Energy Efficiency Potential in New Jersey

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Prepared for

New Jersey Board of Public Utilities

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EXECUTIVE SUMMARY

New Jersey's Clean Energy Act of 2018 (the Act) specifies that:

> *No later than one year after the date of enactment…, the board shall* ***conduct and complete a study to determine the energy savings targets*** *for full economic, cost-effective potential for electricity usage reduction and natural gas usage reduction as well as the potential for peak demand reduction by the customers of each electric public utility and gas public utility and the timeframe for achieving the reductions.* [Emphasis added.]

The Act also has called on the New Jersey Board of Public Utilities (BPU or Board) to require each electric and natural gas public utility to reduce energy use, and has specified minimums for that reduction within the first five years of implementation. The Act directs that:

> *Each electric public utility shall be required to achieve* ***annual reductions in the use of electricity of two percent*** *of the average annual usage in the prior three years within five years of implementation of its electric energy efficiency program. Each natural gas public utility shall be required to achieve* ***annual reductions in the use of natural gas of 0.75 percent*** *of the average annual usage in the prior three years within five years of implementation of its gas energy efficiency program.* [Emphasis added.]

The Act also directed the BPU to:

> *… adopt quantitative performance indicators…for each electric public utility and gas public utility, which shall establish reasonably achievable targets for energy usage reductions and peak demand reductions…*

The Act specifies that incentives and penalties shall be established and used:

> *If an electric public utility or gas public utility achieves the performance targets established in the quantitative performance indicators, the public utility shall receive an incentive as determined by the board…. The incentive shall scale in a linear fashion….*
>
> *If an electric public utility or gas public utility fails to achieve the reductions in its performance target established in the quantitative performance indicators, the public utility shall be assessed a penalty…. The penalty shall scale in a linear fashion*

The Board contracted with Optimal Energy, Inc., to develop the necessary analyses and provide recommendations.

Energy Efficiency Potential

The analysis estimated the **maximum achievable potential for energy efficiency**, defined as the maximum level of program activity and savings possible, given market barriers to adoption of energy-efficient technologies, with no limits on incentive payments, and including administrative costs necessary to implement programs. The analysis period was ten years, 2020 through 2029.

The analysis estimates the following as maximum achievable potential for 2020-2029:

- **Average annual savings of 2.8 percent for electric, and 1.4 percent for gas**
- **Electric cumulative annual load reduction of 21 percent (16.9 million MWh) in 2029**
- **Additional electric reduction potential of 4.2 million MWh from combined heat and power by 2029**
- **Electric peak load reduction of 20 percent or 4,162 MW in 2029**
- **Gas cumulative annual load reduction of 11 percent or 57,005 BBtu in 2029**
- **Gas peak-day load reduction of 722 BBtu in 2029**

Table ES-1 shows the costs and benefits if the maximum achievable potential is captured. It shows that under this hypothetical scenario, the portfolio of statewide programs would produce net present value benefits for New Jersey of $14 billion. The benefit-cost ratio shows that for every dollar of investment, New Jersey would gain $2.57 in economic benefits. The $8.9 billion of costs does not reflect hypothetical program budgets, but could be substantially higher because it considers all costs to society, not just ratepayer costs.

Table ES-1. Cumulative maximum achievable costs, benefits, and benefit-cost ratio (societal cost test), by sector, 2029

Sector	Costs (million $)	Benefits (million $)	Net benefits (million $)	Benefit cost ratio
Residential	$2,967	$6,601	$3,634	2.22
Commercial & Industrial	$5,936	$16,284	$10,349	2.74
Total	$8,903	$22,885	$13,982	2.57

Savings Targets and Quantitative Performance Indicators

The Act directs that quantitative performance indicators (QPIs) be established for electric and gas energy and peak demand reductions, informed by potential analysis results. Optimal Energy has crafted realistic and achievable five-year targets for electric and gas sales reductions from the results (Table ES-2). We estimate that the maximum achievable potential exceeds these values, but that New Jersey administrators will need time to ramp up to those levels.

Table ES-2. Net electric and gas savings targets, 2020 - 2024

Year	Net savings targets (% of load)	Net annual incremental savings targets (GWh)	Net savings targets (% of load)	Net annual incremental savings targets (BBtus)
2020	0.75%	568	0.25%	1,168
2021	1.10%	833	0.50%	2,335
2022	1.45%	1,100	0.75%	3,511

2023	1.80%	1,369	0.95%	4,473
2024	2.15%	1,645	1.10%	5,226

Performance Incentives and Penalties

The Act requires that incentives and penalties be designed and used, and that each be scaled linearly. The figures illustrate how the performance incentive would work *as if it were simply a single metric.* In actuality, each metric would have its own graph with actual values based on actual metric targets. We recommend the total amount of performance incentive or penalty funds be based on a percentage of the planned and approved program budgets, as shown in the Figure ES-1 and Figure ES-2. It is important to note that this value would be fixed for the entire plan period regardless of actual levels of spending, and that all awards or penalties would be based on actual performance outcomes. We also recommend flexibility to achieve the overall targets during the entire plan period, rather than separately for each year. Optimal Energy recommends the performance incentive structure shown in Figure ES-1.

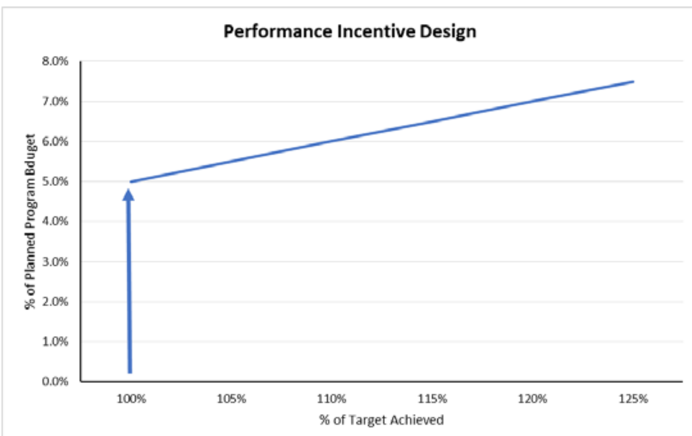

Figure ES-1. Performance incentive design.

The Act also specifies that utilities shall be penalized for performance that does not reach 100% of specified targets, and that penalties also must be scaled linearly. Optimal Energy recommends the penalty structure shown in Figure ES-2.

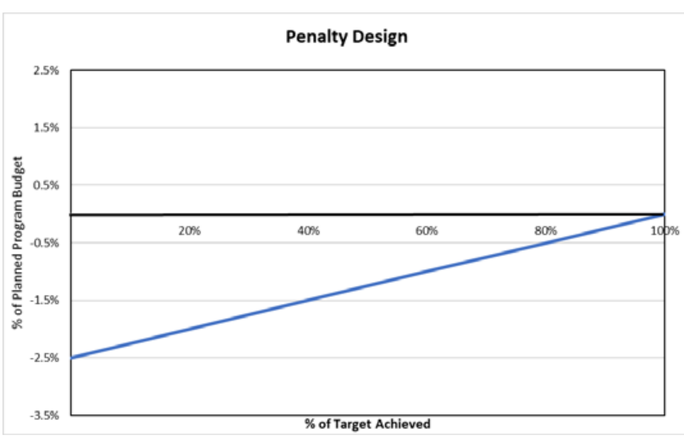

Figure ES-2. Performance penalty design.

The incentive and penalty structures are balanced to provide both upside and downside risks with a net variation of 2.5 percent of planned program budget.

Optimal Energy recommends a weighted set of QPIs be the basis of the performance incentive structure. This is similar in structure to many leading jurisdictions. Multiple PI metrics can help to avoid programs dedicated to a single objective, such as annual energy savings, at the expense of long-term or lifetime savings and other important policy goals of the State.

Metric	Weighting of PI $
Annual energy savings	10%
Annual demand savings	5%
Lifetime energy savings	20%
Lifetime of persisting demand savings	10%
Utility cost test NPV of net benefits	35%
Low-income lifetime savings	7%
Small business lifetime savings	7%
Optional additional metric for key policy objective	6%

Stakeholder Input

The Act directs the BPU to include stakeholders in the process. The Board conducted stakeholder meetings to identify the most important model inputs and results. The meetings and the topics they addressed were:

- February 28, 2019: Data Sources and Key Global Inputs
- March 15, 2019: Measure Characterization / Key Model Inputs
- April 23, 2019: Results of the New Jersey Potential Study
- May 3, 2019: Quantitative Performance Indicators, Performance Incentives

This report draft was provided to stakeholders for comment before the report was finalized.

Conclusion

The ten-year potential analysis supports that the targets provided in the Act are reasonable minimum targets for electric and gas savings. The Board’s decisions about QPIs and performance incentives can set the stage for higher levels of energy efficiency performance in New Jersey over the coming five-year period.

SECTION 1: ENERGY EFFICIENCY POTENTIAL STUDY

STUDY OVERVIEW AND SCOPE

New Jersey's Clean Energy Act of 2018 (the Act) specifies that:

> *No later than one year after the date of enactment of P.L.2018, c.17 (C.48:3-87.8 et al.), the board shall conduct and complete a study to determine the energy savings targets for full economic, cost-effective potential for electricity usage reduction and natural gas usage reduction as well as the potential for peak demand reduction by the customers of each electric public utility and gas public utility and the timeframe for achieving the reductions.*

The Act also called on the New Jersey Board of Public Utilities (BPU or "board") to require each electric and natural gas public utility to reduce energy use, and specified minimums for that reduction within the first five years. The Act directs that:

> *Each electric public utility shall be required to achieve annual reductions in the use of electricity of two percent of the average annual usage in the prior three years within five years of implementation of its electric energy efficiency program. Each natural gas public utility shall be required to achieve annual reductions in the use of natural gas of 0.75 percent of the average annual usage in the prior three years within five years of implementation of its gas energy efficiency program.*

The Act also directed the BPU to:

> *… adopt quantitative performance indicators pursuant to the "Administrative Procedure Act," P.L.1968, c.410 (C.52:14B-1 et seq.) for each electric public utility and gas public utility, which shall establish reasonably achievable targets for energy usage reductions and peak demand reductions ...*

Subsequent to the Act, the BPU issued a Request for Quotation on November 1, 2018, and entered into contract with Optimal Energy, Inc., on January 24, 2019, to perform the potential study, complete a literature review, and make recommendations about quantitative performance indicators and performance incentives. The study involved four stakeholder meetings to obtain comment on methods and results.

This document provides the information that the Act called for, to inform the BPU's establishment of spending and savings targets for future years. The study looked at savings opportunities from electric and gas energy efficiency and electric demand response, over a ten-year horizon. In the results, we develop a single set of multi-fuel potential scenarios. Often, maximum results are most readily achievable when electric and gas programs operate together to provide services in a one-stop shop manner, avoiding the potential for ballooning costs with duplicative marketing, outreach, energy auditing, etc. Our assumption in maximum achievable scenario modeling is that any of those potential program barriers are removed and efficiency programs are providing all cost-effective services in a coordinated and integrated way.

Therefore, although we present results for each separate utility by fuel, the maximum achievable scenarios assume effective delivery of dual-fuel services, where appropriate.

This study evaluated energy efficiency potential for two separate scenarios for efficiency:

- **Economic electric and gas efficiency.** Everything that is cost effective and technically feasible, assuming no market barriers and 100 percent adoption of all efficiency opportunities. A measure is considered to be cost-effective if the net present value (NPV) of the benefits over its effective useful life is equal to or greater than the NPV of the measure cost, based on a societal cost test (SCT), as defined in the most recent avoided cost assumptions estimated by the Rutgers Center for Green Building.[1]
- **Maximum achievable electric and gas efficiency.** The maximum level of program activity and savings that is possible, given the market barriers to adoption of energy-efficient technologies, with no limits on incentive payments, but including administrative costs necessary to implement programs.

Additionally, the study examines electric demand response (DR), which uses a slightly different scenario definition from that used in the efficiency portions, as well as different methods and data sources. DR results are not included in the base efficiency potential, and a separate section provides the methods, data, and results for DR. Additionally, while still an efficiency measure, we have analyzed combined heat and power (CHP) separately from all other efficiency, and provide its methods, data sources, and results in a separate section. We have kept CHP as a stand-alone analysis, because the cost-effective achievable potential for CHP is quite large. However, it is difficult to consider for setting savings targets, because it can come from a few very large systems that cannot be assumed to be captured in any given program year.

SUMMARY OF STUDY PROCESS AND TIMELINE

The study began in late January, and involved a kick-off meeting on January 25, 2019. That meeting involved staff of the New Jersey Board of Public Utilities and Optimal Energy. The parties agreed to key dates for deliverables, and to a schedule of weekly project meetings and monthly progress reports.

The kick-off meeting also contained discussion of potential data sources, methods for outreach to utilities, a provisional schedule, and the stakeholder engagement process. Optimal

[1] Rutgers University Center for Green Building, "Energy Efficiency Cost Benefit Analysis Avoided Cost Assumption: Technical Memo," May 1, 2019, Update. Rutgers University Center for Green Building, "Cost-Benefit Analysis of the NJCEP Energy Efficiency Programs: FY2017 Retrospective and FY2019 Summary Reports with Avoided Costs Commentary," May 2019. Note the one divergence from the existing cost-effectiveness approach defined by the Rutgers assumptions, is the inclusion of transmission and distribution (T&D) capacity costs. Because the Act requires peak demand targets for gas, which have not previously existed in New Jersey, avoided capacity costs had not previously been developed.

had created a draft of the issues for stakeholder engagement, and target dates for holding each session. The topics and schedule tied closely to the need for critical input and feedback. Four topical stakeholder meetings resulted:

February 28, 2019: Data Sources and Key Global Inputs

March 15, 2019: Measure Characterization / Key Model Inputs

April 23, 2019: Results of the New Jersey Potential Study

May 3, 2019: Quantitative Performance Indicators, Performance Incentives

A draft of the Literature and Information Review was delivered on March 25, 2019; a revised draft is contained in this report as Section 2.

Weekly check-ins between the BPU and Optimal ensured that the project tracked to necessary deliverables. Each meeting was documented by Optimal with notes. Other than confirming stakeholder meetings, which had not been scheduled until after the kick-off meeting, there were no significant changes to the project timeline.

ENERGY EFFICIENCY POTENTIAL

This high-level overview of the efficiency potential results also offers a review of methods and data sources. It concludes with detailed results from our analysis of the energy efficiency potential.

High-Level Results of Efficiency Potential

Table 1 and Table 2 show total cumulative potential at the end of the 10-year period for both the economic and maximum achievable scenarios, by sector and total. Overall, we find substantial efficiency potential for both electric and natural gas energy reductions and for demand.

For electric energy, if the entire potential were to be captured, the baseline forecasted energy use would drop by 34 percent for the economic scenario, and 21 percent for the maximum achievable scenario. Similarly for gas, these figures would respectively be 17 percent and 11 percent. Note that these 2029 cumulative figures are less than the sum of the annual incremental potential for each year, because some measures have lives shorter than 10 years, and those savings will drop off during the study period.

For the maximum achievable potential scenario, we assume well-designed and aggressively marketed and delivered programs to target all significant market segments. We further assume there is a consistent set of efficiency programs that address both electricity and gas. We believe New Jersey would not succeed in capturing all cost-effective achievable potential without an approach that sends consistent messages to the entire state market, and ensures good customer service and comprehensiveness by addressing both fuels. There were not sufficient forecast data at the sector level to be able to estimate with any level of confidence the percent of load that would be represented by each sector for the estimated MW and peak gas load reductions in 2029.

Table 1. Electric cumulative potential, 2020 - 2029

Year	Scenario	Res savings (MWh)	Res savings (% of sales)	C&I savings (MWh)	C&I savings (% of sales)	Total savings (MWh)	Total savings (% of sales)
Cumulative energy, 2029	Economic Potential	7,575,463	23%	20,069,796	42%	27,645,258	34%
	Max Achievable Potential	4,110,030	13%	12,749,878	27%	16,859,908	21%
		(MW)	**(% of load)**	**(MW)**	**(% of load)**	**(MW)**	**(% of load)**
Cumulative peak demand reduction, 2029	Economic Potential	2,798	Not Available	4,100	Not Available	6,898	33%
	Max Achievable Potential	1,650	Not Available	2,512	Not Available	4,162	20%

Table 2. Gas cumulative potential, 2020 - 2029[2]

Year	Scenario	Res savings (BBtu)	Res savings (% of sales)	C&I savings (BBtu)	C&I savings (% of sales)	Total savings (BBtu)	Total savings (% of sales)
Cumulative energy, 2029	Economic Potential	25,161	9%	59,483	26%	84,644	17%
	Max Achievable Potential	21,264	8%	35,741	16%	57,005	11%
		(Peak BBtu)	**(% of load)**	**(Peak BBtu)**	**(% of load)**	**(Peak BBtu)**	**(% of load)**
Cumulative peak demand reduction, 2029	Economic Potential	318	Not available	753	Not available	1,071	Not available
	Max Achievable	269	Not available	452	Not available	722	Not available

[2]The gas potential figures are the net total impacts, and include a small amount of negative gas savings resulting from some electric efficiency measures (such as interior lighting and waste heat impacts). Assuming gas utilities would not count these negative savings toward their savings goals, the full efficiency potential they can count would be higher by 2,417 BBtu (0.5 percent of load). The average annual incremental negative impacts total 0.1 percent of load each year. Combined heat and power, which has much larger negative gas impacts, is kept completely separate and reported only in the CHP section.

Year	Scenario	Res savings (BBtu)	Res savings (% of sales)	C&I savings (BBtu)	C&I savings (% of sales)	Total savings (BBtu)	Total savings (% of sales)
	Potential						

Table 3 shows the economic costs and benefits that would benefit the New Jersey economy and all utility customers if the maximum achievable potential is captured. It shows that under this hypothetical scenario, the entire portfolio of statewide programs would produce net present value benefits for New Jersey of $14 billion. The benefit-cost ratio would be 2.57. In other words, for every dollar of investment in efficiency, New Jersey would gain $2.57 in benefits. It is important to note the $8.9 billion of costs does not reflect hypothetical program budgets, but is substantially higher, because it considers all costs to society, not just ratepayer costs.

These numbers are based on the SCT, the use of which is implied by the Clean Energy Act of 2018. All assumptions are consistent with the latest draft of the Rutgers Energy Efficiency Benefit-Cost Analysis Avoided Cost Assumptions. In brief, the societal benefits include the avoided-cost benefits that derive from not using the electricity and gas saved, as well as a societal value of carbon reductions derived from the carbon savings.[3] The benefits also include all other readily quantifiable benefits associated with the measures—including savings in operations and maintenance (O&M) costs and unregulated fossil fuel and water avoided-cost benefits.[4] More details on the cost-effectiveness screening are provided in the discussion of methods.

Table 3. Cumulative maximum achievable costs, benefits, and benefit cost ratio (societal cost test), 2029

Sector / program	Costs (million $)	Benefits (million $)	Net benefits (million $)	Benefit cost ratio
Residential	$2,967	$6,601	$3,634	2.22
New Construction	$273	$546	$273	2.00
Equipment Replacement	$1,820	$3,793	$1,972	2.08
Retrofit	$874	$2,262	$1,389	2.59
Commercial & Industrial	$5,936	$16,284	$10,349	2.74
New Construction	$622	$1,699	$1,077	2.73
Equipment Replacement	$1,476	$4,333	$2,856	2.93

[3] Rutgers University Center for Green Building, "Energy Efficiency Cost Benefit Analysis Avoided Cost Assumption: Technical Memo," January 29, 2019, Update.

[4] As examples: When LED lighting is installed, light bulbs need to be replaced much less frequently. There is a maintenance cost savings for many commercial and industrial facilities. A faucet aerator will reduce the flow of water and therefore the energy costs related to hot water, and will have additional benefit in reducing volumetric charges for water and sewer.

Sector / program	Costs (million $)	Benefits (million $)	Net benefits (million $)	Benefit cost ratio
Retrofit	$3,837	$10,252	$6,415	2.67
Total	$8,903	$22,885	$13,982	2.57

Figure 1 and Figure 2 provide a graphic representation of the respective baseline forecasts for electricity and gas, the cumulative savings by year for each potential scenario, and the resulting forecast if all potential were captured. Percent of load for peak demand savings for the entire system can be estimated, but sector-level peak-demand forecasts were not available.

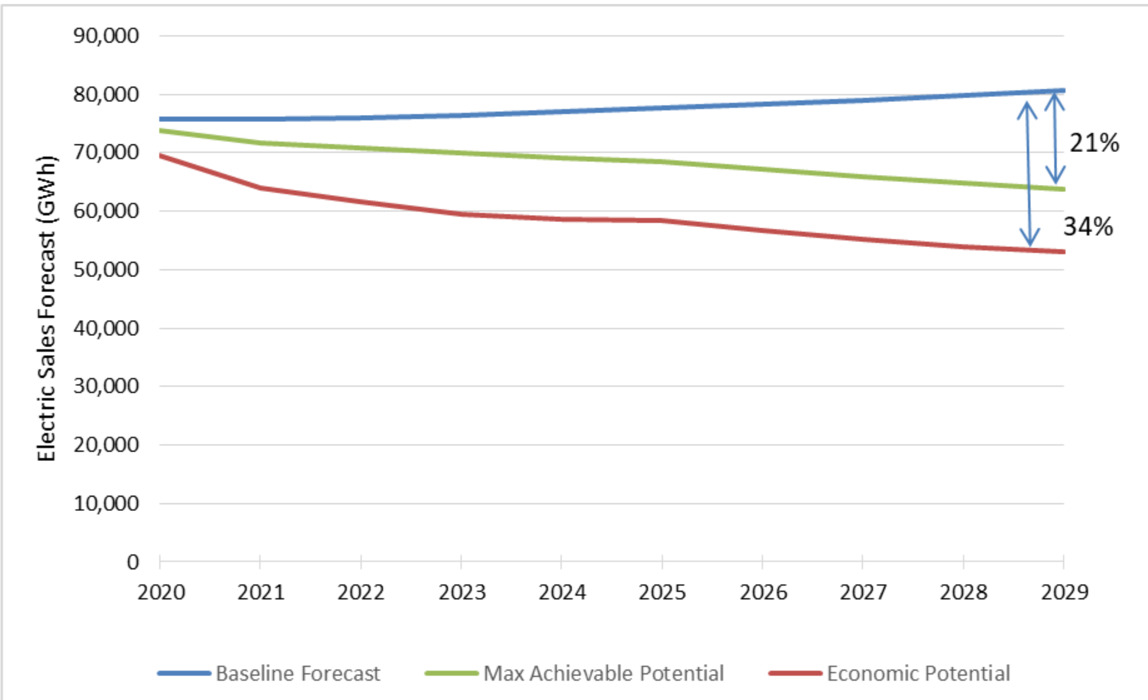

Figure 1. Baseline, economic potential, and maximum achievable potential for electric efficiency, 2020 – 2029.

