Long-Term Demand Side Management Potential in the Entergy New Orleans Service Area

Final Report

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Executive Summary

This report summarizes the results of a demand side management (DSM) potential analysis (Potential Study) conducted by ICF International for Entergy Services, Inc. (ESI) and Entergy New Orleans (ENO). The objectives of the analysis were: (1)To develop high-level, long-run **achievable electric DSM program potential estimates** appropriate for inclusion in ESI's Integrated Resource Planning (IRP) analysis of the ENO service area, and; (2) To develop **achievable gas DSM program potential estimates** consistent with New Orleans City Council requirements, and for consideration by ENO in long-term DSM program strategy.

Consistent with IRP requirements, this Potential Study includes forecasts covering a **20-year planning horizon (2015-2034)**. ESI's System Planning and Operations group's (SPO) primary requirements from the Potential Study were hourly **electric loadshapes and program cost projections** representing **three levels—low, reference, and high—of achievable DSM program savings** from 2015 through 2034. These load shapes and costs are the demand side inputs into their IRP analysis. The outputs of the gas study include **gas savings forecasts**, **program costs**, and **cost-effectiveness estimates**.

The long-run planning nature of the Potential Study means that **the estimates should not be applied directly to short-term DSM planning activities**, including, but not limited to program implementation plans or utility goal setting. Long-run program assumptions do not necessarily translate well for actual implementation in the short-term and may not reflect regulatory or other constraints. Program plans require a different level of attention to program design, costs, delivery mechanisms, measure mix, participation, regulatory guidelines, rate impacts, and other factors.

Note also that the characterization of ICF's achievable potential forecast in this report does not represent how SPO utilized the data for the purposes of the IRP, nor are the loadshapes produced for SPO included in this report.

Approach Summary

ICF used a bottom-up approach to estimate DSM potential. "Bottom-up," in the context of achievable potential studies, refers to an analytical approach that begins with characterizing the market size, or eligible stock of efficiency measures, screening measures for cost-effectiveness, forecasting savings for those measures first at the measure-level, then summing savings to the program, and service area levels.

It was assumed that programs with gas measures would be operated jointly with electric programs. That is, we assumed there would be no stand alone gas programs. This is because there were not any cost-effective gas measures that required the creation of new programs, and because gas savings potential is too small in scale to operate gas programs independently of electric programs.

Types of Potential Estimated

For ESI's and ENO's purposes it was necessary only to estimate **achievable potential**, which is **the level of cost-effective net DSM savings estimated to be reasonably achievable through utility-administered programs in the course of the planning horizon**. Achievable program potential estimates are a function of baseline energy use, energy costs, current levels of efficiency measure market saturation, program inventive levels, program market barriers, and other factors.

Technical and economic potential were not estimated. Technical potential is the estimated level of efficiency savings that could technically be achieved without consideration of economics, customer behavior, and other barriers. Technical potential assumes that customers adopt all of the most energy efficient measures regardless of cost or other market barriers. Economic potential is the cost-effective subset of technical potential. Economic potential assumes that all customers will purchase the most cost-effective measures available regardless of market barriers. Technical and economic potential estimates are theoretical and therefore not suitable for use in this study since they do not reflect the level of DSM that could actually be achieved through utility programs.

Scenarios

Achievable energy efficiency potential was forecasted under three scenarios, which are defined below. ICF first developed the reference case estimates by measure for each program. Then, the high and low case scenarios were developed around the reference case.

- **Reference case potential**. The realistic level of cost-effective savings that could be achieved by utility programs given the best information available at the time of the Potential Study. Incentive levels are generally between 25% and 75% of incremental cost, with the exception of hard-to-reach markets, e.g., small business, where incentives need to be different.
- **High case potential**. The level of cost-effective savings that could be achieved by utility programs at maximum incentive levels. Incentive levels were set to 100% of incremental costs where possible.
- **Low case potential**. The level of cost-effective savings that could be achieved at lower incentive levels. In most cases incentives were capped at 25%.

Uncertainty

DSM potential studies are forecasts, and all forecasts have forecast error, or uncertainty. This Study includes thousands of assumptions, including baseline data, measure parameters, avoided costs, program assumptions, and other inputs. While it is impossible to eliminate uncertainty, it can be mitigated through certain analytical strategies. The most basic strategy is to use the best information available at the time of the analysis. Where possible, this Study used data specific to the ENO service area. Where service area- specific data was unavailable, ICF used the most accurate proxy data available, such as Louisiana-specific data or data specific to the Southern region.

Another basic strategy is to use a bottom-up approach such as the one employed in this Study. Using a bottom-up approach ensures that the market size for efficiency measures is accounted for in developing the forecast. In addition, ICF program managers developed participation estimates at the measure level; these were then aggregated to the program and service area levels. By not using a single, formulaic approach to forecasting all measures, we ensured that baselines changes and market barriers applicable to specific measures were not washed-out in the analysis. Finally, benchmarking data on program performance in other jurisdictions was used, where possible, to help gauge the reasonableness of the estimates.

Energy Efficiency Potential

Figure 1, below, provides an overall summary of this Study's electric forecast including GWh and MW savings, savings impacts, costs, benefits, and cost-effectiveness.

Figure 2 provides similar outputs for gas programs. To review the electric forecast:

- ICF estimates that, in the reference case, **ENO can achieve cost-effective cumulative electric savings equal to 6.1% of load over the 2015 to 2034 time horizon**. Total program **costs** over this 20-year period are estimated to **equal $111 Million**.[1] Total **net benefits** are estimated to equal **$100 Million**.
- In the high case, we estimate that ENO could achieve an additional 223 GWh in savings for an additional $28 Million in program spending beyond the reference case. That is, in the high case, savings would increase 59% over reference case levels while spending would increase 25%.
- In the low case, ICF estimates that ENO would achieve 35% less savings than in the reference case, while costs would decrease 17% compared to the reference case.

To review the gas forecast:

- ICF estimates that, in the reference case, **ENO can achieve cost-effective cumulative gas savings equal to 0.5% of sales over the 2015 to 2034 time horizon**. Total program **costs** over this 20-year period are estimated to equal **$9 Million**.[2] Total **net benefits** are estimated to equal **$24 Million**.
- In the high case, we estimate that ENO could achieve an additional 705,876 therms in savings for an additional $8 Million in program spending beyond the reference case. That is, in the high case, savings would increase 211% over reference case levels while spending would increase 189%.
- In the low case, ICF estimates that ENO would achieve 27% less savings than in the reference case, while costs would decrease 56% compared to the reference case.

[1] Including program incentive and non-incentive costs.

[2] Including program incentive and non-incentive costs.

Combined benefits and costs of all electric and gas programs are shown Figure 3.[3]

A key take-away from the gas analysis is that there is insufficient cost-effective gas potential for ENO to run "gas only" programs - the market size is simply too small. This does not mean cost-effective gas measures should not be considered by ENO, but that they should be included in programs that would be combined electric and gas offerings.

One of the most important things to take in account when reviewing the estimates in this report is that program costs and savings of historical programs, particularly from jurisdictions dissimilar to ENO, cannot be compared on an apples-to-apples basis to the long-run costs and savings forecasted for ENO. This is mainly because minimum efficiency standards for equipment and buildings have improved, significantly in some cases. For example, minimum efficiency standards for the most common light bulbs will require such bulbs to be 60% to 70% more efficient in 2020 than they were in 2012. This and other adopted minimum efficiency standards for lighting, appliances, and new buildings mean that future programs will achieve lower savings levels, and at higher costs, than comparable programs in the past, all else equal.

Figure 1. Total Electric Savings, Savings Impacts, Benefits, Costs and Costs-Effectiveness

Scenario	Cumula-tive GWh Savings (2015-2034)	Cumula-tive GWh Savings as % of Sales	Cumula-tive MW Savings (2015-2034)	Cumula-tive MW Savings as % of Peak[4]	Total TRC Benefits, 2015-2034 ($Mil.)	Total TRC Costs, 2015-2034 ($Mil.)[5]	Net TRC Benefits, 2015-2034 ($Mil.)[6]	TRC B/C Ratio	Total Pro-gram Costs, 2015-2034 ($Mil.)[7]	Level-ized Cost per kWh[8]
Low	246	3.9%	69	5.9%	$182	$124	$58	1.5	$92	$0.05
Reference	378	6.1%	112	9.6%	$293	$193	$100	1.5	$111	$0.06
High	601	10.0%	168	14.5%	$790	$463	$320	1.7	$139	$0.09

[3] Includes benefits and costs of all programs, not just the ten programs noted in Section 5 that include electric and gas measures, but also the benefits and costs of the eight additional programs that include only electric measures.

[4] Forecasted non-coincident peak demand.

[5] TRC (Total Resource Cost) test costs include total measure incremental costs and program non-incentive costs over the time horizon of the forecast (2015-2034).

[6] TRC (Total Resource Cost) test benefits include total electric generation (kWh), capacity (kW), and gas (therm) costs avoided over the time horizon of the forecast (2015-2034).

[7] Program costs include incentive costs and non-incentive costs (e.g., administration, marketing, etc.).

[8] Id.

Figure 2. Total Gas Savings, Savings Impacts, Benefits, Costs and Costs-Effectiveness

Scenario	Cumulative Therm Savings (2015-2034)	Cumulative Therm Savings as % of Sales	Total TRC Benefits, 2015-2034 ($Mil.)	Total TRC Costs, 2015-2034 ($Mil.)[9]	Net TRC Benefits, 2015-2034 ($Mil.)[10]	TRC B/C Ratio	Total Program Costs, 2015-2034 ($Mil.)[11]	Level-ized Cost per Therm
Low	462,039	0.4%	$19	$5	$14	3.7	$4	$0.71
Reference	634,173	0.5%	$31	$6	$24	4.9	$9	$1.16
High	1,340,048	1.1%	$51	$17	$35	3.1	$17	$1.08

Figure 3. Combined Electric and Gas Benefits and Costs for All Programs

Scenario	Total TRC Benefits, 2015-2034 ($Mil.)	Total TRC Costs, 2015-2034 ($Mil.)	Net TRC Benefits, 2015-2034 ($Mil.)	TRC B/C Ratio	Total Program Costs, 2015-2034 ($Mil.)
Low	$201	$129	$72	1.6	$96
Reference	$324	$199	$124	1.6	$120
High	$841	$480	$355	1.8	$156

Organization of the Remainder of the Report

Section 1 of this report describes ICF's approach to estimating achievable potential. Section 2 covers baseline energy use in the ENO service area, and Sections 3 and 4 cover the achievable potential forecasts for electricity and gas, respectively. Individual appendices are listed in Section 5, and the actual appendices are provided separately from this report.

[9] TRC (Total Resource Cost) test costs include total measure incremental costs and program non-incentive costs over the time horizon of the forecast (2015-2034).

[10] TRC (Total Resource Cost) test benefits include gas (therm) costs avoided over the time horizon of the forecast (2015-2034).

[11] Program costs include incentive costs and non-incentive costs (e.g., administration, marketing, etc.).

List of Acronyms

Acronym	Full Description
ACEEE	American Council for an Energy-Efficient Economy
AHRI	Air Conditioning Heating and Refrigeration Institute
CBECS	U.S. Department of Energy Commercial Buildings Energy Consumption Survey
CBI	Commercial Building Inventory
CHP	Combined heat and power
DOE	U.S. Department of Energy
DSM	Demand side management
EIA	U.S. Department of Energy, Energy Information Administration
ENO	Entergy New Orleans
EE	Energy efficiency
ESI	Entergy Services, Inc.
LBNL	Lawrence Berkeley National Laboratory
MECS	U.S. Department of Energy Manufacturing Energy Consumption Survey Consumption Survey
MISO	Midcontinent Independent System Operator
RASS	Residential Appliance Saturation Survey
RECS	U.S. Department of Energy Residential Energy Consumption Survey
SEER	Seasonal Energy Efficiency Ratio
SPO	System Planning and Operations
TRC	Total Resource Cost
TRM	Technical Resource Manual

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1 Analysis Approach

1.1 Overview of Approach

ICF used a bottom-up approach to estimate energy efficiency potential. The approach is illustrated in Figure 4. "Bottom-up," in the context of achievable potential studies, refers to an analytical approach that begins with characterizing the market size, or eligible stock of efficiency measures, screening measures for cost-effectiveness, forecasting savings for those measures first at the measure-level, then summing savings to the program, and service territory levels.

This analysis started with collecting data on all relevant inputs, including baseline data, measure data, and program data. Data types collected are itemized in Figure 5.

Estimating the eligible stock of efficiency options was the next step of the analysis. The eligible stock is the size of the market for efficiency measures, in measure units, such as bulbs, tons of cooling, or homes. ICF estimated the eligible stock for each measure within each end use and sector. This required data on the number on customer types in each service territory, the number and types of buildings, what types of energy using equipment are in each building type, and the current saturation of efficient equipment.

A comprehensive measure database was also developed in the first stages of the analysis. This database includes 228 measure types and 1,056 measures in total. Commercially available electric and gas measures covering each relevant savings opportunity within each end use and sector were included. The database includes prescriptive or "deemed" type measures, whole building and custom options, and behavioral measures. The database is comprised primarily of retrofit measures but also includes replace-on-burnout and new construction measures.

