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October 23, 2014

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

Re: *In Re*: Resolution Regarding Proposed Rulemaking to Establish Integrated Resource Planning Components and Reporting Requirements for Entergy New Orleans, Inc. (Docket No. UD-08-02)

Dear Ms. Johnson:

Pursuant to Council Resolution R-14-224, enclosed please find an original and three copies of the materials that will be presented at the Entergy New Orleans, Inc.'s ("ENO") Integrated Resource Plan ("IRP") Renewables Technical Conference that will be held from 9:00 a.m. until 12 noon on October 30, 2014 at the Lindy C. Boggs International Conference Center located in the University of New Orleans Research and Technology Park, 2045 Lakeshore Drive, New Orleans, Louisiana. A copy of these materials will also be posted to ENO's IRP website. Please file an original and two copies into the record in the above-referenced matter, and return a date-stamped copy to our courier.

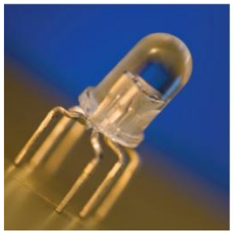
Thank you for your assistance with this matter.

Sincerely,

Timothy S. Cragin

Timothy S. Cragin

Enclosure
cc: Official Service List UD-08-02 *(via electronic mail)*



Entergy New Orleans DSM Potential Study – Preliminary Electric & Gas Potential Estimates

ENO 2015 IRP Milestone 2 Public Technical Conference

October 30, 2014

NOTE: ALL IRP MATERIALS ARE PRELIMINARY & SUBJECT TO CHANGE PRIOR TO THE FINAL REPORT FILING.

Contents

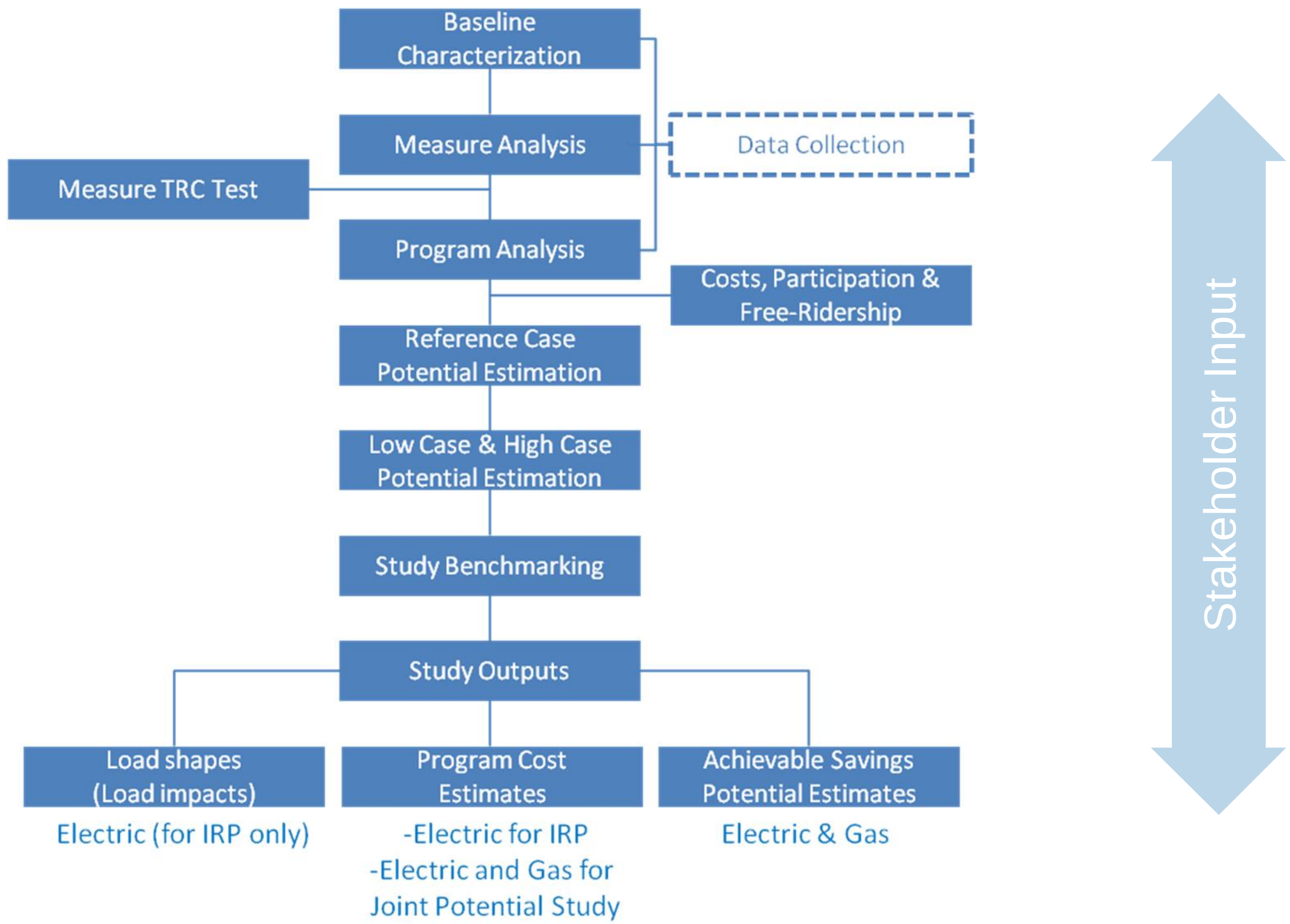
Objectives of the Potential Study

- Develop electric and gas achievable program savings and cost projections[1] representing three levels of achievable DSM (low, reference, and high) over 20 years (2015-2034).
- Develop hourly load shapes for 2015-2034 for ENO's 2015 IRP analysis.

Note: The Potential Study should not be applied directly to short-term DSM planning activities, such as program implementation plans or utility goal setting, but can serve as one of the inputs into the more detailed analysis necessary to support such planning.

[1]Utility costs include: incentives and administrative (and if applicable installation and ongoing costs incurred by ENO)

Electric and Gas DSM Potential Study Approach



Joint Electric & Gas Potential Study

- Joint electric/gas DSM potential study reflects synergies in delivery, where possible
  - Report estimates of joint electric and gas program cost-effectiveness
  - Report cost-effectiveness of stand-alone electric and gas programs
- DSM inputs to IRP
  - Electric measure load shapes
  - Electric portion of DSM program costs

Achievable Potential Scenario Definitions

- **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%.

Key Updates from 2012 Electric Study

- Input Assumptions
  - Eligible stock
  - Measures
  - Avoided energy cost and avoided capacity cost
- Approach
  - Measure TRC testing
  - IRP inputs

Key Residential Modeling Updates

Input	2012 Data	2015 Data
Residential customer counts	2011 Entergy data and forecast	2014 Entergy data and forecast
Residential building characteristics and efficiency saturation	Post-Katrina Study by GCR (2008); 2009 Residential Energy Consumption Survey (RECS), U.S. Dept. of Energy (DOE)	Post-Katrina Study by GCR (2008); 2009 RECS; Some updates to specific measures using primary data collected more recently in other jurisdictions
Residential measure assumptions	ENO Deemed Savings (2008); ICF building simulations and engineering calculations	AR Technical Reference Manual (TRM) v3; OK TRM; IL TRM; adjustments to CDD & HDD* made for weather sensitive measures. ENO evaluations

**Cooling degree days; heating degree days*

Key Commercial Modeling Updates

Input	2012 Data	2015 Data
Commercial customer counts	2011 Entergy data and forecast	2014 Entergy data and forecast
Commercial building characteristics and efficiency saturation	2003 Commercial Buildings Energy Consumption Survey (CBECS), U.S. DOE	2003 CBECS; Commercial Building Institute (CBI) data
Commercial measure assumptions	AR TRM v1; adjustments to CDD/HDD made for weather sensitive measures; ICF building simulations	AR TRM v3; OK TRM; IL TRM; adjustments to CDD/HDD made for weather sensitive measures, ENO evaluations

Key Industrial Modeling Updates

Input	2012 Data	2015 Data
Industrial customer counts, usage and forecast	2011 Entergy and Large Customer data and forecasts	2014 Entergy and Large Customer data and forecasts
End use saturation and measure applicability	2006 Manufacturing Energy Consumption Survey (MECS), U.S. DOE	2010 MECS
Industrial measure assumptions	CA Industrial Potential Study; ICF estimates	DOE studies; EPA studies; LBNL studies; other published studies; ICF estimates

Key Modeling Updates Measure TRC Testing

Input/Approach	2012	2015
Measure TRC costs	Incremental equipment costs	Incremental equipment costs
Measure TRC benefits	Avoided kW, kWh, Therms	Avoided kW, kWh, Therms
Measure TRC test year	Program year 1 (2012)	Program year 1 (2015) for measures with baselines changing in near-term (e.g., CACs); Program year 8 (2022) for all other measures

Key Modeling Updates: DSM Inputs to IRP

Input	2012	2015
Loadshape format	Hourly (load savings estimates for every hour of every year over the 20 year time horizon)	Hourly (load savings estimates for every hour of every year over the 20 year time horizon)
Savings inputs	Bundled Program loadshapes: Program loadshapes were bundled (combined) by like PAC result and program type (e.g., EE & DR)	Program loadshapes <u>not</u> bundled. Load shapes provided for each program for each scenario.
Cost inputs	Total electric program costs, by program by year	Total electric program costs, by program by year

Programs types modeled

RESIDENTIAL

- **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 bring downs the cost of efficient lighting, appliances and consumer electronics.
- **Multifamily**: 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.
- **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.
- **Low Income Weatherization**: Program for qualifying low-income customers that provides home weatherization (e.g., air sealing, insulation) free of charge.

Program types modeled – cont.

RESIDENTIAL

- **Solar Hot Water**: Program that provides incentives for the installation of solar hot water units for residential customers. Accounts for current Louisiana state tax break for solar water heating units.
- **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 different prices for using electricity at different times during the day. Assumed to be "non-technology enabled" for the purposes of this study, since there were no approved plans for a deployment of advanced meters by ENO at the time this Study was performed.

COMMERCIAL

- **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.
- **Retro commissioning (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 different prices for using electricity at different times during the day. Assumed to be "non-technology enabled" for the purposes of this study, since there were no plans for a significant deployment of advanced meters by ENO at the time this analysis was performed.

Program types modeled-cont.

INDUSTRIAL

- **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 (Electric)
  - Process Heating (Electric & Gas)
  - Process Cooling and Refrigeration (Electric)
  - Facility HVAC (Electric & Gas)
  - Facility Lighting (Electric)
  - Other Process/Non-Process Use (Electric)
  - Boilers (Gas)
  - All Systems (e.g., Sub-metering)

Electric Energy End Uses Modeled

Sector	End Use
Residential	Lighting
	Consumer Electronics
	Appliances
	HVAC
	Hot Water
	Shell
	Other (e.g., home energy use benchmarking)
Commercial	Lighting
	HVAC
	Refrigeration
	Hot Water
	Food Service Equipment
	Other (including RCx, Data Center)

Measures included in study:

•Retrofit, replace on burnout, new construction

•Represent commercially available measure types for each end use

•Start with comprehensive list

•Test each for cost-effectiveness

•Include in DSM potential estimates only measures with TRC of at least 1.0, with possible exceptions

Electric Energy End Uses Modeled – cont.