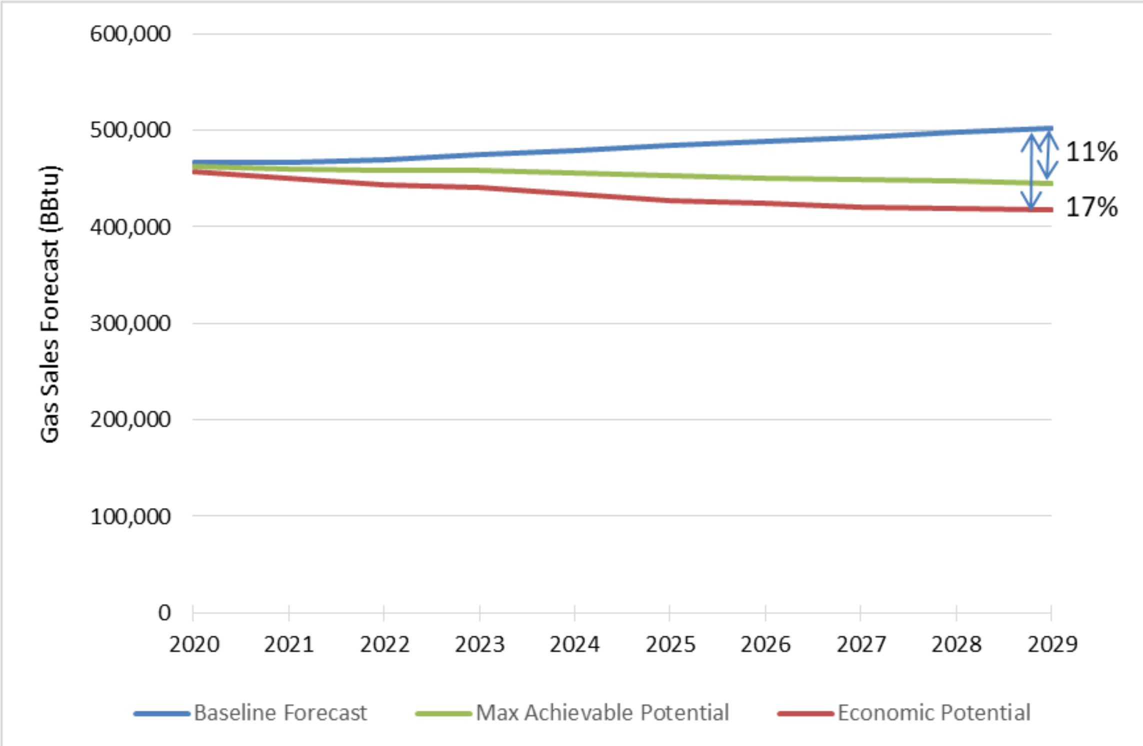

Figure 2. Baseline, economic potential, and maximum achievable potential for natural gas, 2020 – 2029.

Table 4 and Table 5 show the electric and gas annual incremental energy savings potential by scenario and sector, as a percent of the baseline forecasted load.[5] The average annual incremental savings for maximum achievable is 2.8 percent of load for electricity and 1.4 percent of load for gas. As can be seen, we estimate that all cost-effective achievable potential well exceeds the minimum efficiency targets set in the Act.

The estimated potential is dependent on many factors, some of which can drive it up in a given year and others which may drive it down. There are many factors built into the analysis, such as technology adoption curves and changes in codes and standards. As an example of the latter, both the economic and maximum achievable potential for electric efficiency have lower values in 2022 than in 2021. This is at least partially due to the effects of changes in lighting standards as a result of the Energy Independence and Security Act (EISA). After that change, estimated levels of reduction then generally rise again as penetration rates of more complex measures increase as the efficiency market matures.

Table 4. Economic and maximum achievable percent of forecast potential for electric efficiency, 2020 - 2029

[5] Note that each year's potential is shown as a percentage of the baseline forecast for that same year. These percentages will differ slightly than the reduction targets defined in the Act, which provides a minimum percentage based on the average of the prior three years of actual loads.

	Economic Potential			Max Achievable Potential		
Year	Total	Res	C&I	Total	Res	C&I
2020	8.2%	10.1%	6.8%	2.5%	3.1%	2.1%
2021	7.8%	9.9%	6.4%	3.1%	3.8%	2.7%
2022	4.9%	4.6%	5.0%	2.2%	2.0%	2.4%
2023	4.7%	4.5%	4.8%	2.5%	2.2%	2.7%
2024	4.6%	4.4%	4.7%	2.8%	2.4%	3.0%
2025	4.4%	4.3%	4.5%	2.9%	2.5%	3.2%
2026	4.3%	4.2%	4.3%	2.9%	2.5%	3.2%
2027	4.2%	4.2%	4.3%	3.0%	2.5%	3.4%
2028	4.2%	4.1%	4.3%	3.1%	2.5%	3.5%
2029	4.2%	4.1%	4.3%	3.1%	2.4%	3.5%
Average	**5.2%**	**5.4%**	**5.0%**	**2.8%**	**2.6%**	**3.0%**

Table 5. Economic and maximum achievable percent of forecast potential for gas efficiency, 2020 – 2029

	Economic Potential			Max Achievable Potential		
Year	Total	Res	C&I	Total	Res	C&I
2020	2.1%	1.2%	3.2%	0.8%	0.7%	1.0%
2021	2.0%	1.0%	3.1%	0.9%	0.7%	1.2%
2022	2.4%	2.0%	3.0%	1.3%	1.2%	1.4%
2023	2.4%	1.9%	2.9%	1.4%	1.3%	1.6%
2024	2.3%	1.8%	2.8%	1.6%	1.4%	1.8%
2025	2.2%	1.7%	2.7%	1.6%	1.4%	1.8%
2026	2.1%	1.7%	2.6%	1.6%	1.4%	1.9%
2027	2.0%	1.6%	2.5%	1.6%	1.4%	1.9%
2028	2.0%	1.5%	2.5%	1.7%	1.4%	1.9%
2029	1.9%	1.5%	2.4%	1.7%	1.5%	1.9%
Average	**2.1%**	**1.6%**	**2.8%**	**1.4%**	**1.2%**	**1.6%**

Detailed Results: Maximum Achievable Efficiency Potential

This subsection offers detailed efficiency potential results for the maximum achievable scenario only. Economic potential is a hypothetical upper bound of all the cost-effective efficiency opportunities, but is not fully achievable, even with programs paying 100 percent of the costs of all efficiency measures. This is because consumers face many market barriers to efficiency.[6] Therefore, we offer achievable results that more closely inform ultimate savings targets (QPIs).

[6] An excellent overview of market barriers to energy efficiency is Vaidyanathan, S., S. Nadel, J. Amann, C. Bell, A. Chittum, K. Farley, S. Hayes, M. Vigen, and R. Young, "Overcoming Market Barriers and Using Market Forces to Advance Energy Efficiency," ACEEE Report E136, March 2013.

Table 6 and Table 7 show the cumulative electric and gas potential in 2029. For electric, we estimate a total reduction of 21 percent of the forecasted 2029 load is achievable by Year 10 for energy and a reduction of 20 percent for demand. This translates to a reduction of load in 2029 of 16.9 million MWh and 4,162 MW. For gas, we estimate a total reduction of 57,005 billion Btu (BBtu), or 11 percent of 2029 load, and peak day reductions of 722 billion Btu (BBtu).[7]

Table 6. Cumulative maximum achievable electric savings by sector and program, 2029

Sector / program	Electric energy 2029 (MWh)	Sector savings (% of 2029 sales)	Electric demand 2029 (MW)	Sector savings (% of 2029 demand)
Residential	**4,110,030**	13%	**1,650**	Not available
New Construction	281,688		143	
Equipment Replacement	2,179,717		1,285	
Retrofit	1,648,624		222	
Commercial & Industrial	**12,749,878**	27%	**2,512**	Not available
New Construction	1,304,453		264	
Equipment Replacement	2,882,672		660	
Retrofit	8,562,753		1,589	
Total	**16,859,908**	21%	**4,162**	20%

Table 7. Cumulative maximum achievable gas savings by sector and program, 2029

Sector / program	Gas energy 2029 (BBtu)	Sector savings (% of 2029 sales)	Gas demand 2029 (BBtu)	Sector savings (% of 2029 demand)
Residential	**21,264**	8%	**269**	Not available
New Construction	2,074		26	
Equipment Replacement	10,271		130	
Retrofit	8,919		113	
Commercial & Industrial	**35,741**	16%	**452**	Not available
New Construction	3,633		46	
Equipment Replacement	11,030		140	
Retrofit	21,079		267	
Total	**57,005**	11%	**722**	Not available

Table 6 and Table 7 also break out the 2029 maximum achievable potential by sector and by major market. Every technology included in the study is analyzed for every applicable permutation of customer segment and market, resulting in over 4,000 individual efficiency measures. We break out the markets into new construction, equipment replacement (which includes renovations and remodels), and retrofit (early retirement). It is essential to consider

[7] We do not report gas peak day demand savings as a percentage because we were not able to collect all the utility peak day forecasts.

markets separately because the same technology will not save or cost the same as the identical technology in a different market.

For example, if one is replacing a failed furnace, the costs will reflect the *incremental* cost of a new, high-efficiency furnace compared to a standard baseline new furnace, and similarly the savings will also reflect only the incremental savings from the baseline efficiency to the high efficiency. When replacing a still-functioning piece of equipment with a high-efficiency one, on the other hand, the cost is much higher and reflects the *entire cost of new equipment and labor.* But then that cost is also offset at some point in the future with additional benefits from the present value of the long-term or permanent deferral of new capital investment cycles. Similarly, the savings from an early retirement (retrofit) measure initially reflects the full savings of the new high-efficiency equipment compared to the old, inefficient piece of equipment. It will then drop down to a level based on the differential between the high efficiency and new standard baseline for efficient equipment at the end of the existing equipment's remaining useful life. More complete definitions of each market category are provided in the Methods section.

Similar to many other jurisdictions, the retrofit category represents the largest share of potential savings, at about 55 to 70 percent of the total for each fuel in the C&I sector. In the residential sector, approximately 40 percent of savings are expected from retrofit. Also, as one would expect, new construction is fairly small for both sectors, at about 10 percent, reflecting the fact that the rate of growth of new square feet is around 1 percent per year.

Table 8 and Table 9 provide the incremental annual and cumulative potential by year, separately for each fuel and sector.

Table 8. Incremental annual maximum achievable savings by fuel and sector

	Residential				Commercial & Industrial				Total			
Year	Electric (GWh)	Electric savings (% sector sales)	Natural gas (BBtu)	Gas savings (% sector sales)	Electric (GWh)	Electric savings (% sector sales)	Natural gas (BBtu)	Gas savings (% sector sales)	Electric (GWh)	Electric savings (% sector sales)	Natural gas (BBtu)	Gas savings (% sector sales)
2020	947	3.1%	1,821	0.7%	935	2.1%	2,130	1.0%	1,883	2.5%	3,951	0.8%
2021	1,167	3.8%	1,722	0.7%	1,204	2.7%	2,581	1.2%	2,371	3.1%	4,304	0.9%
2022	600	2.0%	3,009	1.2%	1,090	2.4%	3,092	1.4%	1,690	2.2%	6,101	1.3%
2023	685	2.2%	3,280	1.3%	1,234	2.7%	3,548	1.6%	1,919	2.5%	6,828	1.4%
2024	761	2.4%	3,592	1.4%	1,378	3.0%	3,944	1.8%	2,139	2.8%	7,536	1.6%
2025	794	2.5%	3,684	1.4%	1,460	3.2%	4,093	1.8%	2,254	2.9%	7,777	1.6%
2026	786	2.5%	3,761	1.4%	1,507	3.2%	4,187	1.9%	2,294	2.9%	7,949	1.6%
2027	790	2.5%	3,838	1.4%	1,590	3.4%	4,284	1.9%	2,380	3.0%	8,122	1.6%
2028	794	2.5%	3,899	1.4%	1,641	3.5%	4,379	1.9%	2,436	3.1%	8,279	1.7%
2029	782	2.4%	3,953	1.5%	1,698	3.5%	4,455	1.9%	2,481	3.1%	8,408	1.7%

Table 9. Cumulative annual maximum achievable savings by fuel and sector

	Residential				Commercial & Industrial				Total			
Year	**Electric (GWh)**	**Electric Savings (% Sector Sales)**	**Natural Gas (BBtu)**	**Gas Savings (% Sector Sales)**	**Electric (GWh)**	**Electric savings (% sector sales)**	**Natural gas (BBtu)**	**Gas savings (% sector sales)**	**Electric (GWh)**	**Electric savings (% sector sales)**	**Natural gas (BBtu)**	**Gas savings (% sector sales)**
2020	947	3.1%	1,821	0.7%	935	2.1%	2,130	1.0%	1,883	2.5%	3,951	0.8%
2021	1,834	6.0%	2,152	0.9%	2,140	4.7%	4,712	2.2%	3,973	5.2%	6,864	1.5%
2022	2,152	7.0%	3,758	1.5%	3,012	6.6%	7,811	3.6%	5,164	6.8%	11,569	2.5%
2023	2,555	8.3%	5,620	2.2%	3,939	8.6%	11,363	5.1%	6,494	8.5%	16,983	3.6%
2024	2,541	8.2%	8,562	3.3%	5,316	11.6%	15,301	6.9%	7,857	10.2%	23,863	5.0%
2025	2,376	7.6%	11,841	4.6%	6,764	14.6%	19,386	8.7%	9,140	11.8%	31,228	6.4%
2026	2,828	8.9%	14,122	5.4%	8,237	17.7%	23,491	10.4%	11,065	14.1%	37,613	7.7%
2027	3,273	10.2%	16,462	6.2%	9,772	20.8%	27,626	12.2%	13,044	16.5%	44,088	8.9%
2028	3,705	11.5%	18,845	7.0%	11,247	23.7%	31,686	13.8%	14,953	18.7%	50,531	10.1%
2029	4,110	12.6%	21,264	7.8%	12,750	26.6%	35,741	15.5%	16,860	20.9%	57,005	11.3%

Below we provide additional details of the potential results showing how they break out by customer segment and end use. Finally, the section on utility allocations shows many of the same tables separately for every electric and gas utility. Appendices A through G provide the most granular measure level details, as well as various data inputs.[8]

Efficiency Potential by Building Type

The following charts show how each total sector potential breaks out by commercial and residential building. The section on methods provides more detail on segment definitions. The analysis was, by request and design, a ten-year potential analysis, encompassing the years from 2020 through 2029, inclusively. All results are therefore shown as of the close of that ten-year analysis period.

Over 90 percent of the residential potential from electric and gas comes from single-family homes, with about 25 percent of that coming from low-income single-family homes for each of electric and gas, as shown in Figure 3 and Figure 4.

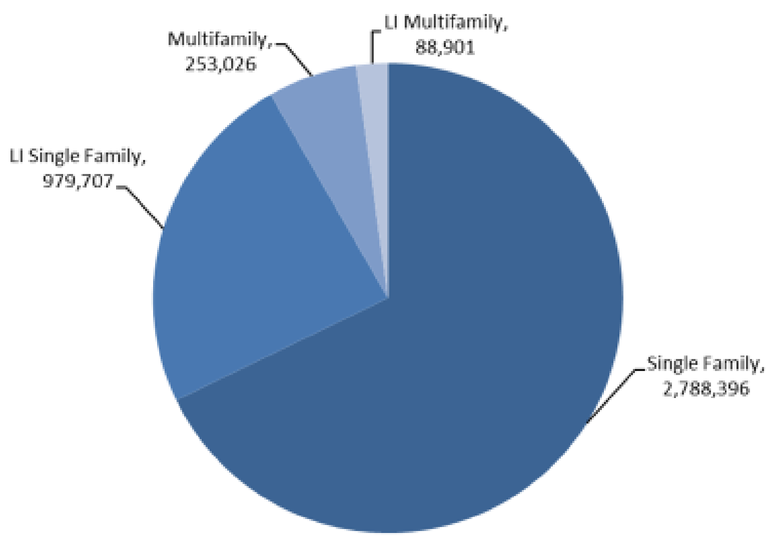

Figure 3. Residential electric maximum achievable potential savings by building type, 2029 (MWh).

[8] Technical appendices will be available as part of the final report.

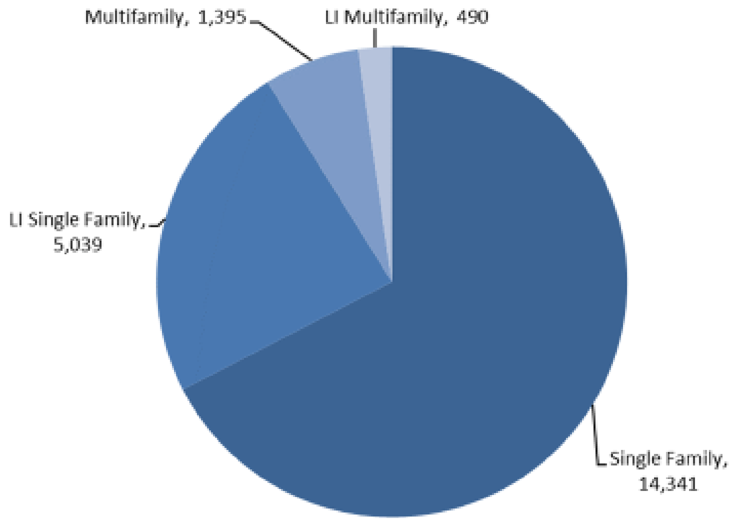

Figure 4. Residential natural gas maximum achievable potential savings by building type, 2029 (BBtu).

The commercial sector electric breakout shows the largest opportunities in large office and large retail, with substantial opportunities in education, food service and grocery. For gas, these relationships shift and small retail and education become the largest opportunities. See Figure 5 and Figure 6.

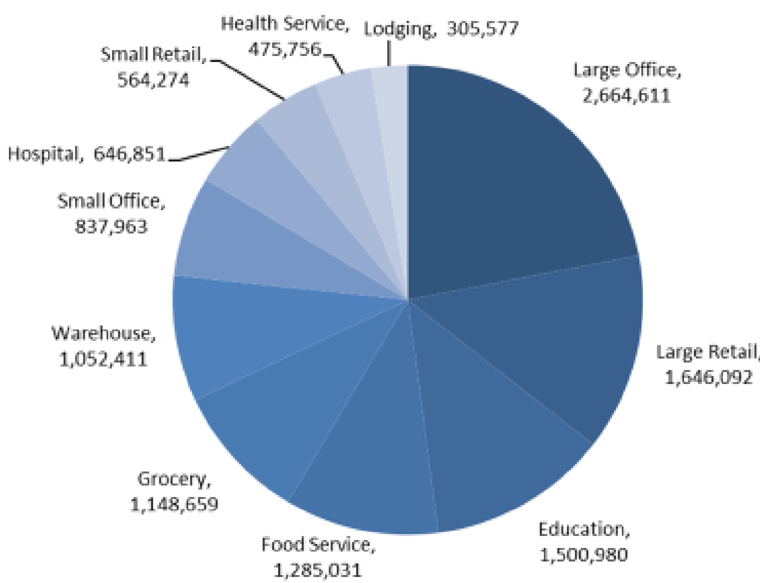

Figure 5. Commercial electric maximum achievable potential savings by building type, 2029 (MWh).

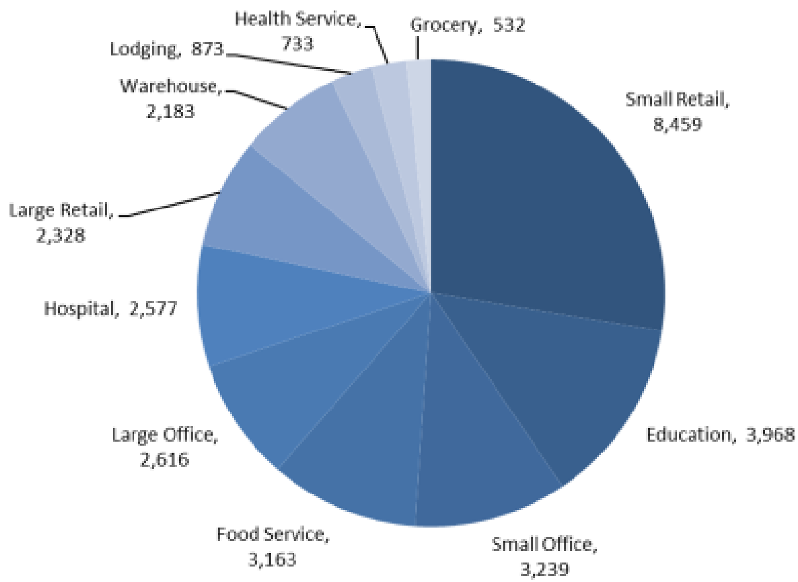

Figure 6. Commercial natural gas maximum achievable potential savings by building type, 2029 (BBtu).

Efficiency Potential by End Use

Similar to the customer segment breakout, we provide the breakout for each sector by major end use category, as shown in Figure 7 and Figure 8. For residential electric, the largest opportunities are in domestic hot water, and cooling. Heat pump water heaters can provide large water-heating savings. Gas shows virtually all savings coming from space and water heating, as is typical. Note that we have end use categories called *whole building*. These reflect measures that address multiple end use savings that we are not able to break out, such as home energy reports, retro-commissioning and strategic energy management. (See section on methods for description of how the potential interactive effects of measures are handled.)

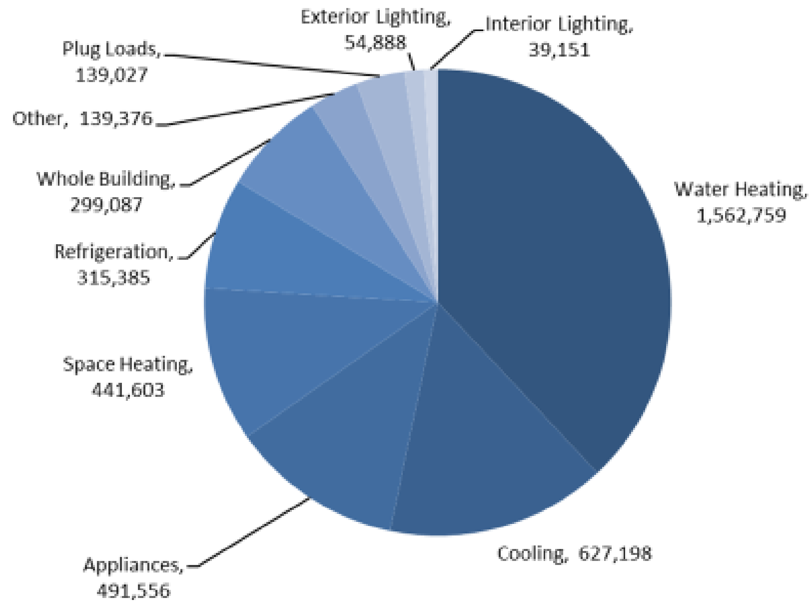

Figure 7. Residential electric maximum achievable potential savings by end use, 2029 (MWh).

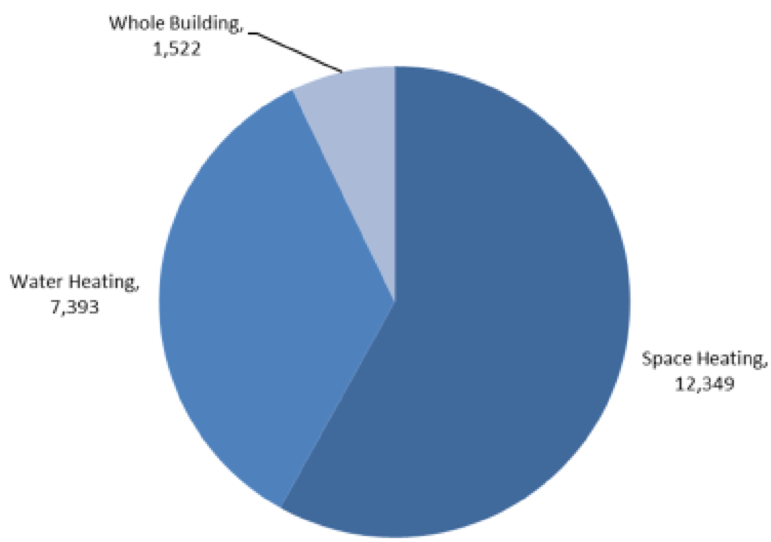

Figure 8. Residential natural gas maximum achievable potential savings by end use, 2029 (BBtu).