Measures were then screened for cost-effectiveness using the measure Total Resource Cost (TRC) test. With few exceptions, only measures with a TRC test result of 1.0 or better were passed on to the next stage of the analysis.

With the eligible stock and measures defined, ICF then performed the achievable potential analysis, which involved developing savings forecasts for measures included in 17 program types across three sectors over the 2015 to 2034 time period under three scenarios:

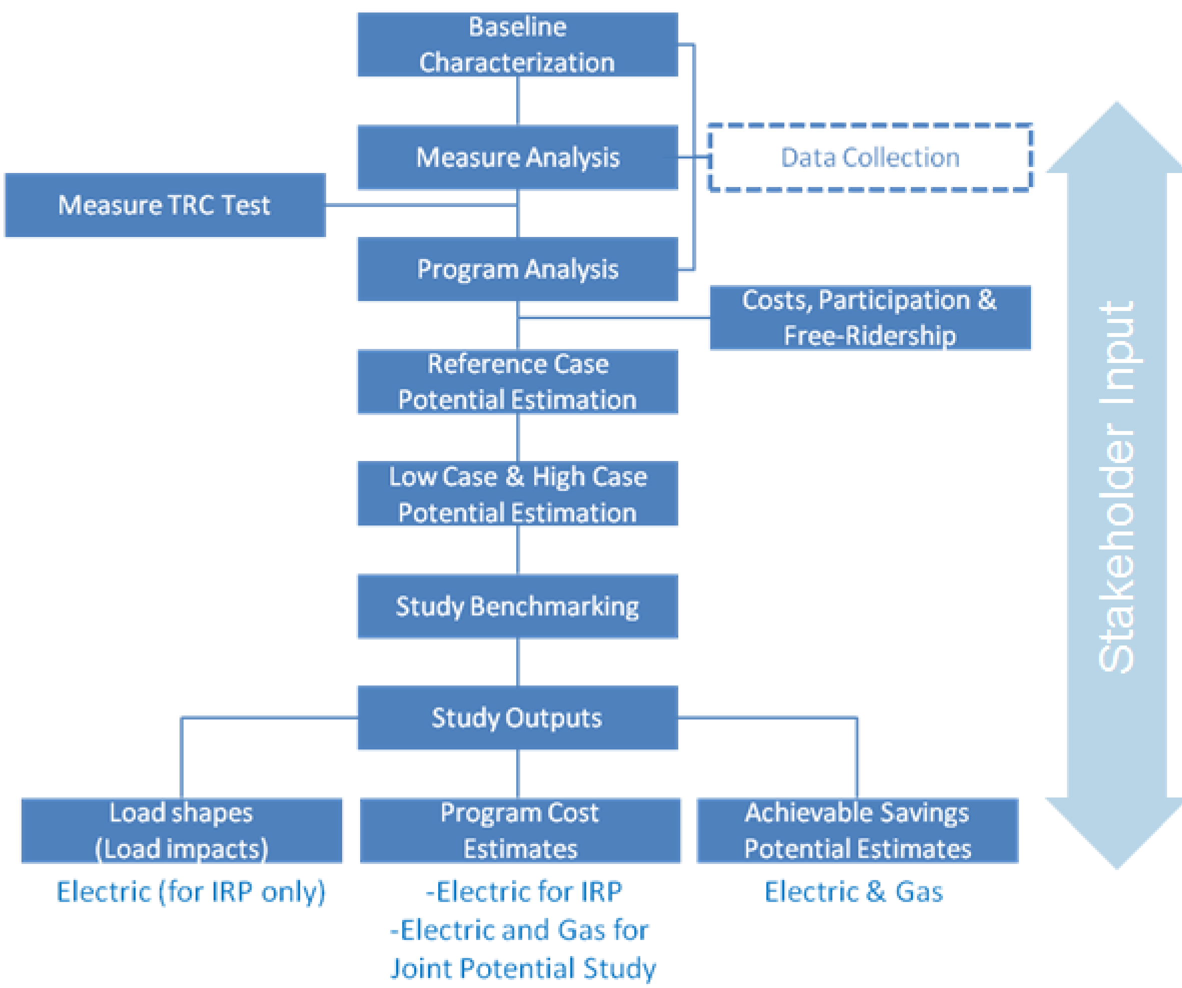
- **Reference case potential**. The realistic level of cost-effective savings that could be achieved by utility programs given the best information available at the time of the Potential Study. Incentive levels are generally between 25% and 75% of incremental cost, with the exception of hard-to-reach markets, e.g., small business, where incentives need to be different.[12]

[12] Incentives for programs targeting hard-to-reach customers tend to be higher than for other programs, since to these customers energy efficiency is less affordable. For example, incentives for the Low Income Weatherization program modeled in this Study are 100% of incremental costs.

- **High case potential**. The level of cost-effective savings that could be achieved by utility programs at maximum incentive levels. Incentive levels were to 100% of incremental costs where possible.
- **Low case potential**. The level of cost-effective savings that could be achieved at lower incentive levels. In most cases incentives were capped at 25%.

Finally, ICF provided Entergy SPO with the DSM inputs required for the IRP. These included loadshapes for each program, which reflect savings forecasted for every hour of every year of the analysis, and annual program costs. Gas savings potential and program costs were also developed, though these were not inputs to the electric IRP. In the sub-sections below, ICF discusses each step in the analysis in further detail.

Figure 4. Potential Study Approach



1.2 Data Collection

The sources of data used in the analysis are shown in Figure 5. Every effort was made to use data that was as current as possible, and to use assumptions specific to the ENO service area; primary data was used where possible.

Figure 5. Data Used in Analysis

Data/Information Type	Source (Year)	Type of Data	Primary Purpose in this Study
Utility Information			
Avoided costs	Entergy (2014)	Forecast	Cost-effectiveness testing
Customer counts	Entergy (2014)	Actual	Calculating the eligible stock
Load forecast	Energy (2014)	Forecast	Calculating load impacts of EE potential
Retail rates	Entergy (2014)	Actual	Achievable potential analysis
Baseline Data			
Residential building characteristics and efficiency saturation	Entergy Residential Appliance Saturation Survey (2006)	Primary	Calculating the eligible stock
	Post-Katrina Study by GCR (2008)	Primary	
	U.S. DOE Residential Energy Consumption Survey (RECS, 2009)	Secondary	
	U.S. Census Data (2009)	Secondary	
	Other Secondary Sources (See Appendix)	Secondary	
	ICF expert judgment	Secondary	
Commercial building characteristics and efficiency saturation	Commercial Building Inventory (CBI) data for Louisiana (2014)	Secondary	
	Air Conditioning Heating and Refrigeration Institute (AHRI, 2014)	Secondary	
	U.S. DOE Commercial Buildings Energy Consumption Survey (CBECS, 2003)	Secondary	
Commercial building characteristics and efficiency saturation	Other Secondary Sources (See Appendix)	Secondary	
	ICF expert judgment	Secondary	

Data/Information Type	Source (Year)	Type of Data	Primary Purpose in this Study
Industrial sub-sector characteristics and efficiency saturation	U.S. DOE Manufacturing Energy Consumption Survey (MECS, 2010)	Secondary	

Data/Information Type	Source (Year)	Type of Data	Primary Purpose in this Study
Measure Assumptions			
Residential measure data	AR Technical Resource Manual (TRM) v. 3.0 (2014)	Measure parameters	Measure database development
	OK TRM (2014)[13]		
	CA DEER (2014)		
	Mid-Atlantic TRM (2014)		
	NREL (2014)		
	IL TRM (2014)[14]		
	ICF measure databases (2014)		
Commercial measure data	AR Technical Resource Manual v. 3.0 (2014)		
	OK TRM (2014)[15]		
	IL TRM (2014)[16]		
	Mid-Atlantic TRM (2014)		
	ICF measure databases (2014)		
Industrial measure data	U.S. DOE studies; U.S. EPA studies; LBNL studies; other published studies (see Appendix)		
	ICF estimates (2014)		
Program Information			
ICF program data and expert judgment	ICF	Secondary	Estimating achievable potential
Historical program savings data	U.S. EIA (2010-2012)	Secondary	Program savings benchmarking
Program cost data	ACEEE (2014)	Secondary	Program cost benchmarking
Customer survey data	ICF	Primary	Payback acceptance calculations

[13] Adjustments to cooling and heating degree days made for weather sensitive measures.

[14] Id.

[15] Id.

[16] Id.

1.3 Eligible Stock

After data collection, estimating the eligible stock of efficiency options was the next step of the analysis. The eligible stock is the size of the market for efficiency measures, in measure units, such as bulbs, tons of cooling, or homes. ICF estimated the eligible stock for each measure within each end use and sector. Key data from the baseline sources noted above includes items such as:

- The percent of homes with a particular type of equipment (e.g., light bulbs, central air conditioner, refrigerator),
- Equipment counts (e.g., number of bulbs per home, tons of cooling per home, refrigerators per home),
- Equipment efficiency level (e.g., bulb type, SEER rating, ENERGY STAR Rating), and
- Equipment age.

A simple example of an eligible stock calculation for residential specialty bulbs is shown below. This example shows there are 1.8 million incandescent specialty screw-in bulbs installed in homes in ENO's service area (row g). This equals 100% of all specialty light bulbs installed (row f). That is, based on the best available information, 100% percent of the existing stock of residential specialty screw-in bulbs could be replaced with more efficient units (e.g., a reflector LED).

Since this is a "replace-on-burnout" measure, the eligible stock must account for stock turnover (row h). Stock turnover is the rate at which existing equipment expires and requires replacement. It is the inverse of equipment age, or one divided by the equipment's effective useful life (EUL).[17] After the application of the stock turnover rate, the total number of specialty bulbs eligible to be replaced in 2014 equals 3.2 million (row i).[18]

[17] For retrofit measures, annual replacement eligibility equals 100%.

[18] ICF's potential model updates the eligible stock in every year of the analysis to account for measures installed in previous years.

Figure 6. Example Eligible Stock Calculation

	Variable	Value	Source/Calculation
	Efficient unit	12 Watt LED Specialty Lamp	AR TRM v. 3.0
	Baseline unit	60W Incandescent Specialty Lamp	AR TRM v. 3.0
a	Baseline unit effective useful life	2	AR TRM v. 3.0
b	# ENO Residential Customers	162,863	Entergy SPO
c	# Bulbs per Home	33.9	U.S. DOE RECS (2009)
d	% Applicability (% of bulbs that are specialty applications)	32%	Entergy RASS
e	Efficient unit saturation	0%	U.S. DOE RECS (2009)
f	Not yet adopted rate	100%	1-e
g	Total eligible stock in 2014	1,766,734	b*c*d*f
h	Annual replacement eligibility (stock turnover rate)	50%	1/a
i	Total # bulbs eligible to be replaced in 2013	883,367	b*c*d*f*h

For many measures, this information is broken down further in ICF's energy efficiency potential model. For example, the eligible stock for residential central air conditioners is further broken down by:

- Efficiency rating (SEER level),
- Home heating type (electric or gas), and
- Decision type (replace-on-burnout, retrofit, new construction).

1.4 Measure Analysis

ICF developed a comprehensive measure database for this Study. The database includes most measures in the Arkansas Technical Reference Manual ("TRM") version 3.0[19] plus additional measures included based on a gap analysis. The final database includes commercially available measures covering each relevant savings opportunity within each end use and sector. The database includes prescriptive or "deemed" type measures, whole building options (such as commercial custom and new construction projects), and behavioral measures (such as residential Home Energy Use Benchmarking and

[19] The AR TRM v.3.0 was the most current, regulator-approved TRM applicable to Entergy services territories at the time of this analysis.

Retrocommissioning measures). Data for each of the characteristics shown in Column A in Figure 7 was developed for each measure.

Figure 7. Illustrative Measure Characteristics (Wall Insulation)

(A) Measure Characteristic	(B) Value
1. Applicable sector	Residential
2. Applicable subsector	Single Family
3. Building type	AC with Gas Heat
4. End-use	Shell
5. Measure name	Wall insulation
6. Measure definition	R-13
7. Baseline definition	No insulation
8. Measure unit	Home
9. Measure delivery type	Retrofit
10. Incremental cost	$1,310 (materials and labor)
11. Baseline unit effective useful life	N/A (baseline=no insulation)
12. Efficient unit effective useful life	20 years
13. Incremental (annual) kWh savings	1,073 kWh
14. Incremental kW savings	0.796 kW
15. Annual Gas savings (Therms)	132.36

1.4.1 Measures Evaluated

In total, ICF analyzed 228 measure types for this Study; 148 electric-only measure types, 66 gas-only measure types, and 14 measures that result in both electric and gas savings. An example of a measure type is a residential central air conditioner (CAC). These measure types represent all end uses and savings opportunities. Many measures required permutations for different applications, such as different building types, lamp wattages, efficiency levels and decision types. For example, there are permutations of CACs by SEER level, subsector, and building type. As shown in Figure 8, ICF developed a total of 1,056 measure permutations for this Study. Sixty-seven percent of these measures are retrofit in nature, 31% are replace-on-burnout type measures, and 2% are new construction type measures.

