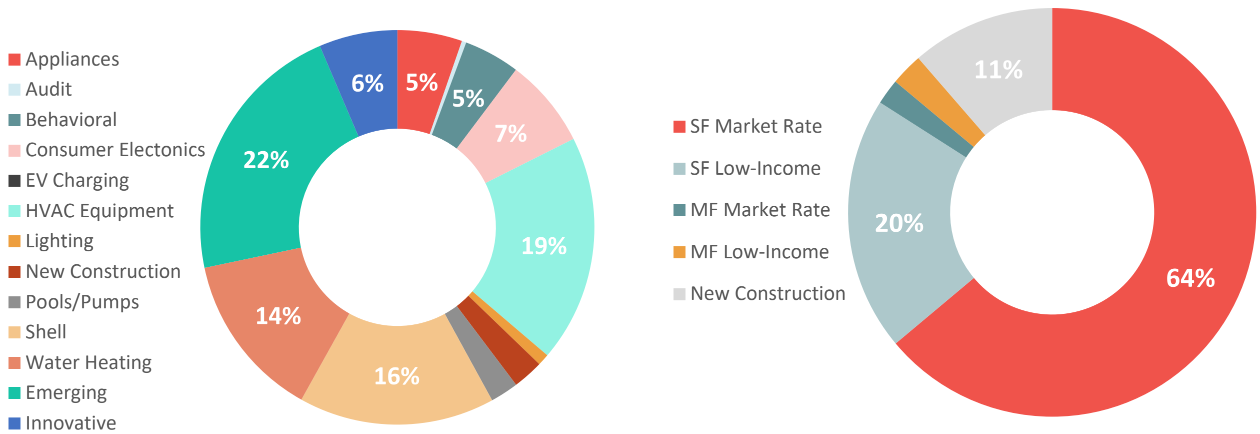

FIGURE 4-4 RESIDENTIAL POTENTIAL BY END-USE AND BUILDING/INCOME TYPE – RAP 2046[12]

Table 4-4 provides incremental annual energy savings by end use for MAP and RAP across the next six years. The Behavioral end-use is the leading end-use in the near-term with significant savings potential from Shell, HVAC Equipment, and Water Heating end uses. Emerging technologies also account for a significant level of potential, though these savings are less proven than measures currently offered by NIPSCO and may be more difficult and costly to acquire than already established measures.

TABLE 4-4 RESIDENTIAL MAP & RAP POTENTIAL – BY END USE

End-Use	2027	2028	2029	2030	2031	2032
MAP						
Appliances	5,026	5,689	6,159	6,384	6,371	6,163
Audit	67	131	202	277	359	461
Behavioral	27,109	27,915	28,541	29,022	29,108	29,189
Consumer Electronics	6,236	5,961	5,399	4,787	4,258	3,960
HVAC Equipment	6,311	7,440	8,391	9,525	10,238	10,834
Lighting	865	997	1,106	1,199	1,318	1,454
New Construction	1,256	1,206	1,100	990	962	904
Pools/Pumps	545	798	991	1,187	1,411	1,725

[12] Missing values reflect end-uses or housing types with < 5% of total of total savings

End-Use	2027	2028	2029	2030	2031	2032
Shell	9,761	11,151	11,258	10,964	10,735	11,308
Water Heating	2,859	3,124	3,355	3,573	4,023	4,525
Emerging	4,637	6,945	7,865	8,579	9,573	11,794
RAP						
Appliances	2,717	3,087	3,366	3,528	3,579	3,536
Audit	67	131	202	277	359	461
Behavioral	27,109	27,915	28,541	29,022	29,108	29,189
Consumer Electronics	4,969	4,745	4,302	3,827	3,419	3,189
HVAC Equipment	3,660	4,338	4,947	5,774	6,319	6,804
Lighting	609	700	782	856	949	1,049
New Construction	1,042	1,000	913	821	798	750
Pools/Pumps	186	272	347	424	511	624
Shell	4,739	5,524	5,675	5,645	5,666	6,125
Water Heating	2,586	2,790	2,936	3,080	3,396	3,766
Emerging	2,892	4,379	5,028	5,559	6,273	7,784

Figure 4-5 shows the annual budget associated with the MAP and RAP scenarios in the residential sector. The MAP budgets increase from about $23 million to $65 million over the timeframe of the study. The RAP budgets increase from $11 million up to $29 million, with about 60% of spending on incentives and the remaining 40% on non-incentive costs.

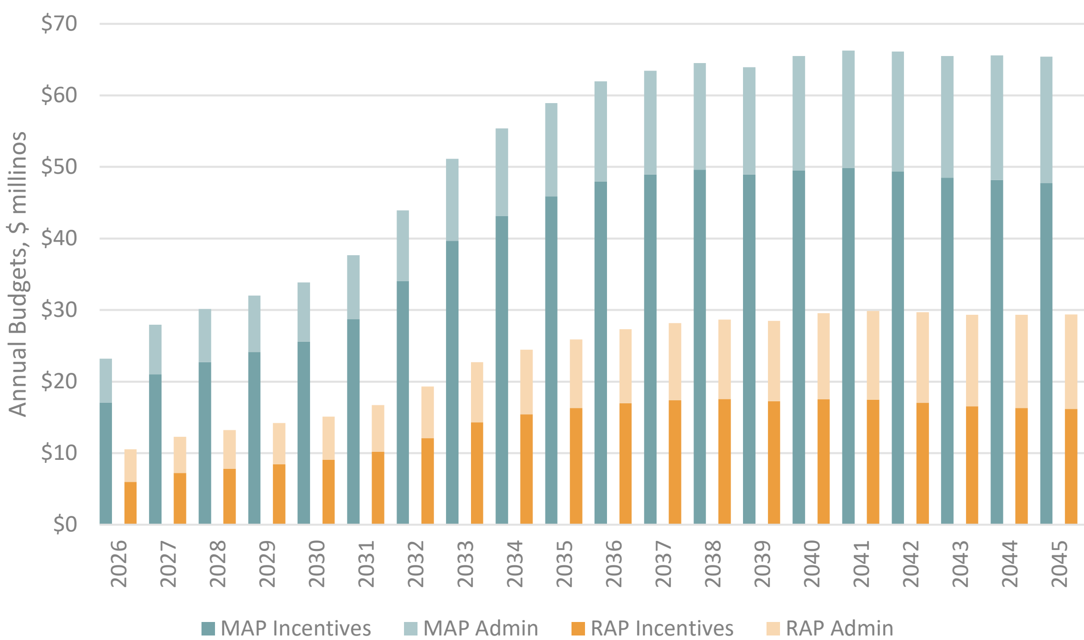

FIGURE 4-5 RESIDENTIAL ANNUAL BUDGETS IN THE MAP AND RAP SCENARIOS

Table 4-5 below shows the NPV benefits and costs associated with the MAP and RAP scenarios. The MAP scenario has $984 million of NPV benefits with a UCT ratio of 1.85. The RAP scenario has $592 million of NPV benefits with a UCT ratio of 2.50.

TABLE 4-5 RESIDENTIAL MAP & RAP POTENTIAL BENEFITS AND COSTS

Scenario	NPV Benefits	NPV Costs	UCT Ratio
MAP	$984,479,685	$531,699,914	1.85
RAP	$591,948,901	$236,440,722	2.50

4.2.3 Enhanced RAP Residential Sector

As noted in Chapter 3, the study included a third scenario called Enhanced RAP. The table below shows the savings and costs of the Enhanced RAP scenario, with a comparison to the RAP scenario also provided. The Enhanced RAP yielded savings 10% higher than the RAP scenario in the near-term (2027-2029) with a total cost per first year kWh of $244/MWh compared to $208/MWh in the RAP scenario over that timeframe. The results of the Enhanced RAP scenario were ultimately used in developing subsequent energy efficiency inputs for the nonresidential sector into the IRP models.

TABLE 4-6 RESIDENTIAL RAP POTENTIAL VS ENHANCED RAP – SAVINGS AND COSTS

End-Use	Enhanced RAP Savings	Enhanced RAP Budget	RAP Savings	RAP Budget
2027	55,508	$12,901,393	50,575	$10,519,160
2028	60,480	$14,908,446	54,882	$12,296,863
2029	62,904	$15,922,883	57,037	$13,235,799
2030	64,732	$16,795,289	58,813	$14,207,522
2031	66,278	$17,645,430	60,376	$15,117,341
2032	69,259	$19,221,277	63,277	$16,739,498
2033	73,728	$21,717,427	67,634	$19,300,726
2034	82,930	$25,257,956	76,697	$22,736,831
2035	86,179	$27,078,071	79,857	$24,439,390
2036	88,683	$28,632,148	82,174	$25,888,556
2037	92,799	$30,315,606	86,211	$27,341,096
2038	93,394	$30,961,256	87,175	$28,159,380
2039	93,789	$31,605,582	87,648	$28,660,711
2040	92,357	$31,514,547	86,600	$28,476,395
2041	96,638	$32,890,080	90,919	$29,585,240
2042	96,651	$33,396,268	90,933	$29,854,785
2043	96,206	$33,513,550	90,345	$29,688,014
2044	94,998	$33,341,147	89,199	$29,323,415

End-Use	Enhanced RAP Savings	Enhanced RAP Budget	RAP Savings	RAP Budget
2045	94,702	$33,529,917	88,809	$29,349,148
2046	93,682	$33,450,731	87,985	$29,396,758

4.3 PROGRAM-LEVEL POTENTIAL

The tables below provide annual savings and budgets by program in the near-term (2027-2032).[13] While GDS aligned the measures in the study with current and prospective NIPSCO offerings, the magnitude of savings from future NIPSCO DSM Plans will have to consider the results of the IRP and how much energy efficiency is ultimately selected, and whether alternative delivery strategies could lead to updated savings and/or costs. Therefore, the reader is cautioned to review the results in these tables as preliminary and illustrative of the relative magnitude of savings and costs across program types and sectors as identified in the MPS.

Table 4-7 provides the annual savings by program within each sector. The three leading programs are the Home Energy Report Program (both market rate and income-qualified), the Home Rebates Program, and the Retail Products. A significant amount of potential exists among measures not currently offered ("No Program") or which are classified as emerging technologies.

TABLE 4-7 ESTIMATED SAVINGS BY PROGRAM

Program	2027	2028	2029	2030	2031	2032
Home Rebates	4,796	5,401	5,853	6,417	6,789	7,200
Retail Products	4,346	4,115	3,774	3,368	2,974	2,598
Home Energy Analysis	466	739	874	992	1,144	1,490
Appliance Recycling	2,704	3,004	3,171	3,171	3,004	2,704
School Education	2,460	2,068	1,684	1,336	1,041	661
Multifamily Direct Install	150	125	81	61	56	48
Home Energy Report	21,318	21,974	22,487	22,885	22,972	23,053
Income Qualified Home Energy Report	5,791	5,941	6,053	6,137	6,137	6,137
Residential New Construction	1,042	1,000	913	821	798	750
HomeLife EE Calculator	492	579	668	770	854	907
Income Qualified Weatherization	1,099	1,116	1,127	1,143	1,157	1,170
Income Qualified HEAR[14]	904	1,092	1,281	1,467	1,642	1,802
Residential Online Marketplace	740	1,099	1,300	1,489	1,748	2,187
Emerging Technology	1,939	2,967	3,377	3,695	4,139	5,161
No Program	2,328	3,661	4,393	5,061	5,920	7,409

[13] The data in this section of the report reflects the RAP scenario.

[14] The Income Qualified HEAR program heading is shown for illustrative purposes only. Savings and costs allocated here do not represent what is assumed to be achieved through NIPSCO programs because these savings are assumed to be tied to incentives associated with federal funds.

Table 4-8 provides the annual budgets by program category. Overall budgets in the RAP scenario range from $10.5 million to $16.7 million. Future DSM plan savings and budget goals will depend on a number of factors, primarily the results of the level of energy efficiency that is ultimately selected by the IRP.

TABLE 4-8 ESTIMATED COSTS BY PROGRAM

Program	2027	2028	2029	2030	2031	2032
Home Rebates	$1,602,029	$1,821,296	$1,996,268	$2,338,728	$2,497,010	$2,684,585
Retail Products	$1,419,020	$1,411,512	$1,357,889	$1,268,795	$1,164,130	$1,051,691
Home Energy Analysis	$127,760	$200,235	$233,756	$262,406	$301,312	$402,440
Appliance Recycling	$452,163	$509,359	$545,186	$552,910	$531,316	$485,111
School Education	$498,189	$421,752	$345,845	$276,418	$217,303	$146,386
Multifamily Direct Install	$37,606	$31,335	$18,646	$13,584	$12,673	$10,755
Home Energy Report	$1,470,949	$1,549,576	$1,620,637	$1,685,625	$1,729,195	$1,773,462
Income Qualified Home Energy Report	$399,587	$418,945	$436,263	$452,000	$461,944	$472,107
Residential New Construction	$230,414	$224,012	$207,137	$188,877	$186,074	$177,117
HomeLife EE Calculator	$102,562	$124,367	$147,223	$172,099	$193,321	$207,449
Income Qualified Weatherization	$996,899	$1,001,130	$1,004,411	$1,008,807	$1,013,300	$1,017,892
Income Qualified HEAR[15]	$963,104	$1,173,270	$1,388,281	$1,604,377	$1,814,570	$2,013,770
Residential Online Marketplace	$162,507	$248,800	$307,945	$367,619	$445,038	$563,823
Emerging Technology	$1,132,608	$1,732,538	$1,967,933	$2,152,317	$2,414,932	$3,043,232
No Program	$923,762	$1,428,736	$1,658,377	$1,862,960	$2,135,224	$2,689,678

[15] The Income Qualified HEAR program heading is shown for illustrative purposes only. Savings and costs allocated here do not represent what is assumed to be achieved through NIPSCO programs because these savings are assumed to be tied to incentives associated with federal funds.

5 NONRESIDENTIAL ENERGY EFFICIENCY POTENTIAL

This chapter provides the potential results for technical, economic, MAP and RAP for the nonresidential (commercial and industrial) sector. Results are broken down by sector and end use. The cost-effectiveness results and budgets for the RAP scenario are also provided.

5.1 SCOPE OF MEASURES & END USES ANALYZED

There were 183 total electric measures included in the nonresidential analysis. Table 5-1 provides the number of measures by end-use (the full list of measures is provided in the appendices volume of this report). The measure list was developed based on a review of current NIPSCO programs, the Indiana TRM, other regional TRMs, and industry documents related to emerging technologies. Data collection activities to characterize measures formed the basis of the assessment of incremental costs, electric energy and demand savings, and measure life.

TABLE 5-1 C&I ENERGY EFFICIENCY MEASURES – BY END USE

End-Use	# of Unique Measures	# of Permutations
Compressed Air	8	53
Cooking	9	90
Lighting	34	295
Hot Water	4	40
HVAC	34	322
Miscellaneous	6	51
Motors	10	46
Plug Loads	10	100
Refrigeration	24	222
Ventilation	3	21
Whole Building	32	186
Process	9	9

5.2 TOTAL NONRESIDENTIAL ELECTRIC POTENTIAL SUMMARY

Table 5-2 provides the technical, economic, MAP and RAP results for the 5-year, 10-year, and 20-year timeframes. The cumulative annual 5-year technical potential is 12.1% of forecasted sales, and the economic potential is also 12.1% of forecasted sales. The cumulative annual 5-year MAP is 9.9% and the RAP is 7.1%, as a percentage of forecasted sales. Over the duration of the study timeframe the technical and economic potential each rise to 33% forecasted sales. This indicates that essentially all of the technical potential is cost-effective. The MAP and RAP rise respectively to 24% and 17% of forecasted sales over the study timeframe. The gap between economic potential and MAP/RAP represents market barriers to prospective program participants, both financial and non-financial, to achieving the full amount of economic potential.

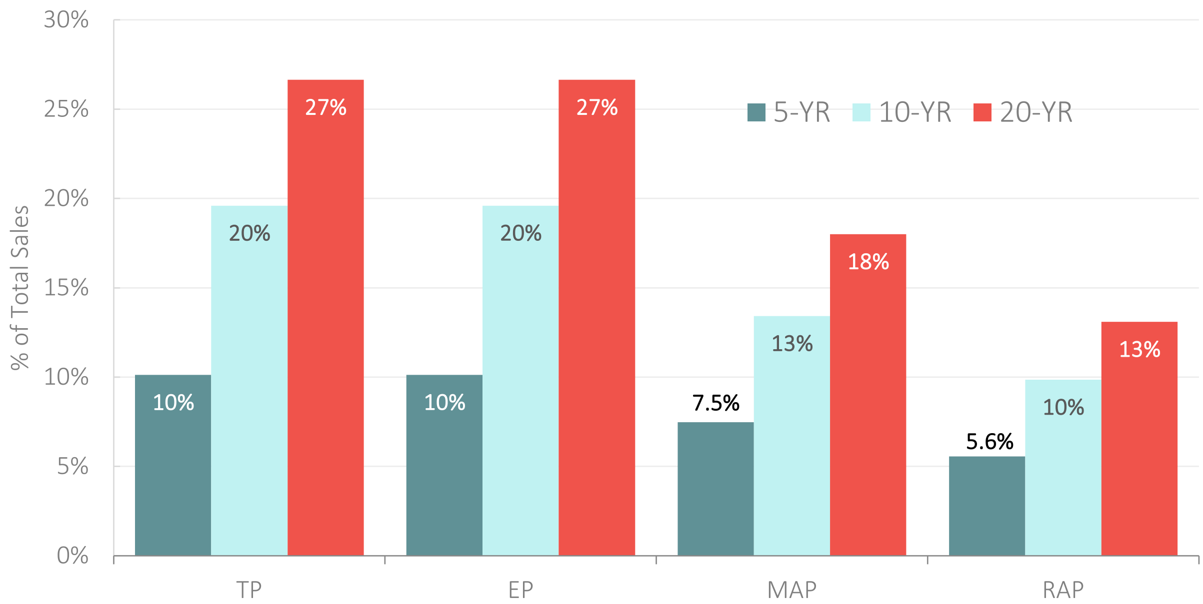

FIGURE 5-1 OVERVIEW OF NONRESIDENTIAL POTENTIAL

Table 5-2 provides additional details of the long-term nonresidential potential, showing the cumulative annual MWh and MW associated with technical, economic and achievable potential. The 20-yr cumulative annual MAP and RAP are over 1.0 million MWh and over 750,000 MWh, respectively, with additional 213 MW and 146 MW savings from energy efficiency in the MAP and RAP scenarios.

TABLE 5-2 LONG-TERM TECHNICAL, ECONOMIC, ACHIEVABLE POTENTIAL SAVINGS (MWH, % SAVINGS, MW)

	5-YR	10-YR	20-YR
Energy (MWh)			
Technical	546,138	1,070,491	1,495,584
Economic	543,560	1,066,337	1,491,118
MAP	447,641	776,947	1,069,271
RAP	319,888	549,443	753,508
Energy Savings (as % of Forecast)			
Technical	12.1%	23.6%	33.3%
Economic	12.1%	23.5%	33.2%
MAP	9.9%	17.1%	23.8%
RAP	7.1%	12.1%	16.8%
MW			
Technical	90	183	289
Economic	89	182	288
MAP	73	134	213

	5-YR	10-YR	20-YR
RAP	52	93	146

Table 5-3 provides additional details of the short-term nonresidential potential, showing the incremental annual MWh and MW associated with technical, economic and achievable potential. The RAP averages about 65,000 MWh from 2027 to 2032, representing between 1.3% and 1.6% of sector-sales.

TABLE 5-3 SHORT-TERM TECHNICAL, ECONOMIC, ACHIEVABLE POTENTIAL SAVINGS (MWH, % SAVINGS, MW)

	2027	2028	2029	2030	2031	2032
Energy (MWh)						
Technical	101,563	108,672	112,662	119,717	120,208	122,677
Economic	101,054	108,142	112,128	119,199	119,707	121,928
MAP	99,074	95,973	91,639	91,666	86,083	82,697
RAP	71,173	68,701	65,499	65,270	61,467	59,656
Energy Savings (as % of Forecast)						
Technical	2.2%	2.4%	2.5%	2.7%	2.7%	2.7%
Economic	2.2%	2.4%	2.5%	2.6%	2.7%	2.7%
MAP	2.2%	2.1%	2.0%	2.0%	1.9%	1.8%
RAP	1.6%	1.5%	1.4%	1.4%	1.4%	1.3%
MW						
Technical	17	18	19	20	20	20
Economic	17	18	18	20	20	20
MAP	17	16	15	15	14	13
RAP	12	11	11	10	10	9

5.2.1 Technical/Economic Potential

Figure 5-2 provides additional annual savings data for the technical and economic potential. The incremental annual technical potential starts off at more than 100,000 MWh in 2027 and rises to almost 160,000 MWh during the study timeframe. The economic potential is nearly identical to the technical potential.

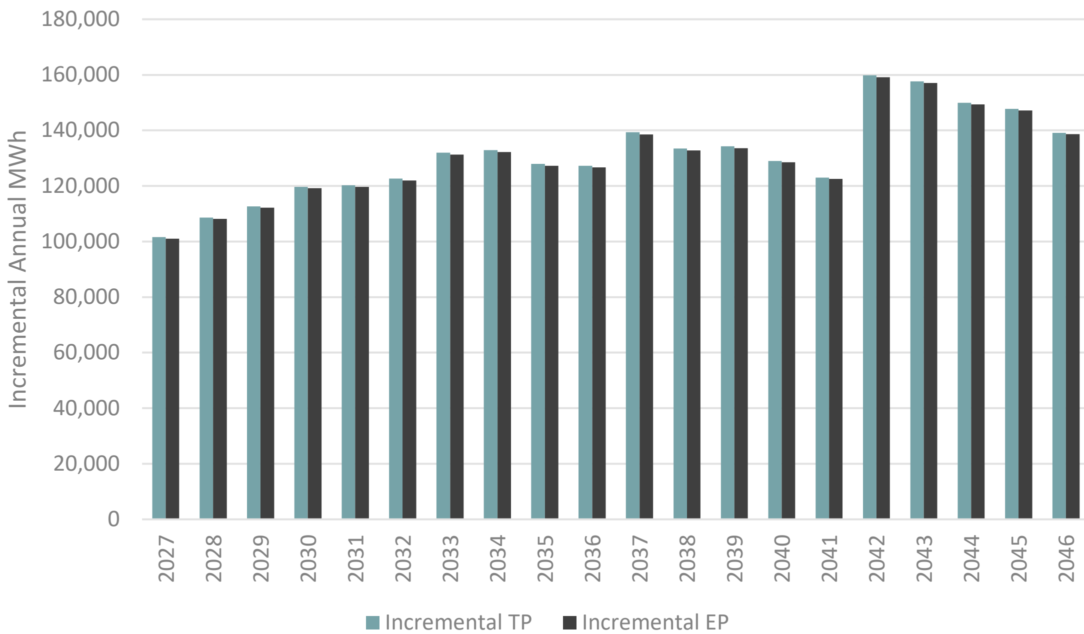

FIGURE 5-2 NONRESIDENTIAL TECHNICAL AND ECONOMIC POTENTIAL

5.2.2 Achievable Potential

Figure 5-3 provides the MAP and RAP across the 20-yr timeframe of the study. The green and red bars provide the respective incremental annual MAP and RAP in MWh per year energy savings. The green and orange lines provide the corresponding cumulative annual MAP and RAP as a percentage of forecasted annual sales. The MAP rises to 24% by 2046, and the RAP rises to 17%.