Sector	End Use
Industrial	Machine Drive
	Pumps
	Fans
	Compressors
	Other applications
	Process Heating
	Process Cooling and Refrigeration
	Other Process Uses
	Electro-Chemical
	Facility HVAC
	Facility Lighting
	Other non-process use

Gas Energy End Uses Modeled

Sector	End Use
Residential	Hot Water
	HVAC
	Shell
	Other
Commercial	HVAC
	Hot Water
Industrial	Process Heating
	Boilers
	HVAC
	All (e.g., Sub-metering and O&M measures)

*Gas measure data sources
•Residential & commercial: Primarily Arkansas TRM 3.0
•Industrial: ICF industrial measures database

Number of measures evaluated

Sector	# Measure Types Evaluated	Total # Measures Evaluated (All Measure Permutations)
Electric Only Measures		
Residential	40	94
Commercial	44	476
Industrial	64	197
Total Electric Only	*148*	*767*
Gas Only Measures		
Residential	10	30
Commercial	12	37
Industrial	44	183
Total Gas Only	*66*	*250*
Measures w/ Electric and Gas Savings		
Residential	13	14
Commercial	1	25
Industrial	0	0
Total Electric & Gas	*14*	*39*
GRAND TOTAL	228	1,056

Decision Type	**% Grand Total Measures**
Retrofit	64%
Replace-on-Burnout	34%
New Construction	2%

Some key baseline efficiency improvements–screw-in light bulbs, impacts of EISA 2007*

Baseline Product Wattage

Year	0–309 lumens 25 w equiv.	310–749 lumens (40 w equiv.)	750–1,049 lumens (60 w equiv.)	1,050–1,489 lumens (75 w equiv.)	1,490–2,600 lumens (100 w equiv.)
2011 (pre-EISA 2007)	25	40	60	75	100
2012	25	40	60	75	100
2013	25	40	60	75	72
2014	25	40	60	58	72
2015	25	33	49	58	72
2016	25	33	49	58	72
2017	25	33	49	58	72
2018	25	33	49	58	72
2019	25	33	49	58	72
2020 and after	25	12	20	28	45

Bulbs affected by EISA 18%-28% more efficient than pre-EISA

EISA 2007 Tier 1 (in effect)

First year of IRP forecast

EISA 2007 Tier 2 takes effect

Bulbs affected by EISA 55%-70% more efficient than pre-EISA

**U.S. Energy Independence and Security Act of 2007*

Sources: Compilation of Lighting program plans, reports, and forecasts nationwide; EISA 2007.

Some key baseline improvements– screw-in light bulbs, impacts of EISA 2007, cont.

- The next EISA milestone, Tier 2, will not take effect until 2020. This phase will require that light bulbs manufactured are up to 70% more efficient than before EISA took effect.
- Lighting industry experts and energy efficiency program planners expect the new baselines to remain relatively stable until the next Tier of EISA takes effect in 2020.
- Future of standard screw-in bulb measures highly uncertain post-2020
  - EISA 2007 does not impact specialty bulbs (e.g., reflector LEDs)

Some key baseline improvements-cont.

- **U.S. DOE rules pertaining to commercial lamps and ballasts** are reflected in baselines for linear florescent lighting. These rules result in a 20% improvement in baseline efficiency for linear florescent lamps. 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. New conservation standards for residential furnaces also go into effect in 2016.
- Louisiana's current **commercial building energy code** is compliant with ASHRAE 90.1-2007. However, due to the 20 year span of the study, 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.
- Louisiana's current **residential building energy code** is compliant with IECC 2009. However, due to the 20 year span of the study, ICF assumed residential new construction baselines consistent with the next (and more efficient) version of the code, which is IECC 2012.

Participation Modeling

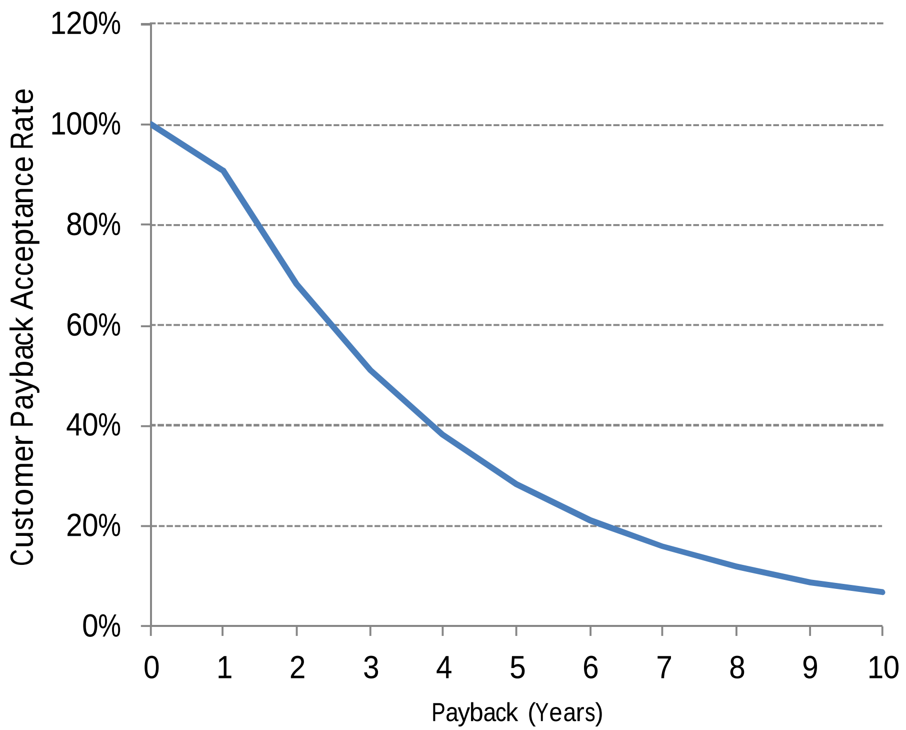
- *Eligible stock*. How many units could be replaced in each year?
  - Applicability; current saturation, replace-on-burnout; retrofit; new construction

- *Financial barriers*. Modeled using payback acceptance.

- *Non-financial barriers.* Contractor participation rates; awareness; customer preference, etc.

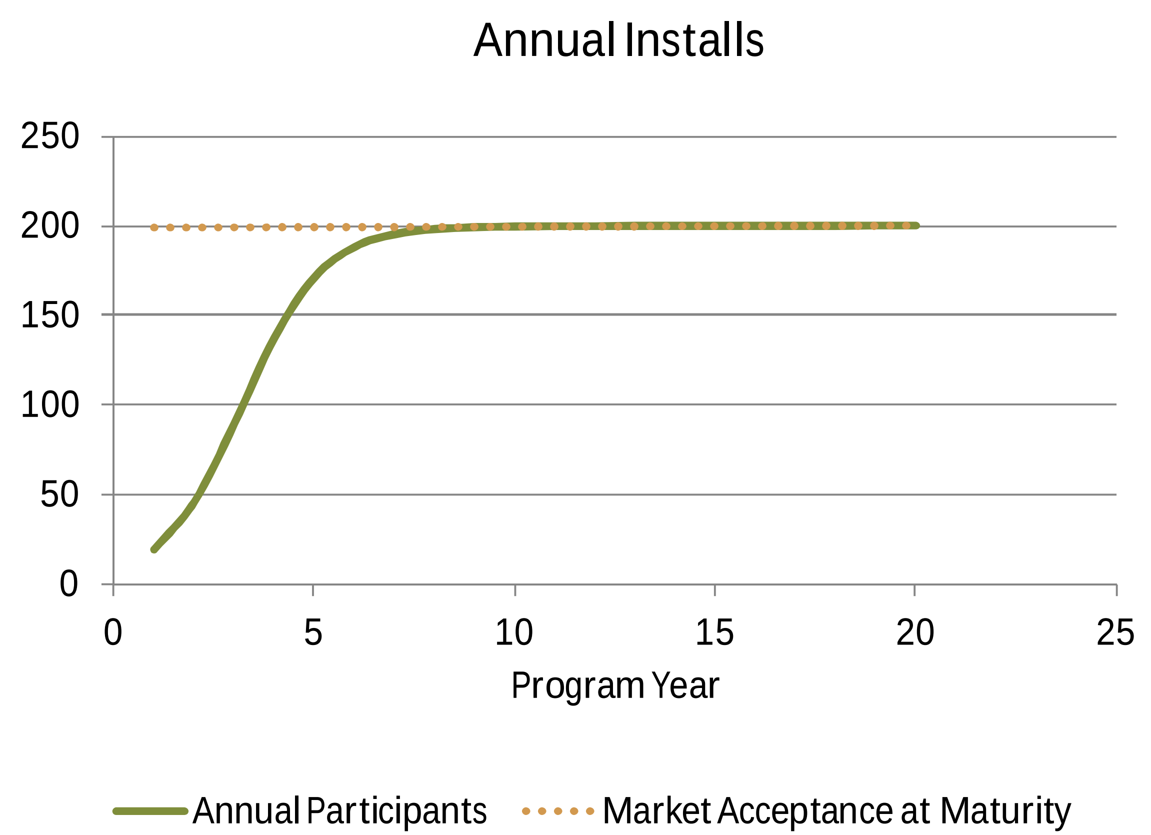
- *Benchmarking.* Consideration of historical participation rates, particularly in the peer territories

Illustrative Payback Acceptance Curve



Note: In the analysis, separate payback curves are used for each sector (residential, commercial, industrial)

Illustrative Measure Participation Curve



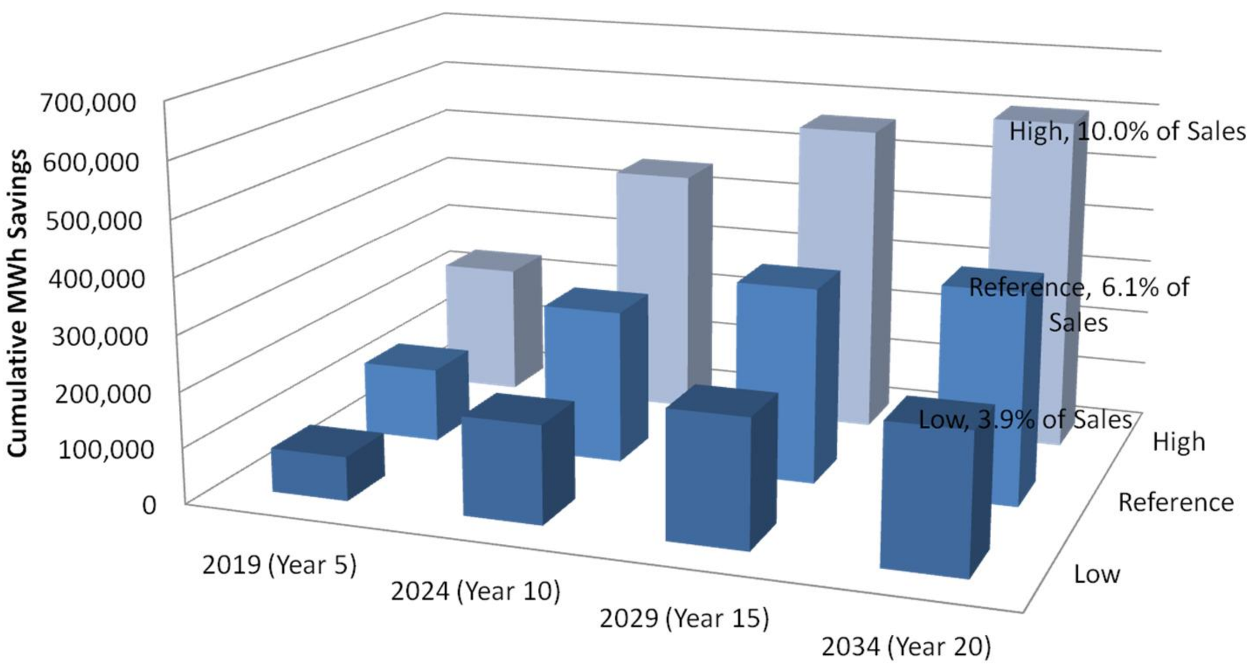
2013 ENO Baseline Customer Energy Use

Sector	2013			
	Gas Use (MCF)	% Total Gas Use	Electricity Use (MWh)	% Total Electric Use
Residential	3,913,030	42%	1,900,791	37%
Commercial[1]	5,115,686	55%	2,756,150	54%
Industrial[2]	193,675	2%	481,245	9%
Total	9,222,391	100%	5,138,186	100%