Descriptions of each measure type and permutation are in the Appendix, as well as measure cost-effectiveness results.

Figure 8. Number of Measures Evaluated and Included

Sector	# Measure Types Evaluated	Total # Measures Evaluated (All Measure Permutations)	# Measures Cost-Effective (TRC>=1)	# Measures Included in Analysis
Electric Only Measures				
Residential	40	94	70	66
Commercial	44	476	363	336
Industrial	64	197	187	187
Total Electric Only	**148**	**767**	**620**	**589**
Gas Only Measures				
Residential	10	30	2	3
Commercial	12	37	10	2
Industrial	44	183	152	149
Total Gas Only	**66**	**250**	**164**	**154**
Electric and Gas Measures				
Residential	13	14	10	10
Commercial	1	25	20	20
Industrial	0	0	0	0
Total Electric and Gas	**14**	**39**	30	30
GRAND TOTAL	**228**	**1,056**	**814**	**773**

1.4.2 Measure Benefit Cost-Screening

All measures were analyzed for cost effectiveness using the measure Total Resource Cost (TRC) test.[20] Electric measure TRC results were calculated in three test years: 2014, 2020, and 2022. Most studies only test measure cost-effectiveness in the base year. However, we decided to test electric measure cost-effectiveness in 2020 and 2022, in addition to doing so in 2014, because short-term avoided electric costs are very low, due in large part to a short-term capacity surplus in MISO. The capacity cost forecast increases every year and stabilizes in 2022.Thus, ICF believes 2022 is a more representative year for testing measure cost-effectiveness for the purposes of this long-run Study, than is 2014.[21] [22]

[20] Measure TRC benefits include avoided energy and avoided capacity costs due to the measure over the measure lifetime. Measure TRC costs are measure incremental costs; these include the difference in equipment and labor costs between the efficient and baseline units.

[21] All else equal, an electric measure tested for cost-effectiveness in 2022 had a higher measure TRC ratio than the same measure tested in 2014.

[22] 2014 was used as the test year for gas only measures.

Therefore, for nearly all electric measures, measure cost-effectiveness was assessed using 2022 as the test year. The only exceptions were for measures that phase-out prior to 2022. Lighting measures impacted by EISA 2007 Tier 2 were tested using 2020 as the test year. Air conditioning and heat pump measures impacted by DOE rules were tested in 2014 (see Section 1.4.3 for a description of how codes and standards were treated in this Study).

In most cases, only measures with a TRC of 1.0 or higher (in their representative test years) were passed on to the next stage of the analysis. A measure TRC result of 1.0 indicates that the measure is cost-effective on a standalone basis (before consideration of program costs or net-to-gross ratios). Exceptions to this rule were made for some low-income measures (the assumption being that low income programs are required by policy), and for non-economic measure permutations where a majority of the permutations of that measure type were cost-effective. For example, if a measure type was cost-effective for a majority of but not all applicable building types, ICF included the measure type for all building types in the achievable potential analysis. This is because it can be impractical in implementation to exclude participation by customers in specific building types.

Some cost-effective measures were also not included in the analysis. If a measure was cost-effective for a minority of building types, ICF excluded all permutations of the measure in the achievable potential analysis since it can be impractical in implementation to limit participation to certain building types. There were also some cost-effective measures with little to no known technical applicability[23] in New Orleans; certain types of commercial gas boiler measures, for example.[24] In such cases, the measure was also excluded from the analysis.

1.4.3 Treatment of Codes and Standards

The treatment of equipment and building energy baselines in this Study is summarized below.

- The Energy Independence and Security Act of 2007 (EISA) set energy efficiency standards for light bulbs manufactured from 2012 forward. From 2012 through 2014, Tier 1 of EISA took effect, phasing-out the manufacture and import of traditional filament incandescent 100W bulbs in 2012 and 75W bulbs in 2013. In 2014, the EISA legislation impacted 60 watt and 40 watt incandescent light bulbs, which are the most common light bulbs in use. The next EISA milestone, Tier 2, takes effect in 2020. This phase will require that all light bulbs manufactured are 60-70% more efficient

[23] Technical applicability is the fraction of the relevant building stock where the measure can actually be installed, or used.

[24] For example, ICF examined commercial boiler cut-out controls as a possible gas measure. However, there was insufficient data on the number and age of commercial boilers in New Orleans to be able to estimate potential for this measure. ICF program experience in the South also suggests that, due to the very low number of heating degree days (HDD) in the region, commercial boiler use for space heating in New Orleans is minimal, and that such boilers are used largely for water heating. Cut-out controls are not applicable in such situations, as their use would result in turning off the hot water supply to the building.

than before EISA took effect. Lighting industry experts and program planners expect residential lighting program savings to be viable up until 2020. However, the current assumption of many experts and planners is that programs may not be able to claim savings for most CFLs and LEDs after 2020 due to the baseline changes, and to significant price decreases of LEDs.[25] The exceptions are specialty CFLs and reflector LEDs, which are exempt from EISA 2007.

- U.S. DOE rules pertaining to commercial lamps and ballasts are reflected in baselines for linear florescent lighting.[26] These rules result in a 20% improvement in baseline efficiency for linear florescent lamps.[27] This is important because efficient linear florescent lighting accounts for the largest portion of historical commercial lighting savings in many jurisdictions.
- U.S. DOE energy conservation standards for residential heat pumps (HPs) and single package central air conditioners (CACs) go into effect in 2015 and 2016, respectively. The improvement from a SEER 13 to a SEER 14 baseline for these units has a negative impact on the savings and cost-effectiveness of CAC and HP measures.
- Louisiana's current commercial building energy code is compliant with ASHRAE 90.1-2007. However, ICF assumed commercial new construction baselines consistent with the next (and more efficient) version of the code, which is ASHRAE 90.1-2010 for the 2015 to 2018 period; for the remainder of the Study period (2019-2034) we assumed the adopted code would be ASHRAE 90.1-2013. These are reasonable assumptions given the long-run nature of the Study.
- Similarly, Louisiana's current residential building energy code is compliant with IECC 2009. However, ICF assumed residential new construction baselines consistent with the next (and more efficient) version of the code, which is IECC 2012. Again, this is a reasonable assumption given the long-run nature of the Study.

1.5 Achievable Potential Approach

This section describes ICF's approach to modeling achievable potential, starting with the program types modeled, followed by subsections on the development of program assumptions, and on the scenario analysis.

1.5.1 Programs Modeled

Eighteen program types were modeled for this Study. These are briefly described below, by sector.

[25] ENERGY STAR-compliant A-line LEDs were available at Home Depot stores in Louisiana for $10 at the time this Study was completed, and prices continue to decline toward the cost of CFLs.

[26] Consistent with the U.S. Energy Policy Act of 2005.

[27] The rules specify a switch from magnetic ballast baseline to an electronic ballast baseline.

Residential Programs

- **Home Energy Use Benchmarking**. Program designed around directly influencing household habits and decision-making on energy consumption through quantitative or graphical feedback on consumption, accompanied by tips on saving energy.
- **Lighting and Appliances**. Midstream incentive program that brings down the cost of efficient lighting, appliances and consumer electronics.
- **Multifamily**. Commercial building characteristics
and efficiency saturation. Program designed to encourage the installation of measures in common areas and units for residential structures of more than four units. Aimed at building owners, managers, and tenants. Due to the very small size of the multifamily housing sector in the ENO service area, it was assumed that this program would merge with the Home Energy Audit and Retrofit program in the long run.
- **Efficient New Homes**. Program that provides incentives to builders for new homes built or manufactured to energy performance standards higher than applicable code.
- **ENERGY STAR Air Conditioning**. Program designed to encourage the distribution, sale, purchase, and installation of residential air conditioners and heat pumps that are more efficient than current standards.
- **Home Energy Audit and Retrofit**. Residential audit program that provides a comprehensive assessment of a home's energy consumption and identification of opportunities to save energy. Incentives are paid for the installation of identified measures such as insulation and duct sealing. Program includes a direct install element where low cost measures are installed with participant permission.
- **Pool Pump**. Program that incentivizes the installation of higher efficiency pumps or variable speed pumps for swimming pools.
- **Water Heating**. Program designed to encourage the distribution, sale, purchase, and installation of water heating systems that are more efficient than current standards.
- **Solar Hot Water**. Program required by City Council of New Orleans to encourage the distribution, sale, purchase, and installation of solar water heating systems.
- **Low Income Weatherization**. Program for qualifying low-income customers that provides home weatherization (e.g., air sealing, insulation) free of charge.
- **Direct Load Control**. A demand response program by which the utility remotely shuts down or cycles a customer's air conditioner.
- **Dynamic Pricing**. Tariff in which residential customers are charged more during times when electricity is more expensive, and less when it is less expensive.

Commercial Programs

- **Commercial Prescriptive and Custom**. Program that provides both financial incentives and technical assistance to all eligible commercial customers seeking to improve the efficiency of existing facilities; provides resources for new higher efficiency equipment purchases, facility modernization, and other efficiency improvements.
- **Data Centers**. Custom program around large-scale server floors or data centers. Projects tend to be site specific and involve some combination of measures for servers, networking devices, HVAC, and energy management systems and software.
- **New Construction**.: Program that provides technical support in the building design phase, and incentives to owners, builders, architects and similar parties for buildings that exceed current energy efficiency codes by prescribed levels.
- **Retrocommissioning (RCx)**. Provides in-depth engineering studies on commercial buildings that focus on operational adjustments designed to optimize building system performance. Incentives are paid for implementing measures identified in studies.
- **Small Business**. Program that provides basic energy audits and direct install measures to small business customers, and deep discounts/incentives for additional measures identified through audits.
- **Dynamic Pricing**. Tariff in which commercial customers are charged more during times when electricity is more expensive, and less when it is less expensive.

Industrial Programs

- **Industrial Prescriptive and Custom**. Program that provides both financial incentives and technical assistance to all eligible industrial customers seeking to improve the efficiency of existing plants; provides resources for new higher efficiency equipment purchases, facility modernization, and other efficiency improvements. Industrial Prescriptive and Custom sub-programs modeled for this Study include:
  - Machine Drive
  - Process Heating
  - Boilers
  - Process Cooling and Refrigeration
  - Facility HVAC
  - Facility Lighting
  - Other Process/Non-Process Use

1.5.2 Gas Programs Modeled

It was assumed that programs with gas measures would be operated jointly with their analogous electric programs. That is, we assumed there would be no stand alone gas programs. This is because there were not any cost-effective gas measures that required the creation of new programs, and because gas savings potential is too small in scale to operate gas programs independently of electric programs.

Ten of the programs described above would include both electric and gas measures:

A. Residential Programs
    1. Efficient New Homes
    2. Home Audit and Retrofit
    3. Home Energy Use Benchmarking
    4. Low Income Weatherization

B. Commercial and Industrial Programs
    5. Commercial Prescriptive and Custom
    6. Industrial Boilers
    7. Industrial HVAC
    8. Industrial Process Heating
    9. Industrial All End Uses
    10. Small Business Solutions

1.5.3 Program Assumptions

This section describes how key assumptions were developed for programs. Key assumptions include costs, participation rates, and net-to-gross ratios.

Program Costs

Program costs were estimated to reflect average annual costs over the long run. Notwithstanding the baseline improvements discussed above, ICF expects program costs in the long run to be lower than program costs today. This is because Louisiana is an immature market for DSM. As programs grow and the market matures, program delivery costs are expected to decrease as a percentage of overall program costs.[28]

Incentive and non-incentive program cost estimates were developed. Incentives are program payments to customers, contractors, retailers, or manufacturers that lower the cost of efficient products and services. Non-incentive costs include administration, marketing, education and training, and evaluation costs. Individual non-incentive cost categories were not estimated for this Potential Study. ICF program experience and program costs in other territories were considered in developing program costs for this

[28] For example, fixed costs associated with program start-up increase program costs in the short-run, not in the long-run.

Potential Study. Cost estimates by program are shown in aggregate in Sections 3 and 4 and by program in the Appendix.

Participation

A participation rate is the percent of the eligible stock or applicable customer population predicted to install an efficiency measure in a given year. The approach to developing participation rates in this potential Study was similar to the approach used in most potential studies. It involves:

1. Developing a maximum market acceptance rate or (S_{max}), which is the maximum annual participation rate for a given measure.
2. Estimating a participation rate in year 1 of the program.
3. Developing a ramp-up schedule from year 1 to the year in which S_{max} is predicted to occur
4. Forecasting participation for the years after the year in which the S_{max} is expected to be achieved.

The shape of participation curves can take a variety of forms depending on the nature of the measure, the program in which it is being delivered, the relevant market barriers, baseline changes and the size and nature of the eligible stock. ICF assessed achievable participation on a measure-by-measure basis. Because such a wide variety of measures are included in this Study, ICF could not apply just one formulaic approach to estimating program participation for all measures. This is illustrated generally by the participation approach types described below, and by the participation estimates for individual measures shown in Appendix A. Each measure was put in a group[29] with similar measures for the purpose of assigning participation approaches and payback curves; these assignments are shown in Appendix C.

Participation Approach A

This approach to estimating participation combines research on customer financial decision making with research on the diffusion of innovative technologies in the marketplace.