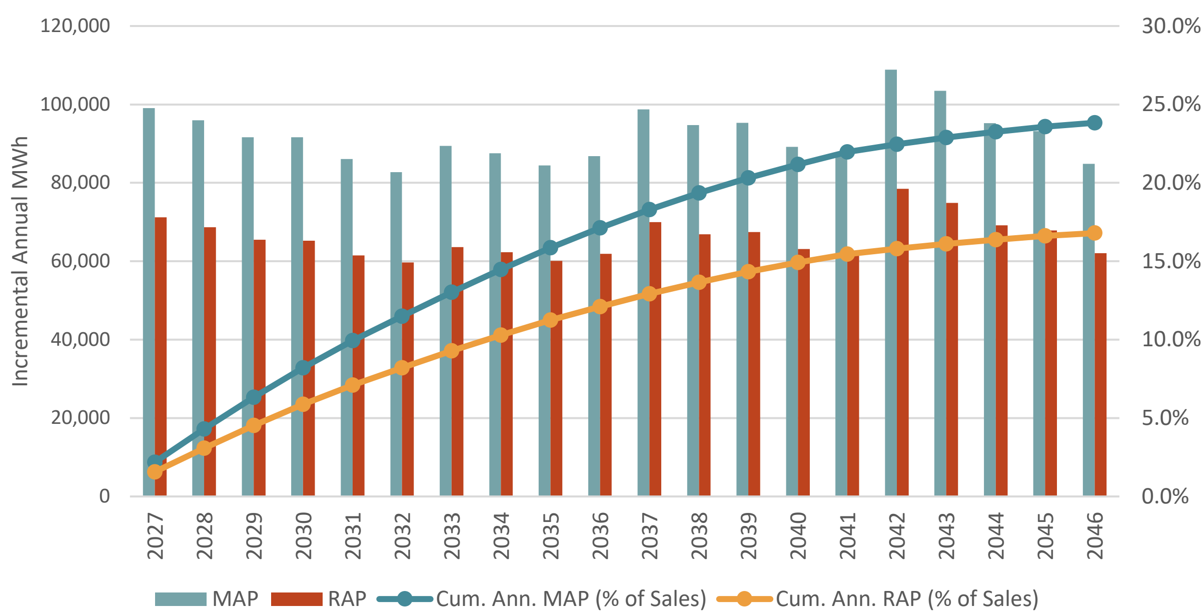

FIGURE 5-3 NONRESIDENTIAL MAXIMUM AND REALISTIC ACHIEVABLE POTENTIAL

Figure 5-4 provides a breakdown of the RAP potential in 2046 across end-uses and building types. The end-use pie chart shows the savings potential from existing measures by end use, as well as among measures classified as emerging and innovative as described in Section 3.3.2 above. Among existing measures, the leading end uses are Whole Building (18%), Lighting (18%), and HVAC (13%). Emerging and innovative measures account for 19% of the long-term RAP. Among building types, Retail (22%) and Industrial buildings (16%) Offices (13%), and Education (11%) lead the way, with the remaining potential allocated towards, Assembly, Food Sales, Food Service, Health, Lodging, Warehouse, Agriculture and Other building types.

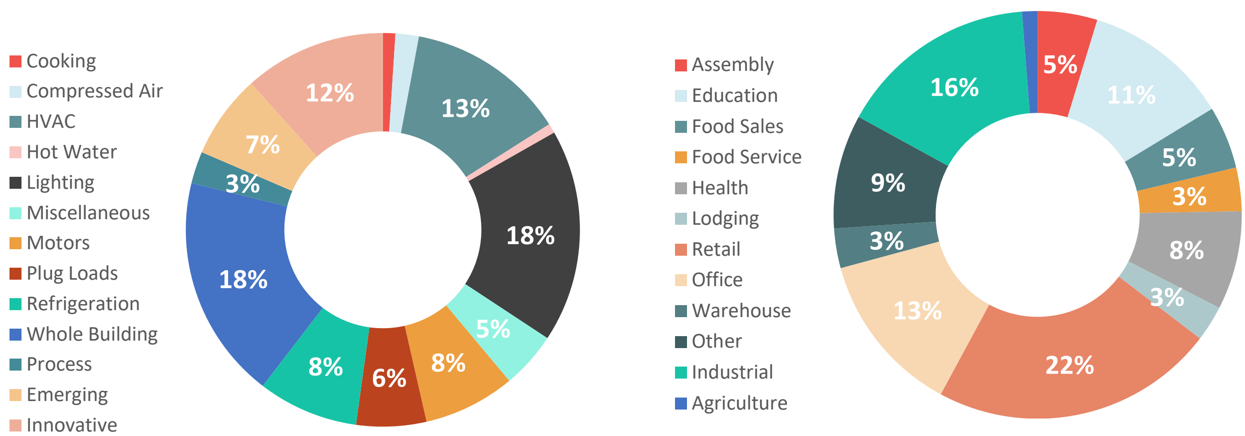

FIGURE 5-4 NONRESIDENTIAL POTENTIAL BY END-USE AND BUILDING TYPE – RAP 2046[16]

Table 5-4 provides incremental annual energy savings by end use for MAP and RAP across the next six years. The data reflects the pie chart above but also shows that there is some near-term lighting potential that begins to tail off.

TABLE 5-4 NONRESIDENTIAL MAP & RAP POTENTIAL – BY END USE

End-Use	2027	2028	2029	2030	2031	2032
MAP						
Cooking	452	496	535	567	595	623
Compressed Air	1,871	1,982	2,023	3,015	2,927	3,028
HVAC	16,264	16,113	15,578	15,957	14,840	13,346
Hot Water	432	385	361	237	282	506
Lighting	37,780	31,974	26,602	21,709	16,774	13,112
Miscellaneous	3,827	4,393	4,885	5,235	5,413	5,403
Motors	3,965	4,431	4,772	6,304	6,441	6,411
Plug Loads	7,122	7,606	7,757	7,547	7,075	6,443

16 Missing values reflect end-uses or building types with < 5% of total of total savings

End-Use	2027	2028	2029	2030	2031	2032
Refrigeration	9,141	9,177	8,988	8,008	8,042	9,512
Whole Building	11,797	12,559	12,552	14,469	14,028	13,978
Process	2,914	3,079	3,152	3,924	3,870	3,716
Emerging	3,509	3,777	4,433	4,694	5,796	6,620
RAP						
Cooking	405	444	478	505	530	554
Compressed Air	1,326	1,405	1,432	2,164	2,095	2,222
HVAC	9,631	9,617	9,345	9,581	8,982	8,131
Hot Water	380	328	298	171	203	407
Lighting	30,215	25,686	21,499	17,668	13,737	10,801
Miscellaneous	2,172	2,526	2,842	3,074	3,201	3,211
Motors	2,533	2,840	3,068	4,055	4,156	4,155
Plug Loads	4,620	4,940	5,041	4,905	4,594	4,175
Refrigeration	7,766	7,831	7,716	6,886	7,035	8,486
Whole Building	8,119	8,784	8,931	10,708	10,577	10,621
Process	1,592	1,689	1,733	2,232	2,204	2,114
Emerging	2,413	2,612	3,114	3,322	4,153	4,776

Figure 5-5 shows the annual budget associated with the MAP and RAP scenarios in the nonresidential sector. The MAP budgets average about $38 million over the timeframe of the study. The RAP budgets increase from $10 million up to more than $14 million, with about 50% of spending on incentives and the remaining 50% on non-incentive costs.

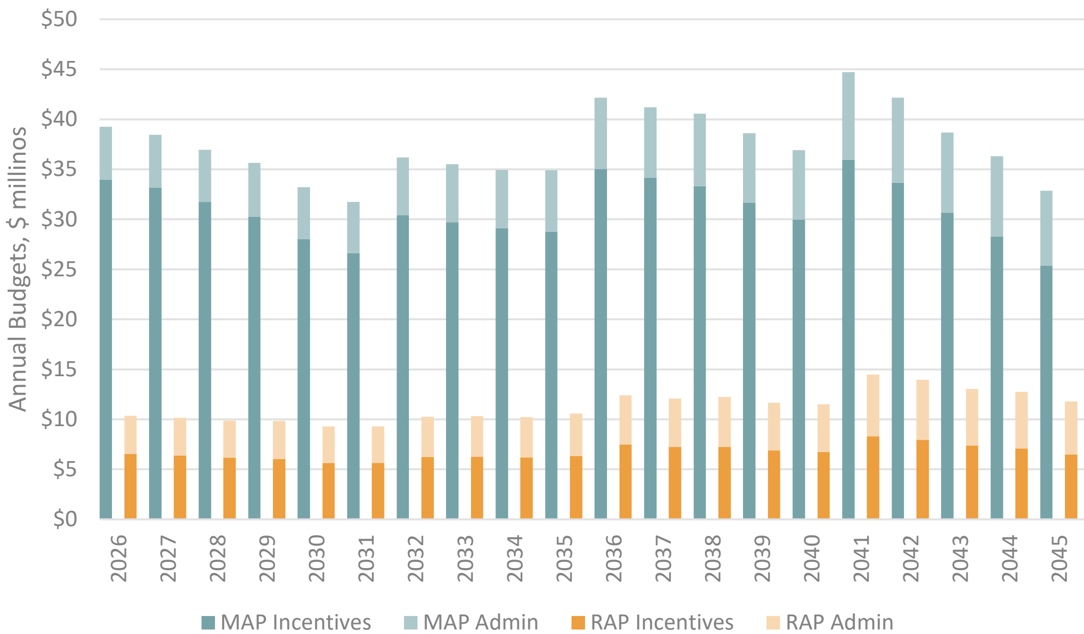

FIGURE 5-5 NONRESIDENTIAL ANNUAL BUDGETS IN THE MAP AND RAP SCENARIOS

Table 5-5 below shows the NPV benefits and costs associated with the MAP and RAP scenarios. The MAP scenario has more than $1.0 billion of NPV benefits with a UCT ratio of 2.44. The RAP scenario has more than $700 million of NPV benefits with a UCT ratio of 5.77.

TABLE 5-5 NONRESIDENTIAL MAP & RAP POTENTIAL BENEFITS AND COSTS

Scenario	NPV Benefits	NPV Costs	UCT Ratio
MAP	$1,036,509,075	$425,219,819	2.44
RAP	$716,158,046	$124,077,509	5.77

5.2.3 Enhanced RAP in the Nonresidential Sector

As noted in Chapter 3, the study included a third scenario called Enhanced RAP. The table below shows the savings and costs of the Enhanced RAP scenario, with a comparison to the RAP scenario also provided. The Enhanced RAP yielded savings 8% higher than the RAP scenario in the near-term (2027-2029) with a total cost per first year kWh of $307/MWh compared to $171/MWh in the RAP scenario over that timeframe. The results of the Enhanced RAP scenario were ultimately used in developing subsequent energy efficiency inputs for the nonresidential sector into the IRP models.

TABLE 5-6 NONRESIDENTIAL RAP POTENTIAL VS ENHANCED RAP – SAVINGS AND COSTS

End-Use	Enhanced RAP Savings	Enhanced RAP Budget	RAP Savings	RAP Budget
2027	75,248	$21,607,993	71,173	$10,360,372
2028	73,411	$21,493,970	68,701	$10,163,890
2029	70,581	$20,991,146	65,499	$9,856,851
2030	70,584	$20,519,432	65,270	$9,836,659
2031	66,907	$19,403,969	61,467	$9,287,855
2032	64,771	$18,742,591	59,656	$9,301,386
2033	70,272	$21,362,724	63,606	$10,254,498
2034	67,586	$20,580,460	62,270	$10,320,037
2035	64,727	$20,142,883	60,106	$10,223,970
2036	66,523	$20,317,097	61,924	$10,574,611
2037	75,247	$24,095,864	69,965	$12,393,030
2038	72,505	$23,772,575	66,853	$12,075,038
2039	72,710	$23,276,809	67,483	$12,227,582
2040	68,189	$22,312,001	63,113	$11,653,371
2041	66,875	$21,652,446	61,737	$11,515,578
2042	83,625	$26,219,047	78,492	$14,464,039
2043	79,917	$24,982,754	74,907	$13,958,534
2044	74,064	$23,136,259	69,160	$13,039,591
2045	72,176	$21,805,668	67,820	$12,754,581
2046	66,060	$19,899,573	62,026	$11,780,106

5.3 PROGRAM-LEVEL POTENTIAL

The tables below provide annual savings and budgets by program in the near-term (2027-2032).[17] While GDS aligned the measures in the study with current and prospective NIPSCO offerings, the magnitude of savings from future NIPSCO DSM Plans will have to consider the results of the IRP and how much energy efficiency is ultimately selected, and whether alternative delivery strategies could lead to updated savings and/or costs. Therefore, the reader is cautioned to review the results in these tables as preliminary and illustrative of the relative magnitude of savings and costs across program types and sectors as identified in the MPS.

Table 5-7 provides the annual savings by program within the nonresidential sector. At the outset of the study timeframe, the Prescriptive program leads the way. By 2029 the leading program is the Custom

[17] The data in this section of the report reflects the RAP scenario.

program. The Retro commissioning program also provides a steady and increasing level of potential over the study period.

TABLE 5-7 ESTIMATED SAVINGS BY PROGRAM

Program	2027	2028	2029	2030	2031	2032
Biz - Prescriptive	37,874	33,283	28,975	24,773	21,200	18,221
Biz - Custom	29,603	31,226	32,122	34,758	34,573	34,010
Biz - RCx	3,696	4,191	4,402	5,738	5,694	7,425

Table 5-8 provides the annual budgets by program category. Overall budgets in the RAP scenario range from $9.3 million to $10.4 million. Future DSM plan savings and budget goals will depend on a number of factors, primarily the results of the level of energy efficiency that is ultimately selected by the IRP.

TABLE 5-8 ESTIMATED COSTS BY PROGRAM

Program	2027	2028	2029	2030	2031	2032
Biz - Prescriptive	$5,310,889	$4,704,696	$4,135,712	$3,582,416	$2,956,745	$2,608,153
Biz - Custom	$4,468,456	$4,786,662	$5,002,709	$5,364,888	$5,439,615	$5,435,864
Biz - RCx	$581,027	$672,532	$718,430	$889,355	$891,495	$1,257,370

PREPARED BY GDS

NIPSCO

NORTHERN INDIANA PUBLIC SERVICE

Demand Side Management Market Potential Study

VOLUME I ELECTRIC ENERGY EFFICIENCY POTENTIAL

2024

GDS Associates, Inc.
ENGINEERS & CONSULTANTS

Demand Side Analytics
DATA DRIVEN RESEARCH AND INSIGHTS

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1.1 OBJECTIVES

This Market Potential Study was conducted to support the 2024 Integrated Resource Plan (IRP) and Demand Side Management (DSM) planning for NIPSCO. This volume provides estimates of the maximum achievable potential (MAP) and realistic achievable potential (RAP) for a selection of demand response (DR) offerings, along with the cost of acquiring the two levels of achievable potential. These outputs of the DR potential study represent inputs for the IRP.

1.2 CONTEXT

This study represents an update to the assessment of demand response (DR) potential that Demand Side Analytics (DSA) and GDS Associates (GDS) conducted in 2021. Since the 2021 study, there have been some notable changes in the regulatory context. Firstly, prior to NIPSCO's rate case in 2018, NIPSCO's DR portfolio was comprised of load curtailment agreements from a small number of large industrial customers served under Rate 531. In the 2018 rate case, it was decided that NIPSCO must now only procure enough resources for a portion of these customers' loads. The result is that NIPSCO now has a lower total load obligation than before the 2018 rate case, but it also cannot claim any demand response from Rate 531 customers. The change to NIPSCO's demand response portfolio is important to keep in mind when making comparisons of NIPSCO's historical demand response offerings to results of this potential study. Secondly, MISO has shifted to a seasonal capacity construct in preparation for its 2024/2025 PRA. This necessitated a DR potential study which examined DR potential for the summer, winter, spring, and fall seasons. Our approach was to assign full capacity value to each season and model the potential and economics of each season as if it were to present a binding requirement in the IRP. This approach will allow the IRP model to select resources and solve capacity shortfalls on a seasonal basis while still considering the program's expected performance in the other seasons. We cover these regulatory changes and their implications for this study in more detail in Chapter 3.

1.3 SCOPE

In addition to the removal of Rate 531 interruptible loads from the NIPSCO DR portfolio, residential AC cycling via direct load control switches was suspended in 2015. NIPSCO does not currently have any other active capacity DR offerings[1] during 2024 but is in negotiations with vendors to launch two DR offerings in 2025: a Residential Bring Your Own Thermostat program, and Commercial & Industrial Load Curtailment program. The timeline and budgets of these offerings are pending regulatory approval. As a result, we considered the following DR program types in this DR potential study:

- Water heater direct load control
- EV managed charging
- Behind-the-meter battery storage
- Behavioral demand response
- Time-varying dynamic rates
- C&I load curtailment

[1] NIPSCO has two energy-only resources (ERR1 and EDR) but they are not recognized as capacity resources

- Data center load curtailment

1.4 RESULTS

Table 1-1 shows the system-level RAP in 2046 for each season and program type. The total summer RAP for all programs is 220.8 MW. For programs that pass the utility cost test, the total summer RAP is 209.8 MW. Potential is highest in the summer and lowest in the spring. The dynamic rates program yields the most DR potential, at 66.1 MW in the summer season.

TABLE 1-1: SYSTEM-LEVEL RAP (MW) IN 2046 BY SEASON AND PROGRAM TYPE

Program	UCT Result	Spring	Summer	Fall	Winter
Connected Thermostats	Pass	12.5	48.7	26.4	42.4
Water Heaters	Fail	0.7	0.4	0.6	0.8
Behavioral DR	Pass	7.4	6.7	6.7	7.4
Dynamic Rates	Pass	30.5	66.1	60.9	30.6
EV Managed Charging	Fail	10.6	9.9	10.2	11.8
BTM Storage	Fail	0.7	0.7	0.7	0.4
C&I Load Curtailment	Pass	27.0	29.4	28.8	25.3
Data Centers - Base	Pass	58.9	58.9	58.9	58.9
Total		**148.4**	**220.8**	**193.2**	**177.6**
Total with UCT > 1		**136.3**	**209.8**	**181.6**	**164.6**

Table 1-2 shows the system-level MAP in 2046 for each season and program type. The total summer MAP for all programs is 322.9 MW. For programs that pass the utility cost test, the total summer RAP is 241 MW. While MAP yields larger potential DR than RAP, it also requires larger program investment and changes the program cost effectiveness. In particular, the connected thermostats program does not pass the utility cost test in the MAP scenario, whereas it did under the RAP scenario.

TABLE 1-2: SYSTEM-LEVEL MAP (MW) IN 2046 BY SEASON AND PROGRAM TYPE

Program	UCT Result	Spring	Summer	Fall	Winter
Connected Thermostats	Fail	19.4	62.3	33.8	66.0
Water Heaters	Fail	1.0	0.5	0.8	1.2
Behavioral DR	Pass	9.9	11.9	11.9	9.9
Dynamic Rates	Pass	39.0	84.4	77.7	39.0
EV Managed Charging	Fail	18.9	17.5	18.2	21.0
BTM Storage	Fail	1.5	1.5	1.5	0.7
C&I Load Curtailment	Pass	46.3	50.4	49.3	43.4
Data Centers - Base	Pass	94.4	94.4	94.4	94.4
Total		**230.3**	**322.9**	**287.6**	**275.6**
Total with UCT > 1		**189.5**	**241.0**	**233.3**	**186.6**

Figure 1 reports summer RAP by year for programs that pass the utility cost test. Notably, the dynamic rates program does not come online until 2030; dynamic rates require advanced metering infrastructure (AMI) which is not due to be rolled out until 2030. Over the 20-year study horizon, estimated summer DR potential increases from about 25 MW to 220 MW. For most of the study horizon, the data centers and dynamic rates programs make up the largest share of DR potential.

FIGURE 1: SUMMER RAP BY YEAR AND PROGRAM FOR SCREENED PROGRAMS

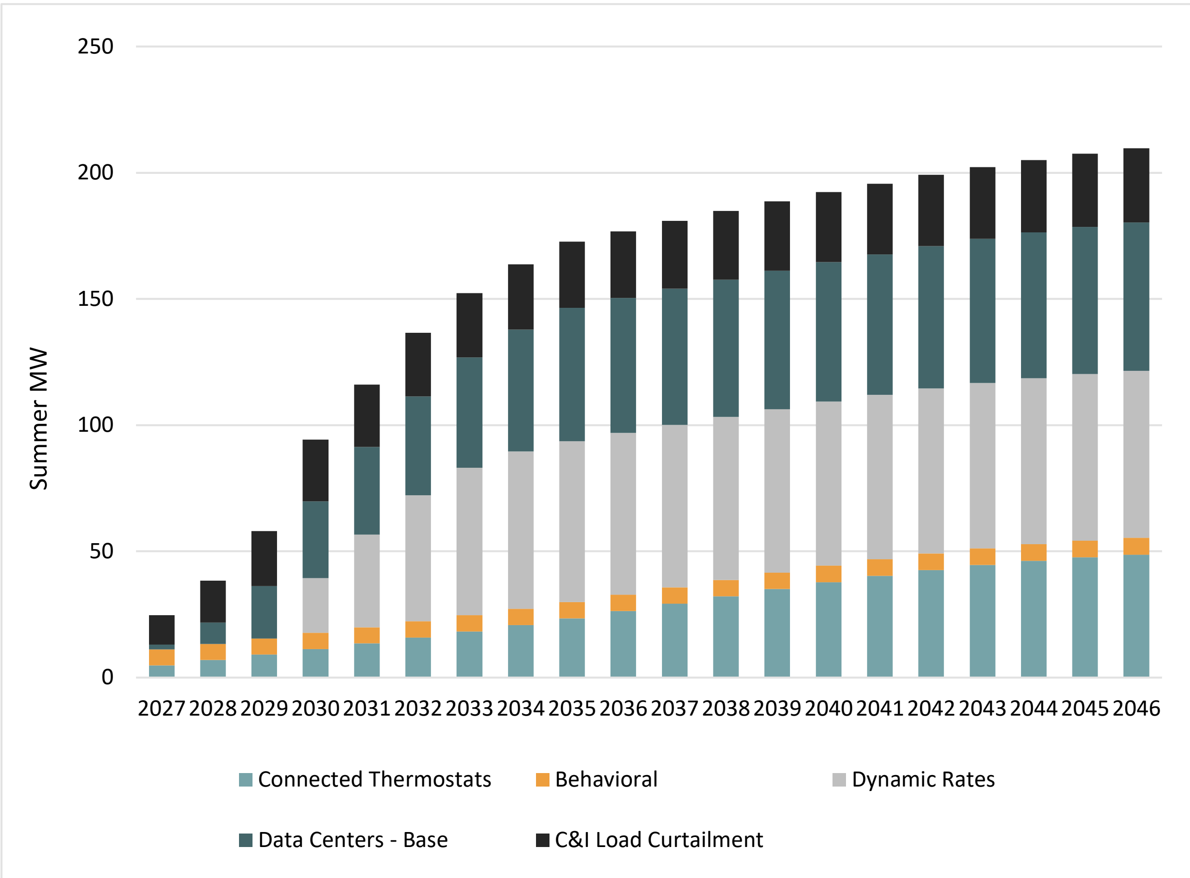


Figure 2 reports summer MAP by year for programs that pass the utility cost test. As discussed above, the connected thermostat program, which had a UCT ratio greater than 1.0 under RAP, does not pass cost-effectiveness screening under MAP, so it is now excluded. Over the 20-year study horizon, estimated summer DR potential increases from about 30 MW to 241 MW. As was the case for the RAP scenario, for most of the study horizon, the data centers and dynamic rates programs make up the largest share of DR potential.