For commercial, we find the largest electric opportunities in interior lighting, whole building, and refrigeration, with substantial opportunities in ventilation and cooling. For gas, space heating and whole building dominate, because water heating is not a major end use for many commercial buildings. Cooking equipment does provide some significant opportunities as well. See Figure 9 and Figure 10. The *whole building* category includes multiple measures for which we cannot with certainty estimate the contribution of each measure, such as "integrated building design" in new construction.

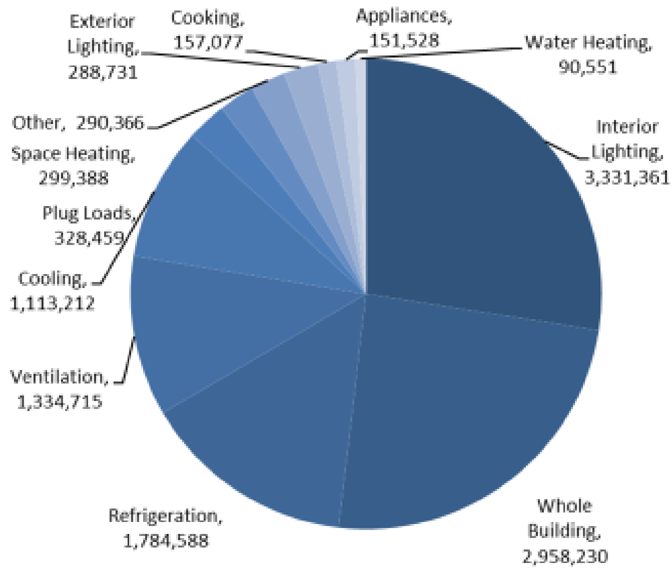

Figure 9. Commercial electric maximum achievable potential savings by end use, 2029 (MWh).

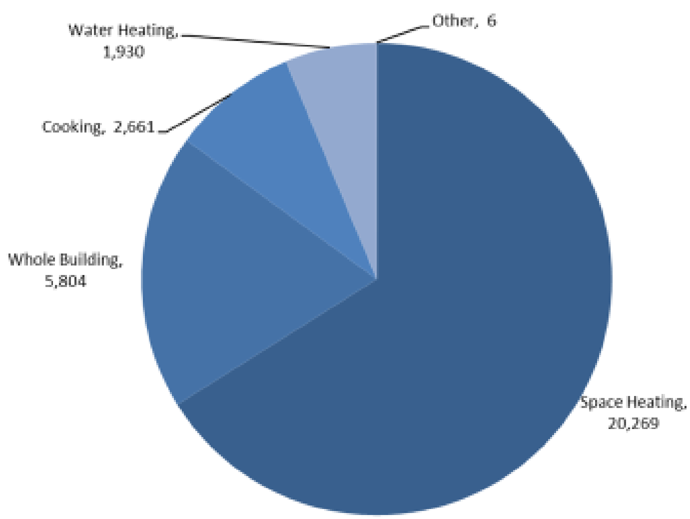

Figure 10. Commercial natural gas maximum achievable potential savings by end use, 2029 (BBtu).

For the industrial sector, the majority of savings comes from process measures, which we break out into many categories. Process loads related to motor systems dominate the process opportunities. Interior lighting is still a significant source of savings as well. For gas, the majority is process heating, but there are still substantial space heating opportunities. See Figure 11 and Figure 12.

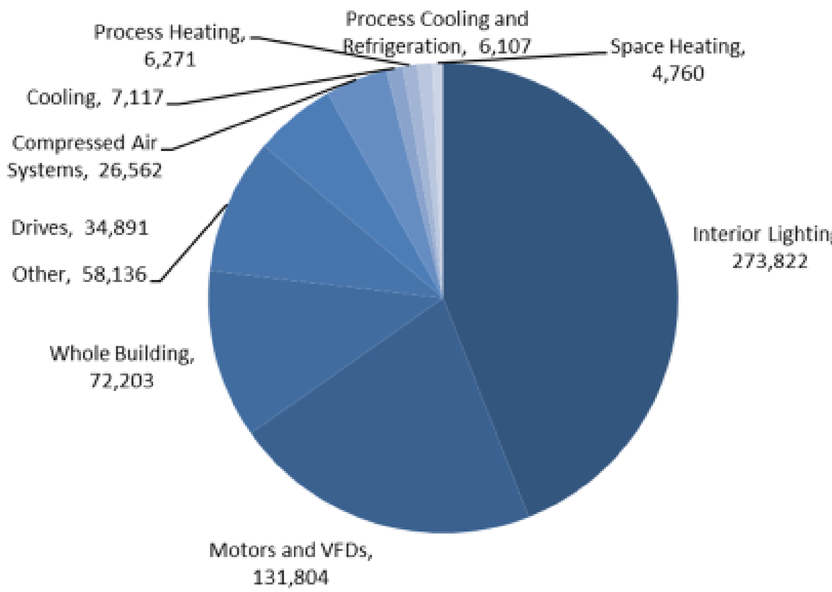

Figure 11. Industrial electric maximum achievable potential savings by end use, 2029 (MWh).

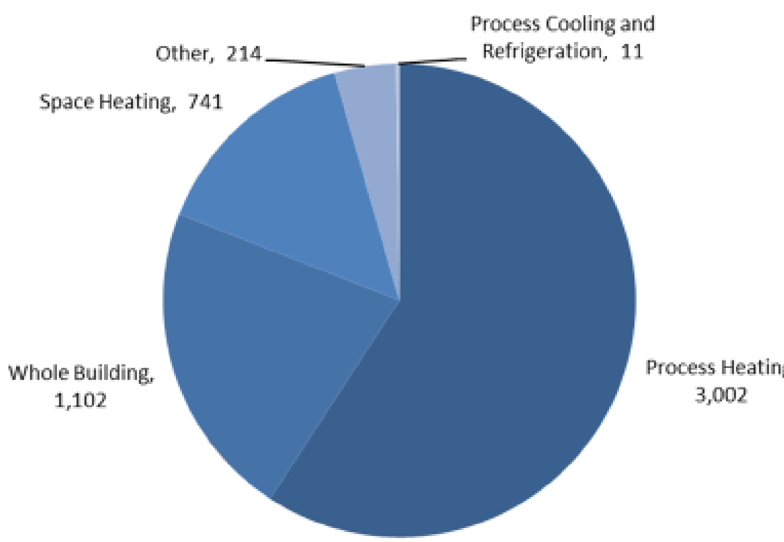

Figure 12. Industrial natural gas maximum achievable potential savings by end use, 2029 (BBtu).

Top Savings Measures

Table 10 through Table 15 show the top 10 highest savings measures in each category, and what share of the total potential in that category they represent. It is important to note that although they give readers an idea of the types of measures that result in large savings, there is a somewhat arbitrary nature to the exact measures that appear on this list, and the order in which they are presented. This is because the sum of individual measure savings far exceeds the total efficiency potential of those measures, collectively. As is explained in more detail in the Methods section, there are many interactions between measures, and there are also sets of mutually exclusive measures. Therefore, the order in which the measures are prioritized significantly influences and reduces the savings to subsequent measures. Different rankings of measures or varying penetration rates shared between mutually exclusive measures (for example, an LED or a CFL screw-in application for a particular socket) can shift which savings make it to the top 10.

Table 10. Residential maximum achievable potential electric energy top savings measures, 2029

Measure name	Cumulative MWh	Percent of total
Heat Pump Water Heater <55 gallon, Gas Space Heat	493,628	12.0%
Heat Pump Water Heater <55 gallon, Electric Space Heat	449,331	10.9%
Home Energy Reports	299,087	7.3%
ENERGY STAR Refrigerators and Freezers	258,462	6.3%
Low Flow Showerhead	231,089	5.6%
ENERGY STAR Clothes Washer, Gas DHW/Electric Dryer	215,619	5.2%
Air Source Heat Pump, Repl. Electric Heat and CAC	174,693	4.3%
Water Heater Jacket Insulation	174,002	4.2%
Smart Thermostat	168,856	4.1%
Advanced Tier 2 Power Strips	139,027	3.4%

Table 11. Residential maximum achievable potential electric summer peak demand top savings measures, 2029

Measure name	Cumulative MW	Percent of total
ENERGY STAR Clothes Washer, Gas Domestic Hot Water / Electric Dryer	275.9	6.6%
ENERGY STAR Room Air Conditioner	264.5	6.4%
ENERGY STAR Clothes Washer, Electric Domestic Hot Water / Electric Dryer - Appliances	172.9	4.2%
ENERGY STAR Dehumidifier	134.7	3.2%
Air Source Heat Pump, Replace Electric Heat and Central Air Conditioning - Cooling	133.8	3.2%
Air Source Heat Pump, Replace Standard ASHP - Cooling	90.2	2.2%
Air Source Heat Pump with Quality Install, Replace Standard ASHP – Cooling	73.8	1.8%
ENERGY STAR Clothes Washer, Electric Domestic Hot Water / Electric Dryer – DHW	58.8	1.4%
Air Source Heat Pump with Quality Install, Replace Electric Heat and Central Air Conditioning – Cooling	58.3	1.4%
Ductless Mini Split Heat Pump	43.3	1.0%

Table 12. Residential maximum achievable potential gas energy top savings measures, 2029

Measure name	Cumulative BBtu	Percent of Total
High Efficiency Furnace	5,384	25.3%
High Efficiency Storage Gas Water Heater	4,273	20.1%
Smart Thermostat	4,257	20.0%
High Efficiency Boiler	2,782	13.1%
Low Flow Showerhead, Single Family	1,864	8.8%
Home Energy Reports	1,522	7.2%
Low Flow Showerhead, Multifamily	547	2.6%
High Efficiency Furnace	469	2.2%
Electronic Ignition Hearth	389	1.8%
High Efficiency Boiler	289	1.4%

Table 13. C&I maximum achievable potential electric energy top savings measures, 2029

Measure name	Cumulative MWh	Percent of total
Comprehensive Data Center Efficiency	733,000	5.7%
Building Energy Management System, Buildings with Gas Space Heat	584,366	4.6%
VFD on HVAC System	545,720	4.3%
LED Tube Replacement Lamps, Buildings with Gas Space Heat	502,008	3.9%
LED Linear Fixtures, Buildings with Gas Space Heat	471,865	3.7%
Interior Lighting Controls, Buildings with Gas Space Heat	429,513	3.4%
Retro-commissioning, Buildings with Gas Space Heat	409,592	3.2%
Refrigeration Evaporator Fan Motor Replacement	352,275	2.8%
Building Energy Management System, Buildings with Electric Space Heat	313,864	2.5%
Refrigeration Evaporator Fan Speed Controls	291,068	2.3%

Table 14. C&I maximum achievable potential electric summer peak demand top savings measures, 2029

Measure name	Cumulative MW	Percent of Total
Smart Thermostat, Buildings with Gas Space Heat	121.4	2.9%
LED Tube Replacement Lamps, Buildings with Gas Space Heat	119.8	2.9%
LED Linear Fixtures, Buildings with Gas Space Heat	113.7	2.7%
Interior Lighting Controls, Buildings with Gas Space Heat	105.5	2.5%
Building Energy Management System, Buildings with Gas Space Heat	94.8	2.3%

Measure name	Cumulative MW	Percent of Total
Demand Control Ventilation, Buildings with Gas Space Heat	73.2	1.8%
Mini-split Ductless Heat Pump	71.3	1.7%
Retro-commissioning, Buildings with Gas Space Heat	68.6	1.6%
LED Tube Replacement Lamps, Buildings without Space Heat	60.9	1.5%
LED Linear Fixtures, Buildings without Space Heat	58.4	1.4%

Table 15. C&I maximum achievable potential gas energy top savings measures, 2029

Measure name	Cumulative BBtu	Percent of Total
Demand Control Ventilation, Buildings with Gas Space Heat	4,513	12.6%
High Efficiency Boiler	4,149	11.6%
Building Energy Management System, Buildings with Gas Space Heat	3,404	9.5%
High Efficiency Furnace	3,019	8.4%
Industrial Process Heating Improvements	3,002	8.4%
Energy Recovery Ventilator	2,791	7.8%
Retro-commissioning, Buildings with Gas Space Heat	2,042	5.7%
Smart Thermostat, Buildings with Gas Space Heat	1,895	5.3%
ENERGY STAR Griddles	1,180	3.3%
ENERGY STAR Ovens	1,143	3.2%

Utility Allocations of Energy Efficiency Potential

The following eight tables (Table 16 through Table 23) show the utility allocations of energy efficiency potential. Utility-specific sales forecasts were used as weights to assign individual utility shares of the estimated statewide potential for electric and gas efficiency. Electric efficiency allocations are presented first, followed by allocations of gas efficiency. In each case, we are reporting cumulative maximum achievable potential by sector for energy and demand. Technical Appendix A will provide additional detailed tables on allocated costs and benefits, as well as incremental estimates by sector and year.

Electric Efficiency Utility Allocations

Table 16. Cumulative maximum achievable potential electric savings, by sector, Atlantic City Electric, 2029

Sector	Electric energy 2029 (GWh)	Sector savings (% of 2029 sales)	Electric demand 2029 (GW)	Sector savings (% of 2029 demand)
Residential	579	13%	237	Not available
Commercial & Industrial	1,218	27%	261	Not available
Total	**1,796**	**20%**	**497**	**19%**

Table 17. Cumulative maximum achievable potential electric savings, by sector, Jersey Central Power & Light, 2029

Sector	Electric energy 2029 (GWh)	Sector savings (% of 2029 sales)	Electric demand 2029 (GW)	Sector savings (% of 2029 demand)
Residential	1,374	13%	543	Not available
Commercial & Industrial	3,320	27%	660	Not available
Total	**4,693**	**20%**	**1,203**	**18%**

Table 18. Cumulative maximum achievable potential electric savings, by sector, Public Service Electric and Gas, 2029

Sector	Electric energy 2029 (GWh)	Sector savings (% of 2029 sales)	Electric demand 2029 (GW)	Sector savings (% of 2029 demand)
Residential	1,947	13%	783	Not available
Commercial & Industrial	7,958	27%	1,541	Not available
Total	**9,905**	**22%**	**2,324**	**21%**

Table 19. Cumulative maximum achievable potential electric savings, by sector, Rockland Electric, 2029

Sector	Electric energy 2029 (GWh)	Sector savings (% of 2029 sales)	Electric demand 2029 (GW)	Sector savings (% of 2029 demand)
Residential	211	13%	87	Not available
Commercial & Industrial	255	27%	50	Not available
Total	**466**	**18%**	**137**	**30%**

Gas Efficiency Utility Allocations

Table 20. Cumulative maximum achievable potential gas savings, by sector, Elizabethtown Gas, 2029

Sector	Gas energy 2029 (BBtu)	Sector savings (% of 2029 sales)	Gas demand 2029 (BBtuh)	Sector savings (% of 2029 demand)
Residential	**2,100**	8%	**26**	Not available
Commercial & Industrial	**4,610**	16%	**57**	Not available
Total	**6,710**	**12%**	**83.34**	Not available

Table 21. Cumulative maximum achievable potential gas savings, by sector, New Jersey Natural Gas, 2029

Sector	Gas energy 2029 (BBtu)	Sector savings (% of 2029 sales)	Gas demand 2029 (BBtuh)	Sector savings (% of 2029 demand)
Residential	**4,548**	8%	**55**	Not available
Commercial & Industrial	**3,738**	16%	**47**	Not available
Total	**8,286**	**10%**	**102**	Not available

Table 22. Cumulative maximum achievable potential gas savings, by sector, Public Service Electric and Gas 2029

Sector	Gas energy 2029 (BBtu)	Sector savings (% of 2029 sales)	Gas demand 2029 (BBtuh)	Sector savings (% of 2029 demand)
Residential	**12,419**	8%	**160**	Not available
Commercial & Industrial	**22,976**	16%	**294**	Not available
Total	**35,395**	**12%**	**454**	Not available

Table 23. Cumulative maximum achievable potential gas savings, by sector, South Jersey Gas, 2029

Sector	Gas energy 2029 (BBtu)	Sector savings (% of 2029 sales)	Gas demand 2029 (BBtuh)	Sector savings (% of 2029 demand)
Residential	**2,197**	8%	**28**	Not available
Commercial & Industrial	**4,417**	16%	**55**	Not available
Total	**6,614**	**12%**	**82**	Not available

DEMAND RESPONSE POTENTIAL

Summary of Approach and Major Assumptions

Demand response (DR) is defined by the s Energy Regulatory Commission (FERC) as "changes in electric usage by end-use customers from their normal consumption patterns in response to either short-term changes in the price of electricity or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized."[9]

[9] FERC, "National Assessment & Action Plan on Demand Response." https://www.ferc.gov/industries/electric/indus-act/demand-response/dr-potential.asp

We base the potential and costs for demand reduction from DR in New Jersey on a review of DR programs by other utilities and on potential studies in other U.S. jurisdictions. We collected data on participation rates, average savings per participating customer, the cost of DR enabling equipment, administrative costs, and necessary incentive costs. We applied these representative values, adjusted to a New Jersey context, to estimate the savings and costs for various DR program strategies in the appropriate customer groups in New Jersey, and based the benefit value on the avoided cost of capacity in New Jersey.

New Jersey customers, especially large commercial and industrial customers, might already have experience with demand response through the regional transmission organization's (PJM's) programs. However, PJM's wholesale peaks and constraints might not coincide with the peak constraints from local utilities. In response, many other states, including Pennsylvania and Maryland, have set up retail demand response programs that can complement the wholesale programs run by PJM. This analysis looks at the potential for retail demand response, and so does not include existing PJM resources as a starting point. Further, as advanced metering infrastructure (AMI) becomes more common throughout the United States, new demand response strategies such as time-based rates and auto-DR are likely to become available. Although New Jersey's AMI is currently quite limited, this analysis assumes a steady rollout of smart meters until the state is fully covered in Year 10 of the study[10]. As AMI becomes available to more customers, the range of program offerings can widen to take advantage of these new technology opportunities.

Methods

This section describes our approach to the DR portion of the potential study analysis. The subsequent sections provide detailed descriptions of the analysis methods and assumptions for each program area.

The analysis of DR potential involved several steps. We began by conducting a literature review of previous DR potential studies, including at the national, state, and utility territory levels. We reviewed DR program evaluations from utilities and their evaluators, as well as available meta-studies of demand response. We reviewed relevant literature throughout the study and used previous studies and program results to compare and check the general scale and validity of our own data. We collected the following values from the literature:

- Peak demand savings per measure
- Equipment cost
- Administrative cost
- Typical incentive cost
- Participation rates

[10] Northeast Energy Efficiency Partnerships (NEEP). Utility Trends in Advanced Metering Infrastructure. https://neep.org/blog/utility-trends-advanced-metering-infrastructure

We also used recent baseline data from Long Island and Hudson Valley to determine the commercial saturation of central air conditioners and electric water heaters for the direct load control measures (discussed below). For the residential sector, we have used the U.S. Energy Information Administration's (EIA's) Residential Energy Consumption Survey (RECS) data to determine equipment saturation rates.

From the literature, we determined major programs based on market sector (residential; and small, medium, and large commercial and industrial [C&I]), program type (for example, direct control, automated response, or time varying rates), and the targeted energy end use (for example, lighting, heating, air conditioning).

Next, we have applied the collected data from the literature to a New Jersey-specific context. We use PJM's peak demand forecast as a baseline, and estimate the number of New Jersey households based on EIA Form 861. Data on demand by disaggregated customer types were not available, so we therefore have used other strategies to estimate the share of demand attributable to these customers.

Measure Characterizations

Critical Peak Pricing, with and without Smart Thermostats

Residential Time-Varying Rates (TVRs) are increasingly being used as a demand response tool to reduce peak demand. Residential load demands particular attention, because the sector often has a much lower load factor than the C&I sector. This means that residential load is "peakier" than C&I load, and thus could significantly benefit from demand response. Further, residential demand response has traditionally been much harder and more expensive to achieve at scale than C&I demand response, since there are lower economies of scale, and the programs have required the utilities to visit the customer and manually install a direct load control (DLC) device. TVRs are a particularly intriguing method for reducing peak demand, since they can be implemented in a mostly revenue-neutral manner. Further, they have minimal ongoing costs for the utility, and can bring significant other benefits by increasing the economic efficiency of how people pay for electricity.

Due to the increasing penetration of AMI, time-varying rates are becoming more common throughout the United States. As examples:

- Ameren and Commonwealth Edison have each enrolled approximately 25,000 customers in a time-varying rate program.
- The Massachusetts Department of Public Utilities has issued a straw proposal calling for a default critical peak pricing and time-of-use rate.
- In 2014, Baltimore Gas and Electric (BG&E) ran a peak time rebate program; of the 867,000 eligible customers, 76 percent participated per event[11]

[11] Ahmad Faruqui, *A Global Perspective on Time Varying Rates*, June 23, 2015, *available at* http://www.brattle.com/system/publications/pdfs/000/005/183/original/A_global_perspective_on_time-varying_rates_Faruqui_061915.pdf?1436207012.

This analysis looks at a type of TVR known as *critical peak pricing* (CPP). Under this rate, customers pay higher peak prices during a discrete number of days when market prices are forecast to be highest. Enrollees are typically notified of these critical events a day in advance. Because this pricing occurs during a set number of days, the difference in electric rate between the critical peak and off-peak periods can be very large. The ratio of the peak price to off-peak prices typically falls around 1 : 8 or 9, meaning that the critical peak price is 8 or 9 times the off-peak price. Examples are:[12]

- OG&E's critical peak price of $0.42 / kWh
- PSE&G's critical peak price added to the off-peak price in a range from $0.23 / kWh (non-summer) to $1.37 / kWh (summer)
- Pacific Gas & Electric's critical peak price adder of $0.60 / kWh
- DTE's critical peak price of $1.00 / kWh (DTE 2014)

Examples of CPP programs are OG&E's SmartHours program and Arizona Public Service's residential Super Peak CPP program.

Rate programs can be designed as "opt-in" or "opt-out" programs. For opt-out programs, the time-varying rate is the default, and customers can decide not to participate. For opt-in programs, customers must actively sign up for the time-varying rate. For opt-out programs, all customers are defaulted to the rate, and have to actively call the utility to opt out. Opt-out programs lower savings per participant than opt-in programs, but this seeming disadvantage to the utility is more than compensated by significantly higher participation. For opt-in programs, spending on marketing and outreach to recruit customers influences participation and savings rates. Some utilities administer these programs as they would any other rate option. Thus, their only costs are program evaluations. Other utilities invest in marketing and outreach to increase rate subscriptions. Programs that use high on-peak prices to penalize energy use during certain times attract customers through low off-peak prices that they can take advantage of. This analysis looks at both opt-in and opt-out programs and assumes some marketing spending for the opt-in program.

We used Arcturus 2.0, a comprehensive database of 200+ residential TVR pricing tests,[13] to estimate savings from critical peak pricing. The Arcturus database currently contains 210 TVR treatments from across the world. We used the extensive data in the Arcturus dataset to create a regression equation that predicts peak savings based on the ratio of the on-peak to off-peak prices, and whether the household has enabling technology (typically a Wi-Fi thermostat). Figure 13 shows peak savings for time-of-use rates, critical peak pricing, and critical peak rebates as a function of the peak-to-off-peak ratio. The figure shows a logarithmic increase in

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[12] Fenrick, S., L. Getachew, C. Ivanov, and J. Smith. "Demand Impact of a Critical Peak Pricing Program: Opt-in and Opt-out Options, Green Attitudes and Other Customer Characteristics." *The Energy Journal 35* (3), 2014. Pages 1 – 25. https://pdfs.semanticscholar.org/a3ca/f0a62d9fa7fb5f25635dc19922fd27580300.pdf.

[13] The Brattle Group, "Arcturus 2.0: A Meta-analysis of Time-varying Rates for Electricity." https://www.brattle.com/news-and-knowledge/publications/arcturus-20-a-meta-analysis-of-time-varying-rates-for-electricity.

peak reduction as the peak-to-off-peak ratio increases, and the entire curve shifts upward if the participating household has enabling technology.