1 Electric sales include includes Government and Lighting sales. Gas sales includes Government

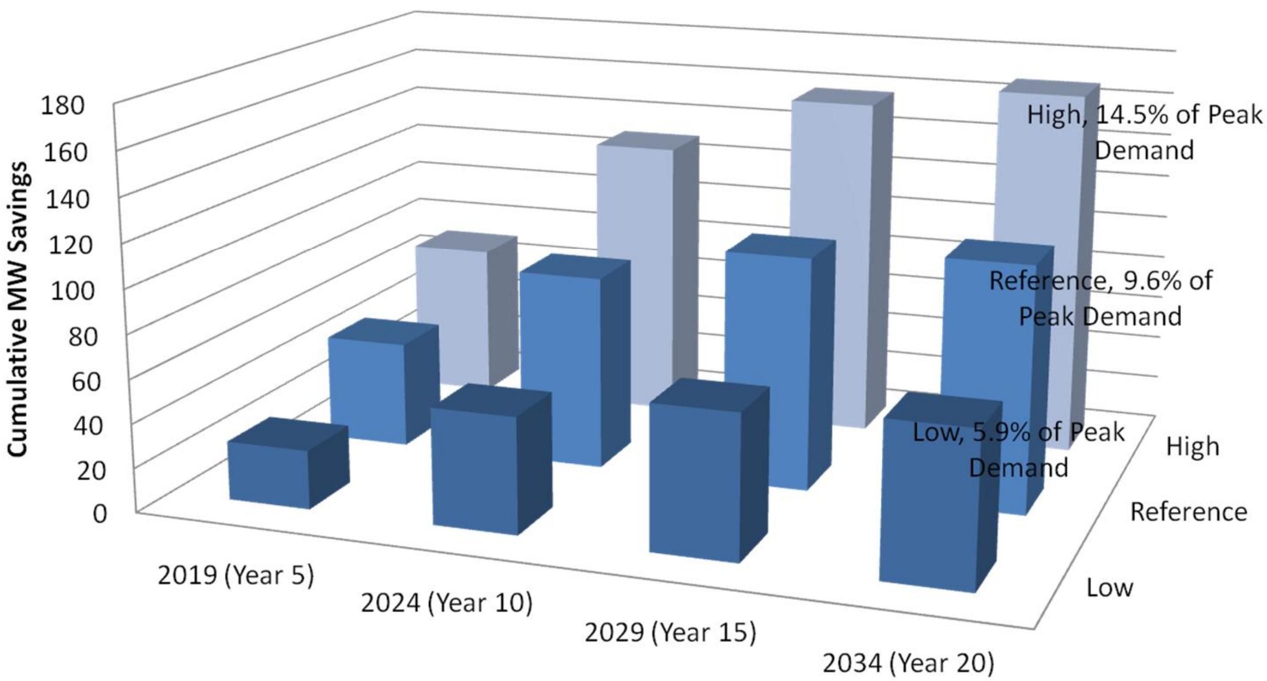
2 Excludes sales to non-jurisdictional ("NJ") large industrial gas customers served by ENO under negotiated rates, terms and conditions specific to each of those customers

Electric Forecast –
Cumulative Net MWh Savings Potential



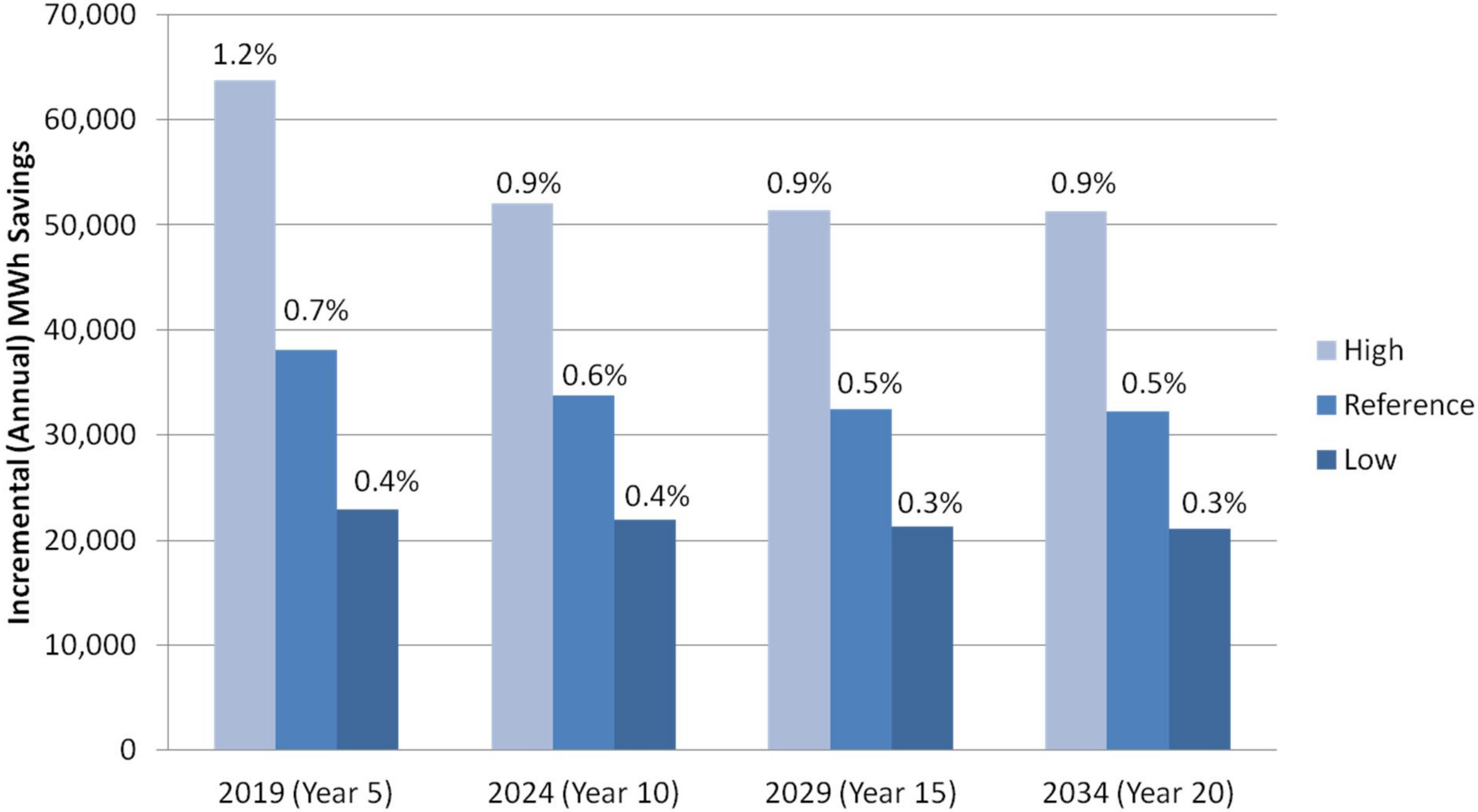
**% savings values are cumulative*

Electric Forecast –
Cumulative Net MW Savings Potential



% savings values are cumulative

Electric Forecast – Incremental Net MWh Savings Potential



- *% values are MWh savings/previous year's MWh sales*
  - *20 year average value*
    - *Low case = 0.3%*
    - *Reference case = 0.6%*
    - *High case = 0.9%*

Incremental Net MWh Savings as % of Sales -
Benchmarking Against Historical Performance of DSM Portfolios in the South

(A) Statistic	(B) Savings as % of Load of Southern Portfolios over 2010-12	(C) Relation of (B) to ENO Preliminary 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 max (2020)
98th Percentile	0.9%	High case average
99th Percentile	1.2%	High case maximum (2020)
Maximum	1.3%	
Average	0.3%	Low case average

The average % savings forecast in the reference case is higher than 86% of Southern DSM portfolios during the 2010 to 2012 period

ENO Energy Smart Year 1 (Apr 2011-Mar 2012). Achieved 111% of goal (15.8 GWh). This is ~0.3% of 2010 Sales.

The above table compares the preliminary 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 preliminary 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 over 2010 to 2012. In total there were 76 administrator-program year pairings used for benchmarking. US EIA Form 861 data for 2010, 2011, and 2012 was used to perform this analysis.

Cumulative Net MWh Savings and Levelized Costs, Reference Case

Program Name	Cumulative MWh Savings, Reference Case, 2034	% Total 2034 Savings	Levelized $ per kWh
Industrial Other Process/Non-Process Use	976	<1%	$0.02
Commercial New Construction	20,478	5%	$0.03
Residential Lighting & Appliances	39,395	10%	$0.03
Industrial Facility Lighting	9,305	2%	$0.03
Industrial Facility HVAC	10,465	3%	$0.03
Industrial Process Heating	3,498	1%	$0.03
Industrial Machine Drive	3,161	1%	$0.03
Multifamily	682	<1%	$0.03
Industrial Process Cooling and Refrigeration	2,708	1%	$0.04
Data Center	12,224	3%	$0.04
RetroCommissioning	8,017	2%	$0.04
ENERGY STAR Air Conditioning	29,953	8%	$0.05
Home Energy Use Benchmarking	2,353	1%	$0.05
Commercial Prescriptive & Custom	188,648	50%	$0.05
Residential Water Heating	4,404	1%	$0.06
Residential Pool Pump	4,298	1%	$0.06
Efficient New Homes	1,453	<1%	$0.08
Residential Solar Hot Water	53	<1%	$0.08
Small Business Solutions	20,737	5%	$0.09
Residential Home Audit & Retrofit	11,134	3%	$0.09
Low-Income Weatherization	4,065	1%	$0.14
Reference Case Total	**378,007**		**$0.05**

**Reflects savings and costs to electric customers*

Electric Cost Benchmarking - Reference Case

State	Avg. Levelized $ per kWh, at Generator, ~7% Discount Rate
Nevada	$0.02
Michigan	$0.02
Pennsylvania	$0.02
Arizona	$0.02
Illinois	$0.02
Iowa	$0.02
Wisconsin	$0.02
New York	$0.02
New Mexico	$0.02
Minnesota	$0.03
Texas	$0.03
Colorado	$0.03
Oregon	$0.03
Utah	$0.03
Hawaii	$0.03
Vermont	$0.04
California	$0.05
Connecticut	$0.05
Rhode Island	$0.05
Massachusetts	$0.05

Notes:

Values for states are averages over 2009-2012 as researched by ACEEE.