FIGURE 2: SUMMER MAP BY YEAR AND PROGRAM FOR SCREENED PROGRAMS

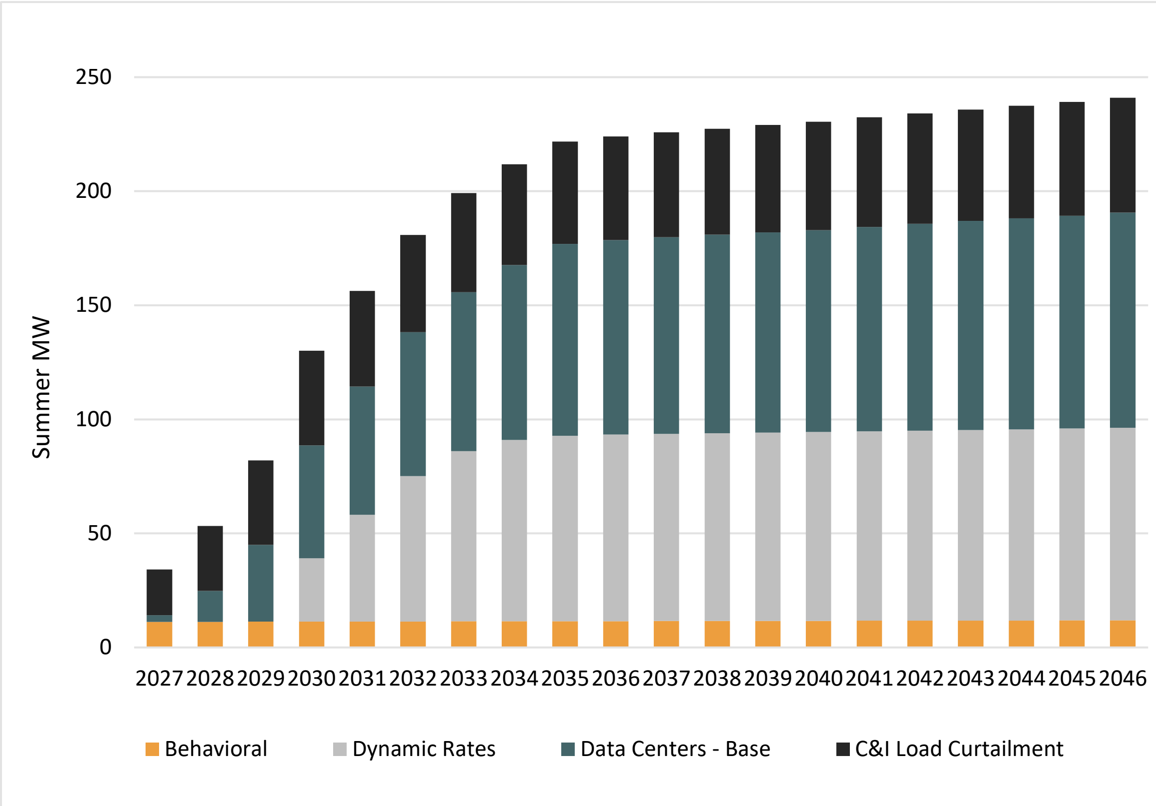


Table 1-3 shows program investment under RAP and MAP scenarios for select years in the program horizon. While the MW values reported above are differentiated by season, the costs reported here are an annual total. They include the full cost of program delivery and incentives. The spending values include only programs with a UCT ratio greater than 1.0 and would be higher if NIPSCO pursued additional components of the RAP or MAP. Program investment under the MAP scenario tends to be about double that under the RAP scenario.

TABLE 1-3: PROGRAM INVESTMENT BY YEAR (NOMINAL $M)

Year	RAP ($M)	MAP ($M)
2027	$3.4	$5.0
2028	$4.3	$8.0
2029	$6.3	$12.7
2036	$24.3	$34.0
2046	$39.6	$50.3

2 Introduction

This Market Potential Study was conducted to support the 2024 Integrated Resource Plan (IRP) and Demand Side Management (DSM) planning for NIPSCO. The effort was highly collaborative, as the GDS Team worked closely alongside NIPSCO, as well as the NIPSCO Oversight Board, to produce reliable estimates of future saving potential, using the best available information and best practices for developing market potential saving estimates. It represents an update to the assessment of demand response (DR) potential that DSA and GDS conducted in 2021. The 2021 study included a comprehensive review of existing programs, historical savings, and projected energy and demand savings opportunities to develop estimates of achievable potential. At that time, the transition of most Rate 531 loads out of NIPSCO's firm service requirements during its 2018 rate case reduced the amount of DR directly offered by the company to nearly zero. Given this starting point, DSA focused the 2021 DR MPS on a relatively short list of ubiquitous DR offerings with the highest likelihood of selection in the IRP and inclusion in future DSM planning. These included residential connected thermostats, water heater direct load control, dynamic rates, and non-residential curtailment agreements. This Market Potential Study makes several noteworthy updates to the previous work. Firstly, we update the modeling of previous offerings with new inputs, assumptions, and modeling framework. Secondly, we consider several new DR options so that the portfolio represents a more complete roster of possible DR offerings. Finally, we model DR potential seasonally to reflect the recent transition to a seasonal capacity construct at MISO.

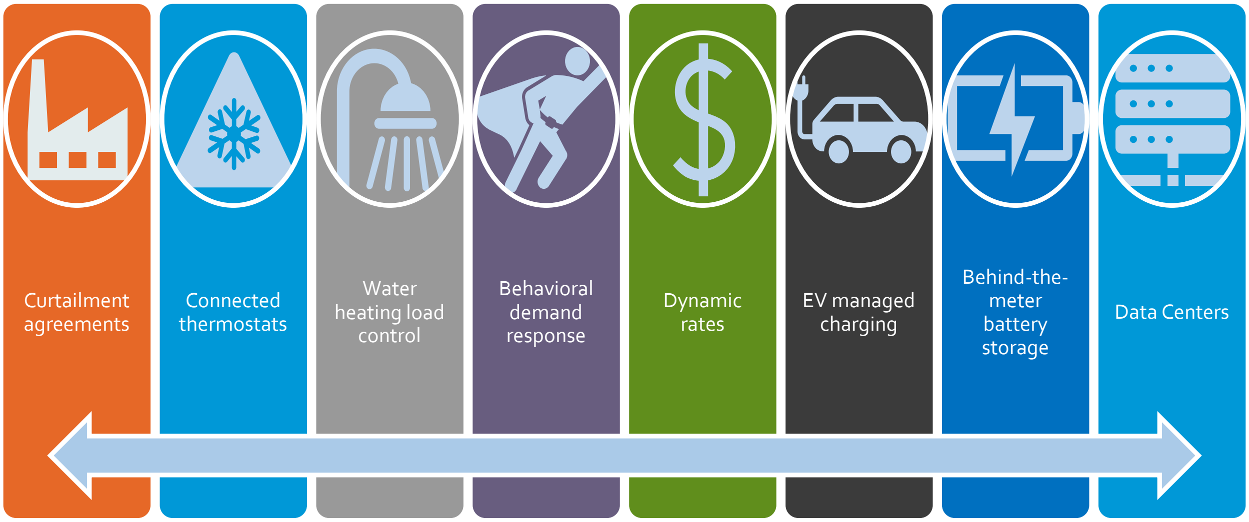
2.1 TYPES OF POTENTIAL ESTIMATED

This volume provides estimates of the maximum achievable potential (MAP) and realistic achievable potential (RAP) for a selection of demand response offerings, along with the cost of acquiring the two levels of achievable potential. The body of this report provides inputs and results by sector and program for a base case set of assumptions for both MAP and RAP scenarios. The outputs of this analysis will be used as inputs for NIPSCO's 2024 Integrated Resource Plan (IRP).

In the residential sector, this study assessed the following demand response offerings: a residential smart thermostat program, a water heater direct load control program, a residential time-varying dynamic rates program, a behind-the-meter battery storage program, a behavioral demand response program, and an electric vehicle (EV) managed charging program. For the commercial and industrial (C&I) sector, we assessed a C&I load curtailment program for existing business customers and a similar offering for forecasted large data center load additions.

In IRP modeling, NIPSCO will consider demand response alongside other supply resources to supply capacity and energy needs. To facilitate this effort, the GDS team provided NIPSCO with annual program costs and potential, by season, for the RAP and MAP scenarios for eight program archetypes shown in Figure 3.

FIGURE 3: DR PROGRAM TYPES



2.2 IMPORTANT STUDY CONSIDERATIONS

A critical distinction between this study and the prior potential study is the examination of DR potential for all seasons rather than just the summer. Our prior DR potential study considered only summer peak demand because NIPSCO is a summer-peaking system and accreditation of Load Modifying Resources at MISO at the time was summer only. Since then, MISO has moved to a seasonal construct.

As was the case in the 2021 study, there is a select set of NIPSCO large industrial customers that offer a substantial portion of their load to the Midcontinent Independent System Operator ("MISO") as a "load-modifying resource", or LMR. As discussed more in Section 3.2, NIPSCO no longer has a firm obligation to serve this portion of customer loads, and they have been removed from the baseline peak load forecast. While these customers still provide demand response, it is not part of NIPSCO's demand response portfolio, and this study does not assume any DR potential from the firm load associated with these customers.

In addition, as discussed in the report in more detail, NIPSCO currently does not have the necessary advanced metering infrastructure (AMI) in place to implement a dynamic rates program and the costs of these programs presented in this study do not reflect the full costs of AMI. This is because AMI can provide several benefits beyond the ability to implement DR programs, including reduced billing costs, faster outage restoration, and better visibility into customers' energy usage. As was the case in the 2021 study, we introduce dynamic rates as a DR strategy in 2030.

2.3 REPORT ORGANIZATION

The rest of the report is organized as follows:

Section 3 Study Context provides context for quantifying demand response market potential in the NIPSCO service area including a review of prior demand response and the peak load forecast.

Section 4 Economic Modeling Framework details the methodology used to assess the potential for future demand response programs.

Section 5 Detailed Findings: Residential provides the results for achievable demand response programs in the residential sector.

Section 6 Detailed Findings: Non-residential provides the results for achievable demand response programs in the C&I Sectors.

Section 7 Alternate Avoided Cost Case Sensitivity provides the results for the alternate avoided cost sensitivity case, in which a lower avoided cost of generation capacity and higher avoided cost of transmission and distribution capacity are used for cost-benefit modeling.

3 Study Context: Regulatory Framework, Prior Demand Response Programs, and Peak Load Forecast

One of the central goals of the IRP is to identify adequate resources to meet long-run projections of peak loads for the NIPSCO service territory plus a reserve margin. Demand response is one of the resource types NIPSCO considers toward satisfying the capacity requirements of the system. Other resource types include thermal generation, renewable generation, battery storage, and energy efficiency. To provide context for demand response market potential, this chapter describes and characterizes the current regulatory framework for demand response, NIPSCO's historical and existing demand response offerings, and NIPSCO's historical and forecast peak loads.

3.1 REGULATORY FRAMEWORK

As a vertically integrated utility participating in energy markets run by MISO, NIPSCO must procure sufficient capacity resources to satisfy peak load and reserve margin requirements. This potential study focuses on MISO resource adequacy hours in each season, with all capacity values representing system-level MW capacity. Capacity values were first calculated at the meter level and then grossed up to include impacts for line losses. Program capacity values shown in this report also include de-rates for expected event drop-outs (certain demand response programs allow customers to opt out of certain events without penalty).

In this report, each of the demand response resources were designed to be LMRs capable of achieving 100% capacity credit based on the current standards in MISO Business Practice Manual 11[2]. Specifically, MISO requires that LMR resources (a) have a notification time of six hours or less, (b) can provide at least 4 consecutive hours of load relief, and (c) are able to respond to at least sixteen events per year to receive 100% capacity credit. LMR accreditation is not the only mechanism for DR impacts to help satisfy NIPSCO's capacity requirements. NIPSCO might choose an alternative recognition strategy or select its own dispatch criteria to "peak shave" independent of MISO triggers. While the programs modeled in this report are not required to be recognized as a LMR if they are chosen to be included in NIPSCO's IRP, they were designed to satisfy current LMR accreditation rules.

MISO has recently proposed a new set of requirements for a resource to be recognized as an LMR, which are targeting implementation in PY28-29[3]. These rules would require LMRs to provide load relief within 30 minutes of notification as well as require resources to respond to an unlimited number of events each year. These changes would have implications for the quantity of DR potential detailed in this study, but, because the proposed new requirements are in the early consideration phase, we do not include them as rules in this potential study and instead focus on the current regulatory framework.

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[2] https://www.misoenergy.org/legal/rules-manuals-and-agreements/business-practice-manuals/ (Manual 11. Page 62-64)

[3] https://cdn.misoenergy.org/20240522%20RASC%20Item%2006a%20LMR%20Accreditation%20Presentation%20(RASC-2019-9)632928.pdf

3.2 HISTORICAL DEMAND RESPONSE PROGRAMS AND RATE 531

Prior to NIPSCO's rate case in 2018, NIPSCO's demand response portfolio was comprised of load curtailment agreements from a small number of large industrial customers.[4] NIPSCO was responsible for procuring capacity to meet the full peak loads of these customers, but also offered a substantial portion of these loads to MISO as LMRs to help satisfy capacity requirements. Following the 2018 rate case, NIPSCO must now only procure enough resources for a portion of these customers' loads (known as "firm" loads, approximately 170 MW in total). However, NIPSCO can no longer claim the remaining "non-firm" portion of these customers' loads as demand response. A new rate class initially referred to as 831, now called 531, was created for these customers to reflect the new arrangement.

Thus, while NIPSCO now has a lower total load obligation than before the 2018 rate case, it also cannot claim any demand response from Rate 531 customers. The change to NIPSCO's demand response portfolio is important to keep in mind when making comparisons of NIPSCO's historical demand response offerings to results of this potential study.

3.3 NIPSCO PEAK LOAD FORECAST

The peak load contribution of different NIPSCO customer classes is an important input to the demand response potential. Charles River Associates (CRA) provided the GDS team with a seasonal peak load forecast that distinguished between the firm load from Rate 531 customers and other customer loads (such as residential, commercial, and small industrial customers) and excludes Rate 531 non-firm loads. The resulting disaggregated peak load forecast is shown in Figure 4. Peak load for non-residential customers includes commercial, industrial non-531, railroad, street lighting, public authority, and company use. It is important to note that this forecast assumes energy efficiency programs continue at historical levels. This "EE first" perspective ensures that the same kW cannot be reduced twice by energy efficiency and demand response. This forecast differs from the peak load forecast used for the IRP, which does not remove future additional energy efficiency programs (because new energy efficiency programs will be a selectable resource for optimization modeling). Increases in peak load over the study period largely occur due to large data center load coming online from 2027 to 2037. Note that seasonal peak load is highest in the summer and fall. Residential load is the most weather sensitive, with the largest relative and absolute difference across seasons.

[4] NIPSCO also previously offered a switch-based air conditioning direct load control program for the residential sector, but this was discontinued in 2015.

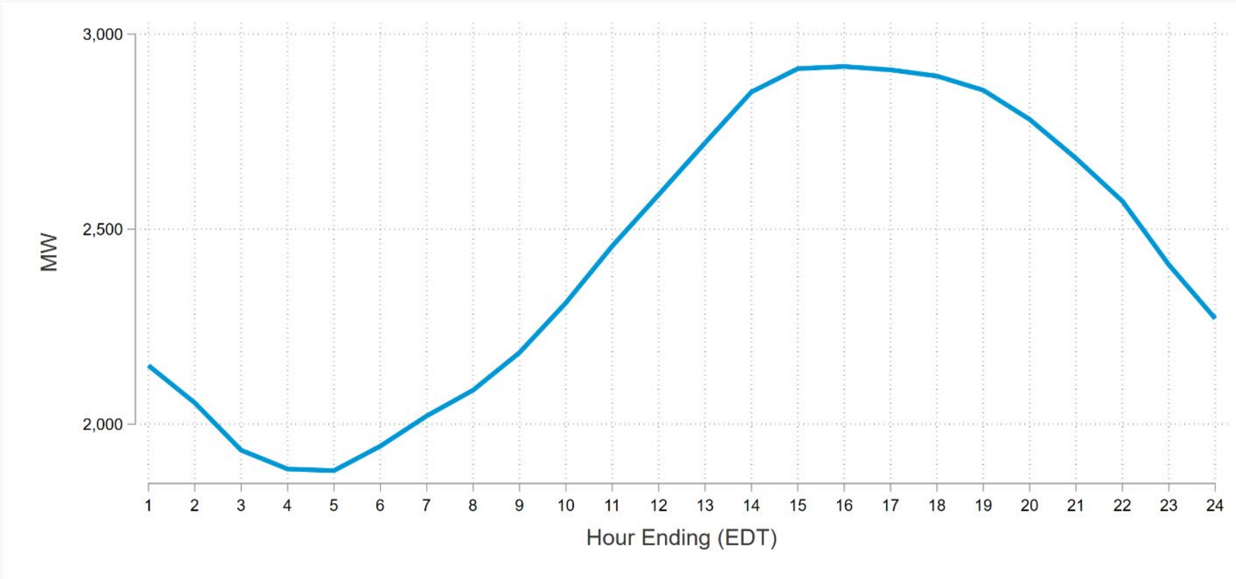
FIGURE 4. STUDY FIRM PEAK LOAD FORECAST, 2027 THROUGH 2042

3.4 CHARACTERIZATION OF PEAK LOADS

The primary use case for demand response resources considered in this study is to reduce energy supply requirements on high-demand days. Because the season, timing, and duration of peak loads can impact the ability of demand response resources to deliver peak load reduction, it is important to characterize the peak demand according to the following dimensions:

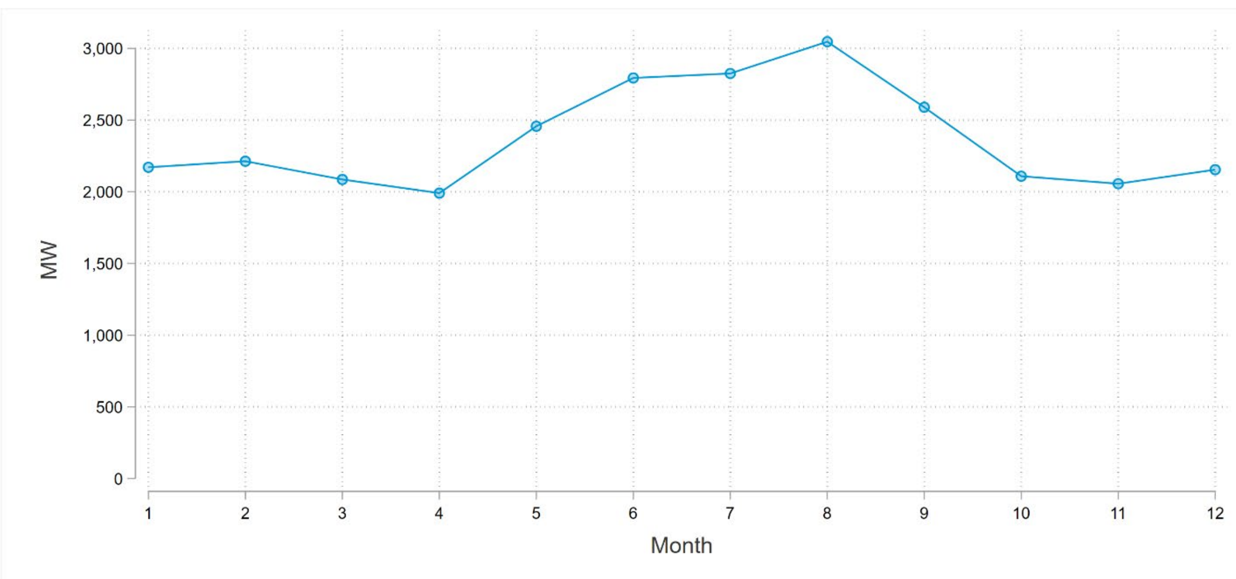
- ***Timing and duration of peak.*** The NIPSCO system has historically peaked between 2 p.m. and 6 p.m., with peaks being relatively long (broad) in duration. Figure 5 shows the average NIPSCO load on the top 10 peak days from 2020-2022. Large amounts of additional solar could result in more of a "duck curve" net load shape that shifts the net peak load back by several hours.

FIGURE 5: AVERAGE NIPSCO PEAK LOAD DAY HOURLY SHAPE FOR TOP 10 DAYS 2020-2022



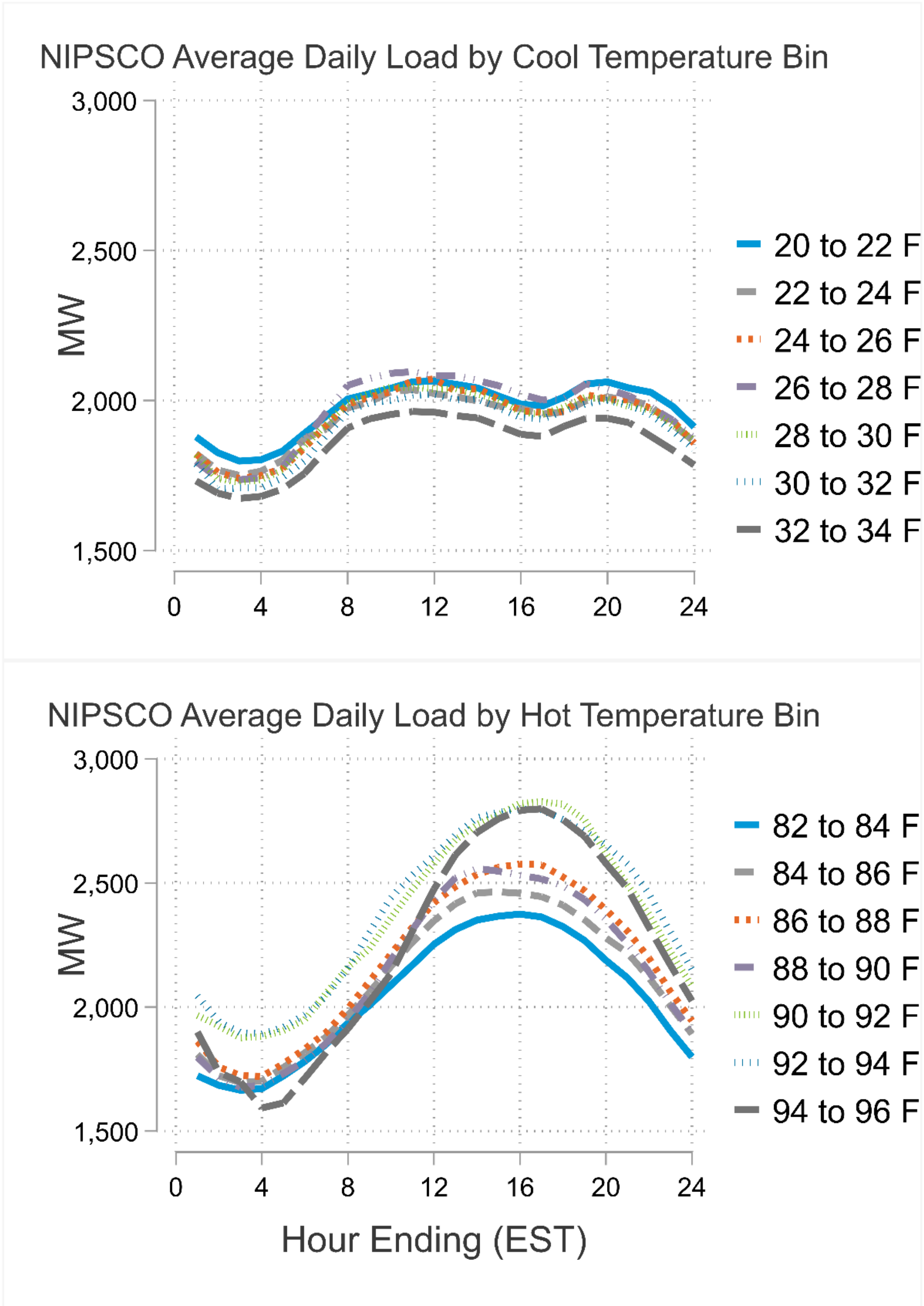
- ***Season of peak.*** Figure 6 shows the average of historical monthly peak hour loads for the NIPSCO system over years 2020-2022. Each data point represents an average of three values: the monthly peak load for 2020, monthly peak load for 2021, and monthly peak load for 2022. The NIPSCO system has historically been summer-peaking, with summer loads that are roughly 750 MW higher than winter loads. At least in the near term, loads will continue to peak during the summer.