[29] Most programs have multiple measure groupings, or bundles. Some, such as Home Energy Use Benchmarking, only have one group.

One way that programs motivate customers to participate is by improving the financial attractiveness of the efficient option over the standard, or baseline option. Financial attractiveness in Approach A is a function of how much the incentive lowers the customer simple payback. Customer payback is the amount of time it takes for a customer to recover the costs of investing in the efficient unit instead of the standard unit. Customer payback equals the difference in cost between the efficient and standard units (commonly known as the incremental cost), divided by the utility bill savings due to the efficient unit.[30] Payback before the incentive is applied is calculated as:

Pre-incentive Customer payback (Years) =
Incremental cost ÷ Utility bill savings

And payback after the incentive is applied is calculated as:

Post-incentive Customer payback (Years) =
(Incremental cost—Incentive cost) ÷ Utility bill savings

In the reference case, measure incentives were calculated to bring down the customer payback to two years, with a cap of 75% of incremental cost, and a minimum incentive of 25% of incremental cost.[31] An incentive calculation for an illustrative measure is shown in Figure 9.[32]

For this illustrative measure the pre-incentive payback is 6.3 years (row 10) and the post-incentive payback is two years (row 17). Not all incentives bring down the payback to two years. This happens when the maximum incentive is reached, when the pre-incentive payback is already less than two years, or when the incentive would need to be greater than the incremental cost to bring the payback down to two years.

[30] Incremental costs include the difference in the cost of equipment, labor and operations, and maintenance.

[31] Incentive levels for other scenarios are shown in Section 1.5.4.

[32] Values shown in Figure 9 are generic and shown only to demonstrate approach. The values should not be construed as actual assumptions used in this Study. Actual assumptions are noted as such in the body of this report and in the Appendix.

Figure 9. Illustrative Measure Incentive Calculation

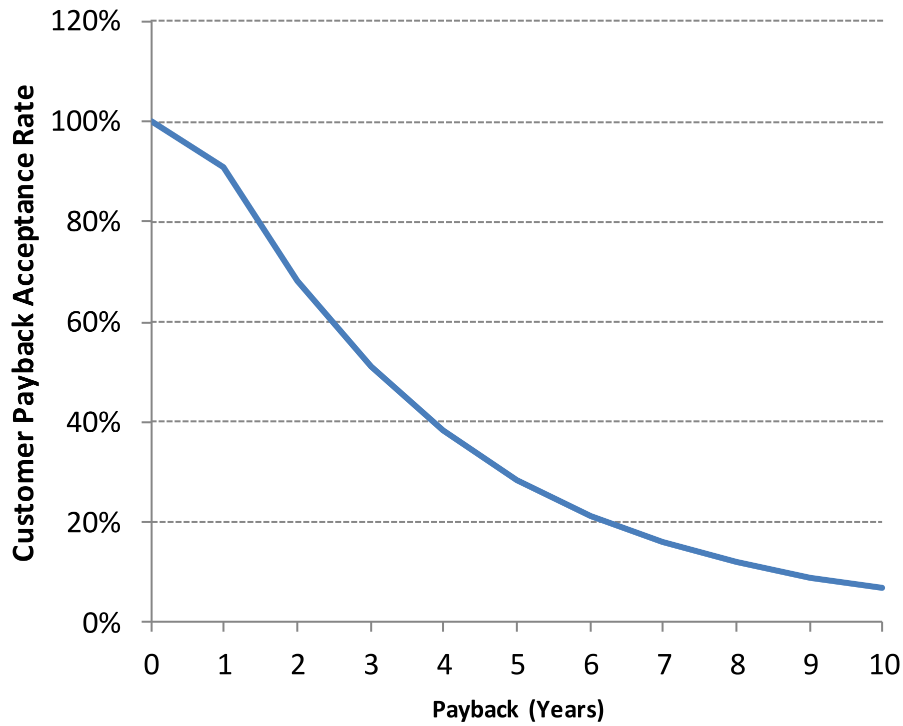
	Incentive Calculations	Value	Source/Calculation
1	Retail Electricity Rate—kWh	$ 0.09	Utility
2	Retail Capacity Charge—kW	$ 0.00	Utility
3	Retail Gas Rate—therm	$ 0.95	Utility
4	Base Measure Life	15	Deemed Savings
5	Total Incremental Cost`	$ 238.00	Deemed Savings
6	Annual kWh Savings	417.33	Deemed Savings
7	Annual kWh Summer-Peak Savings	0.12	Deemed Savings
8	Annual Gas Savings	0.00	Deemed Savings
9	Annual Bill Savings	$ 37.91	Annual Energy Savings by Participant
10	Pre-incentive Payback (Years)	6.3	Total Incremental Cost/Annual Bill Savings
11	**Incentive Assumptions**		
12	Minimum Incentive Level	25%	Reference Case Assumption
13	Maximum Incentive Level	75%	Reference Case Assumption
14	Post-incentive Payback Target (Years)	2	Reference Case Assumption
15	Incentive as % of Incremental Cost	68%	MAX [MIN (Minimum Incentive Level, 1-Post-rebate Payback Target/Pre-rebate Payback)]
16	Incentive	$ 162.18	Incentive as % of Incremental Cost x Total Incremental Cost
17	Post-incentive Payback	2	(Total Incremental Cost-Incentive) / Annual Bill Savings

Incentives are used to calculate program costs and to forecast participation. ICF uses the post-incentive payback to estimate the fraction of customers that may choose the efficient unit over the standard unit. This is done using payback acceptance curves, an example of which is shown in Figure 10. Different payback curves were utilized for each sector. All payback curves utilized in this Study are shown in Appendix C.

The curve in Figure 10 plots results from a residential survey on payback acceptance.[33] The curve shows that 68% of eligible residential customers stated they are willing to accept a two-year measure payback. However, people tend to overstate their payback acceptance in surveys. This is sometimes called survey response bias; when customers are making actual decisions about installing equipment, they are usually willing to accept much shorter payback levels than they stated they would in a survey.

[33] Surveys were conducted prior to this Study outside of Entergy service areas.

Figure 10. Illustrative Payback Acceptance Curve



Survey response bias as well as market barriers need to be accounted for in developing program participation estimates. Market barriers to participation include financial barriers, such as lack of access to capital; information barriers, such as lack of customer understanding about the benefits of efficient equipment; and, delivery barriers, such as contractor recruitment and participation. Response bias and market barriers are considered by ICF when developing participation curves.

In participation Approach A, three variables determine the shape of the participation curve for a measure:

1. A *maximum market acceptance rate*, or "S_{max}"(row 2 in Figure 11) is used to estimate the maximum annual participation rate;[34] next the ramp-up schedule is determined using
2. A *ramp-up rate* (row 3 in Figure 11) to estimate first year participation; and
3. A *ramp-up shape* (row 4 in Figure 11) is applied to reflect how quickly a program could reach the maximum annual participation rate.

The maximum annual market acceptance (S_{max})[35] is the product of the customer stated payback acceptance and the program market acceptance rate (row 8 in Figure 11):

Maximum annual market acceptance rate (S_{max}) =
Customer stated payback acceptance x Program Market Acceptance rate

Moreover, the first year participation rate is maximum annual market rate, divided by the ramp-up rate (row 9 in Figure 11). To summarize:

First year participation rate =
Maximum annual market acceptance rate ÷ Program ramp up rate

Figure 11. Illustrative Market Diffusion Assumptions

	Program Assumptions	Value	Source/Calculation
1	Customer Stated Payback Acceptance	68%	Payback Acceptance Calculation
2	Program Market Acceptance Rate	30%	ICF Program Assumption
3	Ramp-up Rate	5	ICF Program Assumption
4	Ramp-up Shape	100%	ICF Program Assumption
5	Program Start Year	2015	
6	Study Period (years)	20	
7	First Year Participation Estimates		
8	Maximum Annual Market Acceptance (S_{max})	20.4%	Program Market Rate Acceptance x Customer Stated Payback Acceptance
9	First Year Share of Installations (S_o)	4.1%	Maximum Annual Market Acceptance (S_{max})/ Ramp-Up Rate

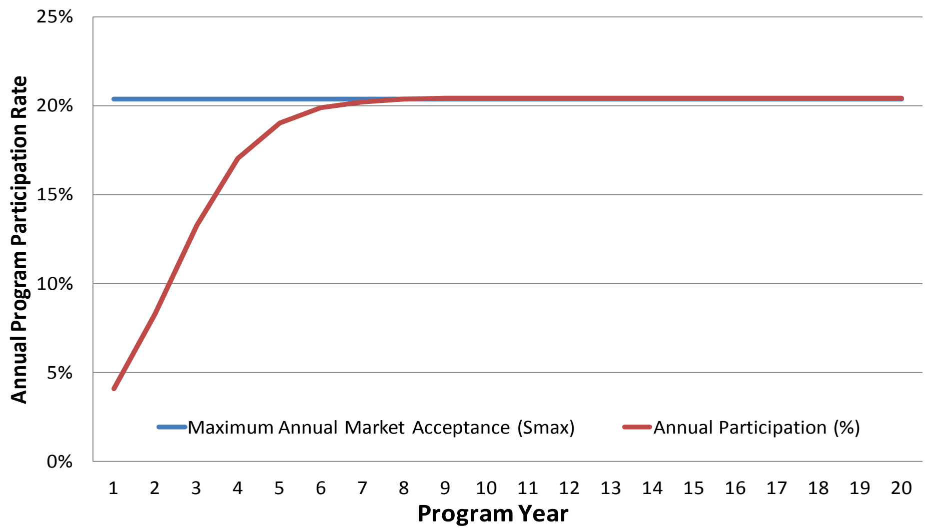
Figure 12 illustrates the outcome of Approach A. Program participation in the first year is 4%. The participation rate in each year grows until it reaches the maximum estimated level of 20%. Increasing

[34] The program participation rate in the year the program reaches maturity.

[35] The highest estimated level of program market penetration in a given year.

the ramp-up shape steepens the curve, and decreasing it makes the curve more gradual. This figure is an example of a "market diffusion" or "s-curve."

Figure 12. Market Diffusion Curve



This approach to modeling DSM program participation is only applicable to measure and program types where payback acceptance is relevant to customer financial decision-making.

Participation Approach B

Participation Approach A is not applicable to DSM measure and program types where payback acceptance is a less relevant proxy for customer financial decision making. This is the case for residential new homes programs, for example, where qualified homebuilders are the target market, not homebuyers. Nor does the payback acceptance survey data apply to customer decisions about participating in demand response programs. For measures where Approach B was used, participation rates were individually inputted for each year based on program experience.

Demand Response Program Participation

Two types of demand response (DR) programs were modeled for this Study: Dynamic Pricing (for Residential and for C&I) and Residential Direct Load Control.

Direct load control participation requires the utility to install a controlling device on the customer's AC or to install a "smart thermostat" inside the customer's home. Participation estimates were split evenly between these two options.

DR participation forecasts in this Study were based on the Expanded Business as Usual (EBAU) case for Louisiana developed for FERC by The Brattle Group.[36] DR programs were assumed to be voluntary, or "opt-in" in nature. This is generally consistent with current regulation of DR options in most service areas.

Net-to-Gross Ratios

Program evaluators independently verify reported savings and conduct empirical studies and other activities to estimate actual energy savings during the period of performance. The ratio of evaluated savings to reported savings is called the program net-to-gross (NTG) ratio. Applying the NTG ratio to gross savings results in net savings. Net savings estimates are reflected in the load shapes provided to SPO for this Potential Study.

Reference case NTG ratios were estimated based on program impact evaluation results from California, Illinois and from the Northeast, and are shown the in Appendix. As noted above, NTG ratios were generally increased in the high scenario, as evaluation research has shown that higher incentive levels are correlated with lower free-ridership. This principal was also applied in the low case; NTG ratios were lowered in most cases from reference case levels since incentives in the low case are lower than in the reference case.

1.5.4 Scenario Development

Achievable energy efficiency potential was forecasted for the above programs under three scenarios, which are defined below. ICF first developed the reference case estimates by measure for each program using the approaches describe d above. Then, the high and low case scenarios were developed around the reference case.

- **Reference case potential**. The realistic level of cost-effective savings that could be achieved by utility programs given the best information available at the time of the Potential Study. Incentive levels are generally between 25% and 75% of incremental cost, with the exception of hard-to-reach markets, e.g., small business, where incentives need to be different.
- **High case potential**. The level of cost-effective savings that could be achieved by utility programs at maximum incentive levels. Incentive levels were set to 100% of incremental costs where possible.
- **Low case potential**. The level of cost-effective savings that could be achieved at lower incentive levels. In most cases incentives were capped at 25%.

Besides incentive levels, program designs were assumed to be identical across scenarios. Assumptions about customer preferences and decision making criteria, utility assumptions such as avoided costs and discount rates, as well as exogenous economic factors such as growth and inflation were all held

[36] Federal Energy Regulatory Commission. A National Assessment of Demand Response Potential. Prepared by The Brattle Group et al. June 2009.

constant across scenarios.[37] As such, the ICF's scenario analysis focused on the impact of varying incentive levels.

Below we provide additional information on how the high and low cases were developed subsequent to the completion of the reference case. Since readers tend to focus more on the high than the low case, more description is provided regarding the development of the high case.