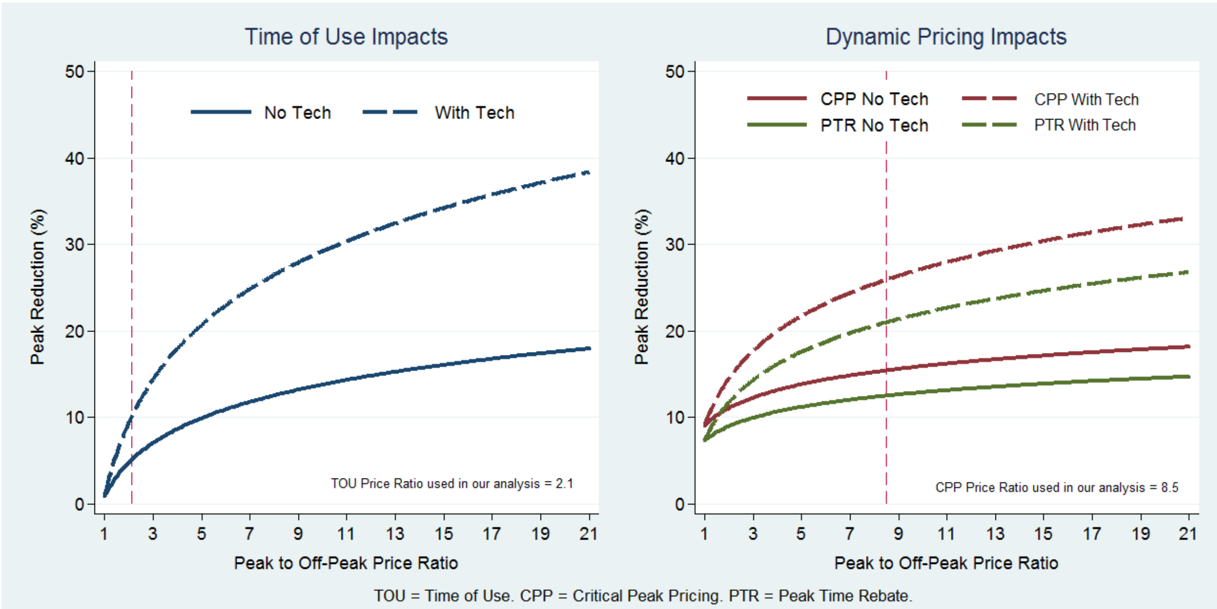

Figure 13. Time-varying rate regression equations.[14]

For this analysis, we use the regression equation derived from Arcturus 2.0 to predict the savings from critical peak pricing and smart thermostats. We supplement this information with data from a Sacramento Municipal Utility District (SMUD) pilot program examining actual differences in savings per customer and participation rates in both opt-in and opt-out rates. Table 24 shows the percent savings per customer, total MW reduction at the customer meter, and percent reduction of the total peak demand forecast for opt-in and opt-out critical peak pricing, both with and without enabling technology.

Table 24. SMUD-observed at meter savings per customer and participation in opt-in and opt-out rate structures, with and without smart technology

	Average % DR during event	Total MW reduction in 2029, at meter	Reduction as % of forecast
Opt in, no thermostats	15.2%	222	1.2%
Opt in thermostats	25.4%	299	1.6%
Opt out, no thermostats	8.5%	521	2.8%
Opt out, thermostats	14.2%	565	3.1%

14 Faruqui, A., and S. Sergici, "Arcturus: International Evidence on Dynamic Pricing," *The Electricity Journal*, July 1, 2013. https://papers.ssrn.com/sol3/papers.cfm?abstract_id=2288116

Direct Load Control

DLC has been the traditional method for demand response in the residential sector, and the main strategy to achieve savings in the absence of advanced metering infrastructure. Direct Load Control devices have to be directly installed on specific pieces of equipment by the utility, and they therefore make sense only for the largest energy-using pieces of equipment: central air conditioners and electric water heaters. Since savings that would be achieved via DLC devices on central air conditioners overlap completely with the savings from Wi-Fi thermostats and time varying rates from the "time varying rates with enabling technology" measure described above, we only analyzed DLC devices for water heaters, and not for CACs.

Residential Direct Load Control

To estimate demand reductions and costs for residential water heater DLC programs, we first estimated local penetration of residential electric water heaters from EIA's RECS. We assume that the presence of an electric water heater would determine the households that would be the target of such a program. RECS identified that an estimated 31 percent of housing units in the Mid-Atlantic U.S. Census zone have electric water heaters. Next, we estimated participation levels from data in the literature. For example, PNM New Mexico achieves a participation rate of 22 percent, Baltimore Gas and Electric's PeakRewards Program achieves participation of 39 percent, various DR potential studies use a range of 25 to 60 percent, and EIA data imply a typical participation of 34 percent.

Similarly, we estimated energy and demand savings and costs assumptions based on DLC and program data from other programs and potential studies.

Small Commercial DLC

Many commercial customers' electrical loads are small enough to use residential-sized equipment. These customers are not affected by TVRs and are too small to merit participating in the medium and large C&I programs we describe below. We therefore also include in the analysis an estimate of the DR potential of DLC on air conditioners and water heaters in small commercial facilities. The methods and data points align with those used for the residential sector, although we determine central air conditioning and electric water heater saturation via baseline survey data recently obtained for New York State.

DLC Summary Results

Table 25 shows the peak reduction per participant, total expected MW reduction at the customer meter by 2029, and the percent reduction of forecast in 2029 for the DLC measures. In the analysis, we assumed a steady ramp-up rate for each measure until each program reached steady-state participation. The 2029 numbers are our estimates of what is achievable once programs have fully scaled.

Table 25. Residential DLC model inputs, per participant

Program measure	Average kW reduction during event, at meter	Total MW reduction in 2029, at meter	Reduction as % of forecast
Residential water heater DLC	0.34	132	0.7%
Small commercial water heater DLC	0.34	38	0.2%
Small commercial central air conditioner DLC	0.68	103	0.6%

Medium and Large C&I Programs

In reviewing the literature, we chose to analyze one program model for the large customers, and two for medium-sized customers:

- Standard offer program (SOP), where the customer is paid to curtail load for a maximum number of times during a set period, usually with 24 hours' advance notice. This is a well-established demand response program for very large C&I customers. Typically, the utility pays a set amount per kW to a third-party curtailment service provider (CSP), which then works with large customers and aggregates peak reduction potential. This program is applied only to large customers (peak demand of at least 150 kW) in the analysis.
- Grid-enabled advanced lighting controls, where the utility sends automated event signals to a lighting control system during peak periods. In response, the system determines how best to reduce peak loads with minimum impact on the occupants, whether it is dimming lights, or turning off certain areas completely. We base the program structure on Pacific Gas & Electric's automated DR program, which offers high up-front incentives to help install the control system, but no ongoing incentives after installation. We apply this measure to medium-sized DR customers, which are too small to be considered for the SOP, but big enough that they use commercial-sized energy-using equipment.
- Grid-enabled energy management systems (EMS), where the utility sends automated event signals to the building energy management system, which will automatically cycle HVAC, reduce set points, and perform other preprogrammed energy management strategies to reduce peak demand. As with the advanced lighting controls, it is assumed that the utility will give high up-front incentives for the installation of the AutoDR EMS, but no

ongoing incentives subsequent to installation. This measure is also applicable to medium-sized C&I customers.

In general, we take a similar approach to the other measures, taking savings, cost, and participation values from programs in other jurisdictions and from other potential studies of demand response. For the SOP, we assume that 50 percent of the medium and large C&I peak demand is from customers large enough to participate in the program. We also assume a 20 percent participation rate of the eligible load, 95 percent participation per event, and that each customer would save 40 percent of energy use, on average.

For the advanced lighting controls, we disaggregate lighting peak demand using EIA's Commercial Building Energy Consumption Survey (CBECS). We also assume that the end use distribution of peak demand is similar to that of energy use. We further assume a steady-state participation of 25 percent, and that the controls would produce a 44 percent reduction in lighting use.

The grid-enabled EMS affects the entire building's energy use. We estimate current saturation of EMS in commercial businesses using baseline survey data from New York State. We assume that 75 percent of facilities that currently have an Energy Management System, and 20 percent of facilities with no current EMS will participate in the program. Table 26 combines these assumptions.

Table 26. Assumptions for medium-sized and large customers

Program measure	Average % reduction per customer	Total MW reduction in 2029, at meter	Reduction as % of applicable forecast
Standard offer program (SOP)	40%	452	2.5%
Advanced lighting controls	44%*	95	0.5%
Grid-enabled EMS	10%	101	0.5%

* 44% of lighting load only

Cost Effectiveness

Each program or measure was also screened for cost effectiveness. In general, we used conservative assumptions for cost-effectiveness screening:

- **No energy savings.** We assume that all reduction in energy use during peak time would be offset by an increase in energy use during non-peak time.
- **Societal cost.** In energy efficiency programs, the incentive is considered a transfer payment, and therefore not included as a cost in the SCT. However, for demand response, there is some real cost to participants who reduce their demand in exchange for an annual incentive payment, whether it is in the form of having to run a generator, or reduced comfort from AC cycling, or something else. This analysis assumes that the cost to the customer is equal to

the value of the incentive payment, and thus the full incentive payment is treated like a measure cost and included in the SCT as a cost.

- **Avoided capacity benefits.** We "de-rate" the capacity avoided costs used for energy efficiency savings, based on a California approach that accounts for:[15]
  - **Availability.** Only a given number of events can be called per year, compared to energy efficiency program peak impacts, which generally reduce peak consistently.
  - **Notification.** If the event is called the day before an expected peak, there is a chance the predictions will be incorrect, and the event will not actually coincide with the peak.
  - **Trigger.** Some DR programs mandate that events can be called only if certain conditions are met, such as if the outdoor temperature exceeds a certain value

  The de-rating factors used in California vary by utility and program, and range from 10 to 50 percent. We use 50 percent in this analysis.

Table 27 shows the cost-effectiveness ratios of each program. As shown, all but the three DLC measures pass the societal cost test. The opt-out program with no thermostats have an incredibly high benefit-to-cost ratio, since it assumes a revenue-neutral rate design and simply entails a switch in rate structure. This phenomenon might incur some upfront costs, but minimal costs for ongoing operations and maintenance, incentives, or program administration.

Table 27. Cost effectiveness by demand response program, under the societal cost test

Measure	SCT ratio
CPP opt in, no thermostat	12.6
CPP opt in, thermostat	2.7
CPP opt out, no thermostat	598.4
CPP opt out, thermostat	10.6
Residential water heater DLC	0.5
Small C&I water heater DLC	0.5
Small C&I CAC DLC	0.5
Large C&I SOP	2.2
Auto-DR advanced lighting controls	3.0
Auto-DR grid-enabled EMS	2.9

The study's results show total costs, peak demand savings, and cost-effectiveness for the evaluated demand response programs. We present findings for years 2020 through 2029. We

[15] See Hledik, R., and A. Faruqui. "Valuing Demand Response: International Best Practices, Case Studies, and Applications." Prepared for EnerNOC by the Brattle Group. January 2015. http://files.brattle.com/files/5766_valuing_demand_response_-_international_best_practices__case_studies__and_applications.pdf.

give results for CPP opt-out with enabling technology, since this program achieves higher savings than the other CPP scenarios. Adding thermostats to the CPP significantly increases program costs, because otherwise it is just a rate change with very little in the way of ongoing expenses.

Results for each of the scenarios are presented in Figure 14, Table 28, and Table 29.

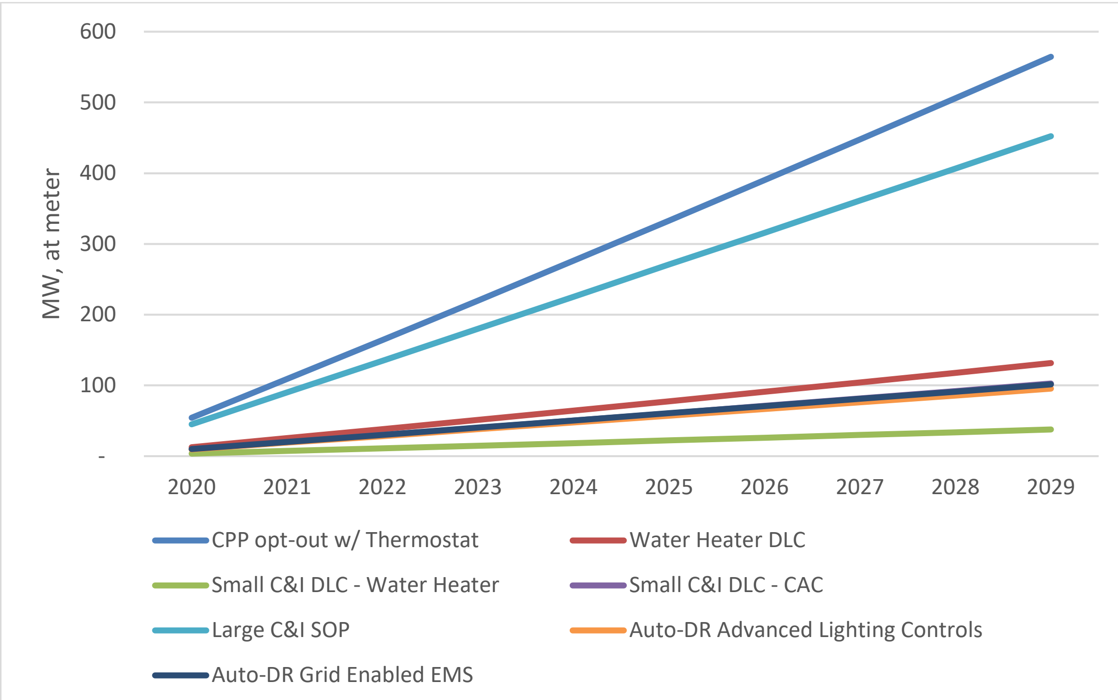

Figure 14. Demand response peak reduction.

Table 28. Demand response peak load reductions summary - MW, at meter

Measure	2020	2024	2029
CPP opt-out, thermostat	54	276	565
Residential water heater DLC	13	64	132
Small C&I water heater DLC	4	18	38
Small C&I CAC DLC	10	50	103
Large C&I SOP	45	225	452
Auto-DR advanced lighting controls	10	48	95
Auto-DR grid-enabled EMS	10	51	101
TOTAL	**145**	**733**	**1,486**
TOTAL Cost-effective	**119**	**600**	**1,214**

Table 29. Demand response peak load reductions summary—as a percent of total peak

Measure	2020	2024	2029
CPP opt out, thermostat	0.3%	1.5%	3.1%

Measure	2020	2024	2029
Residential water heater DLC	0.1%	0.4%	0.7%
Small C&I water heater DLC	0.0%	0.1%	0.2%
Small C&I CAC DLC	0.1%	0.3%	0.6%
Large C&I SOP	0.2%	1.2%	2.5%
Auto-DR advanced lighting controls	0.1%	0.3%	0.5%
Auto-DR grid-enabled EMS	0.1%	0.3%	0.5%
TOTAL	**0.8%**	**4.0%**	**8.1%**
TOTAL Cost-effective	**0.6%**	**3.3%**	**6.6%**

Program Budgets

Table 30 presents annual average program budgets and overall cost-effectiveness results for each program and scenario.

Table 30. Annual program costs, by year

Measure	2020	2024	2029
CPP opt out, thermostat	$11.7	$11.9	$12.4
Residential water heater DLC	$12.2	$17.5	$24.4
Small C&I water heater DLC	$3.2	$3.6	$4.2
Small C&I CAC DLC	$5.5	$11.0	$18.1
Large C&I SOP	$1.5	$6.9	$13.7
Auto-DR advanced lighting controls	$2.3	$2.7	$3.2
Auto-DR grid-enabled EMS	$2.5	$3.0	$3.6
TOTAL	**$38.9**	**$56.7**	**$79.8**
TOTAL Cost-effective	**$18.0**	**$24.6**	**$33.0**

COMBINED HEAT AND POWER POTENTIAL

A CHP plant produces electricity at a commercial or industrial site while using the waste heat from the production of the electricity to meet the demand from a thermal load. Net efficiencies come from the recovered heat that is typically wasted in grid electricity production, and avoided transmission and distribution losses from delivering the electricity from the generator to the customer site.

Optimal's CHP analysis began by characterizing the costs, electricity generated, natural gas consumed, operation and maintenance costs, and measure lifetimes for different CHP types and kW output sizes. The CHP assumptions primarily came from the September 2017 version of the EPA's *Catalog of CHP Technologies*.[16] The lifetimes came from the June 22, 2018, version of the

[16] Combined Heat and Power (CHP) Partnership (U.S. EPA). *Catalog of CHP Technologies*. https://www.epa.gov/chp/catalog-chp-technologies.

New Jersey Board of Public Utilities, the New Jersey Clean Energy Program's *Protocols to Measure Resource Savings.*[17] These CHP costs, savings, and other attributes were entered into a cost-effectiveness screening model, using New Jersey's electric and gas avoided costs to determine which CHP types and sizes would be cost effective. They also offer the likely operating hours required for each of the types to be cost effective.

To get a sense of how many of each size of CHP units in New Jersey were feasible, we referred to the U.S. Department of Energy's (DOE) March 2016 *Technical Potential Analysis*.[18] This technical potential analysis provided MW potential by six capacity ranges and by several industrial and commercial building types.

To estimate how much of the CHP technical potential would be cost effective, we referred to a previous analysis by Optimal Energy, Inc. for NYSERDA. The industrial and commercial economic potential MW as percentages of the technical potential MW were used as estimates for New Jersey.

From the previous cost-effectiveness analysis of the different CHP types and sizes, we chose specific CHP units to represent each kW size range from the U.S. DOE technical potential analysis for New Jersey.[19] Dividing the kW capacity of the CHP unit representative of the kW size range by the economic potential MW provided an estimate of the number of CHP units. Using the MW by building type from the DOE technical potential, we estimated the number of economically potential CHP units by building type and kW size range. The economic potential total benefits, costs, and net benefits were then determined by multiplying the cost-effectiveness results for a single CHP unit by the number of CHP units. This was done for each CHP kW size range and building type.

Based on a consideration of market barriers related to finding suitable CHP applications, long-planning horizons, and reluctance to invest in an unfamiliar technology, we estimated that approximately 50 percent of the CHP economic potential would be achievable over the next ten years. Comparison data from other jurisdictions varies widely from a low of 17 percent estimated recently for Pennsylvania to highs of 77 percent for industrial and 71 percent for commercial in a study for NYSERDA.[20]

The CHP potential analysis results are presented in Table 31.

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[17] New Jersey Board of Public Utilities, *New Jersey Clean Energy Program: Protocols to Measure Resource Savings.* Revisions to FY2016 Protocols, June 29. 2016. http://www.njcleanenergy.com/files/file/NJCEP%20Protocols%20to%20Measure%20Resource%20Savings%20FY17_FINAL.pdf.

[18] U.S. Department of Energy, Combined Heat and Power (CP+HP) Technical Potential in the United States. 2016. https://www.energy.gov/sites/prod/files/2016/04/f30/CHP%20Technical%20Potential%20Study%203-31-2016%20Final.pdf.

[19] U.S. Department of Energy, CHP Technical Assistance Partnerships. "The State of CHP: New Jersey." https://www.energy.gov/sites/prod/files/2017/11/f39/StateOfCHP-NewJersey.pdf.

[20] Optimal Energy, "NYSERDA Commercial Baseline Analysis and Potential Study," (forthcoming); and Optimal Energy, "Pennsylvania Act 129 Statewide Evaluation," (forthcoming).

Table 31. CHP potential results, cumulative, 2020 - 2029

Scenario	Unit	Cumulative annual 2029 potential	% of total load
Economic	GWh	11,355	14.1%
	GW	1.30	6.3%
	BBtu/yr	(48,761)	-9.7%
	Peak BBtu	(106.87)	N/A
Maximum achievable	GWh	4,168	5.2%
	GW	0.48	2.3%
	BBtu/yr	(17,518)	-3.5%
	Peak BBtu	(38.40)	N/A

All Potential Combined

Table 32 shows the combined ten-year potential for energy efficiency, demand response, and CHP, combined for electric energy and demand.

Table 32. Cumulative maximum achievable potential electric savings, by category

Potential component	Electric energy 2029 (MWh)	Savings (% of 2029 sales)	Electric demand 2029 (MW)[a]	Savings (% of 2029 demand)[a]
Energy efficiency	16,859,908	21%	4,162	20%
Demand response[b]	-	0%	1,361	7%
Combined heat and power	4,168,388	5%	476	2%
Total	**21,028,296**	26%	**5,999**	29%

[a] The energy efficiency and demand response analysis were performed in isolation. So although the peak demand impacts are totaled in this summary table, in reality, they are not purely additive, because potential interactions between the two were not considered.
[b] The demand response impacts presented in this table are quantified at generation.

POTENTIAL STUDY METHODS

Overview

Optimal applied a top-down analysis of efficiency potential, relative to the energy sales disaggregation for each sector, and merged it with a bottom-up measure level analysis of costs and savings for each applicable technology. This analysis approach involved several steps. The first are a prerequisite for building the base model used to run each scenario:

- Compiling and adjusting baseline energy forecasts. In this case, we used forecasts provided directly by the New Jersey utilities and adjusted them to add back the projected savings—assuming current, business-as-usual programs.
- Disaggregating adjusted energy forecasts by customer sector (residential, commercial and industrial), by segment (for example, building type), and end use (for example, lighting or cooling).
- Characterizing efficiency measures, including estimating costs, savings, lifetimes, and share of end use level forecasted energy use for each market segment.

To develop each scenario (*economic* and *maximum achievable*) required additional steps specific to the assumptions in each scenario:

- Building up savings by measure / segment, based on measure characterizations calibrated to total energy use
- Accounting for interactions between measures, including savings adjustments based on other measures, and ranking and allocating measures when more than one measure can apply to a particular situation
- Running the stock adjustment model to track existing stock and new equipment purchases, to capture the eligible market for each measure in each year
- Running the efficiency potential model to estimate the total potential for each measure / segment / market combination, to produce results of the potential
- Screening each measure / segment / market combination for cost effectiveness
- Removing failing measures from the analysis and rerunning the model to re-adjust for measure interactions

The study applied an SCT to determine measure cost effectiveness. The SCT considers the costs and benefits of efficiency measures from the perspective of society as a whole. Efficiency measure costs for market-driven measures represent the incremental cost difference between a standard baseline (non-efficient) piece of equipment or practice and the high efficiency measure. For retrofit markets, the full cost of equipment and labor was used because the base case assumes no action on the part of the building owner. Measure benefits are driven primarily by energy savings over the measure lifetime, but might also involve other more easily quantifiable benefits associated with the measures. This could be water savings, and operations and maintenance savings. The energy impacts might include multiple fuels and end uses. For example, efficient lighting reduces waste heat, which in turn reduces the cooling load, but increases the heating load. All of these impacts are accounted for in the estimation of a measure's costs and benefits over its lifetime.

There are two aspects of electric efficiency savings: annual energy and coincident peak demand. The former refers to the reductions in actual energy use, which typically drive the greatest share of electric economic benefits. However, because it is difficult to store electricity, the total reduction in the system peak load is also an important impact. Power producers need to ensure adequate capacity to meet system peak demand, even if that peak is reached for only a few hours each year. As a result, substantial economic benefits can accrue from reducing the system peak demand, even if little energy and emissions are saved during other hours. The electric benefits reported in this study reflect both electric energy savings (MWh) and peak demand reductions (MW) from efficiency measures.