FIGURE 6. AVERAGE 2020-2022 NIPSCO FIRM PEAK LOAD BY MONTH



- ***Weather sensitivity.*** Figure 7 shows the relationship between average daily load by temperature. Winter loads are shown in the upper panel and tend to decrease as temperature rises. Conversely, summer loads tend to increase as temperature rises.

FIGURE 7: AVERAGE 2020-2022 DAILY LOAD BY TEMPERATURE BIN



MISO is facing changes in its generation portfolio driven by retirements of existing capacity and the introduction of new wind and solar capacity. These changes in the portfolio combined with increased electrification prompted policy makers to shift to a seasonal capacity construct in preparation for its

2024/2025 PRA. This necessitated a DR potential study which examined DR potential for the summer, winter, spring, and fall seasons.[5] Our approach was to assign full capacity value to each season and model the potential and economics of each season as if it were to present a binding requirement in the IRP. This approach will allow the IRP model to select resources and solve capacity shortfalls on a seasonal basis while still considering the program's expected performance in the other seasons. An alternative approach would assume a distribution of annual capacity value across the four seasons. However, outcomes of such an approach would be highly sensitive to the assumptions used to allocate across seasons. MISO published seasonal RA hours for the period September 1, 2020 through August 31, 2023. These were defined as the top 3% of load in each season where reserve margin was less than 25%.[6] The GDS team then used the historical distribution of RA hours to estimate peaking risk by hour within each season. The results are shown below in Table 3-1.

TABLE 3-1: PEAKING RISK BY HOUR AND SEASON

Hour Ending	Winter	Spring	Summer	Fall
1	1.1%	0.0%	0.0%	0.0%
2	0.5%	0.0%	0.0%	0.0%
3	0.5%	0.0%	0.0%	0.0%
4	0.5%	0.0%	0.0%	0.0%
5	0.5%	0.0%	0.0%	0.0%
6	0.5%	0.0%	0.0%	0.0%
7	1.6%	1.5%	0.0%	0.0%
8	4.8%	3.1%	0.0%	4.1%
9	10.8%	3.6%	0.0%	4.7%
10	9.1%	4.1%	0.5%	4.1%
11	8.1%	3.1%	0.5%	3.6%
12	7.5%	3.6%	1.0%	3.0%
13	5.4%	4.6%	4.1%	4.1%
14	3.8%	8.7%	6.7%	7.1%
15	2.2%	10.3%	12.3%	9.5%
16	1.6%	10.3%	15.9%	11.8%
17	2.7%	11.8%	19.5%	13.6%
18	4.3%	10.8%	17.9%	14.2%
19	8.6%	9.7%	13.8%	12.4%
20	9.7%	8.2%	5.1%	4.7%
21	6.5%	5.6%	1.5%	3.0%
22	5.4%	1.0%	1.0%	0.0%
23	3.2%	0.0%	0.0%	0.0%
24	1.1%	0.0%	0.0%	0.0%

[5] Summer is defined as months June through August, winter as January and February, spring as March through May, and fall as September through December.
[6] *https://cdn.misoenergy.org/RA Hours PY 24 25630518.xlsx*

For each end use load profile, we then solve for peak load contribution (PLC) for each season s using the equation below. We simply multiply the average hourly load by peaking risk in each season and sum over hours h.

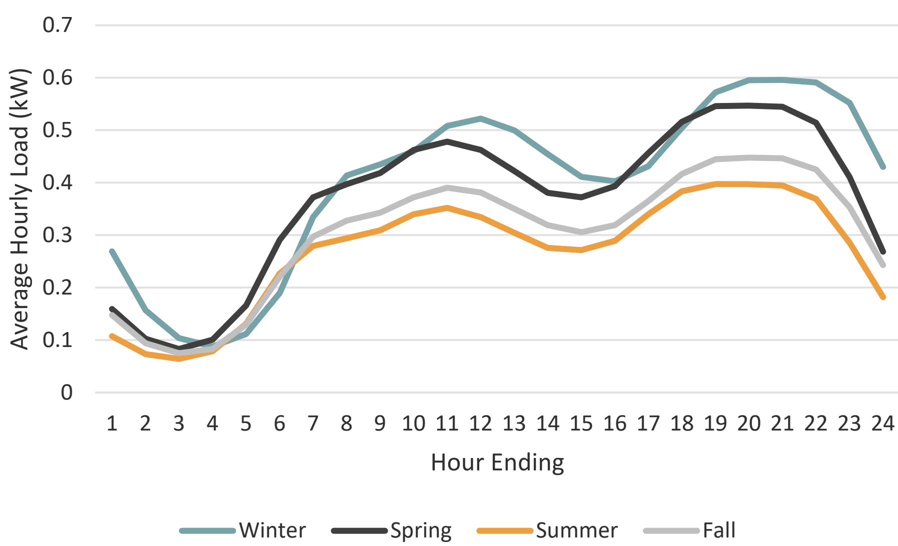
$$PLC_s = \sum_h End\ Use\ Load\ (kW)_{sh} * \ Peaking\ Risk\ (\%)_{sh}$$

3.5 DEMAND RESPONSE PORTFOLIO SEASONALITY

As load characteristics change over time, it is possible that demand response resources could be needed in seasons other than summer. With that in mind, all the demand response program scenarios modeled in this report were modeled separately by season. Modeling the capability of each demand response mechanism in each season allows each resource to be chosen separately by the IRP process based on seasonal resource needs.

Each program's capability varies based on the peak load expectations of participants in the program. For example, the peak load of a resistance water heater is 50% higher in the winter than in the summer. Due to this difference in available load, a demand response program designed to control water heater loads has a much higher capability in the winter. Example resistance water heater load shapes are shown in Figure 8.

FIGURE 8: REFERENCE RESISTANCE WATER HEATER LOAD



Demand response program's seasonal capabilities can also vary by season due to the types of loads they are able to control. A smart thermostat program which can control loads by changing temperature set points of HVAC systems will have a different capability in the summer than it does in the winter. This is not only due to varying peak loads by the season, but also by targeting different sets of customers in different seasons. A smart thermostat program that targets load relief in summer or fall months would target customers that have thermostat controllable air conditioning loads during those months, which includes most homes in NIPSCO's territory. In contrast, a smart thermostat program which is targeting capability in the winter or spring months would target homes that have primary electric heat, either resistance or a heat pump. This group is made up of a much smaller number of homes than those with controllable cooling. This means that, while on average, winter electric heating loads for homes with electric heat are higher than summer AC loads, the overall capability of a smart thermostat program targeting winter loads is lower than one targeting summer loads due to a smaller pool of potential participants.

Overall, most of the programs modeled in this report have their highest capabilities in the summer months, when loads are expected to peak, in the near term. Each program, however, can provide capacity in each season and therefore could be chosen to be used in any season. Separate modeling of each program in each season allows for the IRP process to be more flexible in including demand response resources where needed.

4 Economic Modeling Framework

This section describes the cost-effectiveness test the GDS team used in this study and the conceptual background behind the two types of potential (MAP and RAP) presented in this report.

4.1 UTILITY COST TEST

Demand response programs can be evaluated using various cost-effectiveness tests. The GDS team used the Utility Cost Test (UCT), also known as the Program Administrator Cost Test, to evaluate NIPSCO's demand response options. For each program, we calculated the UCT by comparing the net present value of that program's costs to the net present value of that program's benefits over the useful life of any DR measures installed during the 2027-2046 study period. A UCT ratio less than 1.0 indicates that the program costs exceed the program benefits, while a UCT value of 1.0 indicates that the program costs and benefits are identical, while a UCT ratio greater than 1.0 indicates that the program benefits exceed the costs (and the program is therefore cost-effective). Table 4-1 summarizes the costs and benefits components for the UCT. The avoided generation cost is based on a natural gas combined cycle reference unit. Table 4-2 contains other key assumptions, including the discount rate, inflation rate, and analysis time period. Note that the UCT does not include benefits to society at large such as avoided emissions – though avoided emissions for DR are relatively minor given that DR resources are dispatched relatively infrequently.

TABLE 4-1 SUMMARY OF COSTS AND BENEFIT COMPONENTS

Type	Component
Costs	Program equipment costs
	Program labor costs
	Program marketing costs
	Other program operations and maintenance costs
Benefits	Avoided capacity costs[7]

TABLE 4-2 UTILITY COST TEST KEY PARAMETERS

Parameter	Value	Source
Nominal Discount Rate	6.89%	NIPSCO
Inflation Rate	3.21%	
Analysis Time Period	20 years (2027-2046)	
Avoided Generation Costs	$173.83/kW-yr in 2027	
Avoided Transmission Costs	$0.00/kW-yr in 2027	
Avoided Distribution Costs	$29.55/kW-yr in 2027	
Peak Line Losses	7.5%	

Figure 9 summarizes the main inputs used to calculate UCT ratios and DR potential. Five key factors affect the cost-effectiveness of demand response programs:

[7] Avoided energy costs are not included in this study because of the low assumed annual hours of dispatch (24 hours per year) and the lack of time-differentiation in the avoided energy costs used for this study (i.e., the on-peak and off-peak avoided cost per kWh provided by NIPSCO were the same). Avoided energy costs associated with DR dispatch will, however, be captured in IRP modeling.

1. ***The amount of load reduction (in kW) offered by each participant:*** Load reductions must be sufficiently high to produce program net benefits. All else equal, higher load reductions result in higher potential.
2. ***The avoided capacity costs:*** Avoided generation capacity costs comprise most demand response benefits in this analysis, followed by avoided distribution and transmission costs. The total avoided cost is $203.38/kW-yr in 2027.
3. ***The amount of capacity enrolled in each program by year:*** Program enrollment affects the level of aggregate benefits for each program and whether the program is cost-effective when including overhead costs. The enrollment rate is influenced by the incentive level offered and the program marketing budget.
4. ***The fixed and variable costs of each program:*** Variable costs, including the costs of equipment and installation, marketing, and labor, must be less than per-customer benefits for the program to be cost-effective at the margin. Fixed costs are not affected by program size, but factor into cost-effectiveness.
5. ***Key financial assumptions:*** Assumptions such as the discount rate and analysis period affect program potential.

FIGURE 9: METHODOLOGY SUMMARY

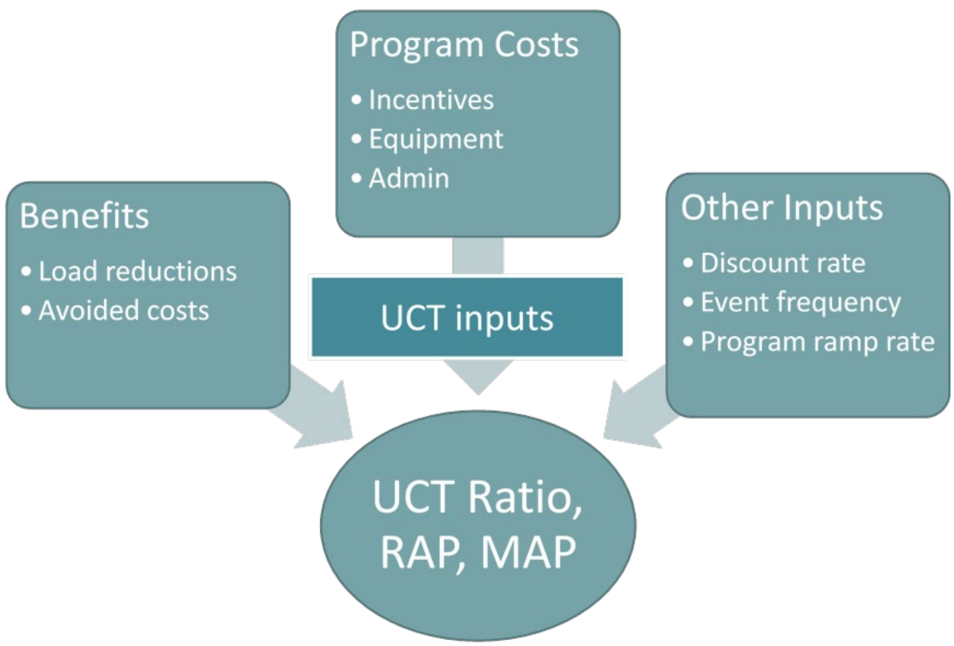


Table 4-3 summarizes the possible cost categories for each program. Costs are categorized as either fixed or volumetric – based on whether they scale directly with program enrollments – and are incurred on either a one-time or a recurring basis. For instance, annual incentive payments to participating customers are volumetric recurring costs because they are paid to each participant each year. Equipment and installation costs, on the other hand, are volumetric one-time costs because they are incurred only when a new customer enrolls in a DR program. Marketing costs are described in more detail within each section, as are “other” costs, which are specific to each program. Because NIPSCO does not have existing demand response offerings for many of these programs, cost estimates were developed based on the GDS teams’ review of other studies and current demand response product marketing.

TABLE 4-3: COST CATEGORIZATION

Component	Cost Type	Cost Frequency
Equipment	Volumetric	One time
Installation Labor	Volumetric	One time
Other One-Time Costs	Volumetric	One time
Support Labor	Fixed/ Volumetric	Recurring
Sign-Up Incentive	Volumetric	One time
Annual Incentive	Volumetric	Recurring
Other Direct Costs	Volumetric	Recurring

4.2 MAXIMUM ACHIEVABLE POTENTIAL AND REALISTIC ACHIEVABLE POTENTIAL

This report presents two estimates of potential—***MAP*** and ***RAP***—that correspond to different perspectives of program costs and benefits. For each program, the ***maximum achievable potential (MAP)*** represents more aggressive assumptions around incentives and program design, which in turn drives higher participation. Therefore, MAP scenarios have higher total demand response potential, but also higher costs. The ***realistic achievable potential (RAP)*** represents more “middle-ground” assumptions around program incentives and design. RAP scenarios have lower total demand response potential but are more cost-effective than the MAP scenarios, mainly because of lower program incentives. Each program is also assumed to have a ramp rate, reaching full program capacity after two or three years, which reflects time required to market to and enroll customers in each program.

We also report levelized costs for each program, denoted in terms of real 2027 dollars per kW-year (2027$/kW-yr). The levelized cost of a resource is the present-value cost of the program per kW acquired over the study horizon. It accounts for differences in when costs are incurred and when DR programs deliver capacity and facilitates comparisons within DR programs and to other capacity resources. Programs with lower levelized costs will have higher UCT ratios, while programs with higher levelized costs will have lower UCT ratios.

5 Detailed Findings: Residential Sector

Table 5-1 shows the summer season MAP and RAP by residential program for select years within the study horizon. The 20-year RAP across the six residential programs totals 132.6 MW and the MAP totals 178.1 MW. The following sections present the methodology and results for the six residential programs considered in this study:

- Residential connected thermostats
- Water heater direct load control
- EV managed charging
- Behind-the-meter battery storage
- Behavioral demand response
- Time-varying dynamic rates

TABLE 5-1. RESIDENTIAL SUMMER REALISTIC AND MAXIMUM ACHIEVABLE POTENTIAL BY PROGRAM (CUMULATIVE BY YEAR)

Program	RAP					MAP				
	2027	2028	2029	2036	2046	2027	2028	2029	2036	2046
Connected Thermostats	4.8	7.0	9.1	26.3	48.7	7.3	11.4	15.3	39.8	62.3
Water Heater Direct Load Control	2.3	2.2	2.1	1.4	0.4	4.6	4.4	4.2	2.7	0.5
EV Managed Charging	0.7	1.0	1.4	7.3	9.9	1.3	1.8	2.5	13.0	17.5
BTM Battery Storage	0.4	0.4	0.5	0.7	0.7	0.7	0.8	0.9	1.4	1.5
Behavioral DR	6.3	6.3	6.3	6.5	6.7	11.2	11.3	11.3	11.5	11.9
Time-Varying and Dynamic Rates				64.1	66.1				81.8	84.4
Total [a]	**14.6**	**16.9**	**19.4**	**106.3**	**132.5**	**25.2**	**29.7**	**34.1**	**150.3**	**178.1**

[a] Total row may not equal the sum of program values due to rounding

5.1 RESIDENTIAL SMART THERMOSTAT PROGRAM

Smart thermostat programs achieve peak demand reductions by allowing the utility to control residential customers' air conditioning and electric heating, if applicable, on a limited number of days per year. The GDS team designed the Residential Smart Thermostat program to capture some percent of existing installed smart thermostats as well as an add-on to the energy efficiency smart thermostat programs. For the add-on enrollment, when purchasing a new smart thermostat, customers would be able to receive an additional rebate, on top of the standard energy efficiency rebate, in exchange for enrolling in the NIPSCO demand response program. For internal consistency, the MAP and RAP demand response apply an assumed enrollment rate to the corresponding energy efficiency MAP and RAP smart thermostat deployment forecasts to arrive at a final participant enrollment count for each scenario. The process is summarized below in Figure 10.

FIGURE 10: RESIDENTIAL SMART THERMOSTAT PROGRAM METHODOLOGY SUMMARY

5.1.1 Program Assumptions

We divided program assumptions into two key categories: cost assumptions and non-cost assumptions. Cost assumptions include those about equipment, incentives, and program overhead costs, while other non-cost assumptions include the assumed enrollment rates and demand reductions.

5.1.1.1 Cost Assumptions

The cost assumptions used for the Smart Thermostat program are shown in Table 5-2. Fixed costs include the cost of support labor for establishing the program in year one and maintaining the program in subsequent years. Volumetric costs include a one-time enrollment incentive cost of $50 in the RAP scenario and $155 in the MAP scenario, as well as a marketing budget of $4 in both scenarios. The enrollment incentive in the MAP scenario includes a $75 rebate on the purchase of the thermostat. Volumetric recurring costs include customer incentives that are provided on an annual basis to participating customers, as opposed to on a one-time sign-up basis, to ensure continued participation, and are assumed to be $40 in the RAP scenario and $80 in the MAP scenario. We also assume a $35 recurring per-device cost associated with annual vendor fees for thermostat control.

TABLE 5-2. RESIDENTIAL AIR CONDITIONING COST ASSUMPTIONS

Scenario	Fixed One-Time	Fixed Recurring	Volumetric One-Time	Volumetric Recurring	Source
RAP	$250,000	$150,000	$54	$75	Taken from similar smart thermostat programs (SCE, AES, PG&E, Eversource)
MAP	$250,000	$150,000	$159	$115	Taken from similar smart thermostat programs (SCE, AES, PG&E, Eversource)

5.1.1.2 Reference Loads

We constructed reference loads for cooling and heating for a representative residential unit in Indiana using NREL ResStock[8]. The ResStock database provides end use level modeled loads for multiple different locations and building types. Figure 11 and Figure 12 show reference cooling and heating loads for the thermostat model. Load is highest in the winter for heating, but it is relatively flat.

[8] https://www.nrel.gov/buildings/end-use-load-profiles.html

FIGURE 11: REFERENCE COOLING LOAD

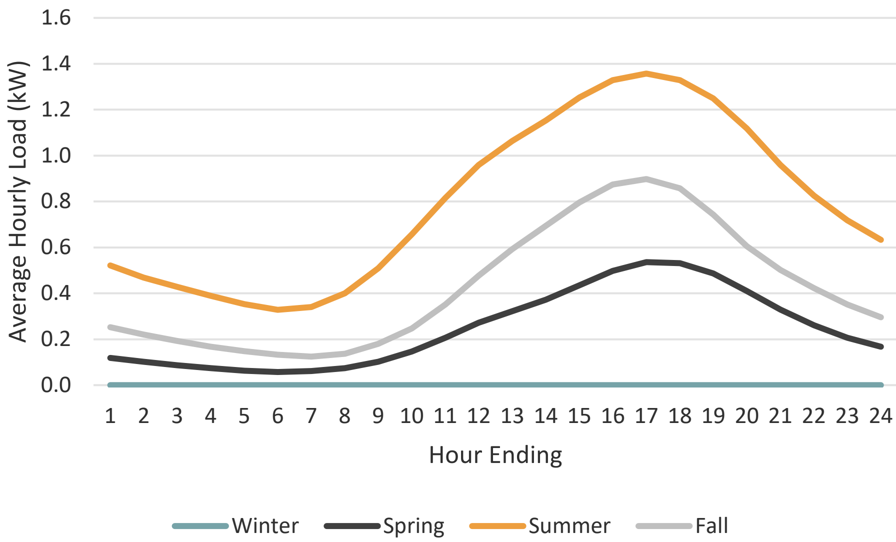
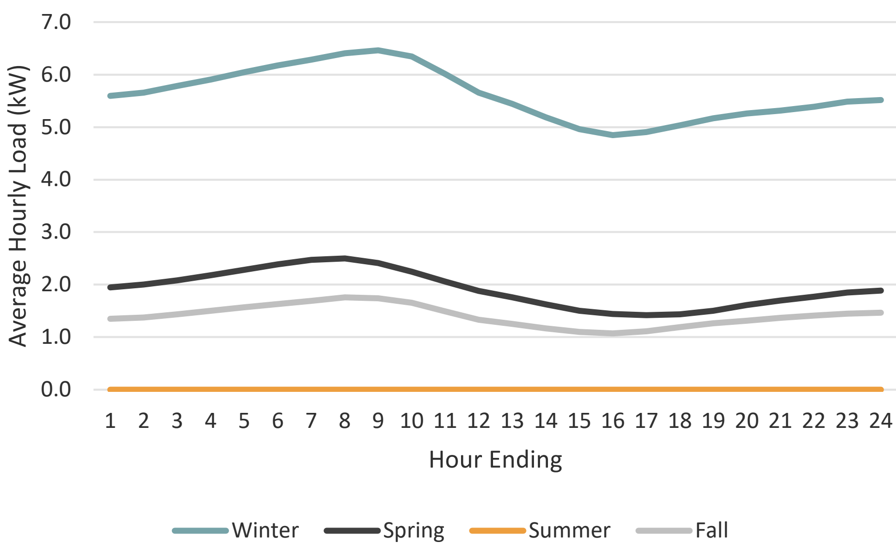


FIGURE 12: REFERENCE HEATING LOAD



5.1.1.3 Other Program Assumptions

Other program assumptions are shown in Table 5-3. Below we provide notes on specific program assumptions:

- ***Load reduction:*** We assume that cooling loads are reduced on average by 50% per event. Recent impact evaluations of smart thermostat demand response impacts have found reductions of similar magnitude on average over a four-hour event window.
- ***Enrollment rates:*** For the RAP scenario, we assume an enrollment rate of 10% for customers purchasing a new smart thermostat and 5% for customers who already own a smart thermostat in the NIPSCO service territory. For the MAP scenario, we assume an enrollment rate of 15% for

customers purchasing a new smart thermostat and 10% for customers who already own a smart thermostat in the NIPSCO service territory.

- ***Fuel shares:*** We assume 100% of enrollees have electric cooling. We assume 20% have electric heating, which is based on an Itron appliances survey. For simplicity, we assume that the winter and spring seasons are heating, and that the summer and fall seasons are cooling.