- **Comparative incentive analysis.** Incentive levels in the reference case are generally between 25% and 75% of measure incremental cost. All incentives in the high case are 100% of incremental cost, except as noted below. In the high case, for measures or programs where incentives are less important, the additional incentive has little to no impact. This is true for the Commercial New Construction program. In other cases, the 100% incentive has a large impact, as with the Commercial Prescriptive and Custom program.
- **Cost-effectiveness constraints.** In the high scenario, incentives could not be increased to 100% for every program due to cost-effectiveness constraints. This is because changing incentive levels can change the mix of measures installed. For example, increasing the incentive to 100% increases participation of high efficiency air conditioners (e.g., SEER 16+), which save more energy than efficient SEER 14-15 units, but also cost considerably more; as a result, they are less cost-effective than the SEER 14-15 options. Increasing uptake of such measures reduced overall cost-effectiveness compared to reference case levels for some programs. In such cases, incentives were increased up to the point where, when non-incentive program costs were added, the program was still cost-effective.
- **Non-incentive program costs.** Changing incentive levels also requires adjusting program non-incentive costs for most programs. If increasing incentives increases participation, then more incentive processing is required, more inspections and other quality assurance must occur, more trainings must be held, etc. And the converse is true when incentives are decreased. Therefore, non-incentive costs were adjusted from reference case levels in the low and high cases commensurate with changes in gross savings estimates. This was done on a program-by-program basis, and required expert input from ICF DSM program managers.
- **Net-to-gross ratios.** Finally, for most programs*,* incentive levels are negatively correlated with free-ridership; higher incentives generally correspond to lower free-ridership, and vice versa. Therefore, NTG ratios for most programs were decreased in the low scenario, and increased in the high scenario. NTG assumptions for each scenario are shown in the Appendix.

[37] One reason these factors are held constant in ICF's model is that ICF's DSM forecasts are used as inputs to SPO's IRP model, which is a dynamic model that varies utility, macroeconomic, and other assumptions.

2 Energy Use in the ENO Service Area

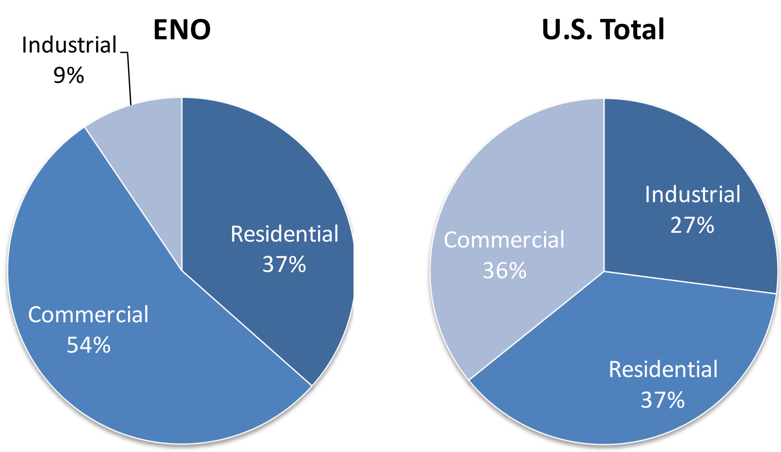
This section of the report begins by briefly describing baseline electricity use in the ENO service area. Next, the baseline natural gas use is described.

2.1 Electricity

Below we describe base year (2013) electricity use in the ENO service territory, in aggregate and by sector by end use. Figure 13 shows the distribution of electricity use in 2013 for ENO and for the U.S. in total. Note the ENO industrial share is one-third the U.S. industrial share, and that the ENO commercial share is 50% higher than the U.S. commercial share. Figure 14 and Figure 15 show the distributions of residential and commercial electricity use by end use. Figure 16 disaggregates industrial use by sector by end use.

As discussed in the Approach section, measures were developed for each applicable end use, and an eligible stock, or market size, was estimated for each measure. Data on the eligible stock is included in the measures section of the Appendix.

Figure 13. Distribution of Total Base Year Electric Electricity Use, by Sector, for ENO and U.S. Total (ENO Total 2013 Sales= 5,105 GWh)[38]



[38] Commercial for ENO also includes government and lighting sales; industrial sales % also includes industrial CHP, which is not included in the industrial subsector totals in Figure 16.

Figure 14. Distribution of Base Year ENO Residential Electricity Use by End Use (Total 2013 Residential Sales=1,867 GWh)[39]

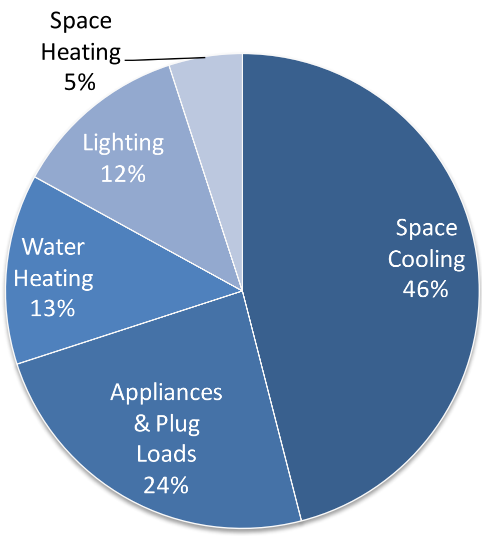
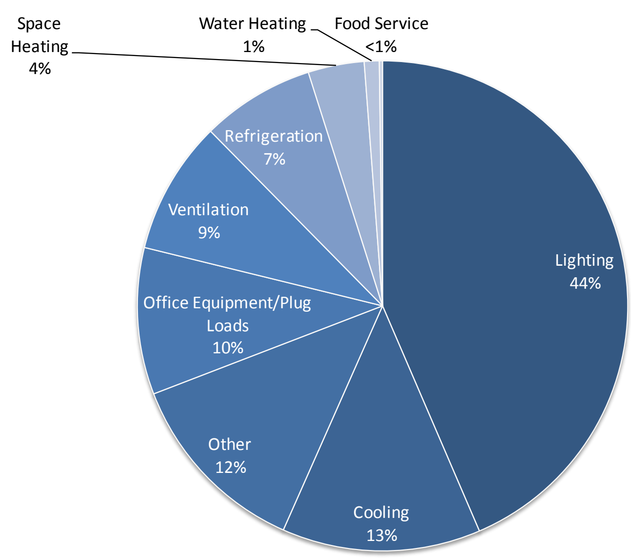


Figure 15. Base Year ENO Commercial Electricity Use by End Use (Total 2013 Commercial Sales=2,767 GWh)[40]



[39] Sources: ICF estimates based on U.S. DOE (CBECS 2003) and CBI commercial building data for Louisiana.

[40] Includes Government and Lighting sales. Sources: Entergy (2014), U.S. DOE (CBECS 2003), Commercial Building Institute (2014)

Figure 16. Base Year Industrial Electricity Use by Sector by End Use (ENO)[41]

	Large Industrial			Small Industrial	All Sectors
	Food Products	Industrial Gases	All Other - Large Industrial		
Total Industrial Base Year (2013) Sales, GWh	65	226	40	150	**481**
% Total Industrial Base Year (2013) Sales	13%	47%	8%	31%	**100%**
End Use	**% Base Year (2013) MWh Use by Sector by End Use**				
Machine Drive	47%	52%	52%	52%	**52%**
-Pumps	11%	14%	14%	14%	**14%**
-Fans	5%	8%	8%	8%	**7%**
-Compressors	5%	9%	9%	9%	**8%**
-Materials handling	4%	7%	7%	7%	**6%**
-Materials processing	17%	13%	13%	13%	**13%**
-Motor - Other Applications	4%	2%	2%	2%	**2%**
Process Heating	5%	11%	11%	11%	**11%**
Process Cooling and Refrigeration	28%	7%	7%	7%	**10%**
Other Process Uses	0%	2%	2%	2%	**2%**
Electro-Chemical	0%	9%	9%	9%	**8%**
Facility HVAC	8%	8%	8%	8%	**8%**
Facility Lighting	8%	6%	6%	6%	**7%**
Other non-process use	3%	2%	2%	2%	**2%**
Other process/Other non-process use	0%	0%	0%	0%	**0%**

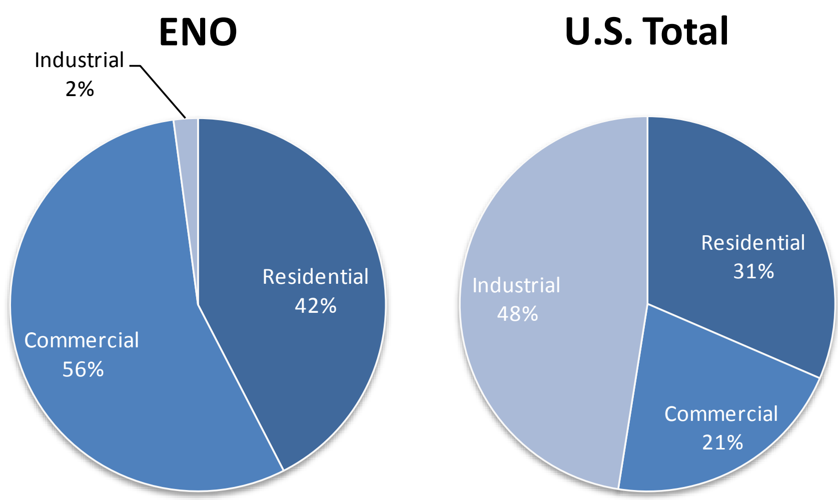
[41] Sources: Entergy (2014), U.S. DOE (MECS 2010). Note industrial total sales shown in the table do not include combined heat and power (CHP). Note also that the industrial sales forecast provided by SPO and used by ICF to determine the industrial baseline for this Potential Study has been updated since this analysis was performed. SPO's updated industrial sector forecast shows higher growth in industrial electricity use than the previous forecast. All else equal, this may mean that industrial savings potential could be slightly underestimated in this Potential Study, but it is too difficult to draw any specific conclusions about the impacts of the updated industrial forecast without further analysis.

2.2 Natural Gas

Below we describe base year (2013) natural gas use in the ENO service territory, in aggregate and by sector by end use. Figure 17 shows the distribution of natural gas use in 2013 for ENO and for the U.S. in total. Note the ENO industrial share 4% of the U.S. industrial share, and the ENO commercial share is 267% of the U.S. commercial share. Figure 18 and Figure 19 show the distributions of residential and commercial electricity use by end use. Figure 20 disaggregates industrial use by sector by end use.

As discussed in the Approach section, measures were developed for each applicable end use, and an eligible stock, or market size, was estimated for each measure. Data on the eligible stock is included in the measures section of the Appendix.

Figure 17. Distribution of Total Base Year Natural Gas Use, by Sector, for ENO and U.S. Total (ENO Total 2013 Sales= 92,223,913 Therms)[42] [43]



[42] Commercial for ENO includes government. ENO industrial share excludes sales to non-jurisdictional ("NJ") large industrial customers served by ENO under negotiated rates, terms and conditions specific to each of those customers.

[43] Sources: ENO; U.S. EIA, 2014.

Figure 18. Distribution of Base Year ENO Residential Natural Gas Use by End Use (Total 2013 Residential Sales= 39,130,304 Therms)[44]

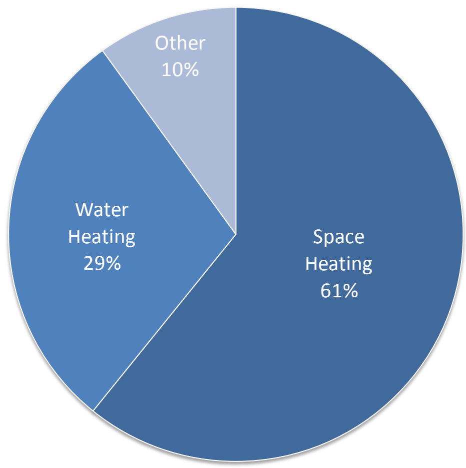
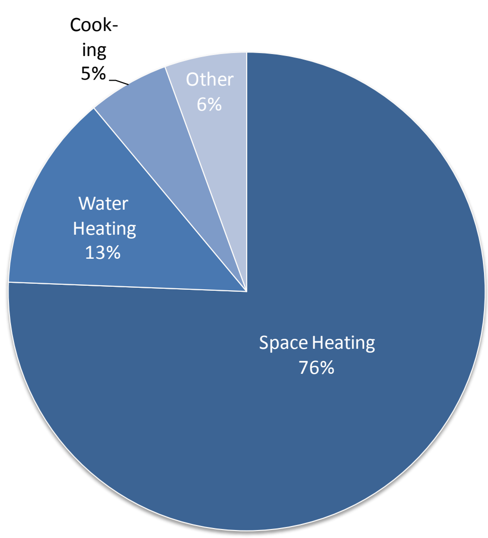


Figure 19. Base Year ENO Commercial Natural Gas Use by End Use (Total 2013 Commercial Sales=51,156,855 Therms)[45]



[44] Sources: Entergy Services, U.S. DOE RECS 2009

[45] Includes Government. Sources: Entergy (2014), U.S. DOE (CBECS 2003), Commercial Building Institute (2014)

Figure 20. Base Year Industrial Natural Gas Use by Sector by End Use [46]

	Large		Small Industrial	All Sectors
	Industrial Gases	All Other - Large Industrial		
Total Industrial Base Year (2013) Sales, Therms	1,051,744	186,724	698,286	**1,936,754**
% Total Industrial Base Year (2013) Sales	54%	10%	36%	**100%**
End Use				
Boilers	18%	13%	13%	**16%**
CHP/Cogeneration	42%	37%	37%	**40%**
Other Electricity Generation	<1%	<1%	<1%	**<1%**
Process Heating	32%	42%	42%	**36%**
Process Cooling and Refrigeration	<1%	<1%	<1%	**<1%**
Other Process Uses	2%	2%	2%	**2%**
Machine Drive	3%	2%	2%	**3%**
HVAC	1%	3%	3%	**2%**
Onsite Transportation	<1%	1%	1%	**1%**
Other Nonprocess	<1%	<1%	<1%	**<1%**

[46] Sources: Entergy (2014), U.S. DOE (MECS 2010). Note industrial total sales shown in the table do not include combined heat and power (CHP). Note also that the industrial sales forecast provided by SPO and used by ICF to determine the industrial baseline for this Potential Study has been updated since this analysis was performed. SPO's updated industrial sector forecast shows higher growth in industrial electricity use than the previous forecast. All else equal, this may mean that industrial savings potential could be slightly underestimated in this Potential Study, but it is too difficult to draw any specific conclusions about the impacts of the updated industrial forecast without further analysis.