Analogously, gas efficiency provides distinct benefits from reducing annual load as well as peak day load. Historically, peak day load has not been seen as an important benefit, but recent constraints in gas transmission during the winter, especially in the Northeast and Mid-Atlantic states, have been changing that perception. We therefore account for benefits associated with lower peak day gas load by annualizing the marginal cost of service for gas and adding it to the commodity avoided cost. In other words, if the marginal cost of peak day gas were $19 per therm, and on average there are 80 annual therms for every peak day therm, we would add approximately 23 cents per therm ($19 / 80 = $0.234) to the avoided commodity cost of natural gas. We derive this number from the marginal cost of service for Orange & Rockland Utilities service territory in New York State.

The primary scenario for the study was the maximum achievable, which reflects what could theoretically be accomplished by aggressive efficiency programs offering incentives equal to 100 percent of measure incremental costs. In order to estimate maximum achievable potential, we first have to estimate total economic potential. The general approach for these two scenarios differed as follows:

- **Economic potential scenario.** We generally assumed that any cost-effective measures would be immediately implemented for market-driven measures such as for new construction or major renovation, and natural replacement ("replace on failure") measures, when the opportunity becomes available. For time-discretionary retrofit measures, we generally assumed that all or nearly all efficiency retrofit opportunities would be realized over the 10-year study period. Spreading out the retrofit opportunities results in a more realistic ramp up, providing a better basis of comparison for the achievable scenarios.
- **Maximum achievable scenario.** This scenario is based on the economic potential scenario, but accounts for real-world market barriers. We assumed that efficiency programs would provide incentives to cover 100 percent of the incremental costs of efficiency measures, so that program participants would have no out-of-pocket costs relative to standard baseline equipment. Further, this scenario assumes the program administrative costs associated with capturing this potential.

Finally, we note that the study scope was limited in a several important respects:

- We were not able to collect recent New Jersey primary data; the study thus relies primarily on existing available data, often from outside New Jersey (although heavily based on very recent and comprehensive primary data collected in New York and Pennsylvania)

- The research did not attempt to separately break out what portion of the potential might be captured by future changes in codes and standards that are not currently planned

Energy Forecasts

Electricity Forecast

The electric and natural gas use forecasts were developed primarily from the information provided by New Jersey utilities. In most cases, the sales forecasts were provided at the sector level, but in cases where sector designations were ambiguous, we relied on the sector breakout, by utility, from EIA. Where not provided for the entire analysis period (that is, from 2020 through 2029), the forecasts were extrapolated from average annual economic growth rates. Assumed savings from efficiency programming running at constant savings into the future were added back into the provided forecast. Current programs save approximately 0.7 percent of total electric sales and 0.2 percent of total gas sales. By adding these savings back to the forecast, the results of the study reflect a base case where no utility-run efficiency programs exist. The energy forecasts are presented in Appendix B.

Forecast Disaggregation by Segment and End Use

The source for the energy disaggregation varies by sector. The commercial disaggregation relies on data from multiple sources. First, total forecasted energy sales are divided across building types using data from the New York State Commercial Baseline Study for the Long Island-Hudson Valley region.[21] We separated building sales into end uses with data from EIA's CBECS for the Mid-Atlantic U.S. Census division. The residential energy sales were segmented into housing type (that is, single-family vs. multifamily), using data from the Pennsylvania Residential Baseline Study[22]—and further segmented into low-income and non-low-income residential categories, based on data from the 2009-2011 American Community Survey (U.S. Census). The EIA's 2015 Residential Energy Consumption Survey was then used to segment the sales by end use. Industrial sales were segmented into end uses from data in the Pennsylvania Non-Residential Baseline Study and the EIA's Manufacturing Energy Consumption Survey.

Sales were further disaggregated into those for new construction and renovated spaces and those for existing facilities. New construction activity was based on EIA *Annual Energy Outlook* projections of new versus existing facilities. No new construction was assumed for the industrial sector. The final sales disaggregation is presented in Appendix C.

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[21] New York State Energy Research and Development Authority (NYSERDA), "Commercial Statewide Baseline Study of New York State." https://www.nyserda.ny.gov/About/Publications/Building-Stock-and-Potential-Studies/Commercial-Statewide-Baseline-Study.

[22] NMR Group, Inc. "2018 Pennsylvania Statewide Act 129 Residential Baseline Study," prepared for the Pennsylvania Public Utility Commission, February 2019. http://www.puc.pa.gov/Electric/pdf/Act129/SWE-Phase3_Res_Baseline_Study_Rpt021219.pdf.

Measure Characterization

The first step for developing measure characterizations is to define the measures to be considered. Optimal shared the list of measures with BPU and stakeholders.

We included and characterized 341 measures for up to three applicable markets:

- **Market-driven, or lost opportunity measures** occur when the market is driving a purchase or sale of a new piece of equipment—for example, for regular, planned lighting change-outs, or when an existing air conditioning unit fails. For these measures, the applicable baseline is a new code-compliant unit, and not the existing conditions. The incremental cost is thus defined as the difference in cost between the efficient unit and a new code-compliant unit. Savings are calculated against code requirements, which are often more stringent than they were when the original equipment was installed.
- **Retrofit measures** happen when there is no driving market force mandating the purchase of new equipment. An example of this is when controls are added to an existing boiler, or when an efficient chiller is retired before the end of its useful life. For retrofit measures, since the counterfactual is no action, the initial cost is the full installed cost of the measure, and the savings are calculated from the existing equipment. In the counterfactual case, there is a time in the future when the existing equipment would have failed and needed replacement. We have assumed that there is a cost that would have been incurred in the future for that replacement, but that cost has not happened because of the retrofit. At the same time, there is often a shift in savings, as the savings are now calculated against the new code-compliant unit instead of the existing, replaced unit.
- **New construction measures** occur when a new construction or major renovation project is planned. These are really a type of market-driven measure, since new construction activity is driven by market forces. However, we separate out these measures since there are several holistic whole-building measures, such as integrated building design and commissioning, that apply only to new construction. Further, our model forecast separates out the energy use in new construction from that in existing buildings. For each measure, in addition to separately characterizing them by market, we also separately analyze measure / market combinations for each building segment (for example, small office, large office, industrial building, restaurant). This results in the modeling of more than 4,000 distinct measure / market / segment permutations for each year of the analysis. Savings for new construction are generally estimated as efficiency gains above code requirements, so savings estimates are generally lower than the estimated savings for retrofit measures.

The overall potential model relies on a top-down approach that begins with the forecast and disaggregates it into loads attributable to each possible measure. In general, measure characterizations include defining the following attributes for each combination of measure, market, and segment:

- Measure lifetime (both baseline and high efficiency options, if different)
- Measure savings (relative to baseline equipment)
- Measure cost (incremental or full installed, depending on market)
- Operations and maintenance (O&M) impacts (relative to baseline equipment)
- Water impacts (relative to baseline equipment)

Energy Savings

For each technology, we estimate the energy use of baseline and high efficiency measures, basing them primarily on engineering analysis. We rely heavily on the New Jersey Protocols, as well as best-practice technical reference manuals (TRMs) from other jurisdictions and Optimal Energy's measure characterization database. For more complex measures not addressed by the TRMs, we used case studies, meta-analyses, and engineering calculations. In each case, we sought and used the best available data about current baselines in New Jersey and the performance of high efficiency equipment or practices. The industrial analysis relied heavily on data from DOE Industrial Assessment Centers. We did not include any building simulation modeling or other sophisticated engineering approaches for establishing detailed, weather-normalized savings.

Costs

Measure costs are drawn from Optimal Energy's measure characterization database when no specific New Jersey costs were available. These costs are the result of long-term development and maintenance of data, which are regularly updated with the latest information, including recent or contemporaneous potential study work in Minnesota, New Orleans, New York, and Pennsylvania. Major sources include the New Jersey Protocols and Mid-Atlantic TRMs, baseline studies, incremental cost studies, direct research into incremental costs, and other analyses and databases that are publicly available. (See Information Review in Literature and Information Review for full information.)

Lifetimes

Where possible, we adopted measure lives from the New Jersey Protocols. Where unavailable, as with measure costs, we used Optimal's measure characterization database for measure lifetime information. These data have been developed over time, and were revised for this study, using the New Jersey Protocols.

Operations and Maintenance Impacts

O&M impacts are costs unrelated to energy costs of operations. They represent, for example, replacement lamp purchases for new high-efficiency fixtures, or changes in labor for servicing high-efficiency vs. standard-efficiency measures. High-efficiency equipment can often reduce O&M costs because of higher-quality components that require less-frequent servicing. On the other hand, some high-efficiency technologies require enhanced servicing, or have expensive components that need to be replaced prior to the end of the measures' lifetimes. For most measures, O&M impacts are very minimal, as many efficient and baseline technologies have the same O&M costs over time. Where they are significant, we base our estimates on our engineering and cost analyses, the New Jersey Protocols, and other available data.

We describe further aspects of measure characterization in the subsection on potential analysis, along with other factors that merge the measure level engineering data with the top-down forecast of applicable loads to each measure. Measure characteristics are presented in Appendix D.

Top-Down Method

The general approach for this study, for all market sectors, is "top-down." We use as a starting point the actual forecasted loads for each sector. As described above, we then break these down into loads attributable to different categories of building equipment. In general terms, the top-down approach starts with the energy sales forecast and disaggregation, and determines the percentage of the applicable end use energy that might be offset by the installation of a given efficiency measure in each year. This contrasts with a "bottom-up" approach in which a specific number of measures are assumed to be installed each year.

Various measure-specific factors are applied to the forecasted building type and end use sales by year, to derive the potential for each measure for each year in the analysis period. This is shown below in the following central equation:

Measure savings	=	Segment / end use / year kWh sales	x	Applicability factor	x	Feasibility factor	x	Turnover factor (replace-ment only)	x	Not-complete factor (retrofit only)	x	Savings fraction	x	Net penetration rate

Where:

- **Applicability** is the fraction of the end use energy sales (from the sales disaggregation) for each building type and year attributable to equipment that could be replaced by the high-efficiency measure. For example, for replacing office interior linear fluorescent lighting with a higher-efficiency LED technology, we would use the portion of total office building interior lighting electrical load attributable to linear fluorescent lighting.
- **Feasibility** is the fraction of end use sales for which it is technically feasible to install the efficiency measure. Numbers less than 100 percent reflect engineering or other technical barriers that would preclude adoption of the measure. Feasibility is not reduced for economic or behavioral barriers that would reduce penetration estimates. Rather, it reflects technical or physical constraints that would make measure adoption impossible or ill advised. An example might be an efficient lighting technology that cannot be used in certain low-temperature applications.
- **Turnover** is the percentage of existing equipment that will be naturally replaced each year due to failure, remodeling, or renovation. This applies to the natural replacement ("replace upon failure") and renovation markets only. In general, turnover factors are assumed to be 1 divided by the baseline

equipment measure life (for example, assuming that 5 percent or 1/20th of existing stock of equipment is replaced each year for a measure with a 20-year estimated life).

- **Not-complete** is the percentage of existing equipment that already represents the high-efficiency option. This applies only to retrofit markets. For example, if 30 percent of current single-family homes already have learning thermostats, then the not-complete factor for residential thermostats would be 70 percent (1.0 – 0.3), reflecting that only 70 percent of the total potential from thermostats remains.
- **Savings fraction** represents the percent savings of the high-efficiency technology, compared to the energy use from either existing stock or new baseline equipment for retrofit and non-retrofit markets, respectively. Savings fractions are based on individual measure data and assumptions about existing stock efficiency, standard practice for new purchases, and high-efficiency options.
  - **Baseline adjustments** shift the savings fractions downward in future years for early-retirement retrofit measures, to account for the fact that newer, standard equipment efficiencies are higher than older, existing-stock efficiencies. We assume average existing equipment being replaced for retrofit measures is at 60 percent of its estimated useful life. The baseline adjustment also comes with a cost credit to reflect the standard equipment that the participant would have had to install to replace the failed unit.
- **Annual net penetrations** are the difference between the base case measure penetrations and the measure penetrations that are assumed for an economic potential. For the economic potential, it is assumed that 100 percent penetration is captured for all markets, with retirement measures generally being phased in and spread out over time to reflect resource constraints such as contractor availability. The product of all of these factors is the total potential for each measure permutation. Costs are then derived from the "cost per energy unit saved" for each measure, applied to the total savings produced by the measure. The same approach is used for other measure impacts—for example, O&M savings.

These factors are presented in Appendix E.

Cost-Effectiveness Analysis

Cost-Effectiveness Test

This study applies the SCT as the basis for excluding non-cost-effective measures from the analysis of potential savings. The SCT considers the costs and benefits of efficiency measures from the perspective of society as a whole. The principles of these cost tests are described in the *California Standard Practice Manual*.[23]

Table 33 provides the costs and benefits from the perspective of each of the cost-effectiveness tests.

Table 33. Overview of cost-effectiveness tests

Monetized benefits / costs	UCT	SCT
Measure cost (incremental over baseline)		Cost
Program administrator incentive costs	Cost	
Program administrator non-incentive program costs	Cost	Cost
Energy & electric demand savings	Benefit	Benefit
Fossil fuel savings (increased use)	Benefit	Benefit (cost)
O&M savings		Benefit
Water savings		Benefit
Deferred replacement credit*		Benefit
Externalities		Benefit

*For early-retirement retrofit measures, the deferred replacement credit accrues when the existing equipment would have needed replacement. The equipment's replacement cycle has been deferred due to the early replacement.

Discounting the Future Value of Money

Future costs and benefits are discounted to the present using a real discount rate of 4.74 percent, estimated from the nominal discount rate of 7 percent used by the Rutgers Center for Green Building for the New Jersey Clean Energy Program (NJCEP) cost-benefit analyses,[24] and a 2.16 percent long-term rate of inflation. For discounting purposes, we assume that initial measure costs are incurred at the beginning of the year, whereas annual energy savings are incurred halfway through the year.

Avoided Energy Supply Costs

Avoided energy supply costs assess the economic value of energy savings (or the costs of increased consumption). Developing avoided costs specific to energy efficiency in New Jersey was outside the scope of this study; however, we relied on the best available data to prepare

[23]Governor's Office of Planning and Research, State of California, *California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects*, July 2002. http://www.calmac.org/events/SPM_9_20_02.pdf.

[24] Rutgers, "Draft Energy Efficiency Cost-Benefit Analysis," 2019.

values that represent reasonable estimates without a substantial investment of time and resources.

We adopted the electric energy, capacity, and transmission and distribution and gas avoided costs estimated by Rutgers University for the BPU, and used in the NJCEP cost-benefit analyses. As noted above, Rutgers has not developed peak-day avoided costs for gas. We estimated an annualized marginal cost of service for gas for Orange & Rockland New York State service territory and added it to the commodity avoided cost. Appendix F presents avoided costs.

Electric Load Shapes

Electric energy load shapes are used to divide annual efficiency measure kWh savings into the energy costing periods of the avoided costs. End use specific load shapes were not available for New Jersey. For this project, load shapes have been based on 2002 Itron eShapes 8760 load profile data for New York. Although the selected load shapes are based on weather stations from a different state, they provide the nearest and best data available. For the purposes of this study, it is unlikely that the load shapes in New Jersey would differ significantly from the load shapes in downstate New York.

The eShapes 8760 load profile data provide information on electric energy use, by sector, and for various end uses and building types. The data were based on approximately 20,000 building audits performed nationwide, primarily in the early 1990s. More than half of the roughly 20,000 audits were performed on site. Building simulations were then performed with proprietary modeling software for many of the audited buildings, to develop prototype buildings calibrated to the measured data for individual sites. The electric load shapes used for this study are presented in Appendix G.

Economic Potential Analysis

The top-down analysis, along with all the data inputs, produce the measure-level potential, with the economic potential being limited to installation of cost-effective measures. However, the total economic potential is less than the sum of each separate measure potential. This is because of interactions between measures and competition among measures. Interactions result from installation of multiple measures in the same facility. For example, a building insulation project reduces the heating load. If a high-efficiency furnace is subsequently installed, savings from the furnace will be lower because the overall heating needs of the building have been lowered. As a result, interactions between measures should be taken into account to avoid over-estimating savings potential. Because the economic potential assumes all possible measures are adopted, interactions assume every building installs all applicable measures. Interactions are accounted for by ranking each set of interacting measures by total savings, and assuming the greatest savings measure is installed first, followed by the next-highest savings measure.

Measures that compete also need to be adjusted for. These are two or more efficiency measures in the same application, but only one can be chosen. An example is choosing between installing an air source heat pump or an efficient central air conditioner, but not both. In this case, the total penetration for all competing measures is 100 percent, with priority given to the measures based on ranking them from highest savings to lowest savings. If the first measure is applicable in all situations, it would have 100 percent penetration and all other competing measures would show no potential. On the other hand, if the first measure could be installed in only 50 percent of opportunities, then the second measure would capture the remaining opportunities.

To estimate the economic potential, we generally assumed 100 percent installation of market-driven measures (natural replacement, new construction / renovation), constrained by measure cost effectiveness and other limitations, as appropriate, such as to account for mutually exclusive measures.

Implementation of retrofit measures was considered to be resource-constrained. That is, it would not be possible to install all cost-effective retrofit measures at the same time. The retrofit penetration rates are generally assumed to be 10 percent of the market for each year in the analysis period.

Maximum Achievable Potential Analysis

For the maximum achievable potential scenario, we did not attempt to design detailed programs to group each measure into. Instead, we make the simplifying assumption that the programs will be well designed and able to capture the amount of market adoption. Thus, this study can help determine the amount of efficiency available, and which measures might offer the most opportunity. However, it is not a detailed roadmap on how to group these measures into programs or how to best promote and market the programs to customers.

Measure Incentives and Penetration Rates

Measure penetration rates, or adoption rates, are affected by a broad variety of factors, depending on the measure: for example, the market barriers that apply and to what degree, the program delivery strategy, incentive levels, marketing and outreach, and technical assistance to installers. Although penetration rates will generally increase with increased spending, how the spending is applied can have a huge impact on actual participation rates. There is large uncertainty inherent in developing penetration rates, and self-report surveys are often not a reliable indicator of eventual adoption. Further, these rates have an outsized effect on the final efficiency available in the maximum achievable scenario. Appendix H contains penetration rates for both the economic and maximum achievable scenarios.

Non-Incentive Program Budgets

The costs of implementing efficiency programs involve both the cost of the efficiency measures themselves and the associated administrative costs for marketing, customer interactions, incentive and rebate processing, evaluation activities, and other features of an efficiency program. To estimate these costs for inclusion in both program budgets and cost-effectiveness testing, we relied on actual program data from best-practice efficiency portfolios. The estimates are specific to our major program categories (for example, residential new construction, or commercial equipment replacement), because different program types and delivery models can have different administrative needs.

We sourced these data from recent program performance for utilities in Massachusetts. These portfolios are generating savings substantially greater than New Jersey's current programs, and are likely to be a better predictor of the administrative costs needed to achieve the level of savings found by our analyses. The average administrative costs for the various program types range from 23 percent to 40 percent of total program costs.

SECTION 2: LITERATURE AND INFORMATION REVIEW

LITERATURE REVIEW

Establishing Goals

Statutory Mandates

The New Jersey Clean Energy Act of 2018 provides

> *3. a. No later than one year after the date of enactment of P.L.2018, c.17 (C.48:3-87.8 et al.), the Board of Public Utilities shall require each electric public utility and gas public utility to reduce the use of electricity, or natural gas, as appropriate, within its territory, by its customers, below what would have otherwise been used. For the purposes of this section, a gas public utility shall reduce the use of natural gas for residential, commercial, and industrial uses, but shall not be required to include a reduction in natural gas used for distributed energy resources such as combined heat and power.*
>
> *Each electric public utility shall be required to achieve annual reductions in the use of electricity of two percent of the average annual usage in the prior three years within five years of implementation of its electric energy efficiency program. Each natural gas public utility shall be required to achieve annual reductions in the use of natural gas of 0.75 percent of the average annual usage in the prior three years within five years of implementation of its gas energy efficiency program. The amount of reduction mandated by the board that exceeds two percent of the average annual usage for electricity and 0.75 percent of the average annual usage for natural gas for the prior three years shall be determined pursuant to the study conducted pursuant to subsection b. of this section until the reduction in energy usage reaches the full economic, cost-effective potential in each service territory, as determined by the board.*

Industry Norms

The American Council for an Energy-Efficient Economy (ACEEE) each year publishes its State Energy Efficiency Scorecard. One of the many metrics reported in the Scorecard is state energy efficiency resource standards (EERS). ACEEE offers data on industry standards and information related to state energy efficiency policies and programs. However, it should be noted that ACEEE has a relaxed definition of an EERS to acknowledge states with clearly established regulatory targets, but which might not actually have traditional EERS. Further, there is a significant lag in ACEEE's reporting, and occasional instances in which the reported information is not comprehensive. In addition, the percent of load achievements for electricity and natural gas reported by ACEEE are, in many cases, lower than the actual savings being achieved by the major utilities in the state. This is because ACEEE considers savings as a percent of entire statewide load, but almost all states have municipal and / or cooperative utilities that do not implement efficiency programs, or do so only minimally. Many states also have some form of "opt-out" mechanism that allows some of the largest customers not to contribute to efficiency programs, or excludes them from participation criteria. Finally, although the Scorecard reports EERS targets in savings as a percent of retail energy sales, not all states actually set their savings targets to this metric. [25]

For electricity savings goals, ACEEE's latest report shows that seven states have annual electric savings targets at or above 2 percent: Massachusetts (2.9 percent), Rhode Island (2.6 percent), Arizona (2.5 percent), Maine (2.4 percent), Vermont (2.1 percent), New York (2.0 percent), and Maryland (2.0 percent).[26] Another six states have targets of 1.5 to 1.99 percent: Illinois, Colorado, Connecticut, Minnesota, New Jersey, and Washington.[27]

For natural gas, ACEEE reports that eight states have annual savings goals at or above the 0.75 percent level that New Jersey has specified in law: Hawaii (1.4 percent), Arkansas (1.2 percent), Nevada (1.1 percent), Michigan (1.0 percent), New Hampshire (1.0 percent), Pennsylvania (0.8 percent), and Wisconsin (0.8 percent). Another two states have goals that are 0.5 – 0.75 percent: Iowa (0.6 percent) and New Mexico (0.6 percent).[28] Three additional states that have policies for all cost-effective efficiency or a target significantly higher than 0.75 percent are Massachusetts, Rhode Island, and New York.[29]

ACEEE also reports on the level of savings achieved for each state. In the 2018 State Scorecard, three states were reported to have achieved annual savings in excess of 2 percent: Vermont (3.33 percent), Rhode Island (3.08 percent), and Massachusetts (2.57 percent). Another two states were in the range of 1.50 – 1.99 percent: California (1.97 percent) and Connecticut (1.62 percent).[30] In general, these figures are net savings, and ACEEE has applied a net-to-gross factor of 0.856 when reporting was at the gross level.[31]

For natural gas savings, six states were reported as having annual savings of 0.75 percent or higher: Minnesota (1.35 percent), Massachusetts (1.08 percent), Rhode Island (1.02 percent),

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[25] For example, Illinois does not set a fixed annual standard, but has a long-term cumulative savings goal. As of January 2018, Commonwealth Edison's (Illinois' largest utility) annual goals are 2.3 percent of load, and expected to stay in that range through 2030, to achieve the mandated 30 percent cumulative savings by 2030.

[26] New York has been pursuing approximately 2.0 percent annual savings; however, Governor Andrew Cuomo announced a new efficiency policy mandating roughly 3 percent per year. This policy has yet to be fully implemented. See: https://www.governor.ny.gov/news/governor-cuomo-announces-new-energy-efficiency-target-cut-greenhouse-gas-emissions-and-combat.