TABLE 5-3. RESIDENTIAL AIR CONDITIONING NON-COST ASSUMPTIONS

Parameter	Input	Notes/Source
Attrition	10%	Average of other similar thermostat based DR programs
Existing smart thermostat penetration	15%	Pennsylvania Residential Baseline Study[9] (2023)
Existing smart thermostat growth	1%	Assumed increase in smart thermostats outside of utility EE programs
Impact	50%	Average of a 4-hour event from similar smart thermostat programs (SCE)
Year 1 enrollment: RAP	10%	Like other Smart Thermostat enrollments (SCE, Consumers). CAC comments on thermostat enrollments were also take into consideration.
Year 1 enrollment: MAP	15%	
Post year 1 EE thermostat enrollment: RAP	10%	
Post year 1 EE thermostat enrollment: MAP	15%	
Post year 1 existing thermostat enrollment: RAP	5%	
Post year 1 existing thermostat enrollment: MAP	10%	
Heating electric fuel share	20%	Itron appliance saturation survey
Cooling electric fuel share	100%	Assumed

5.1.2 Cost-Effectiveness Results

Table 5-4 summarizes the cost-effectiveness results by season and scenario. In the winter season, both the RAP and MAP scenarios have UCT ratios well above 1, indicating that both are cost-effective. Figure 13 shows the trajectory of the program over time for the RAP and MAP scenarios for the summer season. Both the RAP and MAP scenarios ramp up over time as the market share of smart thermostats increases. However, the MAP scenario achieves a much higher demand response capacity. The MAP scenario is modeled using a higher incentive and thus a higher enrollment rate. It also features a higher penetration forecast, so it has more potential enrollees. Combined, the MAP scenario has almost 14 MW more potential than the RAP scenario in 2046, though the RAP scenario is more cost effective than the MAP scenario. The total RAP and MAP demand response capacities are 48.7 and 62.3 MW in summer 2046, respectively. After 2046, the model assumes that there will be no new thermostats enrolled, but the program will continue to operate to capture the full benefits of the program investments made from 2027-

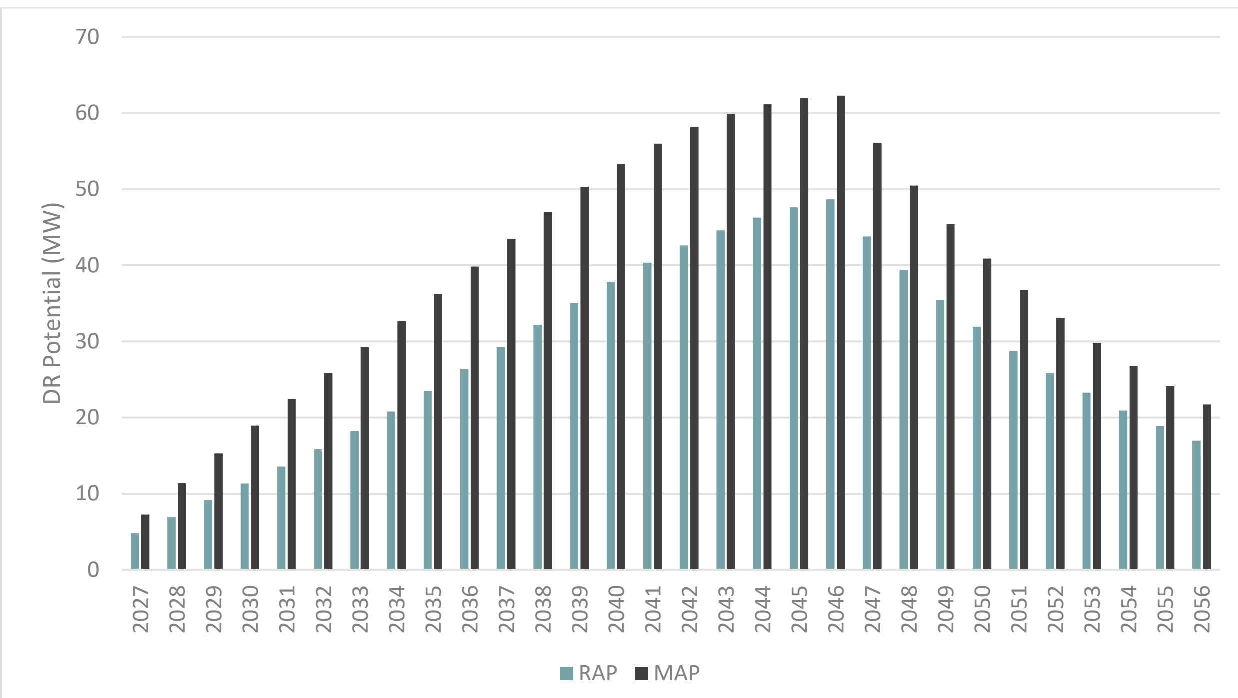
[9] https://www.puc.pa.gov/media/2758/2023_residential_baseline_stakeholder_meeting_presentation013024.pdf

2046. Program potential declines after enrollment stops in 2046 due to expected yearly participant attrition.

TABLE 5-4: RESIDENTIAL SMART THERMOSTAT PROGRAM COST-EFFECTIVENESS RESULTS

Parameter	Summer		Spring		Winter		Fall	
	RAP	MAP	RAP	MAP	RAP	MAP	RAP	MAP
Levelized Cost ($/kW-year)	$198	$313	$203	$283	$60	$83	$364	$578
Modified Levelized Cost ($/kW-year)	$158	$275	$162	$242	$19	$42	$325	$539
Lifetime Benefits ($ thousands)	$85,696	$121,197	$17,031	$27,118	$57,922	$92,226	$46,489	$65,748
Lifetime Costs ($ thousands)	$62,480	$141,849	$12,217	$27,271	$12,217	$27,271	$62,480	$141,849
UCT Ratio	1.37	0.85	1.39	0.99	4.74	3.38	0.74	0.46
Devices in 2046	71,450	91,482	12,217	21,589	13,874	21,589	71,450	91,482
System-level capacity in 2046 (MW)	48.7	62.3	12.5	19.4	42.4	66.0	26.4	33.8

FIGURE 13: SUMMER RESIDENTIAL SMART THERMOSTAT RAP AND MAP DR POTENTIAL BY YEAR



5.2 WATER HEATING DIRECT LOAD CONTROL PROGRAM

The electric water heater direct load control program would rely on Wi-Fi-connected switches to control the electric water heater loads of participating customers for several events per year. These programs have been implemented by utilities across the U.S., typically in southeastern and northwestern parts of the country, which feature higher levels of electric water heating. The GDS team designed the program to capture some percent of existing installed resistance water heaters, through the installation of smart switches, as well as load management of new heat pump water heater installations. Heat pump water heaters are projected to be a core residential energy efficiency measure in the near term and required by code beginning in the 2030s. For the add-on DR enrollment, when purchasing a new heat pump water heater, customers would be able to receive an additional rebate, on top of the standard energy efficiency rebate, in exchange for enrolling in the NIPSCO demand response program and allowing the utility to shift load away from peak periods.

5.2.1 Program Assumptions

As with prior sections, we divided program assumptions into two key categories: cost assumptions and non-cost assumptions. Cost assumptions include those about equipment, incentives, and program overhead costs, while other non-cost assumptions include the assumed enrollment rates and demand reductions.

5.2.1.1 Cost Assumptions

Table 5-5 shows the cost assumptions for the Water Heater Direct Load Control program. Fixed costs include the cost of support labor for establishing the program in year one and maintaining the program in subsequent years. Volumetric costs include one-time recruitment and marketing costs of $25 for enrolling heat pump customers. For resistance heating customers, volumetric one-time costs include $150 of equipment cost, $50 of installation cost, and $25 in recruitment and marketing costs. Heat pump water heaters are assumed to be DR-enabled by the manufacturer and do not require aftermarket equipment or installation costs. The volumetric recurring costs assume an annual incentive of $25 per device in the RAP scenario and $50 per device in the MAP scenario, and a vendor fee of $24.

TABLE 5-5. WATER HEATER DIRECT LOAD CONTROL COST ASSUMPTIONS

Scenario	Fixed One-Time	Fixed Recurring	Volumetric One-Time (Heat Pump)	Volumetric One-Time (Resistance)	Volumetric Recurring	Source
RAP	$150,000	$50,000	$25	$225	$49	$24 Vendor Fee (Average of multiple vendors in a recent pilot study)
MAP	$150,000	$50,000	$25	$225	$74	

5.2.1.2 Reference Loads

We constructed separate reference loads for electric resistance water heaters and heat pump water heaters. The electric resistance load shape comes from the NREL ResStock[10] database for a representative residential unit in Indiana. Figure 14 and Figure 15 show reference resistance and heat pump loads for the water heating model. Load is highest in the winter for heating, but it is relatively flat.

[10] https://www.nrel.gov/buildings/end-use-load-profiles.html

FIGURE 14: REFERENCE RESISTANCE WATER HEATER LOAD

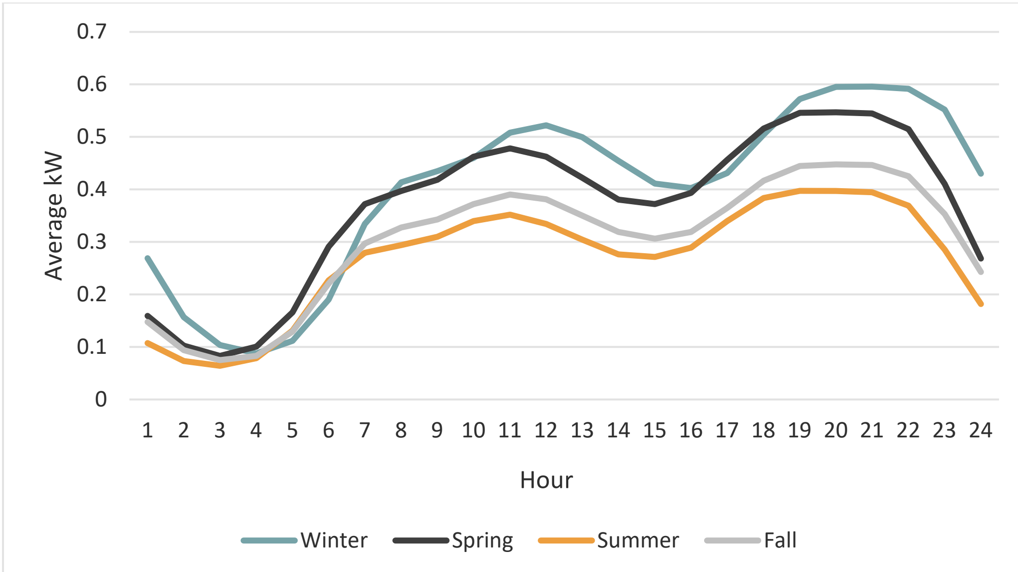
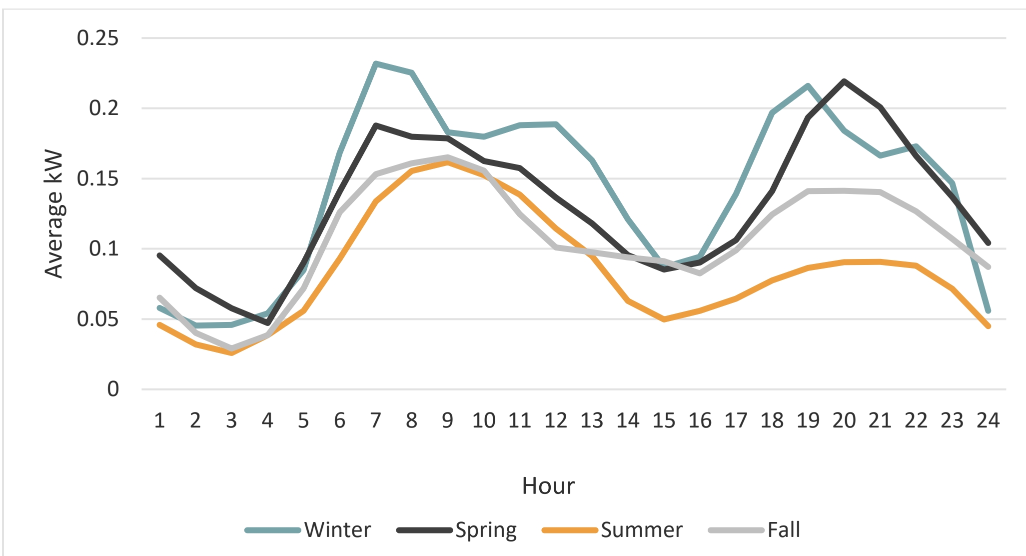


FIGURE 15: REFERENCE HEAT PUMP WATER HEATER LOAD



5.2.1.3 Other Program Assumptions

Table 5-6 shows the key non-cost program assumptions. Some additional detail around these assumptions is provided below:

- ***Number of eligible devices:*** Because NIPSCO service territory has a mix of electric and fossil-fuel-fired heaters, only a portion of customers would be eligible to participate. The share of electric water heaters is based on NIPSCO appliance surveys and is a shared input with the energy efficiency heat pump water heater programs. We assume there is no fuel switching, so heat pump water heaters only replace resistance water heaters. As a result, approximately

56,000 electric accounts are eligible for the water heater direct load control program, and only a fraction of those would enroll.

- ***Enrollment rate:*** For a $25 annual incentive in the RAP scenario, we assume that 20% of all eligible heat pump devices enroll in the program, and that 15% of existing resistance water heaters enroll. For a $50 annual incentive in the MAP scenario, we assume that 30% of all eligible heat pump devices enroll, and that 25% of resistance water heaters enroll.
- ***Per-device demand reduction:*** We assume 100% demand reductions per device. Due to differences in reference loads across seasons, demand reductions for summer events are lower than for winter events, because water heaters use less energy in the summer. Less efficient resistance water heaters have higher load and therefore deliver larger per device demand reductions.

TABLE 5-6: WATER HEATER DIRECT LOAD CONTROL OTHER ASSUMPTIONS

Parameter	Input	Notes/Source
Attrition	5%	Kootenai 2011 DR Pilot
Electric Water Heater Penetration	13%	Common input with EE potential study
Impact: RAP	75%	Illume Georgia Power 2019
Impact: MAP	90%	
Incremental EE Heat Pump Enrollment: RAP	20%	Applied 2017, Global 2011, Navigant 2012, Navigant 2015
Incremental EE Heat Pump Enrollment: MAP	30%	
Existing Resistance Enrollment: RAP	15%	
Existing Resistance Enrollment: MAP	25%	

5.2.2 Cost-Effectiveness Results

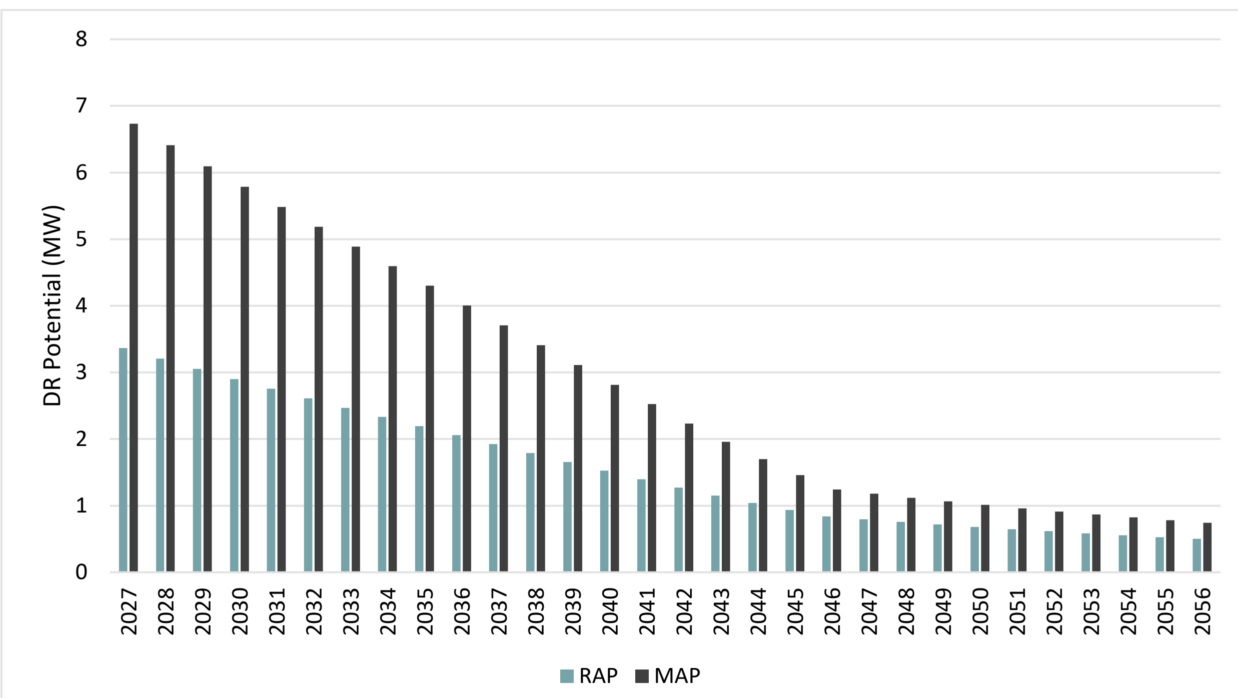
Table 5-7 summarizes the cost-effectiveness results by water heater type and scenario for the winter season. Under the program assumptions described above, none of the water heater direct load control program options are cost effective. Overall, there is relatively low electric water heater penetration in NIPSCO territory. In total, under 7,000 devices are enrolled in the MAP scenario in 2046. Furthermore, heat pump water heaters are very efficient and therefore have low per customers impacts.

TABLE 5-7: WINTER WATER HEATER DIRECT LOAD CONTROL PROGRAM COST-EFFECTIVENESS RESULTS BY PROGRAM TYPE

Parameter	Heat Pump		Resistance		Both	
	RAP	MAP	RAP	MAP	RAP	MAP
Levelized Cost ($/kW-year)	$1,123	$1,000	$265	$270	$296	$320
Modified Levelized Cost ($/kW-year)	$1,081	$958	$232	$237	$261	$286
Lifetime Benefits ($ thousands)	$660	$1,513	$5,858	$10,942	$6,518	$12,455
Lifetime Costs ($ thousands)	$2,533	$5,174	$6,758	$13,025	$8,197	$17,105
UCT Ratio	0.26	0.29	0.87	0.84	0.80	0.73
Devices in 2046	3,530	6,747	855	212	4,385	6,959
System-level capacity in 2046 (MW)	0.5	1.1	0.3	0.1	0.8	1.2

Figure 16 shows the trajectory of the water heater direct load control program over time for the RAP and MAP scenarios for the winter season. Both the RAP and MAP scenarios ramp down over time. Most of the program's capacity is derived from the installation of load control switches on the installed base of resistance water heaters. After the initial recruitment, resistance water heater program participation wanes due to attrition. Heat pump water heater participation increases over time, but the per customer load is small relative to the resistance water heater being replaced which leads to decreasing program performance over time. After 2046, the model assumes that there will be no new devices enrolled, but the program will continue to operate to capture the full benefits of the program investments made from 2027-2046.

FIGURE 16: WINTER WATER HEATER DIRECT LOAD CONTROL RAP AND MAP DR POTENTIAL BY YEAR FOR BOTH RESISTANCE AND HEAT PUMP PROGRAM



5.3 ELECTRIC VEHICLE MANAGED CHARGING PROGRAM

The electric vehicle (EV) managed charging program would seek to mitigate growth in NIPSCO peak loads due to increased transportation electrification. Absent a managed charging initiative or time-varying rate structure, NIPSCO projects almost 150 MW of incremental peak load from light duty electric vehicles by 2046. An EV managed charging program could rely on communication with vehicles, chargers, or both. The study team modeled both active and passive load management strategies. Active management means charging is directly curtailed by the utility during events, while passive management means customers are given rewards for modifying their charging behavior. Managing charging could occur against the backdrop of the current flat volumetric rate structure or a time-varying retail price that encourages off-peak charging once the necessary AMI infrastructure is in place. In this model, the RAP scenario reflects actively managed chargers enrolled on a flat rate, and the MAP scenario reflects passively managed vehicles enrolled on a flat rate. The GDS team designed the program to capture some percent of existing and future electric vehicle load. Similar programs have been implemented at other utilities; many parameters in our model are drawn from Connecticut's Managed Charging program, which was implemented at Eversource and United Illuminating.

5.3.1 Program Assumptions

As with prior sections, we divided program assumptions into two key categories: cost assumptions and non-cost assumptions. Cost assumptions include the equipment, incentives, and program overhead costs, while non-cost assumptions include the assumed enrollment rates and demand reductions.

5.3.1.1 Cost Assumptions

Table 5-8 shows the cost assumptions for the EV Managed Charging program. Fixed costs include the costs of support labor to establish and maintain the program. Based on a review of industry pilots and programs filings, we assume higher fixed costs for programs involving the control of EV chargers compared to programs involving the control of cars (telematics). Similarly, fixed costs are higher for active control than passive control, due to the deployment and testing of curtailment protocols. Volumetric costs differ significantly between the program types with charger-based programs having higher upfront costs but lower recurring costs. Telematics programs don't have the large upfront capital cost to support charger installation but have higher recurring volumetric costs in the form of vendor communication fees and participant incentives.

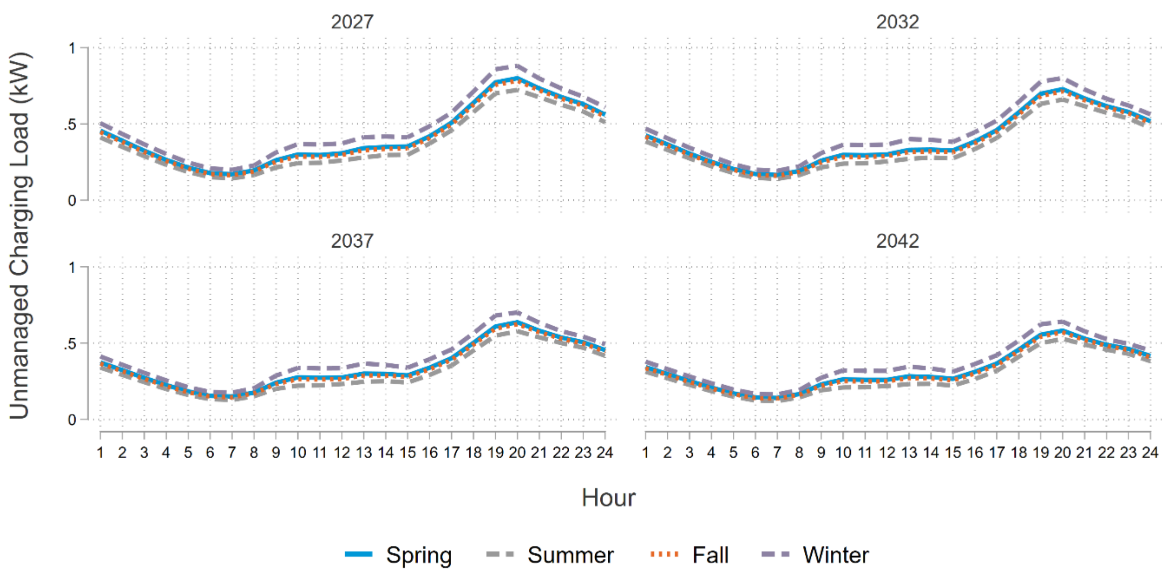
TABLE 5-8: EV MANAGED CHARGING COST ASSUMPTIONS

Program Type	Fixed One-Time	Fixed Recurring	Volumetric One-Time	Volumetric Recurring
RAP: Charger Active Flat	$125,000	$100,000	$175	$50
Car Active Flat	$75,000	$100,000	$25	$75
Charger Passive Flat	$125,000	$50,000	$175	$50
MAP: Car Passive Flat	$75,000	$50,000	$25	$75
Charger Active Dynamic	$125,000	$100,000	$175	$25
Car Active Dynamic	$75,000	$100,000	$50	$50
Charger Passive Dynamic	$125,000	$50,000	$175	$25
Car Passive Dynamic	$75,000	$50,000	$50	$50

5.3.1.2 Reference Loads

Forecasted EV reference loads were provided by CRA for the analysis period and are shown in Figure 17. These reference loads reflect unmanaged vehicle charging load. As vehicles become more efficient over time, per-vehicle charging load declines. Load varies slightly with season and is the highest during winter.