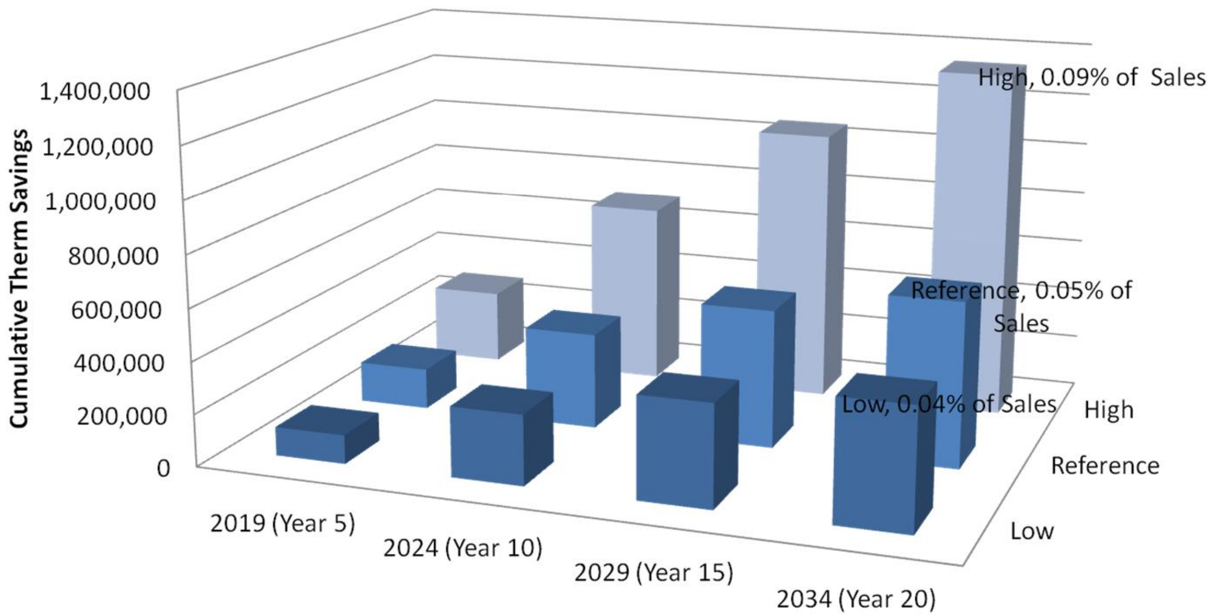
See, *Maggie Molina. The Best Value for America's Energy Dollar: A National Review of the Cost of Utility Energy Efficiency Programs. ACEEE Report U1402. March 2014.*

In considering the total reference case value of this study, account for :

1. **Changes to baselines.** The ACEEE report reflects historical baselines (2009-2012), when there was 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.
2. **The comprehensiveness of the programs modeled**. The portfolio of programs modeled for this Potential Study is comprehensive in scope. It includes a wide variety of measures and programs covering all customer sectors, including hard-to-reach markets.

ENO Reference Case
(this study)=$0.05 per kWh

Gas Forecast – Net Cumulative Savings Potential

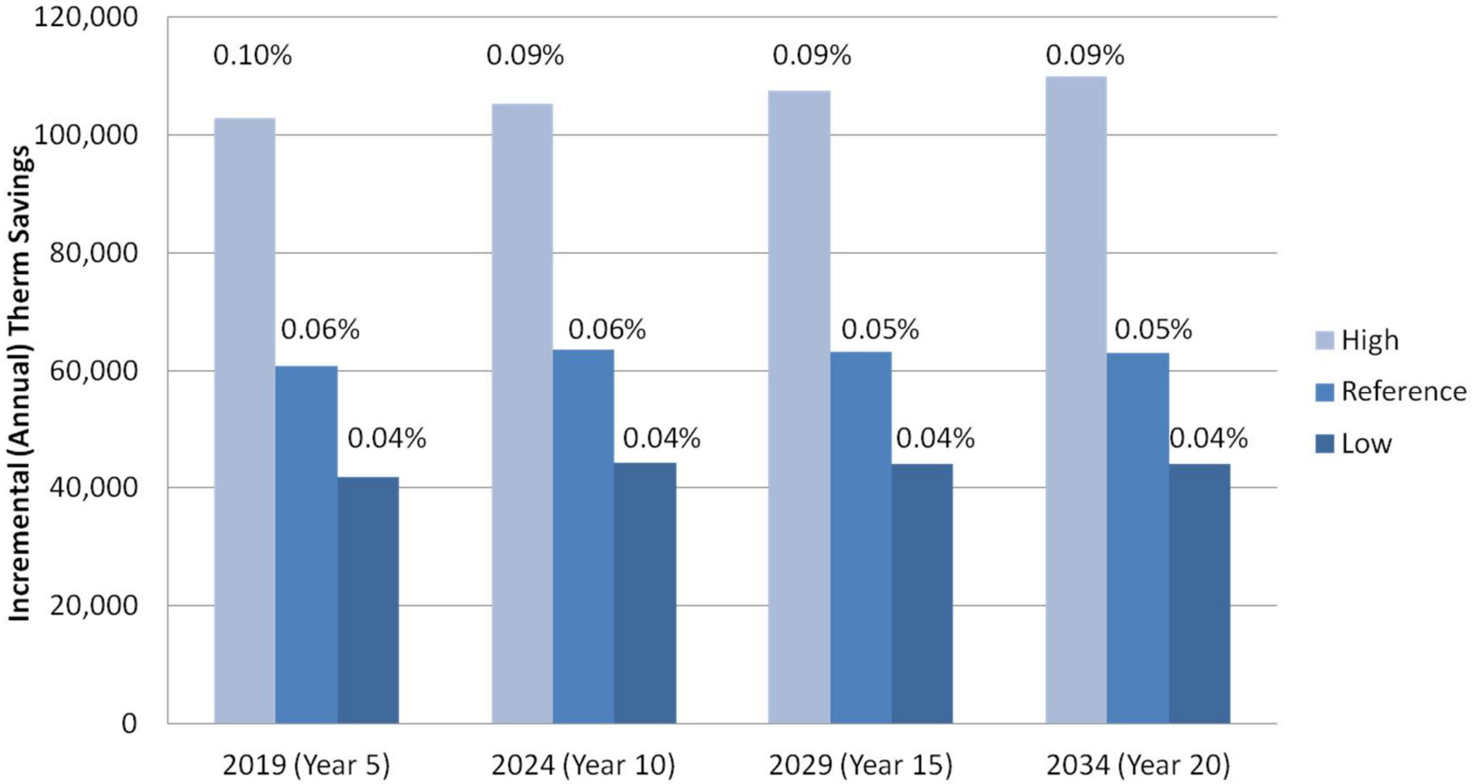


**Reflects savings to ENO gas customers*

Why are gas savings impacts low in comparison to electric savings impacts?
Based on our preliminary analysis, there are at least 3 reasons.

1. The cost of natural gas is low. This limits the number of cost-effective gas measures that could be included in the analysis.
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.

Gas Forecast – Net Incremental Savings Potential



- *% values are Therm savings/previous year's Therm sales*
  - *20 year average value*
    - *Low case = 0.04%*
    - *Reference case = 0.05%*
    - *High case = 0.09%*

**Reflects savings to ENO gas customers*

Cumulative Net Therm Savings and Levelized Costs, Reference Case

Sector	Program	2034 Cumulative Therm Savings, Reference Case	% Total Therm Savings	Levelized $ per Therm
Industrial	Boilers	38,165	1%	$0.10
Industrial	All End Uses	50,625	1%	$0.17
Industrial	HVAC	2,718	<1%	$0.18
Industrial	Process Heating	113,767	3%	$0.25
Commercial	Small Business Solutions	11,010	<1%	$0.46
Residential	Efficient New Homes	1,033	<1%	$0.55
Residential	Home Energy Use Benchmarking	1,557,279	42%	$2.15
Residential	Residential Home Audit & Retrofit	1,948,274	52%	$2.30
Residential	Low-Income Weatherization	17,142	<1%	$5.23
Commercial	Commercial Prescriptive & Custom	205	<1%	$7.45

**Reflects savings and costs to ENO gas customers.*

Includes savings due to gas measures only (not incidental gas savings due to electric measures).

Gas Forecast Benchmarking

- In progress—will be provided with final report
- Limited # of gas DSM programs in South
- Comparisons to North not valid due differences in annual heating degree days

Program costs & cost-effectiveness – perspectives shown

1. **Electric programs**. Would be offered to electric only customers and gas/electric customers
2. **Gas programs**. Would be offered to gas only customers and gas/electric customers
3. **Electric & gas combined programs.** Would be offered to electric only customers, gas only customers, and gas/electric customers
   - Programs modeled that result include gas and electric measures include:
     - Commercial Prescriptive & Custom
     - Small Business Solutions
     - Residential Home Audit & Retrofit
     - Home Energy Use Benchmarking
     - Low Income Weatherization
     - Efficient New Homes

- **In cases where there are programs that includes electric and gas measures:**
  - For the purposes of the IRP, savings (load shapes) will be provided only for electric measures
  - Program costs included in IRP will be allocated based on the proportion of program TRC benefits that are electric

Electric Program Costs and Cost-Effectiveness

Sector	Program	Reference Case Electric Annual Program Costs, $1,000s (2013$)				Electric Program TRC Ratio
		2019 (Year 5)	2024 (Year 10)	2029 (Year 15)	2034 (Year 20)	
Residential	Residential Lighting & Appliances	$1,849	$620	$347	$392	1.9
Residential	Residential Home Audit & Retrofit	$549	$620	$700	$790	1.1
Residential	ENERGY STAR Air Conditioning	$785	$934	$1,055	$1,191	1.2
Residential	Home Energy Use Benchmarking	$97	$109	$123	$139	1.8
Residential	Low-Income Weatherization	$346	$391	$442	$499	0.8
Residential	Efficient New Homes	$72	$79	$89	$100	0.8
Residential	Multifamily	$17	$19	$21	$24	1.5
Residential	Water Heating	$137	$164	$185	$209	1.2
Residential	Pool Pump	$162	$193	$217	$246	1.3
Residential	Direct Load Control	$652	$736	$831	$938	3.8
Residential	Dynamic Pricing	$250	$250	$250	$250	1.8
Residential	Solar Hot Water	$2	$3	$3	$3	0.4
Commercial	Commercial Prescriptive & Custom	$5,613	$7,353	$8,156	$9,006	1.3
Commercial	Small Business Solutions	$872	$1,149	$1,275	$1,408	1.1
Commercial	Non-Residential Dynamic Pricing	$250	$250	$250	$250	1.8
Commercial	RetroCommissioning	$606	$305	$337	$372	1.2
Commercial	Commercial New Construction	$192	$318	$351	$388	1.8
Commercial	Data Center	$319	$352	$388	$429	1.5
Industrial	Machine Drive	$67	$79	$79	$81	3.9
Industrial	Process Heating	$75	$94	$84	$75	4.5
Industrial	Process Cooling and Refrigeration	$103	$122	$111	$102	3.1
Industrial	Facility HVAC	$274	$309	$287	$269	2.9
Industrial	Facility Lighting	$251	$274	$243	$217	3.5
Industrial	Other Process/Non-Process Use	$15	$20	$18	$16	5.9
	TOTAL	$13,554	$14,742	$15,843	$17,393	