[27] Berg, W., S. Nowak, G. Relf, S. Vaidyanathan, E. Junga, M. DiMascio, and E. Cooper, "The 2018 State Energy Efficiency Scorecard," American Council for an Energy-Efficient Economy, October 2018, Table 17, page 42.

[28] Berg et al. 2018, Table 18, page 43.

[29] New York has an all-fuels Btu target, but it was based on targets of 3.0 percent savings for electricity and 1.5 percent for natural gas. See Optimal Energy, "Analysis of Energy Efficiency Savings Targets in New York State," 2018. https://assets.nrdc.org/sites/default/files/optimal-energy-analysis-of-energy-efficiency-savings-targets-in-new-york-state_2018-04-05.pdf?_ga=2.166758142.1941833523.1553446280-1590874612.1553446280.

[30] Berg et al. 2018, Table 8, page 28.

[31] Berg et al. 2018, page 29.

Michigan (1.01 percent), Utah (0.78 percent), and California (0.78 percent). Another five states reported having annual savings rates of 0.50 – 0.74 percent.[32]

Best Practices

As a starting point for energy savings target-setting, states that do not have a legislatively established EERS usually rely on detailed studies that estimate the available cost-effective savings within their jurisdiction. They might also use current or prior experience in implementing efficiency programs to inform target setting.[33] Another option some states have used is to adopt targets similar to those of nearby states that have comparable climates and economic conditions.[34] Many states, such as Illinois and Michigan, define energy savings targets in EERS legislation. In other states, such as California and Massachusetts, targets are set by utility regulatory bodies.[35] Targets are frequently reviewed and set every few years to account for recent program results and changes in energy efficiency potential or policy priorities.[36]

Regardless of the starting point and mechanism for setting targets, the level of energy savings and the timing of those savings are important considerations in the target-setting process. To allow utilities to include energy efficiency into long-term integrated resource planning, savings targets are often set for multiple years.[37] Multi-year targets allow utilities and state governments to plan for the future with a level of certainty. These targets typically allow for a "ramp-up" period. That is, the targets increase over several years.[38]

Providing adequate ramp-up periods is a best practice in energy target setting for several reasons. Namely, it gives utilities sufficient time to plan for, develop, and market their programs, and to build the necessary infrastructure for successfully implementing them.[39] It also allows utilities to test and make adjustments to programs and portfolios as savings targets increase.[40] Last, ramp-up periods can allow for and account for regulatory lag.[41,42]

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32 Berg et al. 2018, Table 10, page 31. Note, as with electricity, ACEEE seems to have omitted several states.

33 Downs, A., and C. Cui, "Energy Efficiency Resource Standards: A New Progress Report on State Experience," ACEEE, April 2014; U.S. Environmental Protection Agency, "State Climate and Energy Program Technical Forum: Energy Efficiency Resource Standards, Background and Resources," January 2010.

34 Downs and Cui 2014; US EPA 2010.

35 Downs and Cui 2014.

36 US EPA 2010.

37 Downs and Cui 2014.

38 Downs and Cui 2014; US EPA 2010; Southeast Energy Efficiency Alliance, "Energy Efficiency Goal Setting in the Southeast," May 2015; State and Local Energy Efficiency Action Network, "Setting Energy Savings Targets for Utilities: Driving Ratepayer-Funded Efficiency through Regulatory Policies Working Group," September 2011.

39 Downs and Cui 2014; US EPA 2010; Southeast Energy Efficiency Alliance 2015; State and Local Energy Efficiency Action Network 2011.

40 Downs and Cui, 2014.

41 *Regulatory lag* refers to the time between a utility's requesting new rates and the utility commission approving those rates.

ACEEE maintains a database of state EERS, which provide many examples of state energy targets ramping up over time.[43] For example, the database indicates:

- In 2010, Massachusetts statewide savings targets were initially set at 1.4 percent of annual electric sales and 0.63 percent of annual natural gas sales. Electric savings targets ramped up an average of 0.30 percent per year from 2010 to 2.94 percent in 2016. Gas savings targets increased by an average of 0.10 percent each year to 1.24 percent in 2016.
- In 2007, Illinois electric savings targets were set at 0.2 percent of annual sales for 2008 and ramped up to 2 percent in 2015. Natural gas goals were set at 0.2 percent in 2012 with a ramp up to 1.5 percent by 2019. Due to budgetary caps imposed by statute, goals were adjusted downward in the later years. Current savings targets are different across utilities, but the average is 1.77 percent of sales from 2018 to 2021.[44] Natural gas targets are 8.5 percent cumulative savings by 2020, which amount to 0.2 percent incremental savings in 2011, ramping up to 1.5 percent in 2019.
- Rhode Island's annual incremental electric savings goals for electricity during the 2012-2014 period began at 1.7 percent and increased to 2.5 percent by 2014. Targets for 2015-2017 range from 2.5 percent to 2.6 percent. Gas savings targets for the 2012-2014 timeframe started at 0.6 percent in 2012, increasing to 1.0 percent in 2014. Targets range from 1 percent to 1.1 percent for 2015-2017.

In some states, the specific ramp-up rate is specified in the EERS. For example, in 2015, Maryland Public Service Commission issued new targets as part of the EmPOWER Maryland Energy Efficiency Act of 2008. The targets specified that utilities need to achieve 2 percent per year by ramping up savings at a rate of 0.2 percent per year starting in 2016.[45]

A ramp-up period does not always reflect a straight-line trajectory. In 2016, when the DC Sustainable Energy Utility (DCSEU) was rebid for a five-year contract period, the savings goals embedded in the RFP and the subsequent contract required a significant ramp up in savings in the third year of the contract.[46]

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42 Downs and Cui 2014; Southeast Energy Efficiency Alliance 2015.

43 "Energy Efficiency Resource Standards," ACEEE. https://database.aceee.org/state/energy-efficiency-resource-standards.

44 Commonwealth Edison's 2018-2021 plan (Docket 17-0213) achieves its statutory goal of 2.3 percent, however, Ameren Illinois' goal (Docket 17-0331) was reduced to approximately 1.6 percent, because of budget caps.

45 "Energy Efficiency Resource Standards," ACEEE.

46 District Department of Energy & Environment, Request for Proposals for District of Columbia Sustainable Energy Utility Contractor, February 2016. https://doee.dc.gov/sites/default/files/dc/sites/ddoe/publication/attachments/DCSEU%20RFP_DOEE-2016-R-0002_FINAL.pdf , Table C.2, page 41, and Table C.3, page 42.

Establishing Quantitative Performance Indicators

Statutory Mandate

The New Jersey Clean Energy Act of 2018 provides:

> *(c) No later than one year after the date of enactment of P.L.2018, c.17 (C.48:3-87.8 et al.), the board shall adopt quantitative performance indicators pursuant to the "Administrative Procedure Act," P.L.1968, c.410 (C.52:14B-1 et seq.) for each electric public utility and gas public utility, which shall establish reasonably achievable targets for energy usage reductions and peak demand reductions and take into account the public utility's energy efficiency measures and other non-utility energy efficiency measures including measures to support the development and implementation of building code changes, appliance efficiency standards, the Clean Energy program, any other State-sponsored energy efficiency or peak reduction programs, and public utility energy efficiency programs that exist on the date of enactment of P.L.2018, c.17 (C.48:3-87.8 et al.). In establishing quantitative performance indicators, the board shall use a methodology that incorporates weather, economic factors, customer growth, outage-adjusted efficiency factors, and any other appropriate factors to ensure that the public utility's incentives or penalties determined pursuant to subsection e. of this section and section 13 of P.L.2007, c.340 (C.48:3-98.1) are based upon performance, and take into account the growth in the use of electric vehicles, microgrids, and distributed energy resources. In establishing quantitative performance indicators, the board shall also consider each public utility's customer class mix and potential for adoption by each of those customer classes of energy efficiency programs offered by the public utility or that are otherwise available. The board shall review each quantitative performance indicator every three years. A public utility may apply all energy savings attributable to programs available to its customers, including demand side management programs, other measures implemented by the public utility, non-utility programs, including those available under energy efficiency programs in existence on the date of enactment of P.L.2018, c.17 (C.48:3-87.8 et al.), building codes, and other efficiency standards in effect, to achieve the targets established in this section.*

Industry Norms

In 2015, Nowak et al. completed a national review of performance incentives, and provided a concise history of the development of performance incentives in the efficiency industry:

> *The historical origins of performance incentives and their rationales vary from state to state. While there are some common themes, the regulatory, policy, and economic circumstances differ enough to defy generalization, as seen in these examples.*
>
> *Massachusetts' first incentives were for New England Electric in the early 1990s. The state lowered the level of performance incentives and introduced decoupling during the mid1990s. The primary motivation for having performance incentives has been to achieve energy savings goals. The ability of the utilities to earn a return on energy efficiency spending persuades them to align their goals with public policy goals.*

Since the 1980s California had decoupling in place. However, in an effort to move toward deregulation during the late 1990s, California suspended decoupling. After the 2001 electricity crisis occurred, the state then reinstated decoupling over the next three years and moved to expand energy efficiency. In 2005, the California Public Utilities Commission added performance incentives in the form of the Risk Reward Incentive Mechanism to encourage greater efficiency. Unlike many states, the regulations at that time also included financial penalties if program performance results were not sufficiently in line with energy savings goals.

Oklahoma's utility performance incentives arose from an investor-owned utility approaching the Corporation Commission in a rate case, resulting in a commission order requiring the development of quick-start energy efficiency programs. The utility came back with a proposal including programs, a rider for cost recovery, lost revenue recovery, and a 25% shared-savings performance incentive mechanism. When it came time for full compliance programs, i.e., no longer only quick-start, the utilities were still allowed to seek lost revenues attributable to energy efficiency through an LRAM [Lost Revenue Adjustment Mechanism]. The incentive was reduced from 25% to 15%. Oklahoma has decoupling for gas, but not electric utilities.

In Rhode Island, energy efficiency programs and utility performance incentives were both instituted years prior to decoupling. Performance incentives for energy efficiency were viewed at that time as one factor that allowed the utilities to support least-cost procurement.

Vermont's statewide energy efficiency utility, Efficiency Vermont, has had quantitative performance indicators to determine the financial incentives since 2000. Vermont Energy Investment Corporation (VEIC) was hired explicitly on a performance-based three-year contract basis, so having incentives was a logical element. In 2011 VEIC was engaged as an efficiency utility via a long-term order of appointment, but the performance incentive continued.[47]

In Vermont, quantifiable performance indicators (QPIs) are now incorporated into the triennial Demand Resources Plan proceeding, conducted by the Vermont Public Utility Commission, as is typical for jurisdictions with performance incentives.[48] For the current three-year period, Efficiency Vermont, the statewide energy efficiency utility, has 5 QPIs and 9 Minimum Performance Requirements (MPRs). The QPIs for Efficiency Vermont are:

- Total resource benefits
- Annual electricity savings

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[47] Nowak, S., B. Baatz, A. Gilleo, M. Kushler, M. Molina, and D. York, "Beyond Carrots for Utilities: A National Review of Performance Incentives for Energy Efficiency," ACEEE, May 2015, page 9.

[48] Vermont Energy Investment Corporation, "Efficiency Vermont Triennial Plan 2018 – 2020," prepared for the Vermont Public Utility Commission, November 2017, page 36. https://www.efficiencyvermont.com/Media/Default/docs/plans-reports-highlights/2018/efficiency-vermont-triennial-plan-2018-2020.pdf.

- Statewide summer peak demand savings
- Statewide winter peak demand savings
- Lifetime electricity savings[49]

In addition to QPIs, Efficiency Vermont is tasked with meeting 9 MPRs:

- Minimum electric benefits
- Threshold level of participation by residential customers
- Threshold level of participation by low-income households
- Threshold level of participation by small business customers
- Geographic equity
- Administrative efficiency
- Service quality
- Resource acquisition performance period spending
- Spending on development and support services in the performance period[50]

QPIs have become fairly routine in the efficiency industry, with their use spelled out in regulatory planning cycles and proceedings. Optimal Energy and Energy Futures Group prepared a report for the Michigan Public Service Commission, addressing the specific issue of how to design performance indicators so as not to reward short-lived measures. Jurisdictions that want to move beyond annual savings, which can be inflated with high levels of inexpensive savings with short lives (on a cost-per-annual-energy-savings calculation basis), but which might be very costly lifetime efficiency resources, can find the conclusions in that report. It contains seven options for adjusting or augmenting savings goals to encourage long-term savings:

1. Lifetime savings goals
2. Discounted lifetime savings goals
3. Net present value of net benefits
4. Cumulative annual savings goals over a multi-year period
5. First-year savings goals with limits on quantities of savings from short-term measures
6. First-year savings goals with bonuses / penalties for long- / short-lived measures
7. First-year savings goal with average measure life adjustment factor.[51]

Illinois provides a good example of comprehensive efficiency legislation that focuses on lifetime savings. The Future Energy Jobs Act (FEJA) of 2016 establishes cumulative utility

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[49] Efficiency Vermont Triennial Plan 2018-20, page 39.

[50] Efficiency Vermont Triennial Plan 2018-20, page 39.

[51] Optimal Energy, Inc., and Energy Futures Group, "Alternative Michigan Energy Savings Goals to Promote Longer Term Savings and Address Small Utility Challenges," prepared for the Michigan Public Service Commission, September 2013, page 20. https://www.michigan.gov/documents/mpsc/final_phase1_report_600393_7.pdf.

efficiency goals by 2030. Although regulators also set annual goals during DSM plan proceedings, these are calculated from formulae established in legislation, and are dependent on past progress and remaining persisting savings.[52] FEJA also provides for performance incentives in the form of rate-basing efficiency expenditures, amortized at the portfolio-weighted average cost of capital, as a regulatory asset for which the utility earns its rate of return, as well as additional performance-based incentives of increases or decreases in the allowable rate-of-return basis points. This practice puts efficiency on the same basis as any other energy-generating asset with respect to the rate of return available to the utility, but that rate is guaranteed only if the utility meets the goals.

In the work done by Nowak and colleagues, the researchers asked respondents what advice they would give to a state that was considering or drafting performance indicators. The advice is worth repeating at this important stage of development in New Jersey:

- Keep the mechanism simple, while fairly aligning the interests of ratepayers and shareholders.
- Choose a shared-benefits incentive that rewards the utility both for achieving higher energy savings levels and for doing so cost effectively.
- Establish clear definitions and a standard that applies to all utilities equally. Standardize the reports, how the savings are calculated and adjusted, and what embedded costs are to be included. Failing to do so may cause confusion and results that vary according to the way they are interpreted.
- Be aware of the size of the incentive. In a structure where the incentive is a function of savings or spending, the total incentive can grow quickly as the energy efficiency budget increases. This is particularly true in the current environment, where greater emphasis is placed on energy efficiency.
- Inform all parties of the likely range of planned incentive levels, so that no one is surprised. Use incentives to encourage utilities to expand their successes beyond the status quo.
- Consider how the QPIs will account for any interactive effects among different programs. There is the potential for competing priorities when implementing multiple programs with different incentive mechanisms. (This recommendation might be most relevant for multi-factor performance incentive mechanisms.)[53]

Best Practices

Quantitative performance indicators in their best form provide incentives for utilities and program administrators to achieve or exceed goals established in law or policy. States handle the establishment of performance indicators differently. Some conclusions on best practices are:

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[52] See Illinois SB 2914. http://www.ilga.gov/legislation/99/SB/PDF/09900SB2814lv.pdf.

[53] Nowak et al. 2015, page 33.

- QPIs should be created collaboratively in a facilitated stakeholder process. This is not universal in practice, but some of the best QPIs are enhanced through this process.
- QPIs must be objectively measurable with relative ease and efficiency, and must leave little room for controversy or conflicting interpretations.
- QPIs should reward and incentivize high performance. QPIs should provide incentives for outcomes, rather than activities. For example, a low-income savings target would be a more appropriate metric than a spending target, which might or might not lead to good performance in energy savings.
- QPIs should be scalable to performance. Incentives should specify a range of performance. Many jurisdictions begin with a threshold level of performance somewhat lower than the plan goals, with increasing rewards for increased performance, up to a cap that is typically around 125 percent of the plan goals. This ensures that a utility has continuous motivation for greater performance and earnings, even if it knows it cannot reach its goal, or even if it has already exceeded its goal.
- QPIs should be designed with an eye on the pitfalls of providing incentives for one thing at the expense of another. For example, if a single metric of annual energy savings is the performance metric, it will be too easy for utilities or program administrators to under-invest in residential and / or low-income programs, which generally have a much higher cost per energy unit saved.
- Although QPIs need to have continuity and length of life, they should change with changing circumstances. Efficiency Vermont's long history with QPIs shows how the State's energy priorities and efficiency programming have changed over time. The three-year cycle that many states now use for energy efficiency program planning is probably ideal for re-visiting QPIs. That does not suggest wholesale revision every three years, but at least the ability to reshape and re-prioritize. The three-year cycle also allows the parties to set the earnings opportunity commensurate with each plan's expected level of effort and budget.

Establishing Incentives

Statutory Mandates

The New Jersey Clean Energy Act of 2018 provides:

> *e. (1) Each electric public utility and gas public utility shall file an annual petition with the board to demonstrate compliance with the energy efficiency and peak demand reduction programs, compliance with the targets established pursuant to the quantitative performance indicators, and for cost recovery of the programs, including any performance incentives or penalties, pursuant to section 13 of P.L.2007, c.340 (C.48:3-98.1). Each electric public utility and gas public utility shall file annually with the board a petition to recover on a full and current basis through a surcharge all*

reasonable and prudent costs incurred as a result of energy efficiency programs and peak demand reduction programs required pursuant to this section, including but not limited to recovery of and on capital investment, and the revenue impact of sales losses resulting from implementation of the energy efficiency and peak demand reduction schedules, which shall be determined by the board pursuant to section 13 of P.L.2007, c.340 (C.48:3-98.1).

(2) If an electric public utility or gas public utility achieves the performance targets established in the quantitative performance indicators, the public utility shall receive an incentive as determined by the board through an accounting mechanism established pursuant to section 13 of P.L.2007, c.340 (C.48:3-98.1) for its energy efficiency measures and peak demand reduction measures for the following year. The incentive shall scale in a linear fashion to a maximum established by the board that reflects the extra value of achieving greater savings.

(3) If an electric public utility or gas public utility fails to achieve the reductions in its performance target established in the quantitative performance indicators, the public utility shall be assessed a penalty as determined by the board through an accounting mechanism established pursuant to section 13 of P.L.2007, c.340 (C.48:3-98.1) for its energy efficiency measures and peak demand reduction measures for the following year. The penalty shall scale in a linear fashion to a maximum established by the board that reflects the extent of the failure to achieve the required savings.

(4) The adjustments made pursuant to this subsection may be made through adjustments of the electric public utility's or gas public utility's return on equity related to the energy efficiency or peak demand reduction programs only, or a specified dollar amount, reflecting the incentive structure as established in this subsection. The adjustments shall not be included in a revenue or cost in any base rate filing and shall be adopted by the board pursuant to the "Administrative Procedure Act.

Industry Norms

Performance incentives provide a way for utilities to earn a return on their spending on energy efficiency, just as they earn a return on other assets. Illinois offers one example of recent legislation that allows utilities to earn the same return on equity, amortized at the portfolio-weighted average cost of capital, on their efficiency spending as they do on other regulatory assets. The condition they must meet is that they have achieved the established performance metrics.

In the 2018 State Scorecard, ACEEE reports that "29 states offer a performance incentive for at least one major electric utility, and 17 states have incentives for natural gas energy efficiency programs. Some states with third-party program administrators have performance incentives for the administrator rather than for the utilities."[54] In some instances, the performance incentives result in higher spending by utilities on efficiency. "While most performance

[54] Berg et al. 2018, page 46.

incentives are based on shared net benefits—viewed as an expense—the relative amounts of the incentives are in the range of 5–15% of program spending."[55]

Many states include minimum thresholds for one or more QPIs, below which performance incentives are not available, or for which penalties apply. These are often base levels of overall energy savings in MWh or therms. They might also exclude increased electricity use from added loads from electric vehicles or other "strategic electrification" measures, or the net results of combined heat and power (CHP) installations. But they might also have to do with overall portfolio benefits or net benefits. Nowak and team provide a useful table summarizing minimum threshold requirements, overall incentive structure, and maximum incentives. They also categorize results into three types of incentive structures:[56]

- Shared net benefits. These provide the utility with the opportunity to earn some portion of the benefits of efficiency that would otherwise go to ratepayers (Arkansas, Arizona, Colorado, Georgia, Kentucky, Minnesota, North Carolina, Ohio, Oklahoma, South Carolina, and Texas)
  - Example: Ohio has used a shared net benefits approach that rewards percentage or kWh energy savings, which has reportedly worked well and has changed over time. A multi-year rate plan was used at first with fixed rates that allowed utilities to retain all or a portion of cost savings from efficiency. A later version used a revenue cap, which required revenue and savings beyond a certain level to be shared with ratepayers. More recent versions involve a predetermined formula or other mechanism that allows revenue or rates to change during the plan.
- Savings-based. These structures reward programs for meeting or exceeding established savings goals (Connecticut, Indiana, Michigan, New Hampshire, Rhode Island, and New York)
  - Example: Connecticut's 2017 plan contains the incentive structure for Southern Connecticut Gas Company, which provides the utility with an incentive of 4.25 percent of the efficiency plan budget if it achieves 100 percent of its efficiency goals. That incentive decreases / increases

[55] Berg et al. 2018, page 32, citing Nowak et al. 2015.

[56] Typology, definitions, and state categorizations by Nowak et al. 2015, page. v and pages 10-14. Examples derived from: (a) Migden-Ostrander, J., D. Littell, J. Shipley, C., Kadoch, and J. Sliger, "Recommendations for Ohio's Power Forward Inquiry," Regulatory Assistance Project, February 2018, page 13, https://www.raponline.org/knowledge-center/recommendations-ohios-power-forward-inquiry/; (b) Eversource Energy, The United Illuminating Company, Connecticut Natural Gas, and Southern Connecticut Gas, "2017 Annual Update of the 2016-2018 Conservation & Load Management Plan," March 2017, page 294, https://www.ct.gov/deep/lib/deep/energy/conserloadmgmt/clm2018planfinal.pdf; (c) NMR Group, Inc., Ecometric Consulting, Demand Side Analytics, Blue Path Labs, and Setty and Associates, "Performance Benchmark Assessment of FY2017 DC Sustainable Energy Utility Programs," prepared for District of Columbia Department of Energy and Environment, September 2018, Table 1, page 1. https://doee.dc.gov/sites/default/files/dc/sites/ddoe/publication/attachments/DCSEU%20FY2017%20Performance%20Benchmarks%20report%20-%20FINAL%20092818.pdf.

commensurately in a linear fashion from 77.5 percent of goal to 137.5 percent of goal.

- Multi-factor. These structures provide performance targets covering multiple policy goals (California, District of Columbia, Hawaii, Massachusetts, Missouri, Vermont, and Wisconsin).
  - Example: The DCSEU earned performance incentives for meeting six 2017 metrics: reduction of electricity consumption; reduction of natural gas consumption; increase in renewable energy generation capacity; increase in energy efficiency of low-income properties (with both expenditure and savings metrics); and increase in green collar jobs. The DCSEU's multi-factor structure is further complicated by the fact that some goals are annual and others are cumulative across the five-year performance period.[57]

In an online toolkit for utility incentives for efficiency, ACEEE notes that incentives can help to put "energy efficiency and supply-side resources on relatively equal financial footing, enabling shareholders to earn a comparable financial benefit on either investment. An important additional advantage with most of these mechanisms is that they are tied to a specific level of performance rather than spending."[58]

In 2015, Synapse Energy Economics prepared a handbook for the Western Interstate Energy Board, which laid out the following principles of design for utilities' performance incentives:

1. Tied to the policy goal
2. Clearly defined
3. Able to be quantified from reasonably available data
4. Sufficiently objective and free from external influences
5. Easily interpreted
6. Easily verified[59]

The authors also make the case that it is important for metrics to be consistent with national or regional standards.[60]

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57 NMR Group et al. 2018, Table 2, page 5.