FIGURE 17: REFERENCE EV LOAD FORECAST



5.3.1.3 Other Program Assumptions

Table 5-9 shows the key non-cost program assumptions. Some additional detail around these assumptions is provided below:

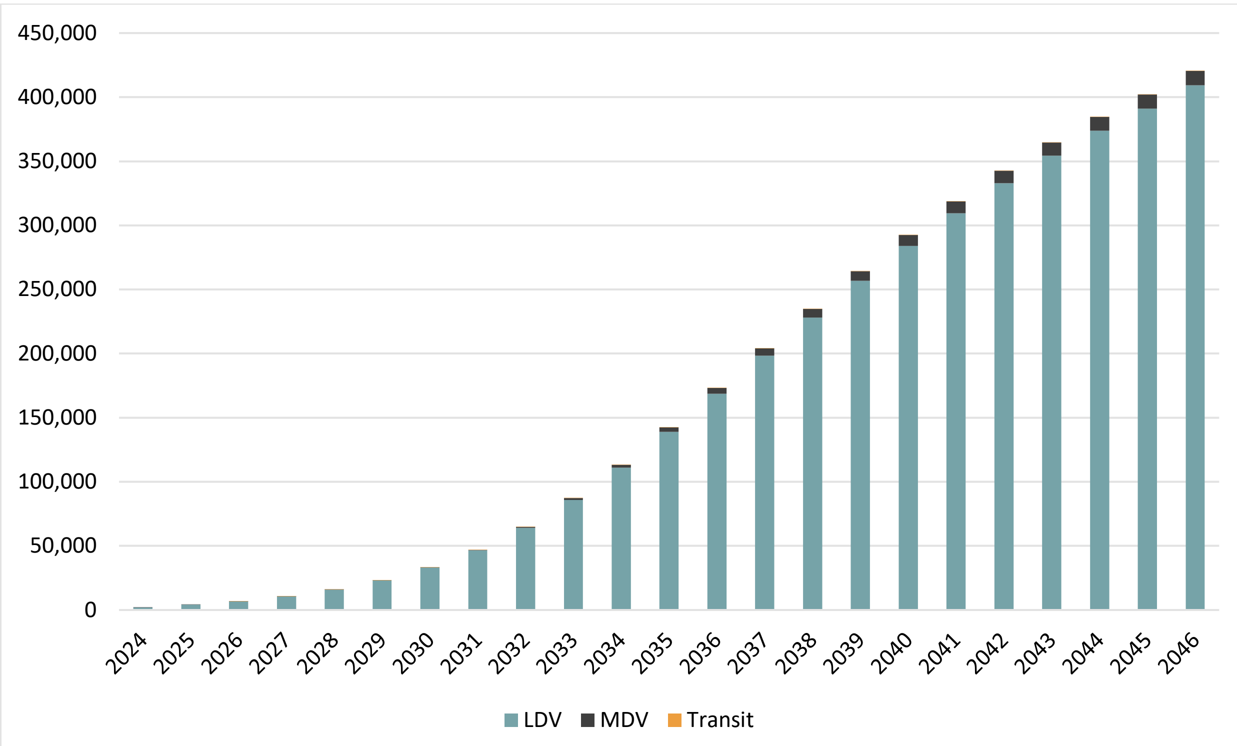
- ***Program attrition:*** We assume an attrition rate of 10%, which reflects the average car ownership period and attrition from other programs.
- ***Per-device demand reduction:*** One of the most important assumptions is the per-participant demand reduction. We apply percent reductions drawn from the Connecticut Managed Charging program which align with initial estimates from NIPSCO's EV pilot scoping efforts. In the RAP scenario, which is modeled as chargers enrolled in an active management strategy on flat rates, the program achieves percent load impacts of 90%. Percent load impacts are 80% in the MAP scenario, which is modeled as vehicles enrolled in a passive management strategy on flat rates.
- ***Enrollment rate:*** The MAP scenario has a higher enrollment rate of 30% than the RAP scenario, which has an enrollment rate of 15%. Customers enroll at higher rates in passively managed charging programs.

TABLE 5-9: EV MANAGED CHARGING OTHER ASSUMPTIONS

Parameter	Input	Notes/Source
Attrition	10%	Average car ownership is 8.4 years. Other participants will move or chose to unenroll
Impact: RAP	90%	NIPSCO pilot experience (4/15/2024 teleconference with Kevin Kirkham) and Connecticut Year 2-3 Managed Charging Evaluation
Impact: MAP	80%	
Enrollment: RAP	15%	Benchmarking of Connecticut and Maryland EV programs
Enrollment: MAP	30%	

Figure 18 shows the forecast of electric vehicles for 2024 through 2046. Forecasted vehicle counts were provided by CRA as part of the 2024 IRP. For this study, eligible vehicles are light-duty vehicles and medium-duty vehicles. By 2046, there will be 420,836 eligible vehicles.

FIGURE 18: ELIGIBLE EV FORECAST



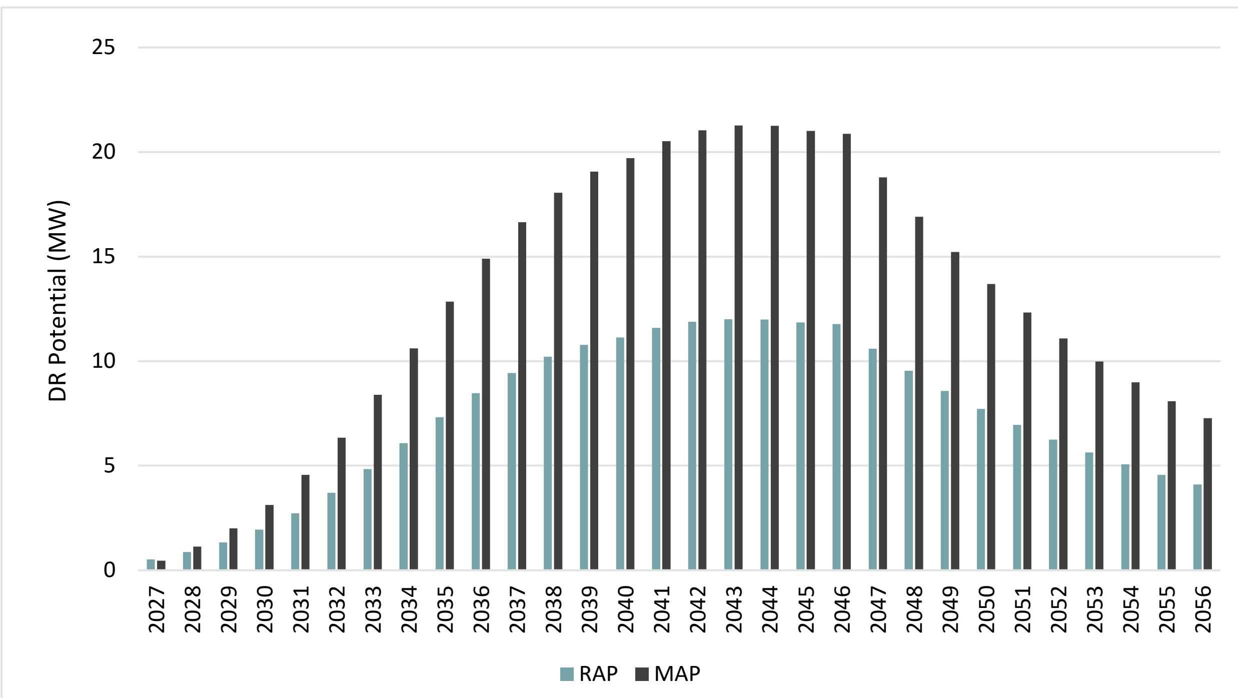
5.3.2 Cost-Effectiveness Results

Table 5-10 summarizes effectiveness results by season and scenario. The EV managed charging program does not pass the UCT for any season under RAP or MAP assumptions. Figure 19 shows the trajectory of the program over time for the RAP and MAP scenarios for the winter season, which has the highest DR potential and lowest levelized cost. Both the RAP and MAP scenarios ramp up over time as the market share of electric vehicles increases. However, the MAP scenario achieves a much higher demand response capacity due to the higher assumed enrollment rate. The MAP scenario is modeled using a passive control strategy which is more attractive to participants and leads to a higher enrollment rate. Combined, the MAP scenario has approximately double the MW potential of the RAP scenario in 2046.

TABLE 5-10: EV MANAGED CHARGING COST-EFFECTIVENESS RESULTS BY PROGRAM TYPE

Parameter	Summer		Spring		Winter		Fall	
	RAP	MAP	RAP	MAP	RAP	MAP	RAP	MAP
Levelized Cost ($/kW-year)	$360	$401	$337	$375	$305	$339	$349	$389
Modified Levelized Cost ($/kW-year)	$320	$361	$297	$335	$265	$299	$310	$349
Lifetime Benefits ($ thousands)	$18,964	$33,184	$20,292	$35,517	$22,440	$39,285	$19,551	$34,219
Lifetime Costs ($ thousands)	$25,116	$48,802	$25,116	$48,802	$25,116	$48,802	$25,116	$48,802
UCT Ratio	0.76	0.68	0.81	0.73	0.89	0.80	0.78	0.70
Participants in 2046	29,497	58,860	29,497	58,860	29,497	58,860	29,497	58,860
System-level capacity in 2046 (MW)	9.8	17.5	10.6	18.8	11.8	20.9	10.2	18.1

FIGURE 19: WINTER EV MANAGED CHARGING RAP AND MAP DR POTENTIAL BY YEAR



5.4 BEHIND-THE-METER BATTERY STORAGE PROGRAM

The behind-the-meter (BTM) battery storage program is a direct load control program that dispatches the batteries of participating customers for several events per year. Similar programs have been implemented by utilities across the U.S. The GDS team designed the program to capture some percent of existing installed batteries in a “bring-your-own” (BYO) style program, as well as an intercept-style program marketed to customers who are installing new BTM batteries. Customers in the BYO program receive a recurring annual incentive per kW of their battery used. Customers in the intercept program receive a smaller incentive per kW of their battery used, but NIPSCO pays 25% of the installation cost of the battery. We forecast battery ownership rates using the existing solar attachment rate for neighboring states, and forecasts of solar penetration from CRA. Future installed battery costs are based on forecasts from NREL.

5.4.1 Program Assumptions

As with prior sections, we divided program assumptions into two key categories: cost assumptions and non-cost assumptions. Cost assumptions include the equipment, incentives, and program overhead costs, while non-cost assumptions include the assumed enrollment rates and demand reductions.

5.4.1.1 Cost Assumptions

Table 5-11 shows the cost assumptions for the BTM Battery Storage program. Fixed costs include the cost of support labor for establishing the program in year one and maintaining the program in subsequent years. These fixed costs are shared across the intercept and BYO programs. The BYO program has a one-time volumetric cost of $100 for marketing costs and a sign-up incentive. This cost is not incurred for intercept customers, who are already installing new BTM batteries and can be reached through the interconnection process. Volumetric costs are API fees of $11/month, for each month of the year, based on vendor fees from similar programs. For BYO customers in the RAP scenario, the participation incentive is $125 per kW of the battery used for the average event. For BYO customers in the MAP scenario, we assume a higher incentive of $250 per kW used. Intercept customers, who have 25% of their installed cost paid for by NIPSCO, have a lower participation incentive of $22.50 per kW used.

TABLE 5-11: BEHIND-THE-METER BATTERY STORAGE COST ASSUMPTIONS

Scenario	Program Type	Fixed One-Time	Fixed Recurring	Volumetric One-Time	Volumetric Recurring	Volumetric Recurring per kW Used	Cost Share	Source
RAP	Intercept	$150,000	$100,000	$0	$121	$22.50	25%	SolarEdge API fees ~$11/site/month x 12 months (Volumetric Recurring); $250 is commensurate with other programs (e.g. Eversource CT) (Volumetric Recurring per kW Used)
	BYO			$100	$121	$125	0%	
MAP	Intercept	$150,000	$100,000	$0	$121	$22.50	25%	
	BYO			$100	$121	$250	0%	

5.4.1.2 Other Program Assumptions

Table 5-12 shows the key non-cost program assumptions. Some additional detail around these assumptions is provided below:

- ***Impact:*** We assume an impact of 25%. Participating batteries are dispatched uniformly over the 4-hour event window. For a 12.5 kWh battery, after accounting for the reserve margin and maximum charge percentage, there remains 10 kWh of available capacity, which when dispatched uniformly over the event window results in 2.5 kW impact per hour.
- ***Battery storage capacity:*** 12.5 kWh is approximately the capacity of many residential behind-the-meter battery systems.

- ***Residential maximum charge percent:*** We assume the battery has 90% of its capacity available for dispatch at the start of an event. In winter, when solar output is lower, we halve the available capacity.
- ***Residential minimum charge percent:*** This is the battery's reservation percentage, below which it will not be dispatched further. We assume 10% based on participant feedback from a pilot study at PG&E.
- ***Participation:*** Participation rates are reported as a percent of installed residential solar systems. They are based on storage attachment rates reported in Berkeley Lab's annual Tracking the Sun report.[11] Indiana does not report data, so we used the average storage attachment rate for neighboring states Kentucky and Illinois, which amounted to 2.5%. For the BYO scenario, we assume all existing systems are enrolled in MAP (2.5%), and half of existing systems are enrolled in RAP (1.25%). For the Intercept program, we assume 7.5% of new solar installations pair a program battery and participate in the MAP scenario, and 3.75% of new solar installations pair a battery in the RAP scenario.

TABLE 5-12: BEHIND-THE-METER BATTERY STORAGE OTHER ASSUMPTIONS

Parameter	Input	Notes/Source
Attrition	5%	Assumed.
Impact	25%	Assume discharge available capacity over 4 hours.
Battery Storage Capacity	12.5 kWh	Assumed.
Residential Max. Charge Pct.	90%	Assumed.
Residential Min. Charge Pct.	10%	From PG&E studies (https://www.etcc-ca.com/reports/residential-battery-virtual-power-plant-vpp-study,
Participation: RAP Intercept	3.75%	Suggestion from NIPSCO Oversight Board during 4/18/2024 meeting
Participation: RAP BYO	1.25%	Based on residential storage attachment rate from Tracking the Sun data for KY and IL which is ~2.5%. RAP BYO assumes 50% enrollment among those with storage.
Participation: MAP Intercept	7.5%	Suggestion from NIPSCO Oversight Board during 4/18/2024 meeting
Participation: MAP BYO	2.5%	Based on residential storage attachment rate from Tracking the Sun data for KY and IL which is ~2.5%. MAP BYO assumes 100% enrollment among those with storage.

Figure 20 shows the forecasted number of residential rooftop solar systems for the analysis window, as provided by CRA. We apply the storage attachment rate discussed above to the number of rooftop systems to yield the number of eligible enrollments.

[11] https://emp.lbl.gov/tracking-the-sun

FIGURE 20: RESIDENTIAL ROOFTOP SOLAR FORECAST

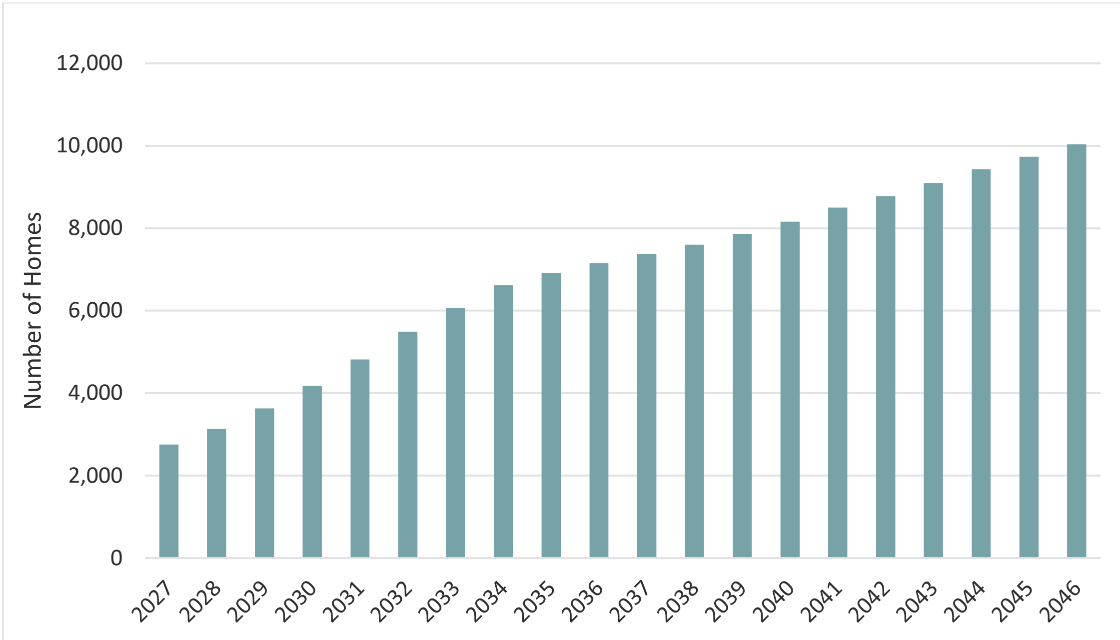
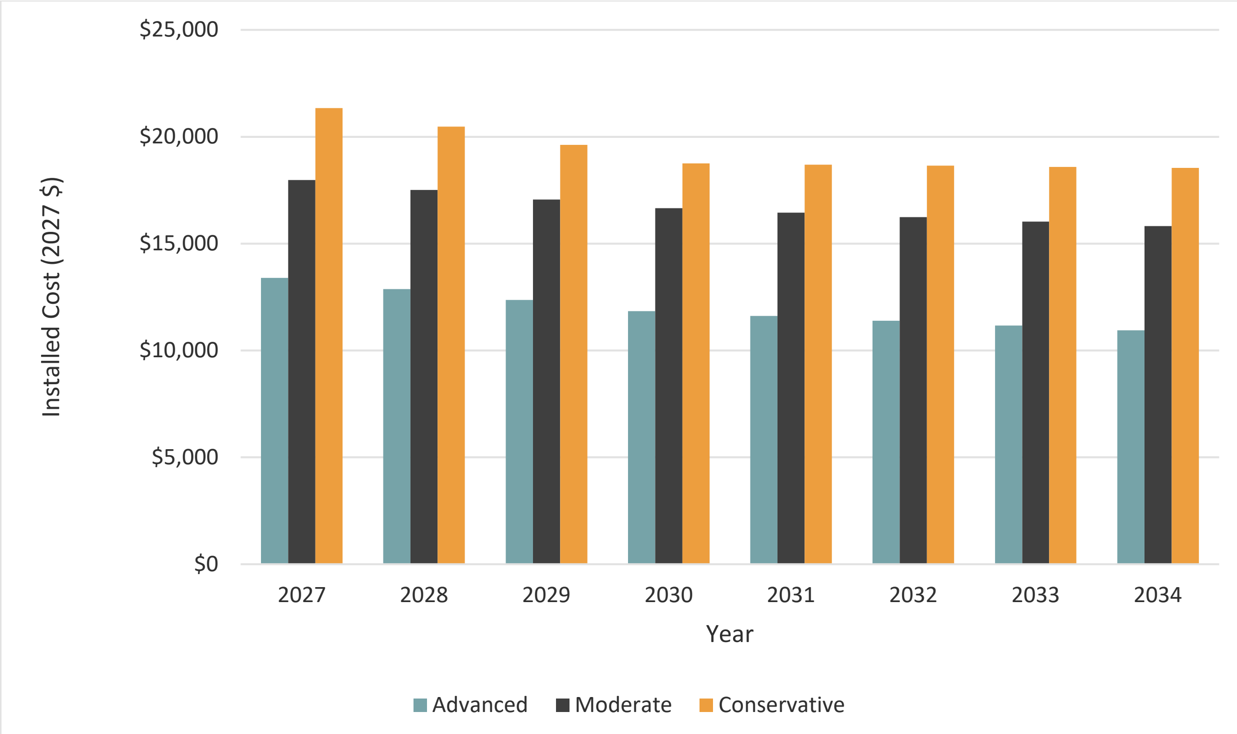


Figure 21 shows NREL forecasts of installed battery costs under three cost scenarios: advanced (low cost), moderate, and conservative (high cost).[12] The installed cost is for a 5 kW, 12.5 kWh residential system. The cost forecast is only relevant for the intercept program, for which 25% of the battery's installed cost is paid for by NIPSCO. Our analysis uses the moderate scenario for both RAP and MAP.

[12] https://atb.nrel.gov/electricity/2023/residential_battery_storage

FIGURE 21: INSTALLED BATTERY COST FORECAST FOR A 12.5 KWH RESIDENTIAL SYSTEM



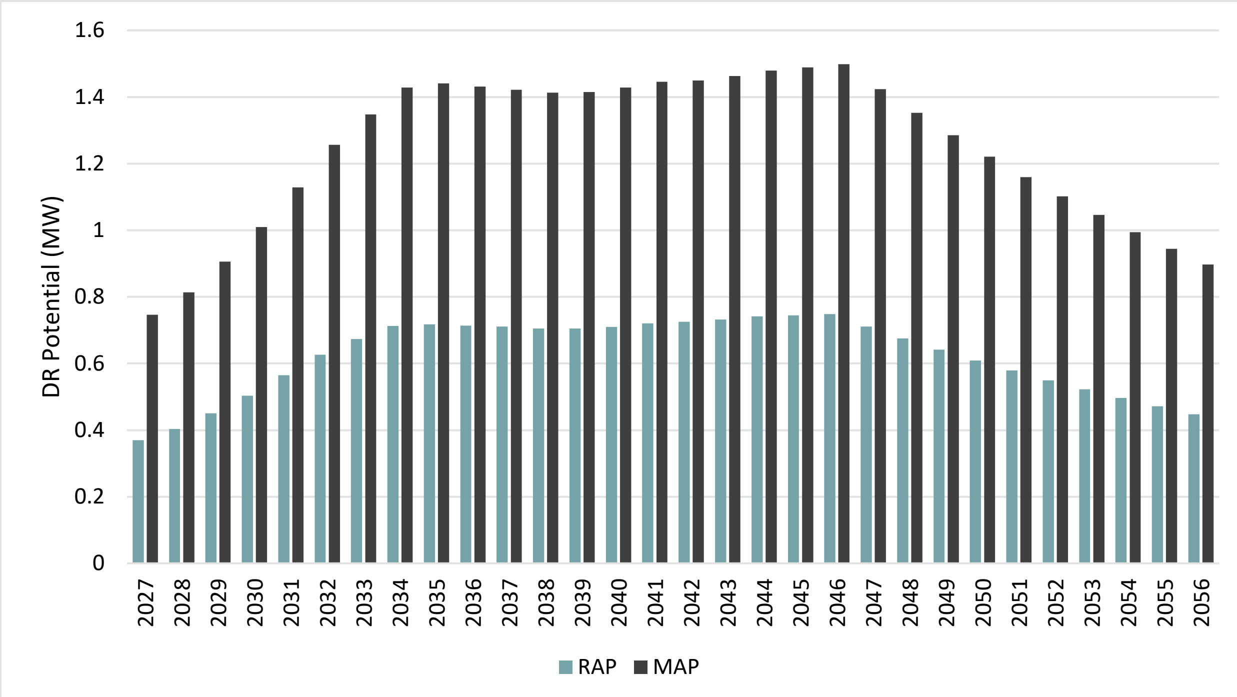
5.4.2 Cost-Effectiveness Results

Table 5-13 summarizes effectiveness results by season and scenario. The UCT ratio is well below one for all seasons, indicating that the program is not cost-effective. Figure 22 shows the trajectory of the program over time for the RAP and MAP scenarios for the summer season, which has the highest DR potential and lowest levelized cost. Both the RAP and MAP scenarios ramp up over time as the number of solar systems increases. The capacity plateaus beginning in2034 when the solar installation rate is lower. The MAP scenario achieves a much higher demand response capacity. The MAP scenario is modeled using a higher incentive and thus a higher enrollment rate, so it has more potential enrollees. The total RAP and MAP demand response capacities are 0.7 and 1.5 MW in 2046, respectively.