**Reflects costs to ENO electric customers.*

Includes only electric measures (incidental gas savings due to electric measures reflected in TRC)

Gas Program Costs and Cost-Effectiveness

Sector	Program	Annual Program Costs, $1,000s (2013$)				Gas Program TRC Ratio
		2019 (Year 5)	2024 (Year 10)	2029 (Year 15)	2034 (Year 20)	
Residential	Residential Home Audit & Retrofit	$256.8	$289.9	$327.3	$369.5	0.4
Residential	Home Energy Use Benchmarking	$20.5	$23.1	$26.1	$29.5	1.0
Residential	Low-Income Weatherization	$97.0	$109.5	$123.6	$139.6	0.4
Residential	Efficient New Homes[1]	$0.0	$0.0	$0.0	$0.0	9.0
Commercial	Commercial Prescriptive & Custom	$0.0	$0.1	$0.1	$0.1	15.6
Commercial	Small Business Solutions	$0.3	$0.4	$0.4	$0.5	11.2
Industrial	Process Heating	$30.7	$37.8	$39.8	$41.9	2.7
Industrial	Boilers	$4.8	$5.4	$5.1	$4.8	2.3
Industrial	HVAC	$0.7	$0.8	$0.7	$0.7	2.6
Industrial	All (facility-wide measures)	$11.1	$12.3	$11.5	$10.8	2.2

[1] Due to DOE rules on minimum residential furnace efficiency levels that go into effect in 2016, efficient gas furnaces are assumed to be installed only in 2015. Therefore, gas measure program costs for Efficient New Homes are $0 after 2015.

**Reflects costs to ENO gas customers.*
Reflects gas measures only

Program Cost-Effectiveness— Combined Gas & Electric Programs

Program	2034 Reference Case Net Cumulative Therm Savings			Program TRC Ratio		
	Due to Electric Measures	Due to Gas Measures	Total	Electric Only Program	Gas Only Program	Combined Electric/Gas Program
Residential Home Audit & Retrofit	130,877	1,948,274	2,079,151	1.1	0.4	0.9
Home Energy Use Benchmarking	7,355	1,557,279	1,564,634	1.8	1.0	1.7
Low-Income Weatherization	20,803	17,142	37,945	0.8	0.4	0.7
Commercial Prescriptive & Custom	459	205	664	1.3	15.6	1.5
Small Business Solutions	24,707	11,010	35,717	1.1	11.2	1.2
Industrial - Total*	0	198,209	198,209	3.4	2.5	2.8

**Based on available data, there are no industrial electric measures that save gas energy in industrial sub-sectors in the ENO service territory. Total Industrial savings shown because savings each industrial end use tested was cost-effective, and in implementation it is likely there would be one "Industrial" program as opposed to individual programs by end use.*

Note: Electric program TRC ratio reflects savings due to gas and electric measures.

Next Steps

- Finalize achievable potential estimates (Nov-Dec 2014)
- Develop IRP inputs (Feb-Mar 2015)
- Draft Potential Study Report (June 2015)

Entergy New Orleans: Proposed Approach to Developing a List of Reasonably Quantifiable Non-Energy Impacts

Milestone 2 Public Technical Conference

October 30, 2014

NOTE: ALL IRP MATERIALS ARE PRELIMINARY & SUBJECT TO CHANGE PRIOR TO THE FINAL REPORT FILING.

Background and Overview

- Background
  - DSM programs result in both energy impacts (e.g., avoided energy and capacity costs) and non-energy impacts (NEIs)
    - Beneficial NEIs can involve costs that should be considered
  - The New Orleans City Council previously directed Entergy New Orleans (ENO) to develop a proposal and cost estimate to track all reasonably quantifiable NEIs

- Overview of this presentation
  - This presentation summarizes ICF's and ENO's proposed approach to developing a list of reasonably quantifiable NEIs
  - The approach specified here proposes a methodology to rank and prioritize a comprehensive list of NEIs for consideration by the City Council and stakeholders
  - If approved by the Council, the next step is to conduct the research and analysis necessary to develop the list of reasonable NEIs

NEI Monetization* and Tracking –
Proposed Approach to Developing List of Reasonable NEIS

The following approach is proposed to establish the list of reasonably quantifiable NEIs for review by the Council and stakeholders:

1. Develop a comprehensive list of NEIs
2. Review/Compare the list of NEIs and data needs with existing data
3. Rank and categorize the NEIs
4. Propose list (subset) of reasonably quantifiable NEIs and timeline for implementation
5. Share proposed list with City Council and stakeholders
6. Finalize list based on direction from the Council

**The estimated monetary value of the NEI, e.g., $ per kWh value for environmental emissions.*

Identify Comprehensive Set of NEIs

Utility NEIs	Participant NEIs	Societal NEIs
Financial & Accounting NEIs, e.g.,	**Residential NEIs, by measure, e.g.,**	**Environmental Externality NEIs, e.g.,**
Arrearages	Water & other fuel use	Avoided carbon and other GHGs
Carrying costs on arrearages	Durability & maintenance NEIs	Avoided SOx, NOx, particulates, etc.
Customer Service NEIs , e.g.,	Health & comfort NEIs	Other NEIs
Terminations & reconnections	Improved Safety NEIs	**Economic Development NEIs, e.g.,**
Customer calls	Other NEIs	Job creation
Other Utility NEIs	**C&I NEIs, by measure, e.g.,**	Tax revenue
	Water & other fuel NEIs	**Other NEIs, e.g.,**
	O&M	National Security
	Administration	
	Materials handling/movements	
	Other NEIs	

Illustrative Residential NEIs

1. **Durability and Maintenance**
   1. Properly Installed Equipment
   2. HVAC Equipment and Distribution
   3. Water and Humidity Management
   4. Appliances
   5. Lighting

2. **Health and Comfort**
   1. Building Thermal/Pressure Envelope
   2. Air Quality
   3. Lighting
   4. Increased Habitable Space
   5. Reduced Risk of Shutting off Services
   6. Lower Monthly Bills

3. **Improved Safety**
   1. Ambient Air Carbon Monoxide Levels
   2. Gas Leaks/Fires
   3. Radon
   4. Detectors, Ventilation, Air Sealing
   5. Lighting

4. **Societal**
   1. Recycling and Proper Disposal
   2. Infill over Greenfield Building
   3. Appliance Recycling
   4. Reduced Mobility

NEI Analysis - Identify Data Needed to Monetize Each NEI

- **Is the data required to calculate the monetary value of the NEI currently available from ENO** (i.e., through utility or program tracking data)?
- **If not, is reliable secondary data available?**
  - Estimates available through secondary sources that are already applicable to ENO's service territory
  - Estimates available through secondary sources requiring calibration to ENO's service territory
- **If secondary data is not available, primary research is required.** The approach to primary research will depend on the nature of the NEI and the research budget available. Examples of standard practice in primary research methods are shown below

Primary Research Methods

- ***Direct calculation and analysis***, e.g., building simulation or performance data (i.e., pre/post testing)
- ***Collected Data Analysis,*** e.g., existing government, industry, or historical data
- ***Created Records,*** e.g., case studies or reporting

- ***Observations,*** e.g., direct observation, participant observation
- ***Interviews***, such as structured interviews, open-ended interviews, in-depth interviews, key information interviews, focus group/panel of experts interviews
- ***Surveys,*** including contingent valuation (Willingness To Pay) and conjoint analyses

What makes an NEI reasonably quantifiable?

- Little consistency in adoption of NEIs across states, with certain exceptions
  - Readily available NEIs for Low Income programs, for example
  - NEI adoption tends to focus on residential programs, or more generally, programs with historically low benefit-cost ratios (the TRC in most states)
  - Some recent focus on C&I NEIs (e.g., in Massachusetts), although most C&I programs tend to have higher TRC values than residential programs, which is why there has traditionally been less focus on C&I-specific NEIs
  - Some states simply include % adders to TRC benefits as proxies for NEIs, an approach considered to be very low in precision

- For ENO, we propose using four criteria to rank NEIs for the purposes of determining a reasonable set of NEIs
  1. **Cost** to monetize
  2. **Uncertainty** around the NEI value
  3. **Prominence** or potential importance of the NEI
  4. **Benefit-cost** impact to program of the NEI

NEI Costing & Ranking

1. **Develop cost and timeline to monetize each NEI** based on data requirements. Provide a range of costs and timelines where applicable (e.g., if there are multiple options for primary research)

2. **Define uncertainty around each NEI** based on the precision of the methods used to develop the NEI data.

3. **Assign each NEI a measure prominence ranking** based upon published values in the literature on the $ per unit value of the NEI, and on historical and forecasted measure importance. NEIs associated with measures with the highest lifetime savings and highest $ per unit values ($ per NEI unit x anticipated unit installations x EUL) would receive the highest prominence rankings.

4. **Assign each NEI a benefit-cost support ranking** based upon historical and forecasted program B/C ratios. Historically, low income programs have had low B/C ratios. Therefore, NEIs applicable to low income programs would receive a high benefit-cost support ranking.