58 ACEEE, "Aligning Utility Business Models with Energy Efficiency," *American Council for an Energy-Efficient Economy Technical Assistance Toolkit*, https://aceee.org/sector/state-policy/toolkit/aligning-utility.

59 Whited, M., T. Woolf, A. Napolean, "Utility Performance Incentive Mechanisms: A Handbook for Regulators," prepared for Western Interstate Energy Board, March 2015, page 28. http://www.synapse-energy.com/sites/default/files/Utility%20Performance%20Incentive%20Mechanisms%2014-098_0.pdf.

60 Whited et al. 2015, page 28.

Best Practices

Optimal Energy's participation in a study of energy policy issues in New Hampshire involved summary of guidance on key factors for consideration, as shown in Table 34.[61]

Table 34. Considerations for designing performance incentives

Level of financial reward	Performance basis	Multivariate metrics	Scalability	Penalties vs. rewards	Evaluation, measurement, & verification
Rewards of 4-8% are typically sufficient. It is easier to evaluate the size of the reward when it is based on program budget, rather than on net benefits or an increased rate of return.	Based on actual measurable and verifiable performance.	Multiple metrics should be used other than savings to discourage cream-skimming and to promote secondary policy objectives.	Incentives should be scaled to encourage performance, even when goals are met (or when it is clear that goals will not be met).	Some states impose penalties instead of, or in addition to performance awards. Penalties can encourage extra effort to meet goals.	To encourage performance, set goals to be aggressive, yet reachable. Performance metrics should be verified by an independent third party.

Effective performance incentives are tied directly to actual outcomes, not actions or activities. They must be measurable and verifiable. The results of effective performance incentives can be seen in the performance of some of the states that are considered the top performers in energy efficiency. These states have paid attention to the best practices of energy efficiency performance incentives, and they have avoided the pitfalls of poorly designed incentives.

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SECTION 3: RECOMMENDATIONS ON QPIS AND PERFORMANCE INCENTIVES

ALIGNMENT OF REQUIREMENTS AND RECOMMENDATIONS FRAMEWORK

The New Jersey Clean Energy Act calls for the BPU to develop savings targets (or "Quantitative Performance Indicators") for all electric and natural gas public utilities. The energy efficiency and demand response potential estimates inform these QPIs. The utilities must ramp up to a *minimum* of 2 percent savings of average prior three-year loads for electricity and 0.75 percent for gas. Ultimately, the Act calls for utilities to pursue all cost-effective and "reasonably achievable" reductions in energy and demand.

> *No later than one year after the date of enactment of P.L.2018, c.17 (C.48:3-87.8 et al.), the board shall adopt quantitative performance indicators pursuant to the "Administrative Procedure Act," P.L.1968, c.410 (C.52:14B-1 et seq.) for each electric public utility and gas public utility, which shall establish reasonably achievable targets for energy usage reductions and peak demand reductions and take into account the public utility's energy efficiency measures and other non-utility energy efficiency measures including measures to support the development and implementation of building code changes, appliance efficiency standards, the Clean Energy program, any other State-sponsored energy efficiency or peak reduction programs, and public utility energy efficiency programs that exist on the date of enactment of P.L.2018, c.17 (C.48:3-87.8 et al.).*

Utilities are allowed to count savings of all efficiency initiatives and other activities that result in savings within their individual territories, regardless of whether the initiative was administered by the utility or by some other party such as the State. The maximum achievable potential estimated by the current potential study corresponds to the full efficiency potential within each utility territory, regardless of how that efficiency is captured. Because efficiency savings are generally fungible, the achievable potential can in theory be captured through the adoption and enforcement of stricter codes and standards, or other initiatives outside utility-administered programs. We therefore focus on the entire maximum achievable efficiency potential and do not make specific assumptions about what strategies are used, what entities deliver them, or what portion of the potential might come from different implementation approaches.

Because the BPU is directed to develop QPIs only for public utilities, this project's scope is limited to the potential and QPIs for those entities. Optimal does not make assertions about specific plans in New Jersey from initiatives outside the public utility sphere that might contribute to the QPIs. This study also does not attempt to allocate savings goals to entities other than the public utilities. Nothing precludes a utility from pursuing improved building code compliance and counting savings from that compliance. Such improvements in compliance might instead be carried out by a State agency and thus contribute to savings, as well. Because a State agency might have activities that result in efficiency that counts toward a utility goal, a utility might develop a plan for its own programs that falls somewhat short of the legislative minimums (2 percent and 0.75 percent for electricity and gas, respectively, in Year 5), assuming non-utility administered initiatives would make up the difference. This approach would create risks for the utilities because they cannot count on, monitor, or control such third-party activities. It would be difficult to know where they are in meeting goals, and what performance incentives or penalties might be at risk.

The Act calls for the savings that count toward targets to be "below what would have otherwise been used." Further, it states:

> *In establishing quantitative performance indicators, the board shall use a methodology that incorporates weather, economic factors, customer growth, outage-adjusted efficiency factors, and any other appropriate factors to ensure that the public utility's incentives or penalties determined pursuant to subsection e. of this section and section 13 of P.L.2007, c.340 (C.48:3-98.1) are based upon performance, and take into account the growth in the use of electric vehicles, microgrids, and distributed energy resources.*

This potential study does just that. We have considered only the potential net savings from capturing efficiency in buildings and industry, based on projected weather-normalized load forecasts, net of any distributed energy resources, expected outages, and other such factors. The Act further requires that estimates of utility territory savings in compliance reporting, and awards for achieved performance, also account for these and other exogenous factors. Although it is tempting to accept an approach of observing and metering actual loads, and then separately adjust for these factors, we do not recommend that approach. It would require many subsequent adjustments for all of the factors that might have affected actual loads that were not driven by the efficiency efforts. In our experience, this approach suffers from challenges that not only introduce administrative burdens but, more important, add substantial uncertainty to any ultimate savings estimates attributable to efficiency. For example:

- Accurate adjustments for weather are inherently uncertain.
- Accurate data on many of the exogenous variables are not available, or are very difficult to estimate accurately. Although some variables, such as distributed generation, might be known and tracked by utilities, there is a wide variety of potential new loads or impacts for which data do not exist.
- Estimating all major exogenous impacts and adjusting for them would be highly problematic, and by necessity cannot include all actual exogenous factors. For example, one might adjust for large and understood impacts such as electric vehicles, distributed generation, and economic growth; but it is very challenging to adjust for changing patterns of behavior and end uses that might be occurring because of natural market forces such as increased computing power or other plug loads.
- This approach makes it exceedingly difficult to manage the accounting of efficiency efforts and to track and measure progress as the efforts are implemented. Because actual savings from a program would be based on future unknown actual loads,

there would be significant lags in feedback on whether programs were working well and whether a utility was on track to meet its goals.

Ultimately, what the utilities, the BPU, and New Jersey residents and businesses care about is what the net savings attributable to the efficiency efforts are, all else being equal, compared to a counterfactual baseline that will never exist and cannot be directly measured. Therefore, we recommend a more traditional evaluation, measurement, and verification (EM&V) approach to estimate and track savings. This approach of tracking actual program activity at the measure level, and assessing what each measure would save, assuming all exogenous factors are held constant, will be more accurate. Further, it is better supported and understood by the industry. And in addition to improving accuracy, it provides some essential and practical benefits. It allows utilities to track programs and to have accurate real-time estimates of performance.[62]

Traditional EM&V approaches also allow for a good understanding of attribution of savings. It is therefore important to understand the net savings that are attributable to each efficiency initiative, to understand how well the initiative is working, to identify improvements that can be made, to assess cost-effectiveness, and whether the initiative should be continued. Measuring only total actual loads for all customers affords little opportunity for insights about program value when assessing program performance and cost effectiveness. Indeed, the Act also requires:

> *Each electric public utility and gas public utility shall file with the board implementation and reporting plans as well as* ***evaluation, measurement, and verification strategies to determine the energy usage reductions and peak demand reductions achieved by the energy efficiency programs and peak demand reduction programs approved pursuant to this section.*** [Emphasis added]

Finally, there is a practical benefit to this approach in New Jersey. The State will benefit from a significant and established EM&V industry, frameworks, and methods that have been tested and improved over decades. Further, the capability and workforce capacity necessary to implement this approach already exist; and in New Jersey, it is the current practice. This approach also allows for reasonable comparisons of performance with efforts in other states and at other utilities. Such comparisons are useful for continuous improvement and moving to more aggressive goals.

Because the Act allows utilities to include savings from the efforts of others (such as codes and standards), estimates of additional savings or actions outside any direct utility programs should be based on those actions. For example, if New Jersey passes new appliance standards,

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[62] Note that we are not suggesting the tracked savings be automatically assumed to be correct. Ex-post verification and evaluation of impacts should be performed by an independent third-party evaluator.

the State will generally have considered, as part of the effort to pass them, the expected impacts that would result from them.[63]

RECOMMENDED TARGETS AND QUANTITATIVE PERFORMANCE INDICATORS

Optimal has derived and recommends overall net savings goals for each utility. Per the requirements of the Act, these goals are defined in terms of *annual incremental net energy savings*.[64] We outline additional QPIs that we recommend, with a performance incentive structure for meeting goals and a penalty structure for when they do not meet goals. We recommend that performance incentives be in place for these other targets, because only annual savings are statutory requirements.

The experience and current state of efficiency programs in New Jersey constitute an important starting point for any recommendations on performance incentives. The current program infrastructure and experience from other states also inform this analysis. The potential study shows that maximum cost-effective achievable efficiency exceeds the mandated minimums. However, we believe that utilities will need to ramp up program implementation and therefore expand staff, infrastructure, and capabilities.

We suggest that a five-year ramp to a level somewhat above the legislatively mandated minimums is reasonable. As was noted in the literature review, there are only a few high-performing states with mature efficiency programs that are now pursuing goals beyond the Act minimums.

In terms of recommendations for energy savings targets for the first five years of program administration under the Act Table 35 and Table 36 show the electric and gas goals, respectively. All targets reflect the percentage of the prior three years' average annual loads, adjusted for any exempt loads.[65] The proposed 2020 QPIs represent relatively small increases over New Jersey historical and currently planned savings. They also recognize that there might be many new programs and additional program administrators and implementers that will need time to ramp up their efforts.

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[63] We recommend that New Jersey initially pursue passage of a model state standards bill based on the Appliance Standards Awareness Project (ASAP). This has been adopted by Vermont, and is being considered in Rhode Island, Massachusetts, Connecticut, and New York

[64] *Annual incremental energy savings* are defined as the additional first-year estimated new savings achieved from the programs during that year. This factor does not include persisting impacts from past program years, nor does it vary in terms of the duration or shifts in annual savings beyond the first year. *Net savings* refers to the estimated additional savings resulting from the programs, beyond what otherwise would have happened.

[65] Certain utility loads are explicitly exempted by the Act, or are assumed to be exempted for these purposes. Such exemptions might be loads attributed to: transportation, feedstock, distributed generation, and wholesale transactions.

Table 35. Electric net annual statewide energy savings targets

Year	Net savings targets (% of load)	Net annual incremental savings targets (GWh)
2020	0.75%	568
2021	1.10%	833
2022	1.45%	1,100
2023	1.80%	1,369
2024	2.15%	1,645

Table 36. Gas net annual statewide energy savings targets

Year	Net savings targets (% of load)	Net annual incremental savings targets (BBtus)
2020	0.25%	1,168
2021	0.50%	2,335
2022	0.75%	3,511
2023	0.95%	4,473
2024	1.10%	5,226

The Act states that targets should be set for "demand reductions for electric public utilities and gas public utilities." It is common for electric utilities to have peak demand goals, and they often design initiatives specifically to capture peak demand savings. Active demand management (including traditional demand response) is also emerging as a likely cost-effective approach important to balancing expected growing contributions of renewable energy in the generation mix. However, it is unusual for gas utility programs to have peak demand targets, and most of them do not even attempt to measure and track peak impacts, or to set separate avoided cost values for peak periods. However, pipeline and storage capacity issues in the Northeast are becoming a more significant concern, due in part to the current heavy reliance on gas generation for the electric grid. Gas peak loads are usually expressed as "peak day" loads, and are primarily driven by potential storage capacity and pipeline constraints. In some cases, there might also be some significant, geographically specific, peaking constraints on distribution lines.

Although the Act does call for establishing peak demand targets, it does not specify minimum levels for these targets, unlike the energy targets. We have recommended peak demand targets that reflect likely demand impacts coinciding with the efficiency impacts of a well-designed and comprehensive portfolio of programs and measures. That portfolio would need to strike a reasonable balance of impacts for all important end uses. We recommend these targets apply only to passive or load-following demand savings that occur as part of energy efficiency efforts. To the extent New Jersey utilities invest in cost-effective active demand management, we recommend separate metrics and targets for these. Table 37 and Table 38 respectively show recommended electric and gas peak impacts. The electric demand targets reflect savings from the energy efficiency programs, and do not include any demand response or active demand management savings, which should have separate QPIs if appropriate.

Table 37. Electric net annual statewide coincident peak demand savings targets

Year	Net savings targets (% of load)	Net coincident peak savings targets (MW)
2020	0.6%	116
2021	0.8%	174
2022	1.2%	245
2023	1.5%	311
2024	1.8%	374

Table 38. Gas net annual statewide coincident peak demand savings targets

Year	Net savings targets (% of load)	Net coincident peak savings targets (BBtus)
2020	N/A	15
2021	N/A	27
2022	N/A	38
2023	N/A	57
2024	N/A	66

RECOMMENDED PERFORMANCE INCENTIVES

Introduction and Rationale for Performance Incentives

This section presents the concepts and guiding principles around performance incentives for efficiency programs. It also summarizes some of the leading states' approaches, more fully discussed in the Literature Review section.

Under traditional cost-of-service ratemaking practices, utilities have a financial incentive for increasing their retail sales of energy. This is because much of the utilities' revenue is captured with volumetric energy or demand charges, and once the rates are set, actual loads will be the primary determinant of total revenue obtained. Of course, this also means if sales are lower than those forecasted in a rate case, the utility will lose money until the next rate case.[66] Thus, the traditional regulatory paradigm causes improved efficiency to reduce utility revenue without a mechanism to adjust for it.

[66] This assumes that the volumetric portion of retail rates exceeds the utilities' avoided costs of supplying the energy service. This has generally been the case, but there have been rare periods in which the inverse of this relationship has occurred. However, given the significant declines in renewable energy generation costs, the inversion seems extremely unlikely to recur.

Another inherent disincentive for prioritizing efficiency also pertains to utility finances. When utilities make capital investments in supply-side infrastructure, the investments are amortized and become a regulatory asset. Under this structure the utility earns a rate of return (ROE, or return on equity) until the assets are fully depreciated. Conversely, traditional demand side efficiency program investments are typically treated as expenses that are recovered annually, rather than being treated as a regulatory asset for which the utility earns an ROE. Therefore, not only do efficiency programs tend to erode utility revenue in the short term, they also reduce or defer the opportunities for utilities to invest in supply-side capital projects for which the utility can earn a return.

Efficiency program performance incentives have been a solution many leading states have adopted to address the utility disincentives to investing in, and succeeding at, efficiency delivery. By allowing efficiency resources to compete with supply resources on an equal footing, PIs can promote best practices and optimal resource planning.

The Act addresses cost recovery of efficiency program investments, as well as performance incentives and lost revenues.

> *Each electric public utility and gas public utility shall file annually with the board a petition to* ***recover on a full and current basis through a surcharge all reasonable and prudent costs incurred*** *as a result of energy efficiency programs and peak demand reduction programs required pursuant to this section, including but not limited to recovery of and on capital investment, and* ***the revenue impact of sales losses resulting from implementation of the energy efficiency and peak demand reduction*** *schedules,* ***which shall be determined by the board pursuant to section 13 of P.L.2007, c.340 (C.48:3-98.1)****.* [Emphases added]

We note that the Act seems to envision an annual accounting and recovery of efficiency investments, and therefore does not anticipate treatment of efficiency program costs as a regulatory asset that is amortized over time. We also note that the Act directs some sort of cost recovery mechanism to account for the utilities' net lost revenue. These features help to overcome disincentives to implement efficiency programs. Therefore, any performance incentives should primarily address the latter foregone earnings opportunities.

A core principle of demand side management is that efficiency is an energy resource that should be considered on an equal footing with supply side resources. Therefore, offering a base earning level on energy efficiency investments equal to the utility-approved ROE on other assets seems to result in similar treatment, on its face. However, efficiency programs carry much lower risks to shareholders than do most supply side investments, because of the vast number of individual efficiency projects and measures versus the investment in a single, large asset like a distribution line or substation. Because some significant portion of the ROE compensates for risk, a lower return might be appropriate.

Existing PI Mechanisms and Best Practices

Most PI mechanisms take one of a few forms, or some hybrid of these forms, as more fully discussed in the Literature Review section.

1. Allowing the utility to earn a base return on investment (often the utility-approved ROE), with adjustments up or down for performance.[67]
2. Establishing a certain amount of base funds that can be earned, with the amount scaling up or down linearly within a minimum and maximum level as performance exceeds or falls short of expectations.[68]
3. Establishing a shared-savings mechanism, or some other rate of incentives per dollar of net benefits or unit of savings, that are earned on all savings.[69]

We recommend a version of the second approach for New Jersey. As mentioned above, earning the full utility ROE on efficiency might be excessive, given the lower risk that efficiency programs present. By expensing annually, absent a major imprudent action, utilities are all but assured of recovering their spending in a timely way. This eliminates risks such as stranded assets, investments that might never be used and useful, or investments that become uneconomic. Examples of uneconomic investments are those occurring now with legacy coal and nuclear plants in many jurisdictions. The value of an efficiency resource comes from thousands of small assets. This provides significant diversity and assurance that the resource will continue to be there as planned, and will also tend to follow loads.[70] The failure of a single power plant, transmission line, or substation can result in much more significant losses and reliability issues.

In addition to the lower risk of efficiency resources, an important principle in PI design is that the incentives should be sufficient to effectively motivate the utilities to establish programs, while paying no more than necessary, to protect ratepayers. Experience in New England has shown that modest levels of total earnings opportunities are sufficient to provide the necessary incentive.

The pure shared savings approach typically will result in earnings for every unit of savings captured. Utilities can earn some form of performance incentive, even if they fall short of actually meeting goals. A utility could spend 100 percent of its efficiency budget of ratepayer funds and capture only 50 percent of the savings goals, and still be rewarded with earnings. Or a hybrid approach could be designed that uses a shared-savings method, but which has minimum threshold targets to be met before becoming eligible for incentives. If, for example, a minimum threshold of 75 percent was established to receive an incentive, then the utility would not qualify to receive the shared-savings incentive if it reaches only 50 percent of the target.

The following guiding principles for effective PI mechanisms are that they are:

1. Performance-based

[67] Illinois and New York are current examples of this approach.

[68] Many New England utilities use this type of model.

[69] Missouri is an example of this type of model.

[70] Load following exists because, for example, an efficient air conditioner will save more energy during a hot summer when cooling loads in general are large and the resource is most needed.

2. Multivariate
3. Scalable
4. Measurable and objective
5. Inclusive of countervailing-influence metrics to address secondary policy objectives

As the name indicates, PI metrics should generally be based on outcomes, rather than on the completion of activities. For example, instead of rewarding a utility for completing a certain number of energy audits or contractor training sessions, it would be better to reward the actual energy savings from audit-driven installed measures or participation rates resulting from the completed training of contractors. Solely rewarding the actions with an assumption that they have led to performance can result in perverse incentives. That is, those incentives would reward the utility even if the efficiency program performs activities poorly and its initiatives are not effective or worthwhile; but there would be no incentive to ensure meaningful actions.

If a program administrator can receive an incentive for performing audits that do not result in efficiency projects, the PI design has failed. Instead, the design should reward measurable savings and other benefits from action. On occasion, regulators might want to encourage a specific approach that is believed to be a critical step to achieving performance or some other policy objective. In such cases, it is advisable to establish approaches as minimum criteria for some portion of PI eligibility.[71]

PI mechanisms benefit from rewarding multiple measures of performance. This allows for incentives that can promote many policy objectives rather than just a single metric. For example, although one might care about whether the utility has met its annual savings goals, another key policy objective could be cost-efficient spending and maximizing net benefits, or maximizing lifetime (rather than annual) savings.

PI mechanisms benefit from scalability. If instead they encourage a "winner take all" approach for meeting a specific target, they are less effective. For example, if a utility realizes in September that it will not succeed in meeting its goal by the end of the year, and will therefore lose its entire incentive (or pay a penalty), the incentive no longer is a motivating factor to still try to maximize what can be captured. Worse yet, the incentive mechanism can actually encourage a utility to delay capture of some savings to apply in the next program year. Similarly, if a utility is doing well and reaches its goal early, an effective PI mechanism would continue to reward the utility for continuing to strive for even better performance. The Act directs that all proposed PI mechanisms be scalable: "The incentive shall scale in a linear fashion to a maximum established by the board that reflects the extra value of achieving greater savings."

It is critical that any PI metric be measurable and objective, as well as based on actual performance. This will ensure that all parties understand and can agree on the level of

[71] Efficiency Vermont, for example, has many minimum performance criteria metrics that call for things like thresholds for low-income spending.

performance achieved, and enables utilities to manage their progress effectively. It is important to clearly define metrics, and establish any assumptions necessary to calculate performance in advance. For example, if a metric is tied to achievement of net benefits, but allows the avoided costs by which they were set to vary, depending on future estimates, or does not clearly identify all the costs and benefits that can be included, it can result in protracted disagreements. Such a situation also makes it difficult for utilities to monitor their programs' progress.

Typically, primary PI metrics are about savings or some other form of benefits accruing from the savings. These are clearly key policy concerns that reflect the primary purpose of the programs. However, dependence on them can result in perverse incentives that can undermine other secondary policy concerns. For example, with fixed program budgets, maximization of savings or net benefits could drive a program administrator to pursue only the easiest and cheapest savings. This might discourage appropriate attention to capturing long-lived and comprehensive savings, or to serving low-income customers or other segments that are typically more costly for an efficiency program to serve. Several jurisdictions have found that a few metrics to promote actions that counter any possible perverse incentives of the primary metrics, or which ensure attention to key policy objects, can be effective at encouraging a balanced portfolio of programs.

The Clean Energy Act of 2018 calls for performance-based incentives and penalties. Regarding incentives, the Act states,

> *If an electric public utility or gas public utility* ***achieves the performance targets established in the quantitative performance indicators, the public utility shall receive an incentive*** *as determined by the board through an accounting mechanism established pursuant to section 13 of P.L.2007, c.340 (C.48:3-98.1) for its energy efficiency measures and peak demand reduction measures for the following year.* ***The incentive shall scale in a linear fashion to a maximum established by the board that reflects the extra value of achieving greater savings.*** [Emphases added.]

Regarding penalties, the Act states,

> *If an electric public utility or gas public utility* ***fails to achieve the reductions in its performance target established in the quantitative performance indicators, the public utility shall be assessed a penalty*** *as determined by the board through an accounting mechanism established pursuant to section 13 of P.L.2007, c.340 (C.48:3-98.1) for its energy efficiency measures and peak demand reduction measures for the following year.* ***The penalty shall scale in a linear fashion to a maximum established by the board that reflects the extent of the failure to achieve the required savings.*** [Emphases added.]