TABLE 5-13: BEHIND-THE-METER BATTERY STORAGE COST-EFFECTIVENESS RESULTS BY PROGRAM TYPE

Parameter	Summer		Spring		Winter		Fall	
	RAP	MAP	RAP	MAP	RAP	MAP	RAP	MAP
Levelized Cost ($/kW-year)	$540	$613	$540	$613	$1,015	$1,120	$540	$613
Modified Levelized Cost ($/kW-year)	$502	$576	$502	$576	$978	$1,083	$502	$576
Lifetime Benefits ($ thousands)	$2,088	$4,186	$2,088	$4,186	$1,044	$2,093	$2,088	$4,186
Lifetime Costs ($ thousands)	$4,375	$9,971	$4,375	$9,971	$4,116	$9,109	$4,375	$9,971
UCT Ratio	0.48	0.42	0.48	0.42	0.25	0.23	0.48	0.42
Participants in 2046	277	555	277	555	277	555	277	555
System-level capacity in 2046 (MW)	0.7	1.5	0.7	1.5	0.4	0.7	0.7	1.5

FIGURE 22: SUMMER BEHIND-THE-METER BATTERY STORAGE RAP AND MAP DR POTENTIAL BY YEAR



5.5 RESIDENTIAL BEHAVIORAL PROGRAM

The residential behavioral program is an example of behavioral demand response (BDR), a DR strategy that relies on timely customer notifications to elicit reductions in demand during DR event hours. As modeled here, the BDR program offers no financial incentive for customers to curtail usage and no-load control equipment is installed in the home. BDR programs are like Home Energy Report programs for Energy Efficiency. A treatment group is encouraged to conserve energy via messaging issued before and after DR events and is presented with social comparisons designed to promote demand reductions during event hours. BDR messaging can happen via email, text, phone, or social media.

The residential behavioral program targets its messaging to the top residential electricity users in NIPSCO's service territory. In the RAP scenario, the top quartile of energy users is targeted for messaging, while in the MAP scenario, the top two quartiles are targeted. Customers may opt-out of messaging from the program, but we assume that for each customer who opts-out, another would be added to the program. While the individual impacts are small, at 40-60 Watts per household for most BDR programs, many households can be included in the program at relatively low cost.

5.5.1 Program Assumptions

5.5.1.1 Cost Assumptions

The cost assumptions used for the Behavioral program are shown in Table 5-14. Fixed costs include the cost of support labor for establishing the program in year one and maintaining the program in subsequent years. There are no Volumetric one-time costs included in the model as there are no incentives for this program. Volumetric recurring costs include only the yearly recurring administrative per-customer fees.

TABLE 5-14: RESIDENTIAL BEHAVIORAL COST ASSUMPTIONS

Scenario	Fixed One-Time	Fixed Recurring	Volumetric One-Time	Volumetric Recurring	Source
RAP	$150,000	$150,000	$0	$4	Similar to other BDR Programs (Met-Ed, West Penn Power)
MAP	$150,000	$200,000	$0	$4	Similar to other BDR Programs (Met-Ed, West Penn Power)

5.5.1.2 Other Program Assumptions

Other program assumptions are shown in Table 5-15. There are several notes on particular program assumptions:

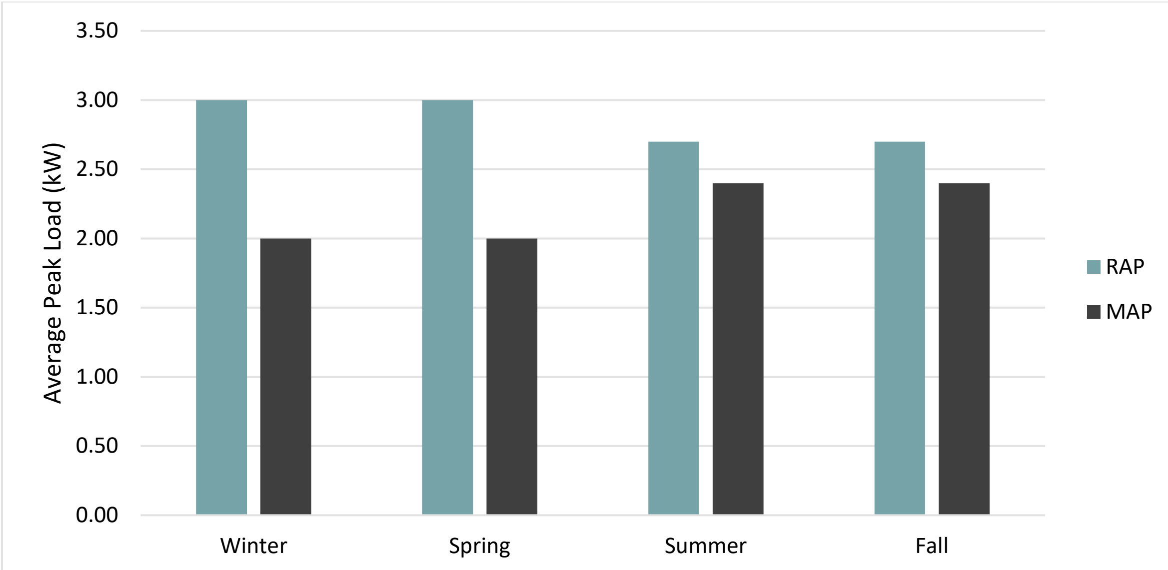
- ***Attrition rate:*** We assume all customers are assigned to treatment. Any non-response is reflected in the percent impacts used below.
- ***Impact:*** We assumed a 2% whole-premise load reduction for both RAP and MAP scenarios. This is a similar percent impact to other BDR programs.
- ***Enrollment rate:*** We assume that the top quartile of customers will be targeted for messaging in the RAP scenario and the top two quartiles of customers will be targeted in the MAP scenario.

TABLE 5-15: RESIDENTIAL BEHAVIORAL PROGRAM NON-COST ASSUMPTIONS

Parameter	Input	Notes/Source
Attrition	0%	No attrition as customers are assigned to treatment.
Impact	2%	Similar to other BDR Programs (Met-Ed, West Penn Power)
Participation: RAP	25%	Similar to other BDR Programs (Assumes the top quartile of customers is enrolled)
Participation: MAP	50%	Similar to other BDR Programs (Assumes the top two quartiles of customers are enrolled)

Figure 23 shows the average program participant residential peak load contribution for the RAP and MAP scenarios by season. The peak loads used for estimating impacts come from similar sets of customers at geographically similar utilities. Peak load contribution is higher for the RAP scenario because only the top quartile of customers is targeted. In the MAP scenario, the top two quartiles are targeted, which results in a lower average peak load contribution across a much larger number of homes.

FIGURE 23: AVERAGE PROGRAM PARTICIPANT RESIDENTIAL PEAK LOAD CONTRIBUTION BY SEASON



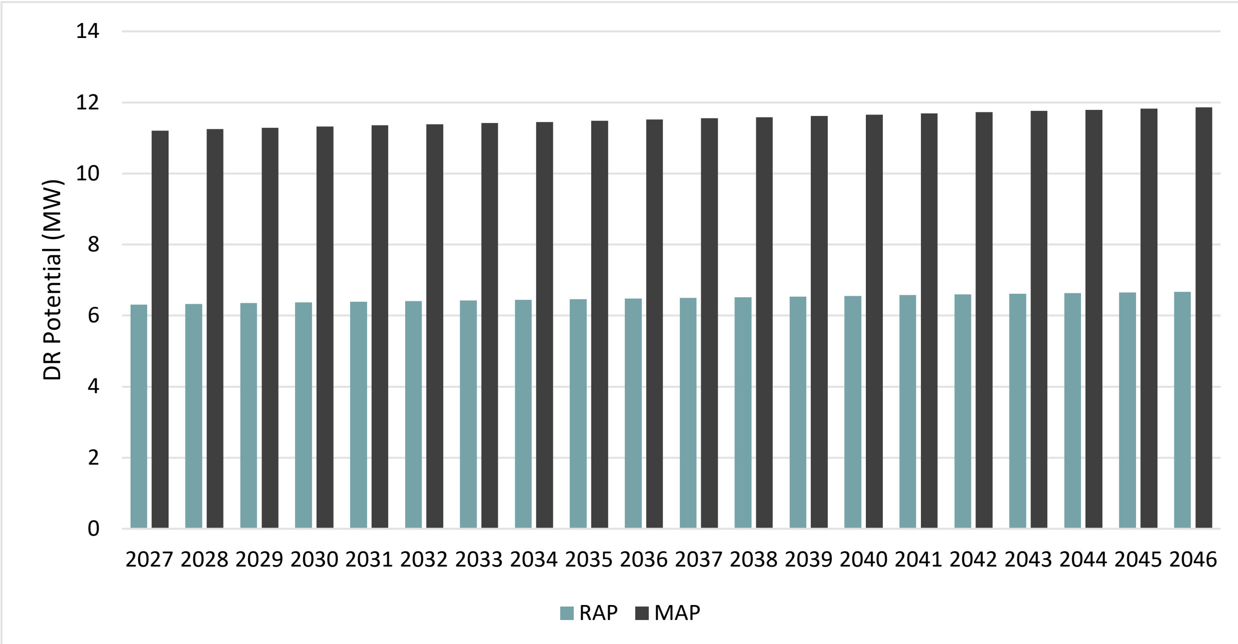
5.5.2 Cost-Effectiveness Results

Table 5-16 summarizes the cost-effectiveness results by season and scenario. The UCT ratio is well above one in all seasons and scenarios. Figure 24 shows the trajectory of the program over time for the RAP and MAP scenarios for the summer season, which has the highest DR potential along with the Fall season. Both the RAP and MAP scenarios ramp up gradually over time as the number of residential customers increases. The MAP scenario achieves a much higher demand response capacity. The MAP scenario is modeled as enrolling 50% of customers versus 25% for the RAP scenario. Combined, the MAP scenario is over 5 MW more potential than the RAP scenario in 2046, though the RAP scenario is more cost effective than the MAP scenario. The total RAP and MAP demand response capacities are 6.7 and 11.9 MW in 2046, respectively.

TABLE 5-16: RESIDENTIAL BEHAVIORAL PROGRAM COST-EFFECTIVENESS RESULTS BY SEASON AND SCENARIO

Parameter	Summer		Spring		Winter		Fall	
	RAP	MAP	RAP	MAP	RAP	MAP	RAP	MAP
Levelized Cost ($/kW-year)	$120	$123	$108	$147	$108	$147	$120	$123
Modified Levelized Cost ($/kW-year)	$85	$88	$73	$112	$73	$112	$85	$88
Lifetime Benefits ($ thousands)	$17,678	$31,427	$19,642	$26,189	$19,642	$26,189	$17,678	$31,427
Lifetime Costs ($ thousands)	$8,830	$16,046	$8,830	$16,046	$8,830	$16,046	$8,830	$16,046
UCT Ratio	2.00	1.96	2.22	1.63	2.22	1.63	2.00	1.96
Participants in 2046	114,308	228,615	114,308	228,615	114,308	228,615	114,308	228,615
System-level capacity in 2046 (MW)	6.7	11.9	7.4	9.9	7.4	9.9	6.7	11.9

FIGURE 24: SUMMER RESIDENTIAL BEHAVIORAL PROGRAM RAP AND MAP DR POTENTIAL BY YEAR



5.6 RESIDENTIAL TIME-VARYING AND DYNAMIC RATES (CRITICAL PEAK PRICING) PROGRAM

Time-varying and dynamic rates provide an economic incentive for customers to reduce electricity usage during high-system-cost periods. For this study we considered three types of programs:

- **Peak-Time Rebate (PTR)**: PTR programs pay participants to use less electricity during a limited number of events that are called by NIPSCO. If load is not reduced, or increases, no payment or penalty occurs.

- **Time-of-Use Rates (TOU):** TOU is an everyday rate structure that varies with the time of day such that prices are discounted during periods of low demand or wholesale energy prices and higher during peak periods of higher demand or wholesale energy prices.

- **Critical Peak Pricing (CPP):** CPP programs offer participants a discounted electricity rate during off-peak hours, but charge customers a much higher energy price during a limited number of events that are called by NIPSCO.

For each rate option, the GDS Team modeled various design choices. Rates can be offered on either a default (opt-out) or opt-in basis. Default designs typically yield lower per-customer impacts for a larger number of customers than opt-in design. Rates can be designed to be cost-reflective, whereby the price ratio that participants face reflects the price ratio in the wholesale energy market, or exaggerated, whereby participants face a higher price ratio. Exaggerated rates typically yield higher impacts. Rates can be offered with enabling technologies such as smart thermostats and in-home displays that yield an increased impact at the expense of higher per-participant costs.

Because NIPSCO has only just begun installation of the enabling advanced metering infrastructure (AMI) that would permit the widespread adoption of dynamic rates, for this study we assumed a rates program beginning in 2030. We assume the rates would be designed to be revenue-neutral for NIPSCO. In addition, while we modeled a full host of options as described above, we designed the RAP and MAP scenarios as specific offerings. The RAP scenario reflects an opt-out (default) PTR program with no enabling technology. The MAP scenario reflects the combination of a default TOU rate with technology and an exaggerated price ratio, and an opt-in CPP rate with technology. The cost and non-cost assumptions for the rates modeled in each scenario are shown below.

5.6.1 Program Assumptions

5.6.1.1 Cost Assumptions

Table 5-17 shows the cost assumptions for the Residential Dynamic Rates program. The first two rows capture the costs of setting up and maintaining billing software, which is more complicated than flat-rate billing systems. One-time volumetric costs include marketing and customer acquisition subsidization of enabling technology for the MAP scenario. Recurring volumetric costs reflect participant settlement costs and the ongoing costs of operating the program. These are based on filings by Consumers Energy, which has default TOU, opt-in CPP, and opt-in PTR. The volumetric costs of PTR reflect payment asymmetry and the fact that NIPSCO would pay participants who reduce load but not bill participants who increase load on event days. Importantly, these costs do not represent the full costs of AMI equipment and deployment costs, which can amount to over $1,000 per meter. The result is that the UCT ratios for the residential rate programs are among the highest in this study. We did not include the full costs of AMI in the UCT ratio because no dynamic rates demand response program would be cost-effective if it had to bear the full costs of AMI deployment. Rather, benefits from the dynamic rates demand response program should be weighed with other benefits of AMI – such as reduced outage times and better system visibility – in a more comprehensive manner when AMI deployment is being considered.

TABLE 5-17: RESIDENTIAL RATES COST ASSUMPTIONS

Scenario	Pricing Program Component	Fixed One-Time	Fixed Recurring	Volumetric One-Time	Volumetric Recurring
RAP	PTR Default No Tech Cost-Reflective	$540,000	$288,000	$20	$18
MAP	TOU Default w/ Tech Exaggerated	$653,000	$392,000	$100	$10
MAP	CPP Opt-In w/ Tech against TOU	$320,000	$320,000	$100	$10

5.6.1.2 Other Program Assumptions

Other program assumptions are shown in Table 5-18. The study team offers the following notes on specific program assumptions:

- ***Load reduction:*** The load reductions are based on the Arcturus model from The Brattle Group, which uses compiled evaluation results from dozens of dynamic rates programs to develop a relationship between the load reduction percentage and the rate price differential.[13] The assumed load reductions vary based on the rate offering, the price differential, the enrollment type, and whether enabling technology is offered. For the RAP scenario, we assume a rate price differential of 400%. For the MAP scenario, we assume a rate price differential of 200% for the

[13] https://www.brattle.com/news-and-knowledge/publications/arcturus-20-a-meta-analysis-of-time-varying-rates-for-electricity.

TOU rate and 400% for the CPP rate. Load reductions vary according to whether the program is offered on a default or opt-in basis. The RAP scenario assumes the load reduction is 6.9%. The result is a per premise impact of 0.17 kW at the meter. The MAP scenario assumes the load reductions are 6.2% for TOU and 17.4% for CPP. This yields per premise impacts at the meter of 0.15 kW and 0.28 kW, respectively.

- ***Program start year:*** As discussed above, we assumed that AMI infrastructure is put into place before 2030, when we assume the dynamic rate program takes effect. We assume a multi-year ramp rate where customers are transitioned gradually rather than all at once in 2030.
- ***Enrollment rate:*** For programs offered on a default basis, we assume an enrollment rate of 80%. The opt-in enrollment rate is set to 15%.
- ***Attrition rate:*** A high program attrition rate can have a negative effect on program cost-effectiveness. We assume a 5% attrition rate per year for the opt-in CPP rate, based on program data for a similar program from a Midwest utility.

TABLE 5-18: RESIDENTIAL RATES NON-COST ASSUMPTIONS

Parameter	RAP	MAP	
	PTR Default No Tech Cost-Reflective	TOU Default w/ Tech Exaggerated	CPP Opt-In w/ Tech against TOU
Rate Price Differential (hi/low)	400%	200%	400%
Arcturus Curve	tou_notech_default	tou_tech_default	tou_tech
Enrollment Type	Default	Default	Opt-In
Pct. Impact	6.9%	6.2%	17.4%
EUL (years)	20	20	20
Start Year	2030	2030	2030
Hours of Dispatch	32	320	32
Enrollment rate	80%	80%	15%
Per-Premise Reduction at Meter (kW)	0.171	0.152	0.275
Per-Premise Reduction at System (kW)	0.166	0.165	0.268
Event Opt-Out Rate	10%	0%	10%
Year-Over-Year Attrition Rate	0%	0%	5%

Table 5-19 shows reference loads per premise for residential customers by season. These values reflect the peak load forecast for 2030-2046 provided by CRA, after adjustments for line losses.

TABLE 5-19: RESIDENTIAL PER PREMISE REFERENCE LOAD WITH LINE LOSSES BY SEASON

Season	Per Premise Load (kW)
Fall	2.46
Spring	1.14
Summer	2.47
Winter	1.14

5.6.2 Cost-Effectiveness Results

Table 5-20 and Table 5-21 summarize the cost-effectiveness results, while Figure 25 shows the program capacity over time for the RAP and MAP scenarios. For the MAP scenario, we show results for each rate offering separately, but values should be summed where appropriate to reflect that they are offered jointly. The cost-effectiveness results for the Residential Dynamic Rates should be interpreted with two key considerations in mind. First, the enabling AMI infrastructure is not currently in place that would render these programs feasible in the near term, and so the assumed start date for this program is in 2030. Second, these values exclude the majority of costs that would be incurred to deploy AMI in the NIPSCO territory. The UCT ratios for both the RAP and MAP scenarios are quite high, in part due to the exclusion of most AMI costs. Because reference loads in summer and fall are much higher than in spring and winter, capacity is also highest in the summer and fall seasons. In addition, the MAP scenario capacity is just over 18 MW larger than the RAP scenario in the summer season, largely because of the CPP offering on top of the TOU rate. The total RAP and MAP demand response capacities are 66 and 84 MW in 2046, respectively.

TABLE 5-20: RESIDENTIAL DYNAMIC RATES PROGRAM COST-EFFECTIVENESS RESULTS – SUMMER AND FALL

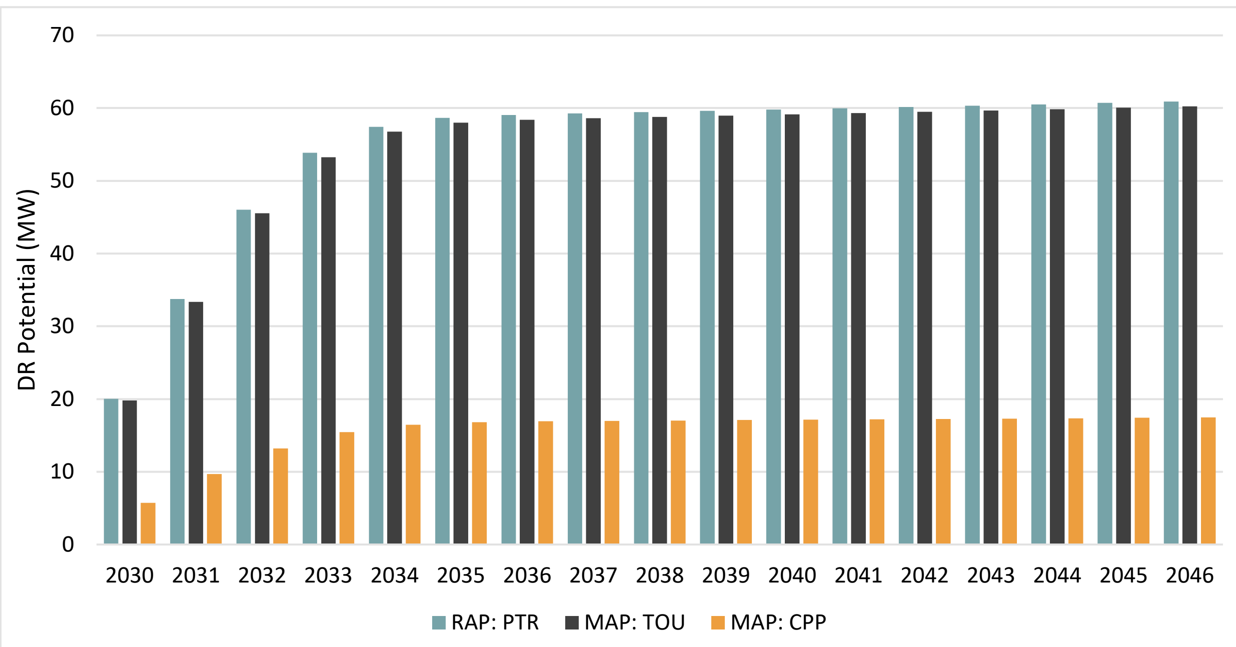
Parameter	Summer			Fall		
	RAP: PTR	MAP: TOU	MAP: CPP	RAP: PTR	MAP: TOU	MAP: CPP
Levelized Cost ($/kW-year)	$167	$154	$119	$175	$167	$129
Modified Levelized Cost ($/kW-year)	$130	$117	$82	$138	$130	$92
Lifetime Benefits ($ thousands)	$123,437	$122,085	$35,411	$113,679	$112,434	$32,612
Lifetime Costs ($ thousands)	$80,866	$73,848	$16,565	$78,240	$73,848	$16,565
UCT Ratio	1.53	1.65	2.14	1.45	1.52	1.97
Participants in 2046	366,150	366,150	65,220	366,150	366,150	65,220
System-level capacity in 2046 (MW)	66.1	65.4	19.0	60.9	60.3	17.5

TABLE 5-21: RESIDENTIAL DYNAMIC RATES PROGRAM COST-EFFECTIVENESS RESULTS – SUMMER AND FALL

Parameter	Spring			Winter		
	RAP: PTR	MAP: TOU	MAP: CPP	RAP: PTR	MAP: TOU	MAP: CPP
Levelized Cost ($/kW-year)	$281	$333	$258	$281	$333	$257
Modified Levelized Cost ($/kW-year)	$244	$297	$221	$244	$296	$221
Lifetime Benefits ($ thousands)	$56,989	$56,365	$16,349	$57,079	$56,453	$16,375
Lifetime Costs ($ thousands)	$62,983	$73,848	$16,565	$63,007	$73,848	$16,565
UCT Ratio	0.90	0.76	0.99	0.91	0.76	0.99
Participants in 2046	366,150	366,150	65,220	366,150	366,150	65,220
System-level capacity in 2046 (MW)	30.5	30.2	8.8	30.6	30.3	8.8

Figure 25 shows system-level capacity over time for each scenario and rate offering. The growth in capacity from 2030 to 2035 reflects an assumed program ramp rate across the service territory over time. Electric utilities typically default customers in waves over time rather than all at once and opt-in enrollments take time to acquire. NIPSCO could choose to accelerate or slow down the deployment of dynamic rates compared to what was assumed for this study.