3 Achievable Electric Energy Efficiency Potential

This section includes the presentation and analysis of ICF's forecast of total achievable electric DSM potential for the ENO service area for 2015 through 2034. Total achievable potential is the sum of residential, commercial, and industrial potential. Electric savings and program cost estimates are shown, as well as benefit-cost estimates. The forecast is put in context through benchmarking analysis.

3.1 Cumulative Potential

Total achievable potential is the sum of achievable potential estimated for each measure in the analysis. Total cumulative achievable potential estimates are shown in Figure 21, along with cumulative savings[47] impacts. Figure 22 provides an overall summary of this Study's forecast including electricity and demand savings, savings impacts, costs, benefits, and cost-effectiveness. To review the forecast:

- ICF estimates that, in the reference case, ENO can achieve cost-effective cumulative electric savings equal to 6.1% of load over the 2015 to 2034 time horizon. Total program costs over this 20-year period are estimated to equal $111 Million.[48] Total net benefits are estimated to equal $100 Million.
- In the high case, we estimate that ENO could achieve an additional 223 GWh in savings for an additional $28 Million in program spending beyond the reference case. That is, in the high case, savings would increase 59% over reference case levels while spending would increase 25%.
- In the low case, ICF estimates that ENO would achieve 35% less savings than in the reference case, while costs would decrease 17% compared to the reference case.

[47] The summation of savings from multiple projects or programs over 2015-2034, taking into account the time of measure installation in the first year, annual energy savings for subsequent years, and the life of the installed measures.

[48] Including program incentive and non-incentive costs.

Figure 21. ENO Cumulative MWh Savings Forecast, by Scenario

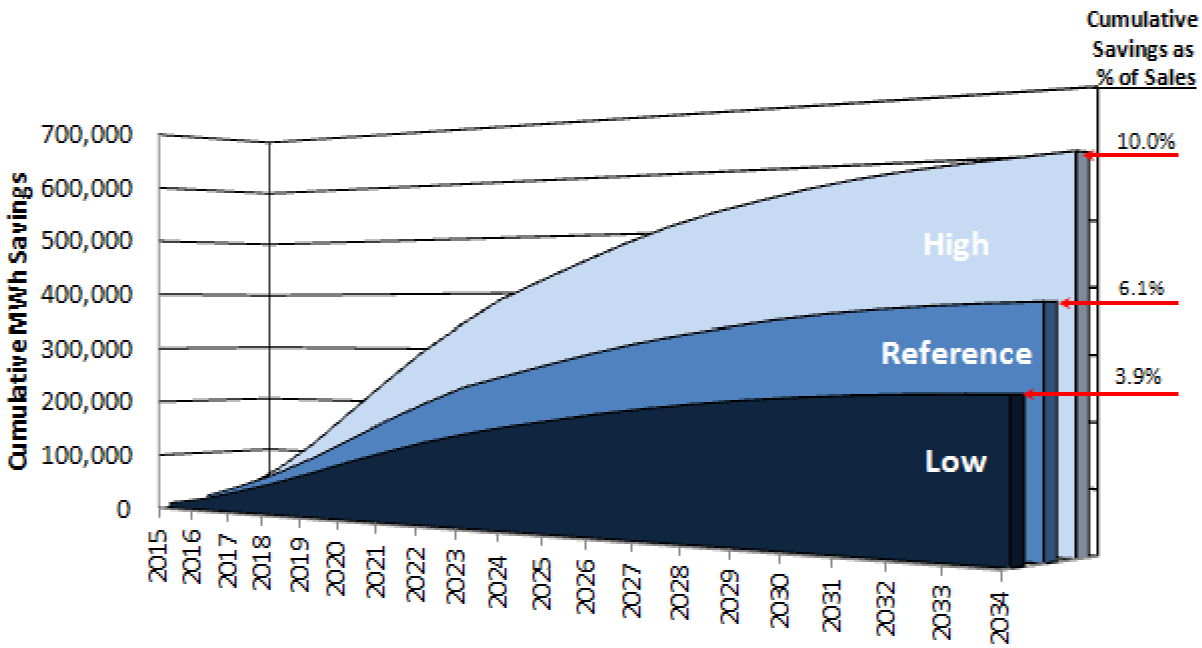


Figure 22. Total Electric Savings, Savings Impacts, Benefits, Costs and Costs-Effectiveness, by Scenario

Scenario	Cumula-tive GWh Savings (2015-2034)	Cumula-tive GWh Savings as % of Sales	Cumula-tive MW Savings (2015-2034)	Cumula-tive MW Savings as % of Peak[49]	Total TRC Benefits, 2015-2034 ($Mil.)	Total TRC Costs, 2015-2034 ($Mil.)[50]	Net TRC Benefits, 2015-2034 ($Mil.)[51]	TRC B/C Ratio	Total Pro-gram Costs, 2015-2034 ($Mil.)[52]	Level-ized Cost per kWh[53]
Low	246	3.9%	69	5.9%	$182	$124	$58	1.5	$92	$0.05
Reference	378	6.1%	112	9.6%	$293	$193	$100	1.5	$111	$0.06
High	601	10.0%	168	14.5%	$790	$463	$320	1.7	$139	$0.09

[49] Forecasted non-coincident peak demand.

[50] TRC (Total Resource Cost) test costs include total measure incremental costs and program non-incentive costs over the time horizon of the forecast (2015-2034).

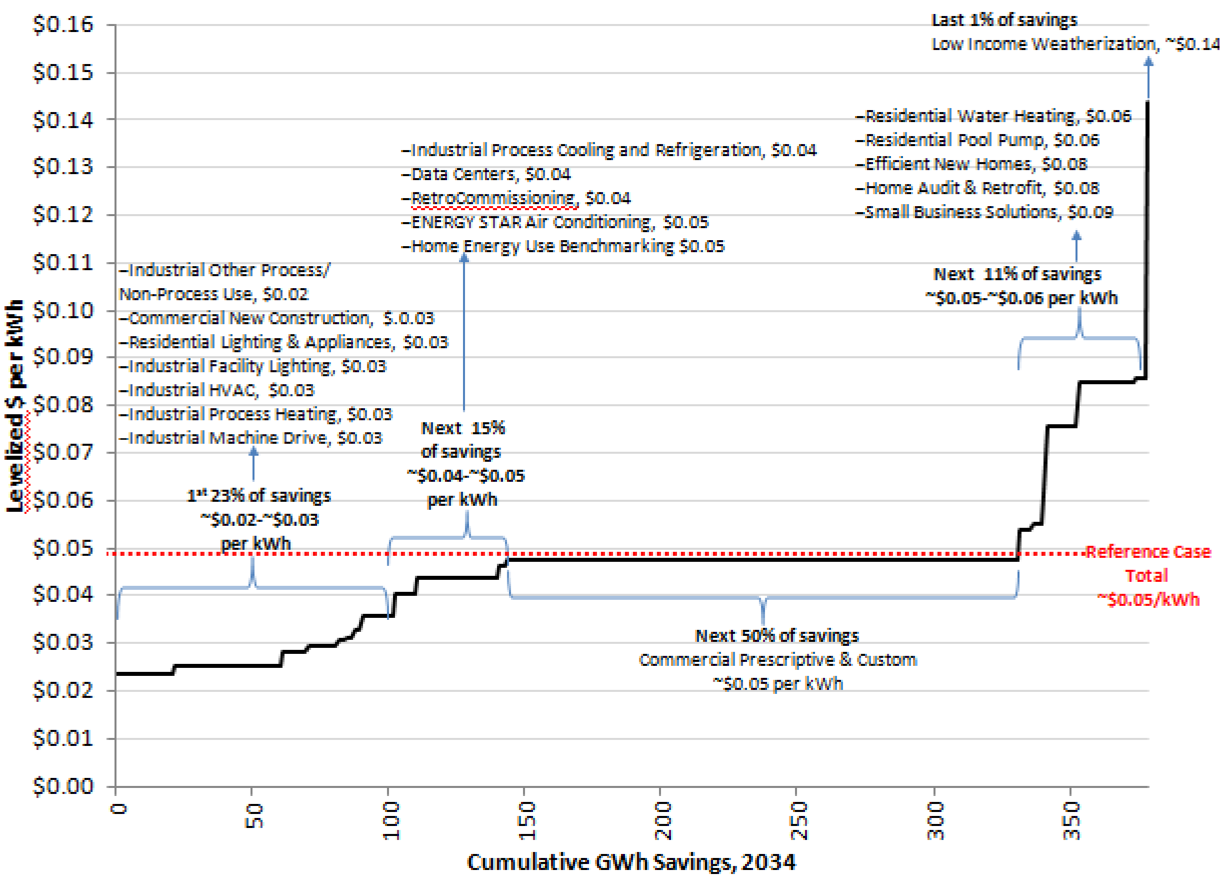
[51] TRC (Total Resource Cost) test benefits include total electric generation (kWh), capacity (kW), and gas (therm) costs avoided over the time horizon of the forecast (2015-2034).

[52] Program costs include incentive costs and non-incentive costs (e.g., administration, marketing, etc.).

[53] Id.

Figure 23 shows the reference case DSM supply curve, which plots cumulative electric savings on the x-axis and levelized program costs on the y-axis.[54] The graph shows that 23% of savings could be achieved through programs that cost $0.02-$0.03 per kWh. Moving from left to right, each additional group of programs shown in the graph is more costly on a per kWh basis. The programs listed in each group on the supply curve are sorted from lowest to highest levelized cost per kWh; Industrial Other Process/Non-Process Use and Commercial New Construction are the least costly; Low Income Weatherization is the most costly. The program with the largest savings impact is Commercial Prescriptive and Custom.

Figure 23. ENO Electric DSM Supply Curve, Reference Case[55]



54 Levelized costs are the result of a computational approach used to compare the cost of different projects or technologies. The stream of each project's net costs is discounted to a single year using a discount rate (creating a net present value) and divided by the project's expected lifetime output (kWh in this case).

55 Reference case total levelized cost shown ($0.05/kWh) does not include DR programs. If DR is included, the Reference case total levelized cost is $0.06/kWh.

3.2 Costs in Context

A recent ACEEE report[56] summarized levelized program costs over the 2009 to 2012 period across 20 states. Data reported in this study was used to develop Figure 24.[57] Although historical program costs in other states are not necessarily comparable to future program costs in Louisiana due to differences in baselines, customer mixes, avoided costs, and other factors, it is helpful to put the costs projected in this Potential Study into context.

The total levelized cost per kWh in the reference case in this Potential Study is about $0.05 per kWh. This is at the upper end of the costs shown for other states in Figure 24 and are similar to the costs researched by ACEEE for Vermont, California, Rhode Island, Connecticut and Massachusetts; this makes sense for at least two reasons.

First, the portfolio of programs modeled for this Study is comprehensive in scope. It includes a wide variety of measures and programs covering all customer sectors, including hard-to-reach markets. Such is the nature of the portfolios run by administrators in the states listed above. If cost-effectiveness was the only goal for energy efficiency, DSM program administrators would likely spend program funding on elements at the lower end of the supply curve.