Our interpretation of the law therefore is that incentives can be earned only once a utility achieves 100 percent of goals, and that penalties must be assessed for any achievement level falling short of 100 percent. It further specifies that both incentives and penalties must scale linearly. However, our interpretation is that there can be two separate linear scales. We have therefore proposed two separate scales, as discussed in the section below and shown in Figure 15 (incentives for goals met) and Figure 16 (penalties for goals not met).

Proposed PI Mechanism Framework

We recommend adopting a PI mechanism framework that allows utilities to begin earning incentives once they achieve 100 percent of a set PI metric target. The earned PI then scales linearly up to a maximum at 125 percent of the metric target. This is shown in Figure 15. We recommend that each PI metric have a specific weighting of the total earnings opportunity. For illustration, Figure 16 demonstrates this as if there were a single PI metric with the entire earnings opportunity tied to it.

If a program administrator does not reach 100 percent of goal, the utility would be exposed to a penalty, which would also scale in a straight line, as required by law. The penalty would continue to scale to the point where no savings (or other metric quantity) at all were achieved. This is shown in Figure 16.

Under our proposed mechanism, the BPU can establish a set amount of base earnings opportunity and a ramp rate for incentives as well as a base penalty level and negative ramp rate. Many PI mechanism frameworks establish these values by selecting a base percentage of *planned annual budgets*. It is important to note that the total amount of earnings opportunity is based on *planned budgets* and fixed for the duration of the plan, regardless of the actual spending. This avoids creating a situation in which one method to raise earnings is to simply spend more money and be less cost efficient. Although all metrics should be based solely on a measure of *performance*, and not on spending or some other activity, using a percentage of budget is a useful approach for establishing the amount of money available. It is a good proxy for the overall level of effort involved in delivering a portfolio of programs.

We also recommend a cap on incentive earnings. It might seem attractive to omit a cap so that the utility is motivated to continue to pursue all possible cost-effective efficiency, even above 125 percent of goals. However, most jurisdictions use a cap so that the maximum ratepayer liability is known, and can ensure that the possibility for an unexpected very high rate impact cannot happen.

We suggest that the base earning incentive for program administrators be 5.0 percent of *planned and approved budgets,* once the program performs at the 100 percent PI threshold metric. The PI would then scale upward, reaching the maximum level of 7.5 percent of *planned and approved budgets* if they reach all the way to 125 percent of PI metrics targets. The proposed performance incentive mechanism framework is depicted in Figure 15.

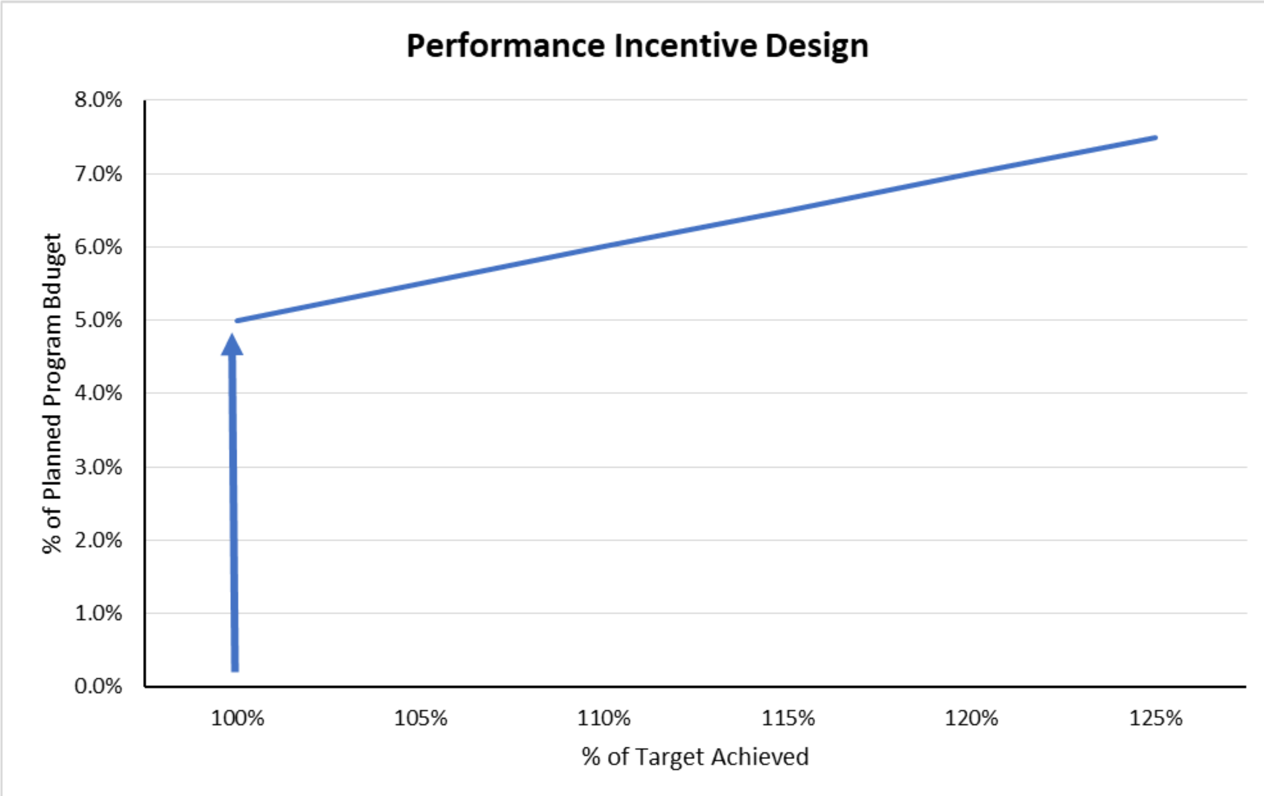

Figure 15. Design for a performance incentive, showing reward for exceeding targets.

At the maximum of 125 percent of the goal, the incentive would be 7.5 percent of earnings. Although this is lower than some utility ROEs, we believe it is consistent with current utility ROEs, especially when the risk premium required for larger and riskier supply side investments is considered. Given the linear scaling, once a utility achieves 100 percent of its performance goal(s), additional gains would proportional. A 1 percent improvement in performance above 100 percent, would earn an additional 0.1 percent until the cap of 125 percent is reached.

For situations where a utility fails to achieve or surpass the goal, a financial penalty would be applied, as shown in Figure 16.

Unlike the positive incentive, the penalty would continue to scale all the way to a hypothetical state in which the utility failed to achieve *any savings* or other metric. We believe this is appropriate. If there is a dramatic failure in achievement, utilities should always be encouraged to make up for as much of the failure as possible and thus minimize its penalty. For the penalties, we propose a downward scaling starting at a zero percent penalty if the program has achieved 100 percent of the goal, and scaling in a straight line downward until it reaches a 2.5 percent penalty (that is, the utility is fined 2.5 percent of its planned and approved budget). This method results in the maximum penalty scaling and the maximum incentive scaling to both represent a 2.5 percent differential, compared to the base target of 100 percent of goal.

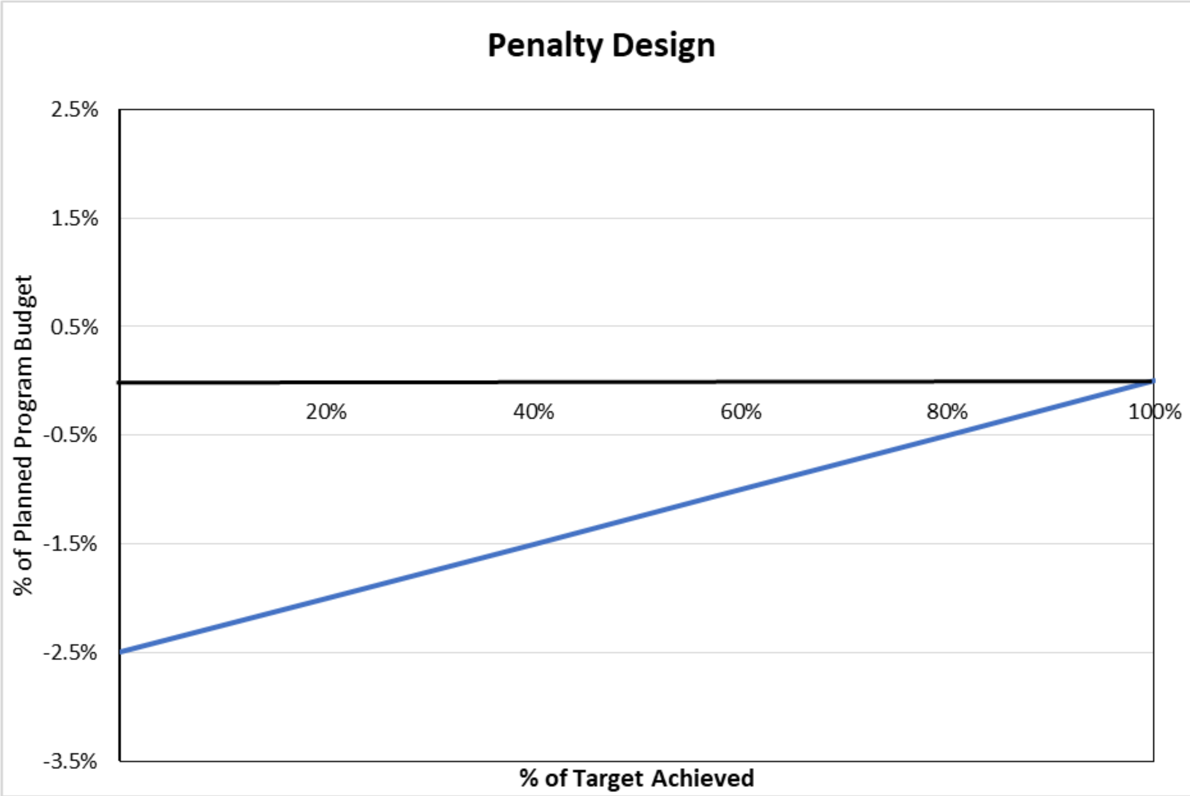

Figure 16. Design for a performance penalty, showing penalty for not meeting targets.

The Act states that

> *Each electric public utility and gas public utility shall file* ***annually*** *with the board a petition to* ***recover on a full and current basis*** *through a surcharge all reasonable and prudent costs incurred…"* [Emphases added.]

This seems to imply a complete settling up of all impacts on ultimate cost recovery each year. Although it seems clear from the context that "costs incurred" applies to actual program costs and any lost revenue recovery, it is less clear whether it requires complete finalization of the PI earnings resulting from the prior year's performance in the current year. If allowable, we recommend an approach in which the PI targets apply for the full plan period, and are based on fully evaluated and verified net impacts at the end of each plan period.

This approach provides flexibility for utilities to make midcourse corrections and to make up for an early year's poor performance in subsequent years. Especially in the first plan period this could be important, because if utilities implement the programs, they will not be accustomed to carrying out the core efficiency efforts in New Jersey. This raises the risk that some utilities could struggle with the start-up of certain program efforts. Further, it eliminates the need for annual comprehensive impact evaluations of each program. Annual impact evaluations, especially for relatively mature programs, can be burdensome, expensive, and unnecessary.[72] Massachusetts originally provided annual PI earnings, but has moved to an approach where all PI awards are now based on cumulative three-year performance. Regardless of whether PIs are set and awarded annually or for some other period, we suggest that all applicable metrics (for example, savings and net benefits) be based on net evaluated impacts.

We recommend a total of eight PI metrics, with the primary weighting on savings and net benefits metrics. Table 39 summarizes our proposed approach, with greater detail on each metric following.

Table 39. Proposed approaches, target metrics, and possible corresponding PI awards

Metric	Targets	Weighting of PI $	Notes
Annual energy savings (kWh / th)	Utility-specific QPI	10%	Ex-post evaluated net annual incremental savings for the plan period
Annual demand savings (KW / peak-day th)	Utility-specific QPI	5%	Ex-post evaluated net annual incremental peak demand savings for the plan period. Demand savings reflect “passive” demand resulting from efficiency programs, and does not include active demand management / demand response savings
Lifetime energy savings (kWh / th)	Utility-specific QPI	20%	Ex-post evaluated net cumulative lifetime savings captured during the plan period
Lifetime of persisting demand savings (KW-yr / Peak-day th-yr)	Utility-specific QPI	10%	Ex-post evaluated net cumulative “lifetime demand savings” captured during the plan period. Lifetime demand savings are the annual peak demand achieved times the number of years the peak savings are expected to persist. Demand savings reflect “passive” demand resulting from efficiency programs, and do not include active demand management / demand response
Utility cost test NPV of net benefits ($)	Utility-specific QPI	35%	Ex-post evaluated NPV net benefits achieved during the plan period. Benefits involve only resulting electricity / gas present value lifetime

72 Note that some form of independent verification of impacts should happen annually, but it does not need to be at the level of comprehensive impact evaluations and net-to-gross studies—for example, confirming data integrity, and alignment with the appropriate protocol’s document version.

Metric	Targets	Weighting of PI $	Notes
			avoided-cost benefits in utility territory for the plan period. Costs include only utility-specific actual program expenditures for the plan.
Low-income lifetime savings (kWh/Th)	Utility-specific QPI	7%	Ex-post evaluated net cumulative lifetime savings captured during the plan period from qualifying low income programs
Small business (less than *specified kWh / th annual load) lifetime savings (kWh / th)	Utility-specific QPI	7%	Definition of *small business* can be customized and be utility specific, where appropriate, to align with data availability (e.g., a tariff cut point)
Optional additional metric for key policy objective and relevant to utility-specific plans	Utility-specific QPI	6%	Placeholder. This can be eliminated from the first plan, or might be based on what is most appropriate to a given plan

Annual and Lifetime Savings. Lifetime savings are more important than annual savings, and will drive overall net benefits captured and long-term energy use. Attention to longer lifetimes also encourages the capture of a comprehensive mix of persisting measures, and discourages over-reliance on very-short-term savings. For example, home energy reports might appear inexpensive as an annual cost, but across the lifetime of an initiative are typically more costly than many other programs. However, we also recommend annual savings as a metric because the Act imposes annual savings goals only. We note that because utilities will be assuring compliance with the Act, and have annual budgetary limits, the absence of a lifetime metric can create a strong and potentially perverse incentive that encourages over-reliance on measures with very short lives and marginal lifetime cost-effectiveness, if the cost per annual kWh is very low.

This study also establishes savings metrics for energy and peak demand. Peak demand has become important for several reasons. For electricity, there are issues of grid stability, and growing renewable and distributed generation. Peak-day gas demand is important because of significant supply and delivery limitations on gas during extreme winter weather events, which can effect costs for both on-site use as well electric generation. As with energy savings, how long the impacts persist is a major driver of the overall benefits. We define *peak electric demand* as coincident peak kW, as is also defined in the New Jersey Protocols. Gas peak savings are measured for peak-day therm capacity, the industry standard, and reflects storage and pipeline supply constraints. The Act calls for annual gas peak targets, and we assume the Protocols will adopt an appropriate approach and definition for development of those impacts.

All demand savings for this metric are related to "passive" demand. This approach counts durable demand savings that result from efficiency measures delivered through the efficiency programs, or from codes and standards, as applicable. It is not clear whether New Jersey utilities will be pursuing active demand (often referred to as *demand response*, but likely to be broader in nature in the near future with active Internet-connected management of customer-sited equipment and storage). We recommend that, to the extent active demand management initiatives are adopted, a separate PI metric(s) be developed for them. Active demand management impacts are typically driven by reliability needs or economics, and are used (or not used) at the discretion of the utility. These are not resources assumed to be *hypothetically* available. We believe it should have separate targets from durable and consistent demand reductions from efficiency programs.

Note that our current recommended savings targets for demand are based on what we believe to be a reasonable ratio of energy to demand savings, for a well-balanced portfolio of programs targeting the proposed levels of energy goals, and informed by the potential study results. In the future, we expect the peak demand targets, as well as the energy and utility cost test (UCT) net benefits targets, would be based on the approved utility plan targets for each of these metrics.

For all energy and demand savings metrics, we propose a combined 45 percent weighting, as shown in Table 39. This means that 45 percent of the total amount of funds dedicated to all performance incentives and penalties would be available for these metrics.

UCT Net Benefits. We acknowledge a high correlation between savings and net benefits, meaning there is some overlap in these metrics in terms of what it is encouraging. However, UCT net benefits also more directly encourage efforts at improving cost efficiency that pure savings metrics do not. In other words, if a utility can achieve its goals with less funds than planned, they will achieve higher net benefits than if they spent the entire budget. We believe that is an important consideration, and therefore have put similar weight on net benefits (35 percent), as we have for combined savings metrics. We expect that the societal cost test (SCT) will be the primary cost-effectiveness driver of what programs utilities or other program administrators pursue. However, we propose UCT net benefits primarily because that test more effectively meets the principle of ensuring metrics are measurable and objective. It also most closely reflects the direct value to all ratepayers on overall utility costs. In our experience, total net benefits used for an SCT calculation can be both difficult to track and measure, and potentially subjective. Metrics dependent on them can result in disagreements around which benefits and costs should be included. Other disagreements might involve specific assumptions around quantifying those benefits and costs that are not readily measurable.

For example, neither utilities nor the BPU can truly know the customer contributions to efficiency investments, so these must be assumed and are highly uncertain. In addition, parties might disagree on the inclusion of, or valuation of, certain non-energy impacts, or other possible costs and benefits. UCT net benefits, on the other hand, are readily and easily measured and tracked by utilities, because their costs represent only the utility expenditures, and benefits depend only on savings and agreed-upon avoided costs.[73] The avoided costs should be defined and held constant for the duration of the PI period for purposes of calculating incentives and penalties. Further, because the BPU charge is to protect ratepayers, the electricity and gas avoided-cost benefits can be viewed as more important and appropriate to compare with ratepayer expenditures, to ensure direct customer benefits will accrue to all ratepayers from the efficiency programs.

Non-savings or Benefits Metrics. We recommend that a few additional metrics be established, utility by utility, and as part of plan approvals. That is, they should be appropriate and applicable to the actual utility plans, and to specific key policy objectives or concerns related to pursuing those plans. We have suggested a few objectives that we believe are of universal importance as policy objectives around equity, energy burden, and environmental justice. In addition, low-income and small-business savings are typically more difficult to capture and more costly to realize than many other efficiency initiatives. Therefore, all else being equal, utilities are likely to prefer easy-to-reach customers and less expensive programs and savings. All the other metrics can only reinforce those preferences, given budget constraints. Because we believe any balanced portfolio should ensure some minimum offerings and benefits for these harder-to-reach segments, we suggest them here for initial additional metrics. However, we expect that the BPU and stakeholders will find other important policy objectives that deserve attention. In many cases, they might be dependent on the specific initiatives planned, or on problems identified from past performance and evaluations.

RECOMMENDED UTILITY TARGETS

Allocations for energy and demand savings QPIs were allocated on the same basis as were the energy efficiency allocations presented in Section 1. Allocations are shown below, first for electric utilities (Table 40 through Table 47) and then for gas utilities (Table 48 through Table 55).

Electric Utility Targets

Table 40. Electric net annual energy savings targets, Atlantic City Electric

Year)	Net savings targets (% of load)	Net annual incremental savings targets (GWh)
2020	0.75%	71
2021	1.10%	104
2022	1.45%	136
2023	1.80%	167
2024	2.15%	198

73 Where possible, if savings from other sources besides utility-administered programs are included in overall savings and benefits, then the costs of achieving them should be included, too.

Table 41. Electric net annual coincident peak demand savings, Atlantic City Electric

Year	Net savings targets (% of load)	Net coincident peak savings targets (MW)
2020	0.6%	15
2021	0.8%	22
2022	1.2%	30
2023	1.5%	38
2024	1.8%	45

Table 42. Electric net annual energy savings targets, JCP&L

Year	Net savings targets (% of load)	Net annual incremental savings targets (GWh)
2020	0.75%	165
2021	1.10%	241
2022	1.45%	318
2023	1.80%	396
2024	2.15%	476

Table 43. Electric net annual coincident peak demand savings, JCP&L

Year	Net savings targets (% of load)	Net coincident peak savings targets (MW)
2020	0.6%	34
2021	0.8%	50
2022	1.2%	71
2023	1.5%	90
2024	1.8%	108

Table 44. Electric net annual energy savings targets, PSE&G

Year	Net savings targets (% of load)	Net annual incremental savings targets (GWh)
2020	0.75%	313
2021	1.10%	460
2022	1.45%	609
2023	1.80%	761
2024	2.15%	916

Table 45. Electric net annual coincident peak demand savings, PSE&G

Year	Net savings targets (% of load)	Net coincident peak savings targets (MW)
2020	0.6%	64
2021	0.8%	96
2022	1.2%	135
2023	1.5%	173
2024	1.8%	208

Table 46. Electric net annual energy savings targets, Rockland Electric

Year	Net savings targets (% of load)	Net annual incremental savings targets (GWh)
2020	0.75%	19
2021	1.10%	28
2022	1.45%	37
2023	1.80%	46
2024	2.15%	55

Table 47. Electric net annual coincident peak demand savings, Rockland Electric

Year	Net savings targets (% of load)	Net coincident peak savings targets (MW)
2020	0.6%	3.9
2021	0.8%	5.8
2022	1.2%	8.1
2023	1.5%	10.5
2024	1.8%	12.4

Gas Utility Targets

Table 48. Gas net annual energy savings targets, Elizabethtown Gas

Year	Net savings targets (% of load)	Net annual incremental savings targets (BBtus)
2020	0.25%	128
2021	0.50%	256
2022	0.75%	386
2023	0.95%	493
2024	1.10%	578

Table 49. Gas net annual coincident peak demand savings targets, Elizabethtown Gas

Year	Net savings targets (% of load)	Net coincident peak savings targets (BBtus)
2020	N/A	1.6
2021	N/A	2.9
2022	N/A	4.2
2023	N/A	6.2
2024	N/A	7.3

Table 50. Gas net annual energy savings targets, New Jersey Natural Gas

Year	Net savings targets (% of load)	Net annual incremental savings targets (BBtus)
2020	0.25%	178
2021	0.50%	360
2022	0.75%	544
2023	0.95%	699
2024	1.10%	823

Table 51. Gas net annual coincident peak demand savings targets, New Jersey Natural Gas

Year	Net savings targets (% of load)	Net coincident peak savings targets (BBtus)
2020	N/A	2.3
2021	N/A	4.1
2022	N/A	6.0
2023	N/A	8.8
2024	N/A	10.4

Table 52. Gas net annual energy savings targets, PSE&G

Year	Net savings targets (% of load)	Net annual incremental savings targets (BBtus)
2020	0.25%	734
2021	0.50%	1,463
2022	0.75%	2,195
2023	0.95%	2,788
2024	1.10%	3,247

Table 53. Gas net annual coincident peak demand savings targets, PSE&G

Year	Net savings targets (% of load)	Net coincident peak savings targets (BBtus)
2020	N/A	9.3
2021	N/A	16.7
2022	N/A	24.1
2023	N/A	35.3
2024	N/A	41.1

Table 54. Gas net annual energy savings targets, South Jersey Gas

Year	Net savings targets (% of load)	Net annual incremental savings targets (BBtus)
2020	0.25%	128
2021	0.50%	256
2022	0.75%	386
2023	0.95%	493
2024	1.10%	578

Table 55. Gas net annual coincident peak demand savings targets, South Jersey Gas

Year	Net savings targets (% of load)	Net coincident peak savings targets (BBtus)
2020	N/A	1.6
2021	N/A	2.9
2022	N/A	4.2
2023	N/A	6.2
2024	N/A	7.3

TECHNICAL APPENDICES

Appendix A: Detailed Utility Allocations

Appendix B: Energy Forecasts

Appendix C: Energy Sales Disaggregations

Appendix D: Measure Characterizations

Appendix E: Impact Factors

Appendix F: Avoided Costs

Appendix G: Load Shapes

Appendix H: Measure Penetrations

Technical Appendices will be provided in the final report.