FIGURE 25: RESIDENTIAL DYNAMIC RATES PROGRAM RAP AND MAP BY YEAR



6 Detailed Findings: Non-Residential Sector

Table 6-1 shows the MAP and RAP by non-residential program for select years within the study horizon. The 20-year MAP across the two non-residential programs totals 145 MW and the RAP totals 88 MW. The Data Center program comprises the majority of demand response capacity in both the MAP and the RAP scenarios, followed by the C&I load curtailment program. The Data Center results are based on the forecast of data center load additions incorporated into all IRP scenarios rather than the Emerging Load Sensitivity – which has an additional 6,000 MW of data center load by 2035. The following sections present the methodology and results for the non-residential programs considered in this study:

- Commercial and Non-531 Industrial Load Curtailment
- Data Center Load Curtailment

TABLE 6-1: NON-RESIDENTIAL MAXIMUM AND REALISTIC ACHIEVABLE POTENTIAL BY PROGRAM (CUMULATIVE BY YEAR)

Program	RAP					MAP				
	2027	2028	2029	2036	2046	2027	2028	2029	2036	2046
C&I Load Curtailment	11.8	16.7	21.8	26.4	29.4	20.0	28.4	21.8	45.5	50.4
Data Center – Base Scenario	1.9	8.5	20.8	53.5	58.9	3.0	13.6	33.7	85.2	94.4
Total [a]	**13.6**	**25.1**	**42.6**	**79.8**	**88.3**	**23.0**	**42.0**	**55.4**	**130.7**	**144.8**

[a] Total row may not equal the sum of program values due to rounding

6.1 C&I LOAD CURTAILMENT

Load curtailment is a class of demand response programs where customers agree to reduce load upon request in exchange for a financial incentive, which can be tariff-based or a supplemental payment contract:

- ***Tariff-Based:*** Participants are assigned to a tariff with more favorable billing determinants in exchange for agreeing to have a portion of their load interrupted or operations curtailed in response to direction from the utility or grid operator.
- ***Payment Contract:*** Participants enter a separate contract with the utility or grid operator to curtail load upon request. Generally, the program administrator will specify the dispatch parameters and participants will commit to reducing a certain amount of load upon dispatch for one or more years.

The GDS team modeled the load curtailment opportunity as a payment contract program. The commercial and non-531 industrial potential was modeled separately from data center loads because data centers are expected loads and not a current class of customer at NIPSCO. The peak load contribution for the commercial, small industrial, and large non-531 industrial load curtailment program comes from the IRP input forecasts. Peak loads for the customer classes included in this program are expected to be 1,067 MW in Summer 2027.

6.1.1 Methodology

The load curtailment potential for non-residential customers is a function of several important factors. For our top-down model, the GDS team uses seasonal peak load forecasts as a foundation, with other relevant inputs that include financial variables (retail rates, avoided capacity costs, and avoided energy costs), customer sensitivity to changes in electricity price (demand response price elasticity), and components of the program design (frequency and duration of events and amount of notification time and incentive payments). Table 6-2 describes these assumptions, as well as the sources for other key inputs into the demand response potential estimates, followed by a discussion of the price elasticity of demand response supply and how it can be used to estimate load curtailment potential.

TABLE 6-2: SUMMARY OF C&I LOAD CURTAILMENT INPUT ASSUMPTIONS AND SOURCES

Input Variable	Sources, Notes, and Assumptions
Retail Electricity Cost ($/MWh)	NIPSCO provided a retail rate escalation factor which, when matched with the EIA Form 861 commercial retail rate average for 2023, provided a forecast of future retail electricity costs. The value in 2027 nominal dollars is $169.64 ($/MWh).
Avoided Cost of Capacity ($/kW-year)	NIPSCO provided the GDS team with avoided costs of generation, transmission, and distribution capacity. The total avoided cost of capacity for commercial and non-531 industrial customers in nominal dollars is $203.38/kW-yr in 2027. The new data center load is assumed to be transmission-connected so it only receives $173.83 in avoided cost of generation and transmission.
Avoided Energy Costs ($/MWh)	Avoided energy costs represent the difference between the summer on-peak and summer off-peak periods. As with other sectors, we did not model any differential between energy costs because the on and off-peak prices provided by NIPSCO were the same values.
Program Design (event frequency and duration)	The team assumed up to 64 event hours per year across the study horizon with an average of six events annually (24 event hours). For our load curtailment potential estimates, we assumed a *day-of* notification design, with a three- to six-hour notice, for consistency with MISO rules for LMR resources.
Peak Load Contribution	Based on the inputs used for the 2024 IRP, peak load contribution of commercial and non-531 industrial customers is 1,067 MW in Summer 2027 and rising by a small amount in each year thereafter. The fall, spring, and winter peak load contributions in 2027 are 1,060 MW, 949 MW, and 974 MW, respectively.
Participant Incentive	For load curtailment programs, the GDS team modeled the incentive as an annual reservation payment provided to the participant. In exchange, the participant agrees to curtail load when events are dispatched. For RAP, we set the optimal incentive level using maximized net benefits, performing a simulation where the key input was the incentive level, and the key output was the net benefit of the demand response program. The team leveraged several of the inputs discussed herein for this simulation and performed the calculations for the first-year of the study horizon (2027). Incentive levels were then escalated by the inflation rate over the remaining years of the study period. Table 6-4 shows the incentive levels by year and modeling perspective. Participant incentives are a variable cost because they scale directly with the quantity of nominated capacity.
Price Elasticity of Demand Coefficients	We derived the price elasticity coefficients from seven years of Base Residual Auction clearing results from the PJM Interconnection LLC (PJM) Reliability Pricing Model. Additional details are included in the Price Elasticity section.
Program Management Budget (Non-Incentive Costs)	The team assumed three program management budget components: (1) We assumed that *fixed program management costs* start at $400,000 in 2027 and escalate annually. (2) We set the *marketing and customer acquisition costs* during the expansion period at $300,000 in 2027 and escalated annually until 2031 (after which there is no fixed cost for marketing and customer acquisition). (3) We set the *variable program administration costs*, the largest component that scales according to program size, equal to 20% of the incentive cost. For example, if the annual incentive cost was $1,000 the variable administrative cost would be equal to $200, for a total of $1,200 in variable costs.

Input Variable	Sources, Notes, and Assumptions
Line Losses	The team used a top-down model for the load curtailment opportunity using system loads, so the resulting estimates of demand response potential are inclusive of line losses.
Ramp Rate	To account for the program needing a few years to fully mature, the GDS team assumed a three-year ramp up to full program potential. We applied ramp rate factors of 50%, 70%, and 90% in the first three program years (2027-2029) respectively.

The GDS team produced estimates of both MAP and RAP, which are defined in the context of C&I load curtailment as follows:

- MAP is the load curtailment potential for a program where customer incentives are as high as possible while still producing a cost-effective program (that is, the largest incentive value such that the UCT ratio does not fall below 1.0).
- RAP is the load curtailment potential for a program where customer incentives are designed to maximize the present value of the net program benefits.

6.1.1.1 Price Elasticity

The price elasticity of demand is the ratio between the percentage change in the quantity of electricity demanded and the percentage change in the price (with and without an incentive) of demand response:

$$Elasticity = \frac{Percentage\ Change\ in\ Quantity}{Percentage\ Change\ in\ Price}$$

Where:

$$Percentage\ Change\ in\ Quantity = \frac{(Summer\ Peak - \ Demand\ Response\ Potential) - Summer\ Peak}{Summer\ Peak} * 100\%$$

$$Percentage\ Change\ in\ Price = \frac{(Retail\ Rate + Incentive\ Payment) - Retail\ Rate}{Retail\ Rate} * 100\%$$

We derived price elasticities from seven years of PJM Base Residual Auction results.[14] The PJM market is a useful benchmark because the capacity performance definition largely excludes residential demand response from the market. Following each capacity auction, PJM publishes the quantity of cleared DR potential by zone along with the zonal resource clearing price. Figure 26 shows the quantity of cleared DR in the Base Residual Auction for the 2024/2025 delivery year. The peak load, by season, for each zone was also compiled from PJM forecasts for use in the calculations along with average retail rates derived from EIA Form 861 reporting.[15] The numerator of the elasticity calculation (% change in Quantity) reflects both the enrollment rate and reductions observed amongst participants relative to their reference loads. The denominator of the elasticity calculation (% change in Price) was based on (1) the resource clearing price, (2) the typical number of event hours, and (3) average retail rates, by sector, expressed as an “all in” cost per kWh.

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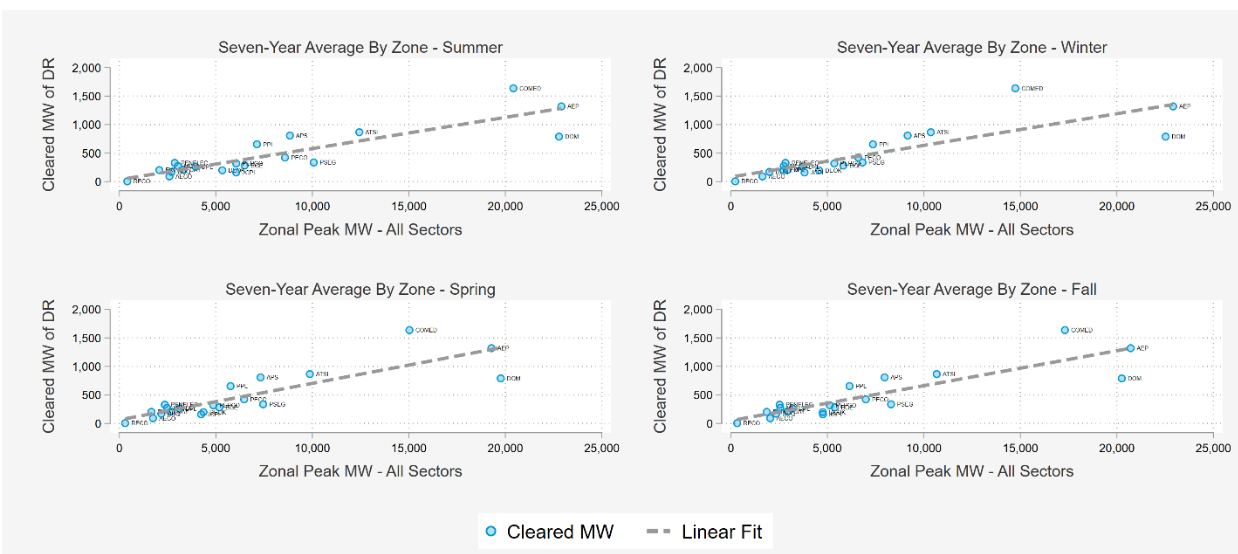
[14] https://www.pjm.com/markets-and-operations/rpm
[15] https://www.eia.gov/electricity/data/eia861/

FIGURE 26: OFFERED AND CLEARED MW FOR THE 2024/2025 DELIVERY YEAR

		Offered MW (UCAP)*			Cleared MW (UCAP)*		
LDA	Zone	DR	EE	Total	DR	EE	Total
EMAAC	AECO	93.8	153.8	**247.6**	66.8	152.0	**218.8**
EMAAC/DPL-S	DPL	173.1	208.2	**381.3**	151.6	202.4	**354.0**
EMAAC	JCPL	175.1	326.8	**501.9**	131.8	317.4	**449.2**
EMAAC	PECO	429.3	615.8	**1,045.1**	365.4	583.9	**949.3**
PSEG/PS-N	PSEG	389.0	817.2	**1,206.2**	285.7	771.4	**1,057.1**
EMAAC	RECO	3.4	3.2	**6.6**	2.7	3.2	**5.9**
EMAAC Sub Total		**1,263.7**	**2,125.0**	**3,388.7**	**1,004.0**	**2,030.3**	**3,034.3**
PEPCO	PEPCO	232.0	421.1	**653.1**	160.4	398.9	**559.3**
BGE	BGE	224.1	392.9	**617.0**	198.1	380.3	**578.4**
MAAC	METED	258.4	166.3	**424.7**	217.8	157.1	**374.9**
MAAC	PENELEC	347.6	148.0	**495.6**	313.9	140.6	**454.5**
PPL	PPL	658.4	422.0	**1,080.4**	603.4	391.4	**994.8**
MAAC Sub Total**		**2,984.2**	**3,675.3**	**6,659.5**	**2,497.6**	**3,498.6**	**5,996.2**
RTO	AEP	1,590.1	883.4	**2,473.5**	1,102.8	790.8	**1,893.6**
RTO	APS	861.8	407.9	**1,269.7**	635.1	375.8	**1,010.9**
ATSI/ATSI-C	ATSI	953.5	689.1	**1,642.6**	674.6	587.3	**1,261.9**
COMED	COMED	1,899.8	1,284.7	**3,184.5**	1,542.0	1,063.4	**2,605.4**
DAY	DAY	233.5	146.1	**379.6**	191.1	128.3	**319.4**
DEOK	DEOK	231.2	202.2	**433.4**	221.9	188.1	**410.0**
RTO	DOM	892.4	977.2	**1,869.6**	710.5	901.1	**1,611.6**
RTO	DUQ	210.9	151.1	**362.0**	120.6	133.8	**254.4**
RTO	EKPC	289.0	-	**289.0**	289.0	-	**289.0**
Grand Total		**10,146.4**	**8,417.0**	**18,563.4**	**7,985.2**	**7,667.2**	**15,652.4**

Figure 27 compares the seven-year average quantity of cleared demand response MW to the seasonal peak load for each zone. Demand response represents 5-7% of seasonal peak load for most zones, on average.

FIGURE 27. SEVEN-YEAR AVERAGE PJM ZONAL DEMAND RESPONSE COMMITMENTS VERSUS PEAK LOAD BY SEASON



Lastly, two sets of adjustments were applied to the PJM elasticity to better reflect NIPSCO's C&I opportunity. First, the estimated share of each PJM zone's peak load attributable to the residential class was removed by dividing the elasticity values by a seasonal estimate of non-residential peak load contribution (typically 55%-65%). Second, a 70% calibration factor was applied to account for the fact that

NIPSCO's largest and most DR-capable accounts are ineligible due to the Rate 531 design. Table 6-3 shows the final values used to model load curtailment potential by season.

TABLE 6-3. PRICE ELASTICITY VALUES

Season	Elasticity
Summer	0.00105
Winter	0.00102
Spring	0.00112
Fall	0.00104

6.1.1.2 Sample Calculation

Rearranging the terms from the first equation above yields a sample calculation:

$$Percentage\ Change\ in\ Quantity = Elasticity *\ Percentage\ Change\ in\ Price$$

Note that the price elasticity and the sample calculation both have percentage change in quantity in the equation. These two equations can be combined:

$$Elasticity *\ Percentage\ Change\ in\ Price = \frac{(Summer\ Peak -\ Demand\ Response\ Potential) - Summer\ Peak}{Summer\ Peak}$$

The terms in the above equation can then be rearranged to solve for demand response potential:

$$Demand\ Response\ Potential = \frac{Elasticity *\ Percentage\ Change\ in\ Price * Summer\ Peak}{100\%}$$

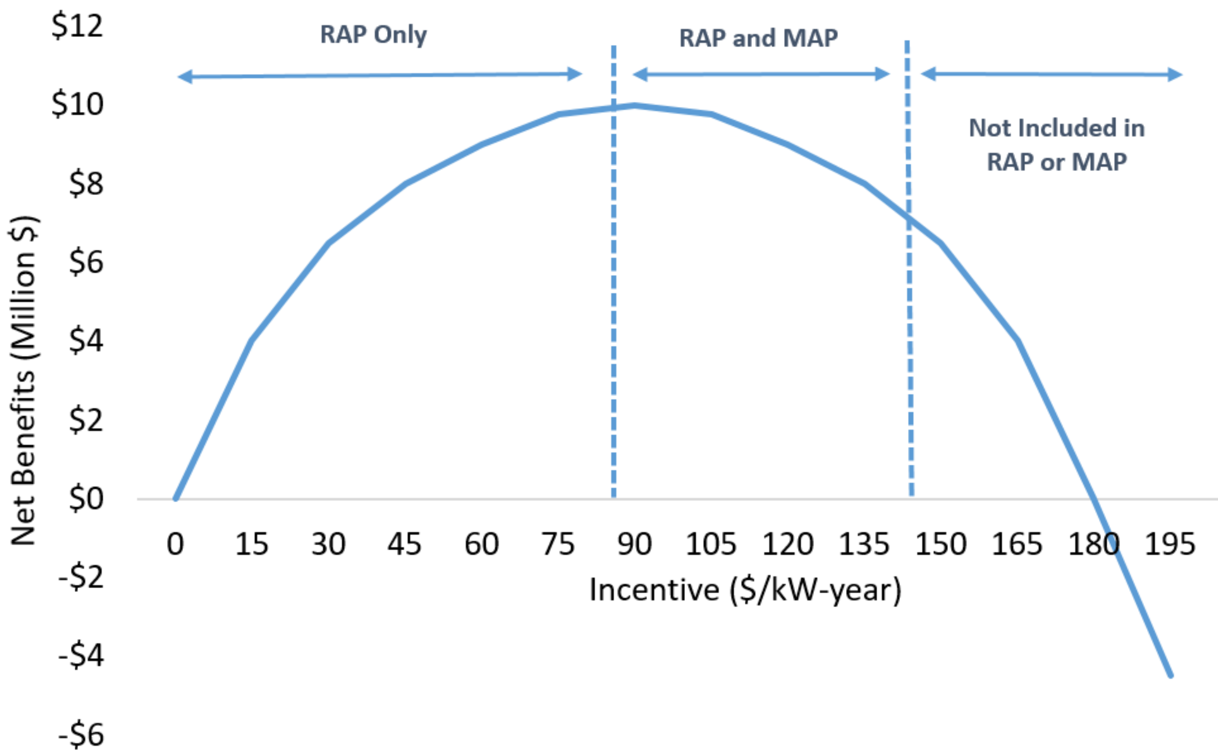
Using the summer elasticity from Table 6-3 (0.00105), a summer peak load contribution of 1,067 MW, a retail rate of $0.17 per kilowatt-hour, and an incentive reservation payment of $85 per kW-year spread across 24 event hours (two summer events, two winter events, one fall event, and one spring event at four hours each), demand response potential would be 23 MW:

$$Demand\ Response\ Potential =\ 0.00105 * \left(\frac{\left(0.17 + \frac{85}{24}\right) - 0.17}{0.17}\right) * 1{,}067 = 23\ MW$$

6.1.1.3 Determination of RAP and MAP Incentive Levels

The primary costs of a business load curtailment program are the customer incentive costs, and program management costs incurred by NIPSCO. As noted above, we calculated estimates of MAP using the highest incentive possible without net benefits dropping below $0, and calculated estimates of RAP using an incentive level that maximizes the net benefits of the program. Figure 28 illustrates the simulation exercise using a simplified example. The highest level of net benefits – the peak of the curve – is associated with an incentive level of approximately $85/kW-year. This incentive level would be used to calculate RAP. The greatest incentive level that maintains positive net benefits – where the curve crosses zero – is $145/kW-year and is the value that would be used to calculate MAP.

FIGURE 28. ILLUSTRATIVE RELATIONSHIP BETWEEN NET BENEFITS AND INCENTIVE LEVEL



The team conducted a simulation for the business sector as a whole and applied the aggregate simulation results. Table 6-4 shows the resulting incentive levels for RAP and MAP from the simulation for select years.

TABLE 6-4: INCENTIVE PAYMENTS BY YEAR

Year	RAP Incentive ($/kW-year)	MAP Incentive ($/kW-year)
2027	$85	$145
2028	$88	$150
2029	$91	$155
2036	$112	$193
2046	$154	$264

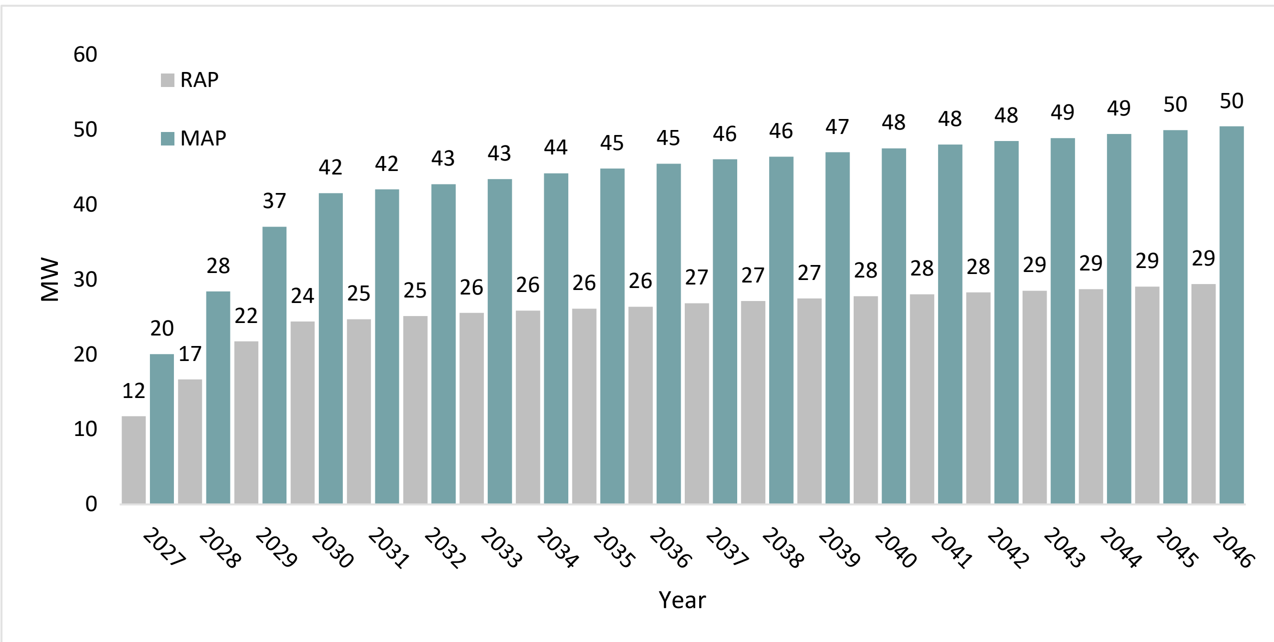
6.1.2 Cost-Effectiveness Results

Table 6-5 summarizes the economic results. Recall that the MAP scenario is designed to set the incentive that maximizes the quantity of demand response while keeping the UCT ratio slightly above 1. The RAP scenario features a lower incentive and therefore a higher UCT ratio, at the expense of less demand response capacity. Figure 29 shows the RAP and MAP trajectory for both sectors over time for the summer season. The total RAP and MAP demand response capacities are 29 and 50 MW in 2046, respectively.

TABLE 6-5: C&I LOAD CURTAILMENT PROGRAM COST-EFFECTIVENESS RESULTS

Parameter	RAP	MAP
PV Lifetime Benefits ($ thousands)	$63,449	$108,456
PV Lifetime Costs ($ thousands)	$36,690	$103,748
UCT Ratio	1.73	1.05
System-level capacity in 2046 (Summer MW)	29	50

FIGURE 29: C&I LOAD CURTAILMENT PROGRAM SUMMER RAP AND MAP POTENTIAL BY YEAR



6.2 DATA CENTERS

The Data Center load curtailment program shares key modeling assumptions and general approach with the C&I load curtailment program. NIPSCO's data center load projection does not vary by season, so the applicable peak load is the same for summer, winter, fall, and spring. Given the limited body of information on utility DR programs for large scale data centers, the study team applied the same price elasticity coefficients derived for existing C&I customers and shown in Table 6-3, to data centers. An average value of 0.001056 was applied to all four seasons. A key difference is that because data center load is assumed to be transmission-connected, we do not consider avoided distribution capacity costs. This leads to slightly lower RAP and MAP incentive levels compared to the C&I load curtailment analysis. The team conducted a simulation for data centers and applied the aggregate simulation results to each subgroup. The resulting incentive levels for RAP and MAP from the simulation for select years are shown in Table 6-6.

TABLE 6-6: DATA CENTER INCENTIVE PAYMENTS BY YEAR

Year	RAP Incentive ($/kW-year)	MAP Incentive ($/kW-year)
2027	$72	$115
2028	$74	$119
2029	$76	$123
2036	$96	$153
2046	$131	$210

FIGURE 30: DATA CENTER LOAD CURTAILMENT PROGRAM RAP AND MAP POTENTIAL BY YEAR