Each NEI will be assigned a score for each of the above criteria and a total score for the purposes of ranking and prioritization

Estimated cost range to develop list of reasonable NEIs

- Depending on the timing and budget available, the cost to perform the above analysis could range from ~$50,000 to ~$300,000
- Approximate timing ~6-12 months

Next steps

- Feedback on proposed approach

ICF INTERNATIONAL

ENO IRP Public Technical Conference
2015 IRP Process Update

Milestone 2 – IRP Inputs

October 30, 2014

Conference Objectives

- Present Milestone 2 Deliverables
- Highlight process and timeline for continued public input

Milestone 2 Deliverables

Milestone 2 Deliverables

- Milestone 2 is the second of 4 milestones in the process for development of the ENO 2015 IRP

- Pursuant to the Council's process for the ENO 2015 IRP, the Milestone 2 deliverables include:

  - Preliminary results for the 2015 DSM Potential Study

  - Key inputs and assumptions to the IRP Modeling phase (i.e. Milestone 3)

  - Proposal to identify reasonably quantifiable Non-Energy Impacts (NEIs)

Process Update for ENO 2015 IRP

2015 IRP Process Update

- The following are key milestones in the Council's process:
  - ~~June 27 Milestone 1 – Inputs to DSM Potential Study~~
  - ~~Sep 22 Interim Milestone – Renewables Technical Conference~~
  - Oct 30 Milestone 2 – DSM Potential Study Results / IRP Inputs
  - Feb 2015 Milestone 3 – IRP Modeling Results
  - Jun 2015 Milestone 4 – Draft IRP Report
  - Oct 2015 Final ENO 2015 IRP
- ENO will seek input at each of the milestones above

IRP Stakeholder Process Timeline

- The process for development of the ENO 2015 IRP provides an opportunity for input at each milestone in the process:

Milestone	Target for Technical Conference	Questions Due From Stakeholders*	Company Responses Due*	Intervenor Comments*	Council/ Advisor Comments*
Milestone 1 – DSM Potential Study Inputs (Including Avoided Cost)	June 27, 2014	July 3, 2014	July 28, 2014	Aug. 26, 2014	Sept. 25, 2014
Milestone 2 – IRP Inputs Including DSM Potential Study Results	Oct. 30, 2014	Nov. 6, 2014	Dec. 1, 2014	Dec. 29, 2014	Jan. 28, 2015
Milestone 3 – IRP Modeling Results	February 2015	Within 7 days	Within 30 days	Within 60 days	Within 90 days
Milestone 4 – Draft IRP Report	June 2015	Within 7 days	Within 30 days	Within 60 days	Within 90 Days

**** Deadline is from the date of each respective technical conference once the meeting date is established.***

Questions

- After this meeting (and future meetings), ENO will accept questions and comments relevant to the IRP through its website:
  - Visit http://www.entergy-neworleans.com/IRP/
  - Fill out the "Submit a Question" Form
  - The last day to submit a question pertaining to Milestone 2 is *November 6th*
  - ENO will post responses to relevant questions associated with Milestone 2 by *December 1st*

ENTERGY NEW ORLEANS

Portfolio Design Analytics (Scenarios & Sensitivities) AURORA Documentation

2015 ENO Integrated Resource Plan

Milestone 2 Public Technical Conference

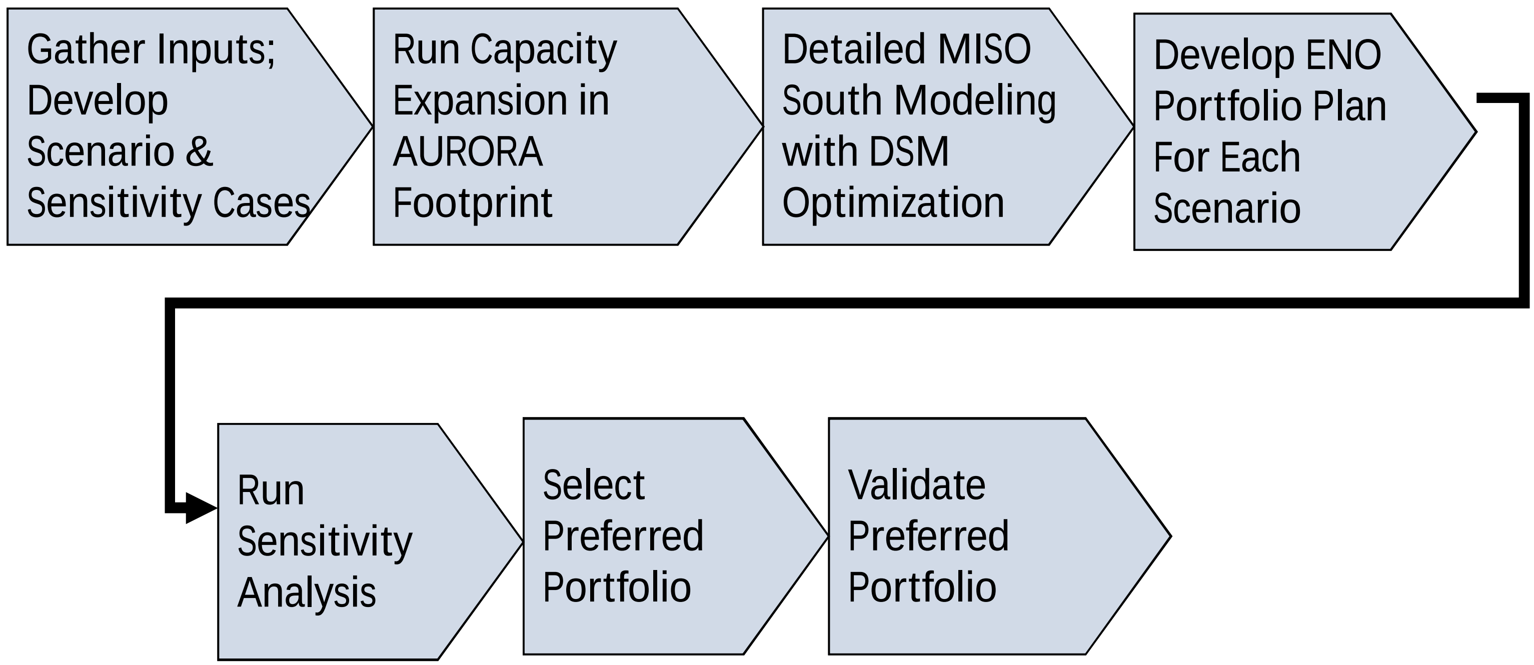
OCTOBER 30, 2014

NOTE: ALL IRP MATERIALS ARE PRELIMINARY & SUBJECT TO CHANGE PRIOR TO THE FINAL REPORT FILING.

Portfolio Design Analytics (Scenarios & Sensitivities)

PORTFOLIO DESIGN ANALYTICS

As required in Resolution R-10-142, IRP analytics will rely on a combination of scenario and sensitivity analyses. The process will include seven broad steps:



The IRP is a dynamic process for long-range planning that provides for a flexible approach to resource selection. The Preferred Portfolio resulting from the IRP planning process provides guidance regarding long-term resource additions, but is not intended as a static plan or pre-determined schedule for resource additions. Actual portfolio decisions are made at the time of execution.

SCENARIOS AND SENSITIVITIES TO BE PERFORMED

The companies plan to examine four scenarios to assess alternative portfolio strategies under varying market conditions. The four scenarios are:

- Scenario 1 (Industrial Renaissance)
  - Reference Load, Gas, Oil, and Coal Prices
  - No direct CO_2 cap and trade or tax on existing resources or new resources but EPA CO_2 standards for new resources allowed to go into effect as currently proposed.
  - Most renewable incentives allowed to sunset
  - No new RPS Standards
- Three additional scenarios listed below and described on the next page.
  - Scenario 2 (Business Boom)
  - Scenario 3 (Distributed Disruption)
  - Scenario 4 (Generation Shift)

*ENO uses MISO capacity market purchases/sales to ensure appropriate resource adequacy

**To the extent that there is a CO_2 cap and trade or tax it is assumed to apply to new and existing resources equally.

The Sensitivity Analysis will consider the following uncertainties:

- Natural gas prices
- Coal prices
- Load (only change ENO energy & peaks)*
- Capital cost for new generation
- General inflation rate and resulting cost of capital
- Implementation of CO_2 cost**
- Gas and CO_2 combination**

SCENARIO STORYLINES

	Scenario 2	Scenario 3	Scenario 4
	Business Boom	Distributed Disruption	Generation Shift
General Themes	• U.S. energy boom continues with low gas and coal prices discounted to world prices. U.S. oil production remains strong but price stays linked to world market. • Low fuel prices drive high load growth especially in industrial class, but with Residential and Commercial class spillover benefits. • Higher capital cost for new power plants.	• States continue to support distributed generation. Consumers and businesses see it as a way to manage their own energy uses. • Medium-high oil prices drive consumer awareness across energy spectrum. • Overall economic conditions are steady with moderate GDP growth which enables investment in energy infrastructure.	• High natural gas exports and more coal exports lead to higher prices at home. • Slow economic growth due to higher energy prices. • Consumers and government look for utility transformation to cleaner and more stable fuels. • Conditions are ripe for renewables and new nuclear but their challenges remain.
Power Sales	• Power sales driven by industrial growth and modest rate increases due to low natural gas and coal prices.	• Power sales growth slows and ultimately turns negative. • Solar PV and Combined Heat and Power impact utility sales, however, most customers stay grid connected. • Customers seek maximum flexibility and reliability by relying on self generation and grid power to meet their needs.	• Slow economic growth leads to relatively low power sales.
CO_2 Policy	• Congress or the EPA ultimately passes a mild CO_2 cap and trade program (power sector only) effective in 2023.	• Congress or the EPA ultimately passes a mild CO2 cap and trade program (power sector only) effective in 2023.	• Congress takes control of CO2 cap and trade away from EPA and passes a Kerry -Lieberman style CO_2 program effective in 2023.
Energy Policy	• Most renewable energy subsidies sunset. • Not all states meet RPS goals.	• Net metering continues but issues related to cross subsidization are addressed. • Federal and state renewable subsidies continue	• Federal and state renewable subsidies continue • No new state RPSs.
Fuels	• Low fuel prices, but natural gas and coal still plentiful as exploration and production costs are also lower. Coal prices low to retain share.	• Natural gas prices are driven higher by EPA regulation of fracking & local opposition. Coal and oil prices also high.	• Natural gas, coal, and oil prices are high.

SENSITIVITY ANALYSIS

- Test sensitivity of objective function results of each portfolio by rerunning production cost and changing one or two variables.
- Run 15 sensitivity cases times 4 scenarios for a total of 60 cases. Yellow shading indicates the assumption in the respective scenario storyline.

	Scenario 1 (Industrial Renaissance)			Scenario 2 (Business Boom)		
1 Natural gas prices	Ref	Low	High	Low	Ref	High
2 Coal prices	Ref	Low	High	Low	Ref	High
3 Load (only change EGSL/ELL energy & peaks)*	Ref	Scenarios 2, 3 and 4		Scenario 2	Scenarios 1, 3 & 4	
4 Capital cost for new generation	Ref	Low	High	High	Low	High
5 General inflation and resulting cost of capital	Ref	Low	High	Ref	Low	High
6 Implementation of CO2 cost	None	Ref	High	Ref	None	High
7 Gas and CO2 combination	Ref / None	Low / Ref	High / High	Low / Ref	Ref / None	High / High

	Scenario 3 (Distributed Disruption)			Scenario 4 (Generation Shift)		
1 Natural gas prices	Ref	Low	High	High	Low	Ref
2 Coal prices	Ref	Low	High	High	Low	Ref
3 Load (only change EGSL/ELL energy & peaks)*	Scenario 3	Scenarios 1, 2 and 4		Scenario 4	Scenarios 1, 2 and 3	
4 Capital cost for new generation	Ref	Low	High	Low	Ref	High
5 General inflation and resulting cost of capital	Ref	Low	High	Ref	Low	High
6 Implementation of CO2 cost	Ref	None	High	High	None	Ref
7 Gas and CO2 combination	Ref / Ref	Low / None	High / High	High / High	Low / None	Ref / Ref