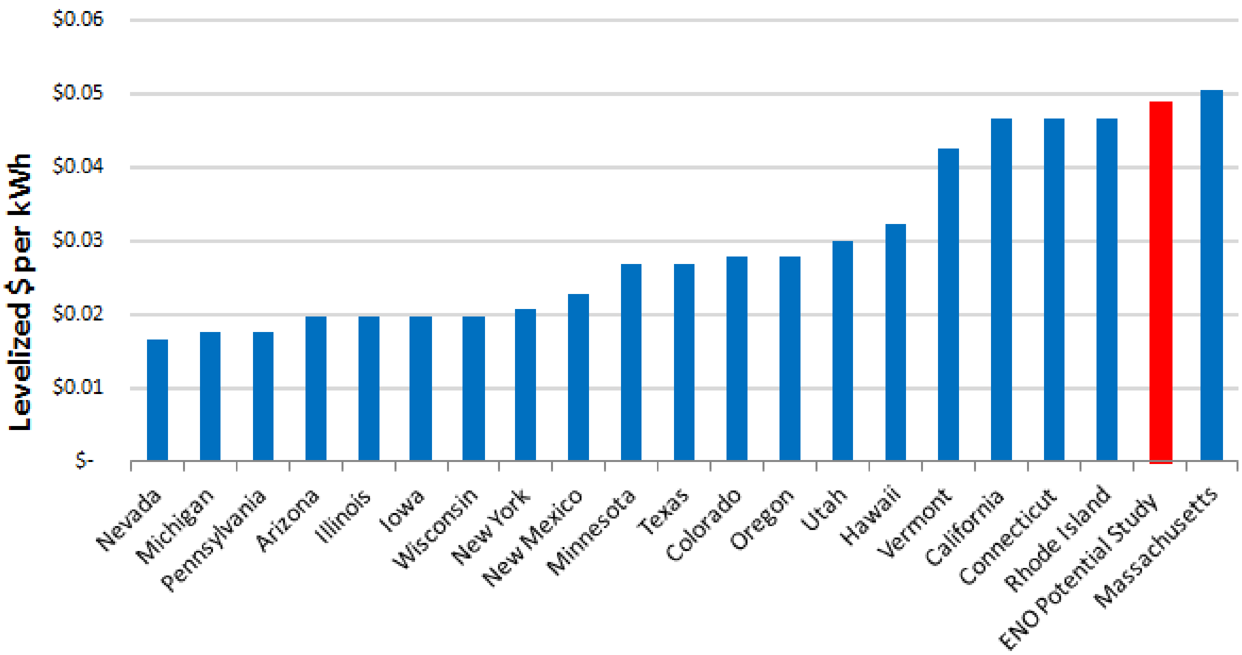
Second, costs in the ACEEE report reflect historical baselines, and heavy program reliance on very cost-effective, popular measures such as CFLs that will either not be available to programs in the future, or will have significantly diminished savings due to baseline changes. For example, according to Efficiency Vermont's 2010 Annual Report, 74% of cumulative residential program savings in 2010 were due to lighting measures.[58] By comparison, only 39% of cumulative residential program savings for ENO is forecasted to be due to lighting measures -- this is largely due to the impacts of EISA 2007. Given what ICF knows today, such improvements to technology and new construction minimum efficiency standards mean that, all else equal, future programs are likely to be less cost-effective than historical programs.

[56] Maggie Molina. The Best Value for America's Energy Dollar: A National Review of the Cost of Utility Energy Efficiency Programs. ACEEE Report U1402. March 2014.

[57] Note that that the levelized costs reported in the ACEEE report reflect savings at the meter, whereas costs in this Study are reported at generator. Also, ACEEE's assumed discount rate was 5%, whereas ENO's discount rate is closer to 7%. ACEEE estimates that accounting for line losses and bringing the savings to the generator level would reduce levelized costs about 7%, and that increasing the discount rate from 5% to 7% would increase levelized costs 10%. These adjustments were made to the levelized cost values reported by ACEEE, and are reflected in Figure 24.

[58] Efficiency Vermont. Annual Report 2010. February 2012.

Figure 24. Average Levelized Costs of Energy Efficiency in 20 States (2009-2012) and as Forecasted for ENO for this Potential Study (2015-2034)



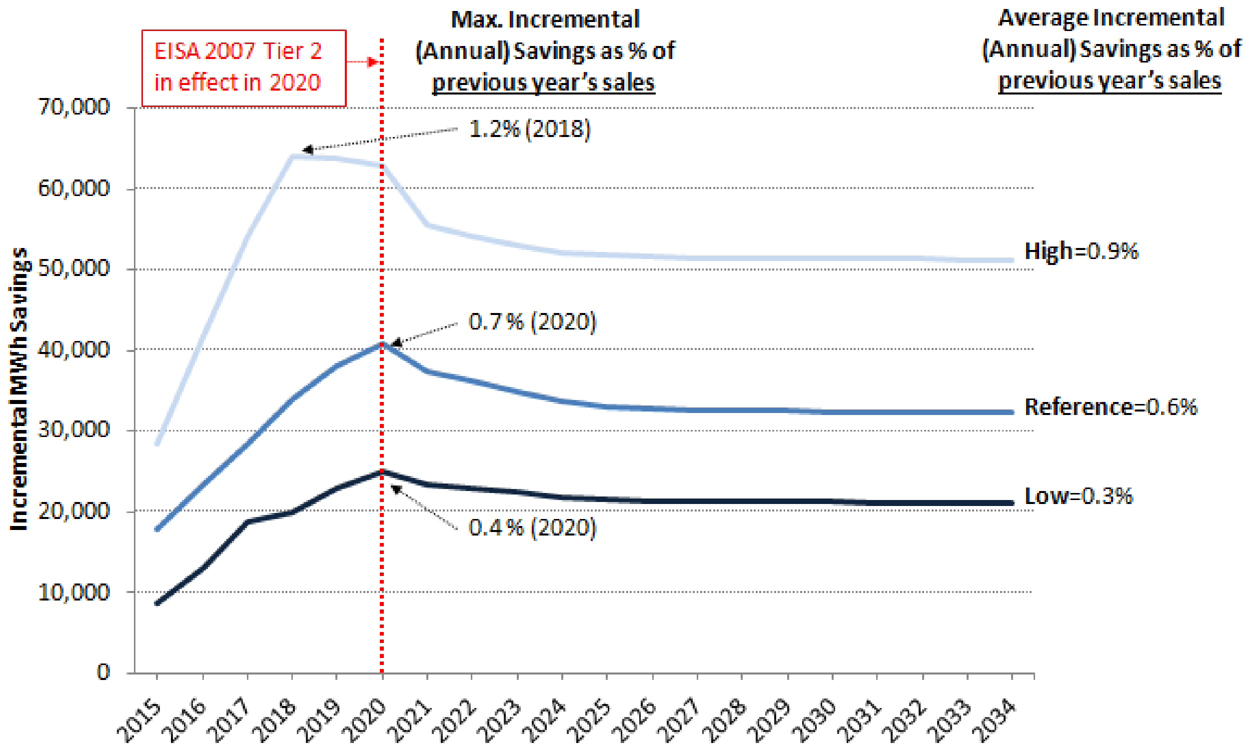
3.3 Incremental Savings Potential

Figure 25 shows the total incremental MWh savings[59] forecast by scenario. The graph shows that programs are assumed to have different ramp-up schedules in each scenario, with the schedules being the most aggressive in the high case due to the very high incentive levels.

Figure 25 also shows the impacts of EISA 2007 Tier 2, where savings drop significantly post-2020. Prior to 2020, ICF assumed ENO would pursue very aggressive (but achievable) CFL and LED lighting savings for bulb-types that will be phased-out.

[59] The difference between the amount of energy savings acquired or planned to be acquired as a result of energy efficiency activities in one year, and the amount of energy savings acquired or planned to be acquired as a result of the energy efficiency activities in the prior year.

Figure 25. Incremental MWh Savings, by Scenario



3.4 Savings in context

Figure 26 compares forecasted incremental savings impacts for this Study to savings impacts in Southern states achieved during 2010 through 2012. Column A describes the relevant statistic. Column B provides the statistical values in savings as % of load (i.e., savings as % of sales) for Southern states, and Column C provides a description of the forecast in this Study compared to Column B. To develop the statistics in this table, program performance data was aggregated across 27 EE portfolios and 10 states in the South[60] over 2010 to 2012.[61] In total there were 76 administrator-program year pairings used for benchmarking. This data is shown in the Appendix.

Average reference case savings impacts forecasted for this Study are equal to the 86th percentile of the benchmarking sample, or 0.6% of sales. In simple terms, this means ICF forecasts that ENO's DSM portfolio could achieve higher savings impacts than did 86% of Southern DSM portfolios during the 2010 to 2012 period. ICF forecasts that, at a minimum, ENO could achieve median-level savings. The maximum level of savings in an average year is equal to the 98% percentile of Southern DSM portfolios during the 2010 to 2012 time period.

[60] Based on climate zone designations. States in Southern climate zones include: Alabama, Arkansas, Florida, Georgia, Louisiana, Mississippi, North Carolina, Oklahoma, South Carolina, Texas and Virginia.

[61] Using U.S. EIA Form 861 data.

Figure 26. Incremental Savings in Context

(A) Statistic	(B) Savings as % of Load of Southern Portfolios over 2010-12	(C) Relation of (B) to ENO Forecast Scenario (Savings as % of Load)
Minimum	<0.1%	
25th Percentile	0.2%	
50th Percentile (Median)	0.3%	Low case average
73rd Percentile	0.4%	Low case maximum (2020)
86th Percentile	0.6%	Reference case average
92nd Percentile	0.7%	Reference case maximum (2020)
98th Percentile	0.9%	High case average
99th Percentile	1.2%	High case maximum (2018)
Maximum	1.3%	
Average	0.3%	

It is appropriate to compare ENO program performance to that of other programs in the Southern region, and not to a broader, national database of programs for at least two reasons:

- **Comparable Retail Rates.** As shown in Figure 27, Louisiana has some of the lowest retail electric rates in the country. Although there are other barriers to EE besides cost, cost is important, and higher retail rates mean that measures pay for themselves faster, and are therefore more attractive to customers.

Figure 27. U.S. Retail Electric Rates, 2013[62]

Census Division	2013 YTD Avg Retail Rate ($/kWh)
West South Central	$0.085
-Louisiana	$0.080
East South Central	$0.087
West North Central	$0.090
Mountain	$0.092
East North Central	$0.093
South Atlantic	$0.097
Pacific Contiguous	$0.121
Middle Atlantic	$0.129
New England	$0.145
Pacific Noncontiguous	$0.266
U.S. Total	**$0.101**

- **Comparable Weather.** Louisiana is in the Southern U.S. Climate region. This is relevant to EE because many measures, such as air conditioners and insulation, are weather sensitive. These measures have similar savings levels across states with similar climates. For example, air conditioners have a much higher number of operating hours in the South than in the North, and conversely, insulation results in more winter savings in the North than in the South. This is one reason why is it difficult to compare the performance of Southern and Northern programs.

It is true there are administrators with retail rates and weather that are comparable to ENO and that have achieved savings levels higher than that forecasted in this Study. However, those are exceptions and would need to be benchmarked against ENO on a case-by-case basis.

[62] Source: U.S. EIA Electric Power Monthly, February 2014.

4 Achievable Natural Gas Efficiency Potential

This section includes the presentation and analysis of ICF's forecast of total achievable natural gas energy efficiency potential for the ENO service area for 2015 through 2034. Total achievable potential is the sum of residential, commercial, and industrial potential. Gas savings and program cost estimates are shown, as well as benefit-cost estimates..

4.1 Cumulative Potential

Total achievable potential is the sum of achievable potential estimated for each measure in the analysis. Total cumulative achievable potential estimates are shown in Figure 21, along with cumulative savings[63] impacts. Figure 29 provides an overall summary of this Study's gas forecast including savings, savings impacts, costs, benefits, and cost-effectiveness. To review the forecast:

- ICF estimates that, in the reference case, ENO can achieve cost-effective cumulative gas savings equal to 0.5% of sales over the 2015 to 2034 time horizon. Total program costs over this 20-year period are estimated to equal $9 Million.[64] Total net benefits are estimated to equal $24 Million.
- In the high case, we estimate that ENO could achieve an additional 705,876 therms in savings for an additional $8 Million in program spending beyond the reference case. That is, in the high case, savings would increase 211% over reference case levels while spending would increase 189%.
- In the low case, ICF estimates that ENO would achieve 27% less savings than in the reference case, while costs would decrease 56% compared to the reference case.

[63] The summation of savings from multiple projects or programs over 2015-2034, taking into account the time of measure installation in the first year, annual energy savings for subsequent years, and the life of the installed measures.

[64] Including program incentive and non-incentive costs.

Figure 28. Cumulative Achievable Natural Gas Energy Efficiency Potential, by Scenario

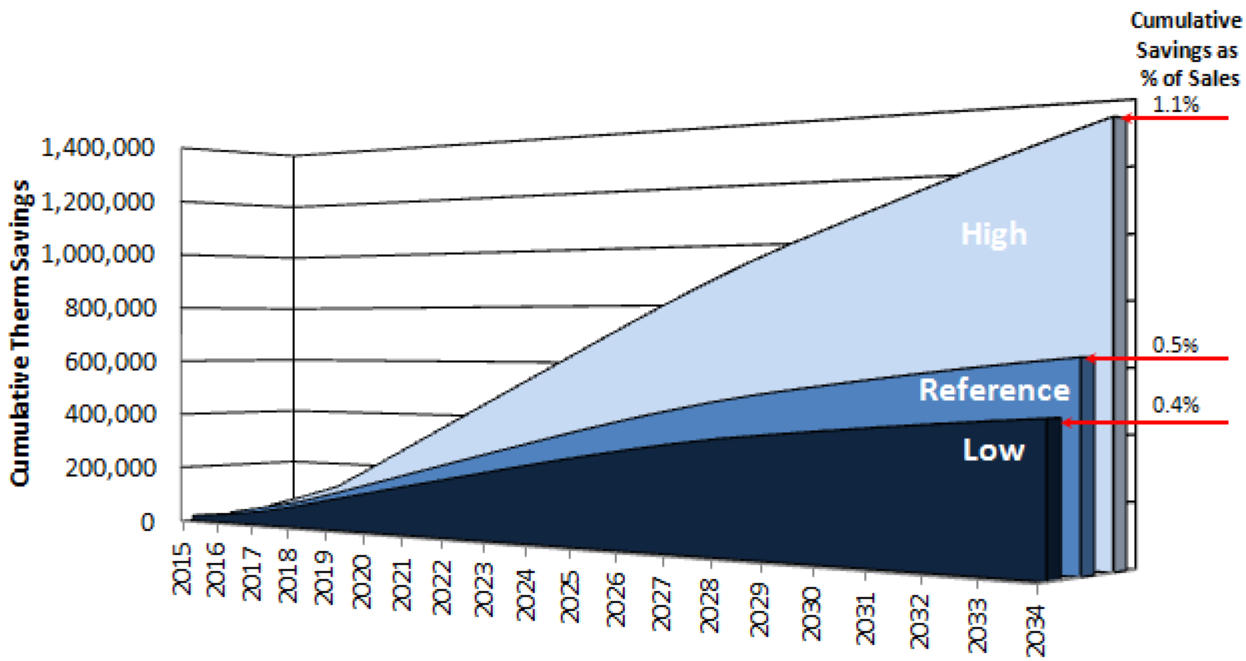


Figure 29. Total Gas Savings, Savings Impacts, Benefits, Costs and Costs-Effectiveness, by Scenario

Scenario	Cumulative Therm Savings (2015-2034)	Cumulative Therm Savings as % of Sales	Total TRC Benefits, 2015-2034 ($Mil.)	Total TRC Costs, 2015-2034 ($Mil.)[65]	Net TRC Benefits, 2015-2034 ($Mil.)[66]	TRC B/C Ratio	Total Program Costs, 2015-2034 ($Mil.)[67]	Level-ized Cost per Therm
Low	462,039	0.4%	$19	$5	$14	3.7	$4	$0.71
Reference	634,173	0.5%	$31	$6	$24	4.9	$9	$1.16
High	1,340,048	1.1%	$51	$17	$35	3.1	$17	$1.08

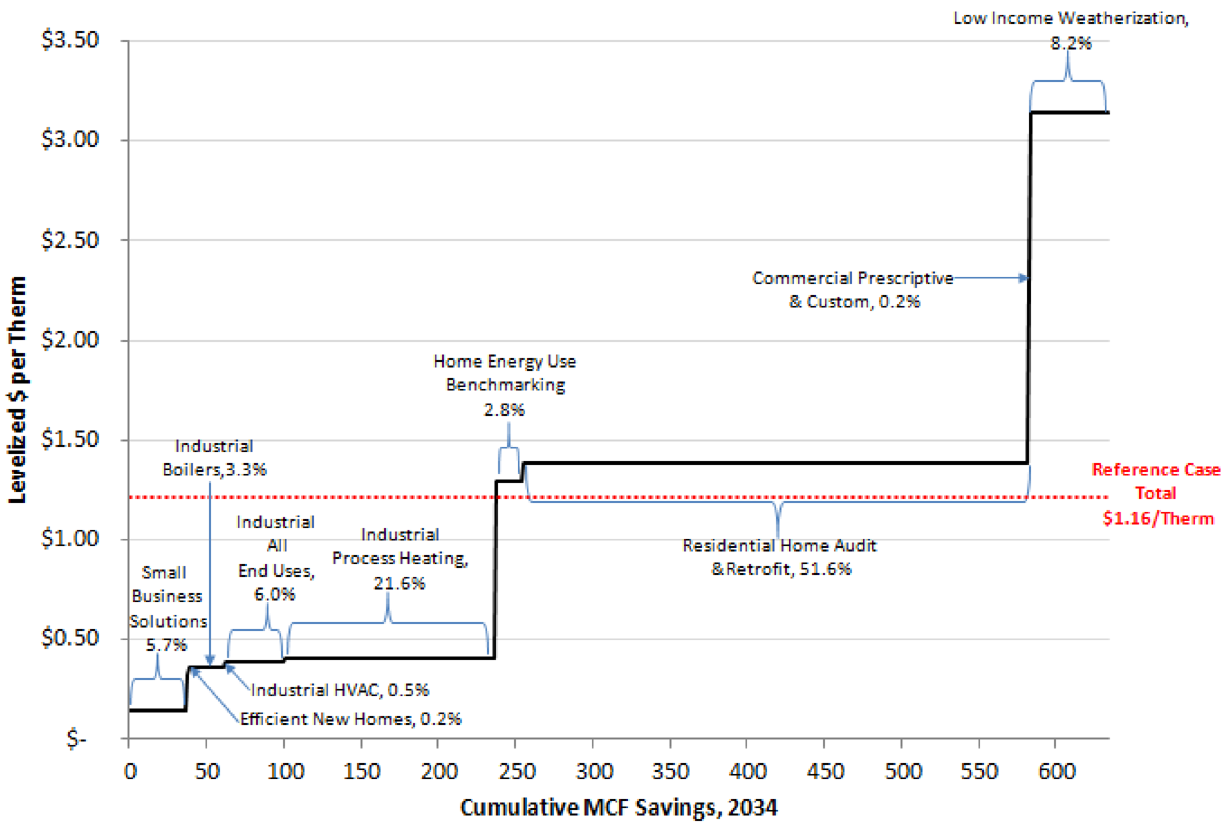
[65] TRC (Total Resource Cost) test costs include total measure incremental costs and program non-incentive costs over the time horizon of the forecast (2015-2034).

[66] TRC (Total Resource Cost) test benefits include gas (therm) costs avoided over the time horizon of the forecast (2015-2034).

[67] Program costs include incentive costs and non-incentive costs (e.g., administration, marketing, etc.).

Figure 30 shows the reference case gas efficiency supply curve, which plots cumulative gas savings on the x-axis and levelized program costs on the y-axis.[68] The first horizontal segment on the bottom left of the plot shows that 5.7% of savings could be achieved through the Small Business program at a cost of $0.14 per therm. Moving from left to right, each additional program shown in the graph is more costly on a per therm basis. Residential Home Audit and Retrofit is the program with the largest gas savings potential, while Efficient New Homes and Commercial Prescriptive and Custom have the smallest levels of gas savings potential.

Figure 30. ENO Gas Efficiency Supply Curve, Reference Case

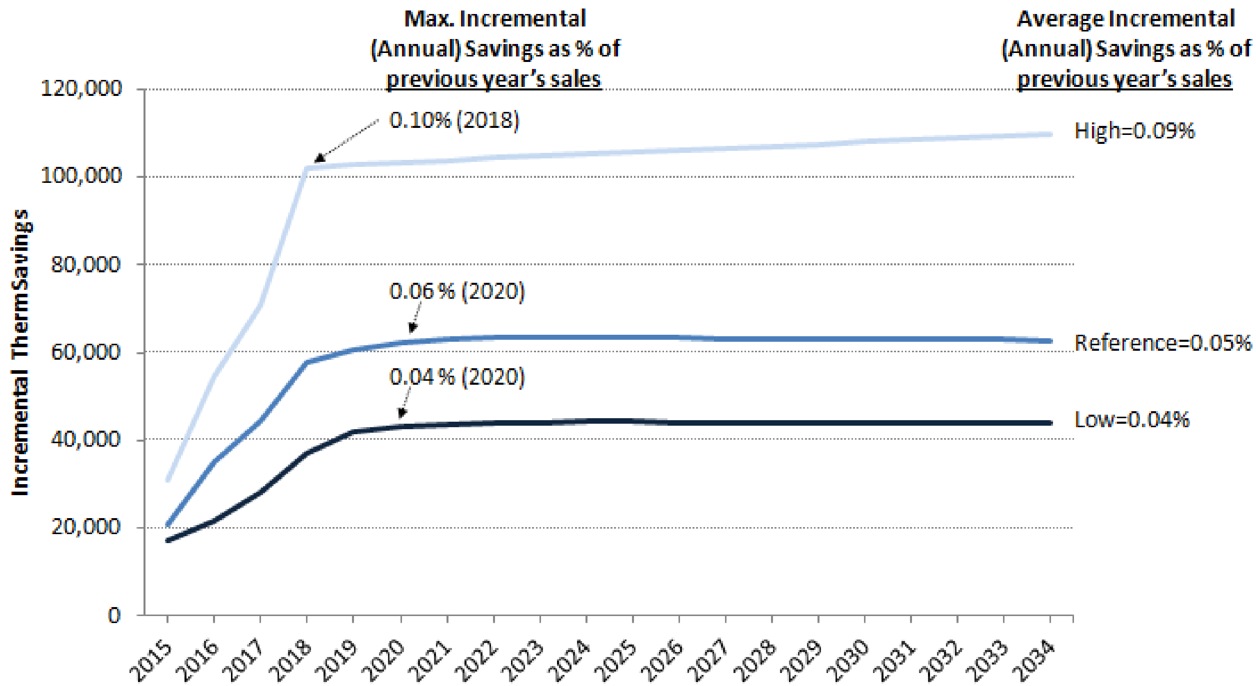


[68] Levelized costs are the result of a computational approach used to compare the cost of different projects or technologies. The stream of each project's net costs is discounted to a single year using a discount rate (creating a net present value) and divided by the project's expected lifetime output (Therms in this case).

4.2 Incremental Potential

Figure 31 shows the total incremental therm savings[69] forecast by scenario. The graph shows that programs are assumed to have different ramp-up schedules in each scenario, with the schedules being the most aggressive in the high case due to the very high incentive levels.

Figure 31. Incremental Achievable Natural Gas Energy Efficiency Potential, by Scenario



4.3 Gas Program Benchmarking

Research indicates there are an insufficient number of existing gas efficiency programs in the Southern region against which to benchmark the ENO gas potential forecasts. Finding appropriate peer administrators for ENO gas programs is further complicated by the unique composition of ENO's gas customer base, as shown in Figure 17.

Readers may note that gas savings potential is small compared to electric savings potential. There are at least three reasons for this:

[69] The difference between the amount of energy savings acquired or planned to be acquired as a result of energy efficiency activities in one year, and the amount of energy savings acquired or planned to be acquired as a result of the energy efficiency activities in the prior year.

1. The cost of natural gas is low, and forecasts at the time of the analysis indicate it will continue to be low for the foreseeable future. This limited the number of gas measures that passed the measure TRC cost-effectiveness screen.

2. For residential and commercial gas measures that are cost-effective, there is limited gas savings since these measures are weather sensitive. New Orleans is in the Southern U.S. Climate Region where there is a low number of annual heating degree days.

3. While most industrial gas measures are not weather sensitive, the market size for this sector is small—industrial constitutes only 2% of gas sales.

A key take-away from the gas analysis is that there is insufficient cost-effective gas potential for ENO to run "gas only" programs - the market size is simply too small. This does not mean cost-effective gas measures should not be considered by ENO, but that they should be included in programs that would be combined electric and gas offerings.

5 Combined Electric & Gas Benefits & Costs

Combined electric and gas program benefits and costs are shown in Figure 32.[70] As stated above in the Approach section, it was assumed that programs with gas measures would be operated jointly with their analogous electric programs. That is, we assumed there would be no stand alone gas programs. This is because there were not any cost-effective gas measures that required the creation of new programs, and because gas savings potential is too small in scale to operate gas programs independently of electric programs.

Ten of the programs described in Section 1.5.1, Programs Modeled, would include both electric and gas measures:

A. Residential Programs
   1. Efficient New Homes
   2. Home Audit and Retrofit
   3. Home Energy Use Benchmarking
   4. Low Income Weatherization
B. Commercial and Industrial Programs
   5. Commercial Prescriptive and Custom
   6. Industrial Boilers
   7. Industrial HVAC
   8. Industrial Process Heating
   9. Industrial All End Uses

[70] Figure 32 includes benefits and costs for all electric and gas programs, i.e., not just for the ten programs listed where there are electric and gas measures included.

10. Small Business Solutions

Figure 32. Combined Electric and Gas Benefits and Costs for All Programs

Scenario	Total TRC Benefits, 2015-2034 ($Mil.)	Total TRC Costs, 2015-2034 ($Mil.)	Net TRC Benefits, 2015-2034 ($Mil.)	TRC B/C Ratio	Total Program Costs, 2015-2034 ($Mil.)
Low	$201	$129	$72	1.6	$96
Reference	$324	$199	$124	1.6	$120
High	$841	$480	$355	1.8	$156

6 Appendices

A. Measure characteristics and assumptions
B. Net-to-gross assumptions
C. Payback acceptance curves and participation approaches utilized
D. Program level savings, costs and cost-effectiveness
E. Benchmarking data
F. Avoided costs