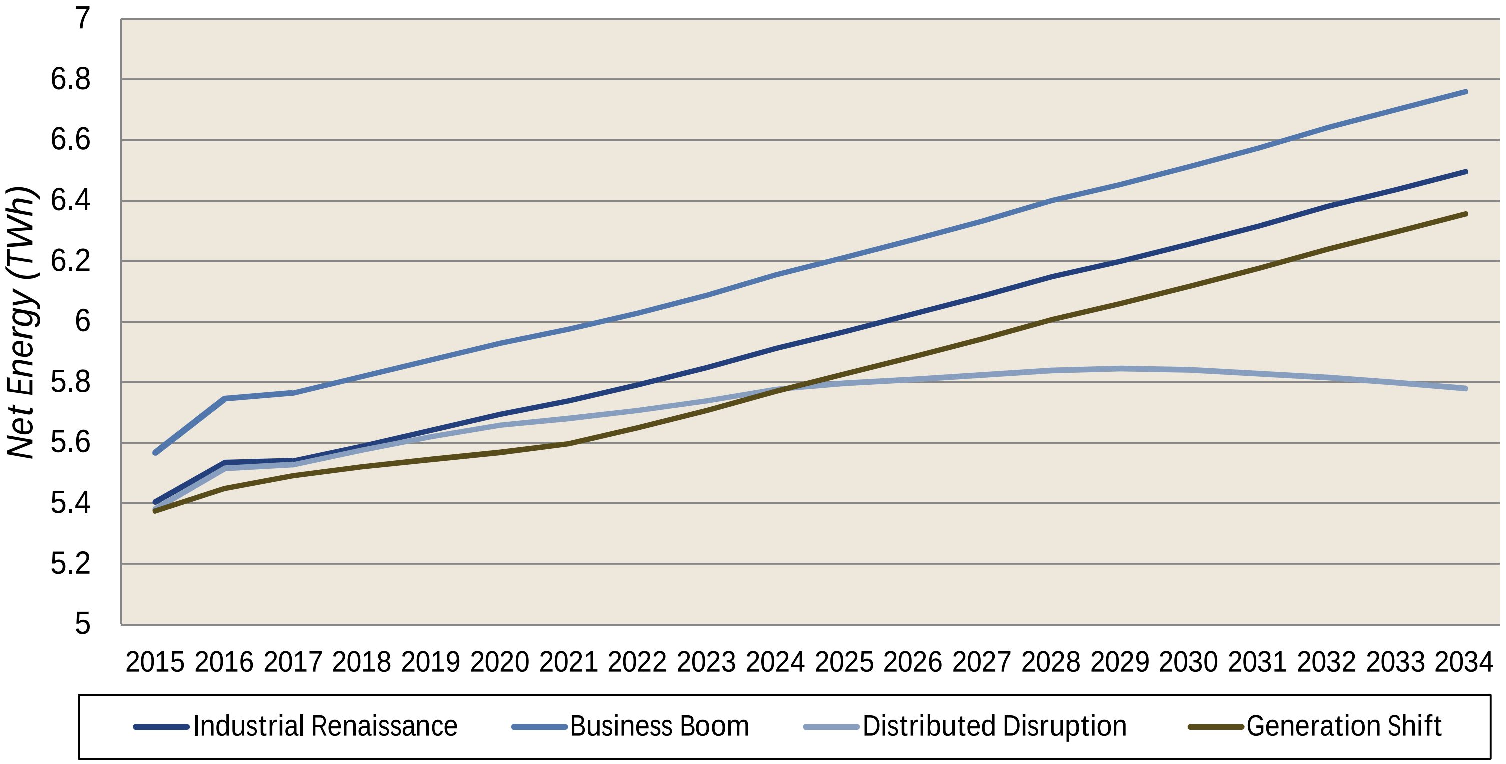
*ENO uses MISO capacity market purchases/sales to ensure appropriate resource adequacy

20 YEAR MARKET MODEL INPUTS (2015-2034)

	Industrial Renaissance	Business Boom	Distributed Disruption	Generation Shift
Electricity CAGR (Energy GWh)	~1.0%	~1.0%	~0.4%	~0.8%
Peak Load Growth CAGR	~0.7%	~0.7%	~0.7%	~0.7%
Henry Hub Natural Gas Prices ($/MMBtu)*	$4.87 levelized 2014$	Low Case $3.84 levelized 2014$	Same as Reference Case ($4.87 levelized 2014$)	High Case ($8.18 levelized 2014$)
WTI Crude Oil ($/Barrel)*	$73.99 levelized 2013$	Low Case $69.00 levelized 2013$	Medium High ($109.12 levelized 2013$)	High Case ($173.71 levelized 2013$)
CO_2 ($/short ton)*	None	Cap and trade starts in 2023 $6.70 levelized 2013$	Cap and trade starts in 2023 $6.70 levelized 2013$	Cap and trade starts in 2023 $14.32 levelized 2013$
Conventional Emissions Allowance Markets	CSAPR & MATS	CSAPR & MATS	CSAPR & MATS	CSAPR & MATS
Delivered Coal Prices – Entergy Owned Plants (Plant Specific Includes Current Contracts) $/MMBtu*	Reference Case (Vol. Weighted Avg. $2.81 levelized 2013$)	Low Case (Vol. Weighted Avg. $2.43 levelized 2013$)	Same as Reference Case (Vol. Weighted Avg. $2.81 levelized 2013$)	High Case (Vol. Weighted Avg. $2.53 levelized 2013$)
Delivered Coal Prices – Non Entergy Plants In Entergy Region	Reference Case (Price Varies by Plant)	Low Case (Price Varies by Plant)	Same as Reference Case	High Case (Price Varies by Plant)
Delivered Coal Prices – Non Entergy Regions	Reference Case (Price Varies by Plant)	Low Case (Price Varies by Plant)	Same as Reference Case	High Case (Price Varies by Plant)
Coal Retirements Capacity (GW)*	Age 60**	Age 70**	Age 60**	Age 50**

*Figures shown are for the period 2015-2034 covering a sub-set of the Eastern Interconnect which is approximately 34% of total U.S. 2011 TWh electricity sales.
Note: Levelized prices refer to the price in 2013 dollars where the NPV of that price grown with inflation over the 2015-2034 period would equal the NPV of levelized nominal prices over the 2015-2034 period when the discount rate is 6.93%. (ENO WACC).
**Entergy owned coal plants assumed to operate beyond the end of the IRP (2034). Some non Entergy plants retire early due to environmental compliance considerations

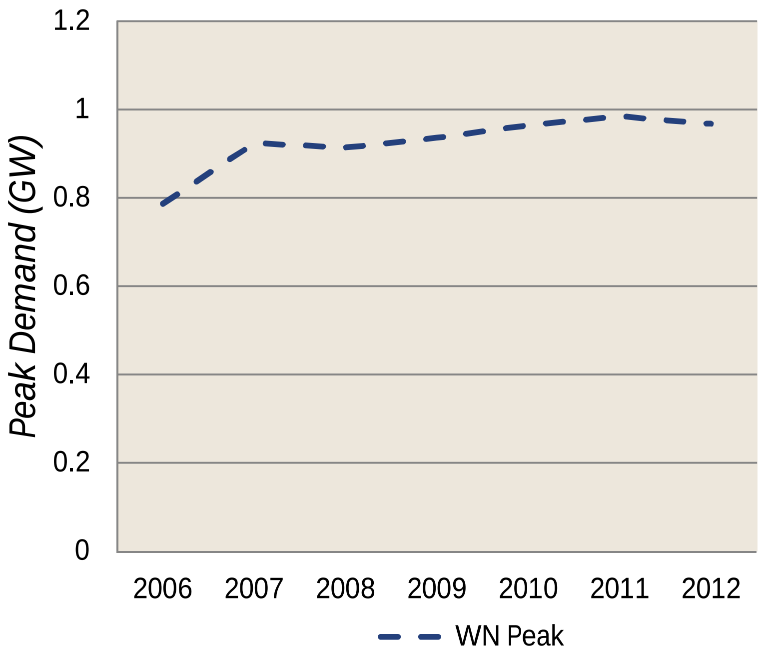
ENO TOTAL ENERGY LOAD FORECAST



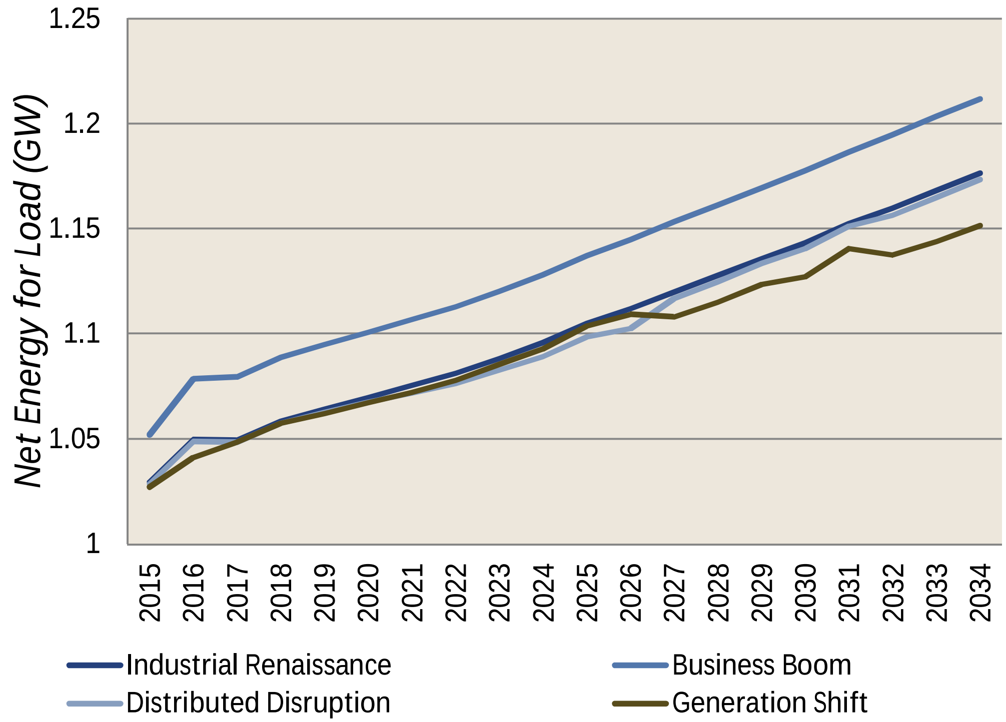
2015 Update	2015-2025 CAGR	2025-2034 CAGR
Industrial Renaissance	1.0%	0.9%
Business Boom	1.1%	0.9%
Distributed Disruption	0.7%	0.0%
Generation Shift	0.8%	0.9%

2015 Update Energy Forecast (GWh)	2015	2020	2025	2030	2034
Industrial Renaissance	5,406	5,695	5,968	6,258	6,497
Business Boom	5,568	5,929	6,213	6,514	6,762
Distributed Disruption	5,383	5,660	5,796	5,842	5,779
Generation Shift	5,375	5,567	5,827	6,117	6,356

ENO PEAK FORECAST



WN Peak = Actual peak adjusted to normal weather



2015 Update	2015-2025 CAGR	2025-2034 CAGR
Industrial Renaissance	0.7%	0.6%
Business Boom	0.8%	0.6%
Distributed Disruption	0.7%	0.5%
Generation Shift	0.7%	0.6%

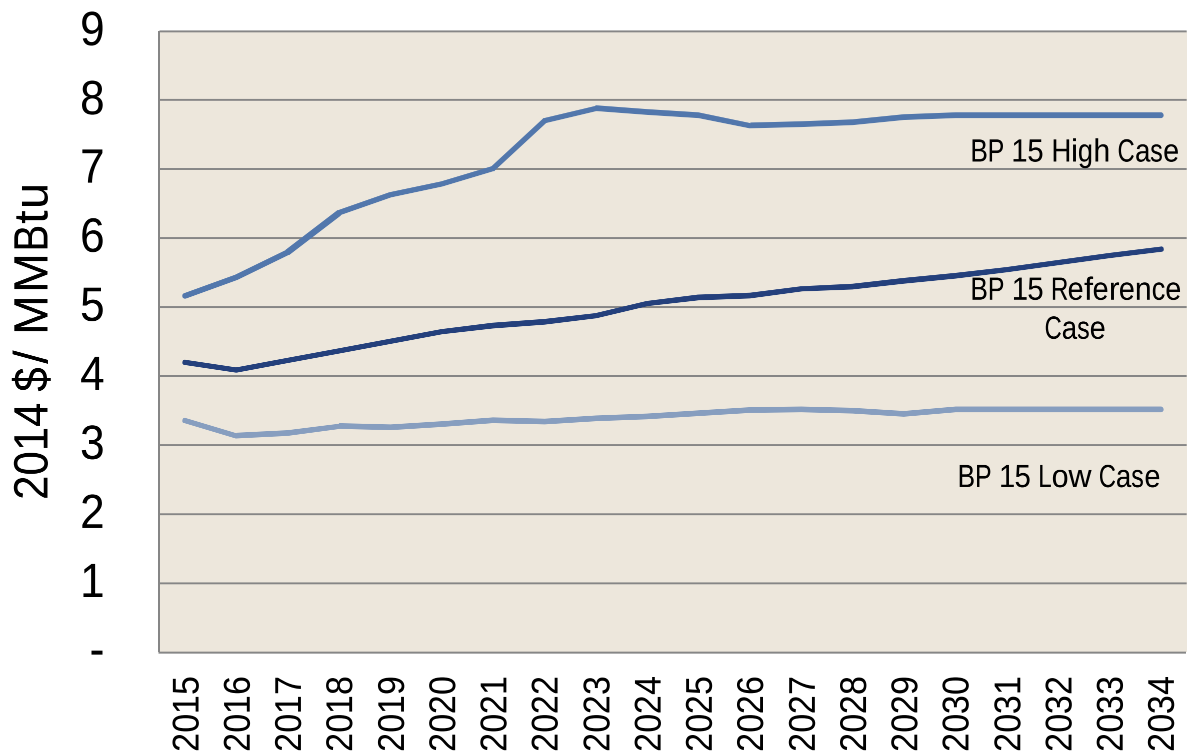
2015 Update Total Peak Forecast (MWs)	2015	2020	2025	2030	2034
Industrial Renaissance	1,029	1,070	1,105	1,143	1,176
Business Boom	1,052	1,101	1,137	1,178	1,212
Distributed Disruption	1,029	1,068	1,099	1,127	1,151
Generation Shift	1,027	1,067	1,104	1,141	1,173

HENRY HUB NATURAL GAS PRICE FORECAST

SPO 2015 Long-Term Henry Hub Natural Gas Price Forecasts (2014$/MMBtu)

Process

- SPO Planning Analysis relies on a number of leading consultants in preparing the natural gas price forecast.
- The early years of the long-term forecast (~1st 3 years) are based on NYMEX forward prices without modification.
- In the later years, the Industrial Renaissance Natural Gas forecast represents a consensus view of the consultants' forecasts.
- The High and Low Cases represent plausible alternative scenarios developed by SPO (informed by consultants and a review of historical fundamentals and prices).



FUEL PRICE METHODOLOGIES USED IN MODELING (CONTINUED)

FUEL PRICE METHODLOGY				
Fuel	*Load Serving Entity*	*Commodity Treatment*	*Transportation Treatment*	*Impact on Power Prices*
Diesel/Fuel Oil	Entergy OPCOs	Use of petroleum for emergency use only at selected plants and therefore not modeled		Not meaningful*
Diesel/Fuel Oil	Non Entergy MISO South	Use of petroleum for emergency use only at selected plants and therefore not modeled		Not meaningful*
Diesel/Fuel Oil	Other Modeled Footprint	The delivered price forecast provided by AURORA vendor EPIS is used		Not meaningful*
Biomass	Entergy OPCOs	Proprietary forecast of delivered price based on market assessments by Argus Research and a forecast of lumber and wood price escalations provided by IHS Global Insight		Not meaningful
Biomass	Non Entergy MISO South	Proprietary forecast of delivered price based on market assessments by Argus Research and a forecast of lumber and wood price escalations provided by IHS Global Insight		Not meaningful
Biomass	Other Modeled Footprint	The delivered price forecast provided by AURORA vendor EPIS is used		Not meaningful

*Diesel prices impact coal transportation cost so the current and future outlook for diesel prices are considered in coal price forecasts.

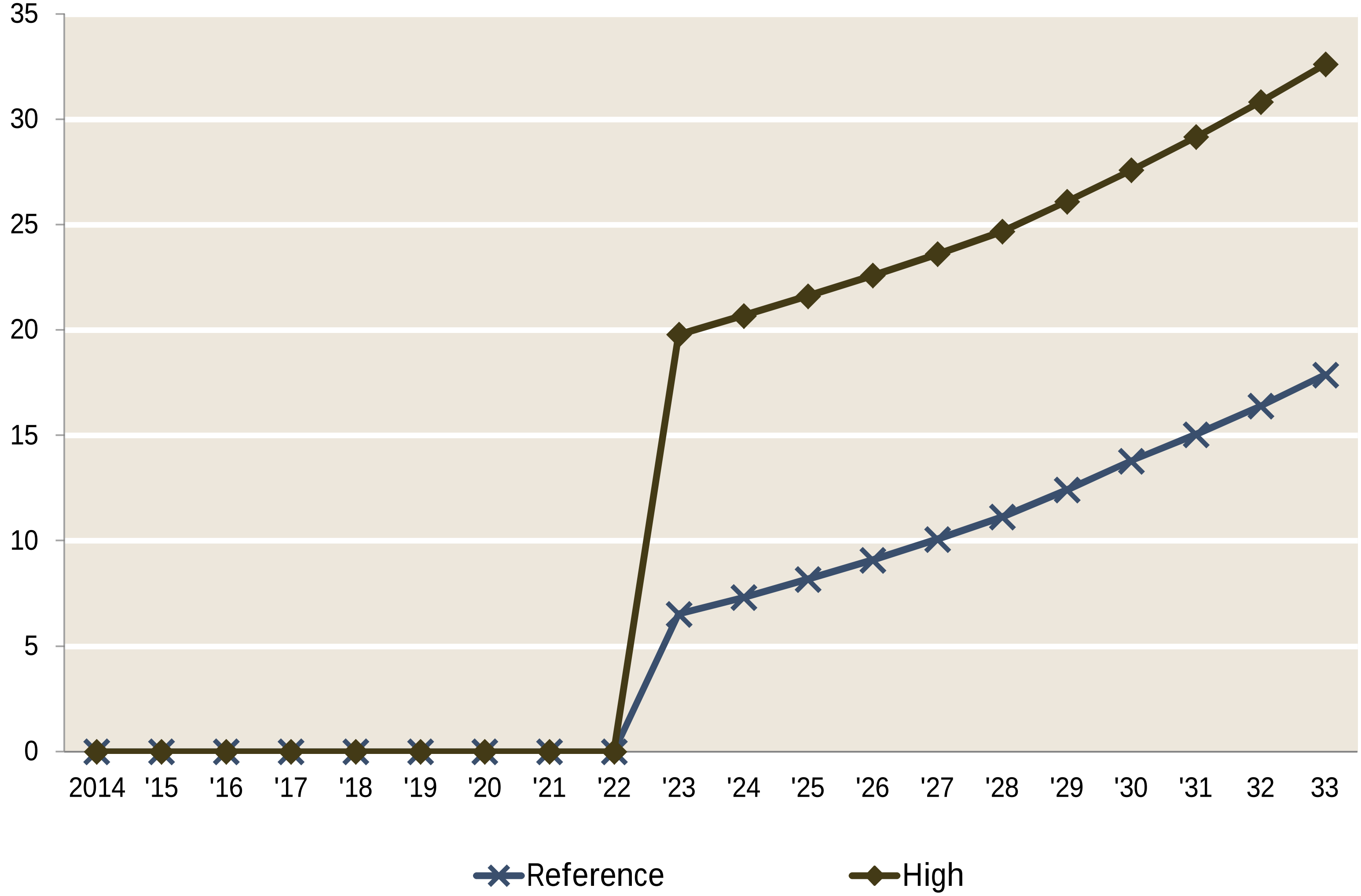
FUEL PRICE METHODOLOGIES USED IN MODELING

Two factors drive the rigor and frequency of fuel price forecast updates. First the impact the fuel price assumption has on forecasting power prices; and secondly whether Entergy resources utilize the fuel in question.

FUEL PRICE METHODLOGY				
Fuel	*Load Serving Entity*	*Commodity Treatment*	*Transportation Treatment*	*Impact on Power Prices*
Natural Gas	Entergy OPCOs	Henry Hub proprietary forecast plus basis adjustments based on a historical analysis of basis	Transportation contracts and taxes to arrive at delivered price.	High
Natural Gas	Non Entergy MISO South	Henry Hub proprietary forecast plus adjustments from consultant averages of the basis differential at each non-Entergy hub	Default transportation adders provided by EPIS based on how they classify the resources (peaking, cycling, etc.)	High
Natural Gas	Other Modeled Footprint	Same as above		High
Coal	Entergy OPCOs	Proprietary forecast using future spot prices of Powder River Basin coal forecast by Energy Ventures Analysis plus existing coal contracts	Proprietary forecast of transportation cost based on rail contracts and forecasted spot rail prices by Energy Ventures Analysis	High
Coal	Non Entergy MISO South	Delivered price forecast on a plant by plant basis from Energy Ventures Analysis		High
Coal	Other Modeled Footprint	Delivered price forecast on a plant by plant basis from Energy Ventures Analysis		High
Nuclear Fuel	Entergy OPCOs	Proprietary forecast of each nuclear unit's commodity & fabrication cost considering existing contracts and future spot transportation cost	Proprietary forecast of each nuclear unit's transport cost considering existing contracts and future spot transportation cost	Low
Nuclear Fuel	Non Entergy MISO South	Volume weighted average cost for Entergy's regulated nuclear plants used for other nuclear plants		Low
Nuclear Fuel	Other Modeled Footprint	Same as above		Low

CO_2 PRICE FORECAST

April 2013 Long-Term CO_2 Price Forecast (2013$/U.S. Ton) Reaffirmed in August 2014



AURORA MODELING OVERVIEW

AURORAXMP ELECTRIC MARKET MODEL

- AURORAxmp Electric Market Model (AURORA) is a production cost model licensed by Entergy in April 2011 from software firm EPIS, Inc. in Sandpoint, ID (www.epis.com). Use of the tool at Entergy has advanced to the point where it is now the primary production cost tool used for MISO market modeling and Entergy long-term planning.

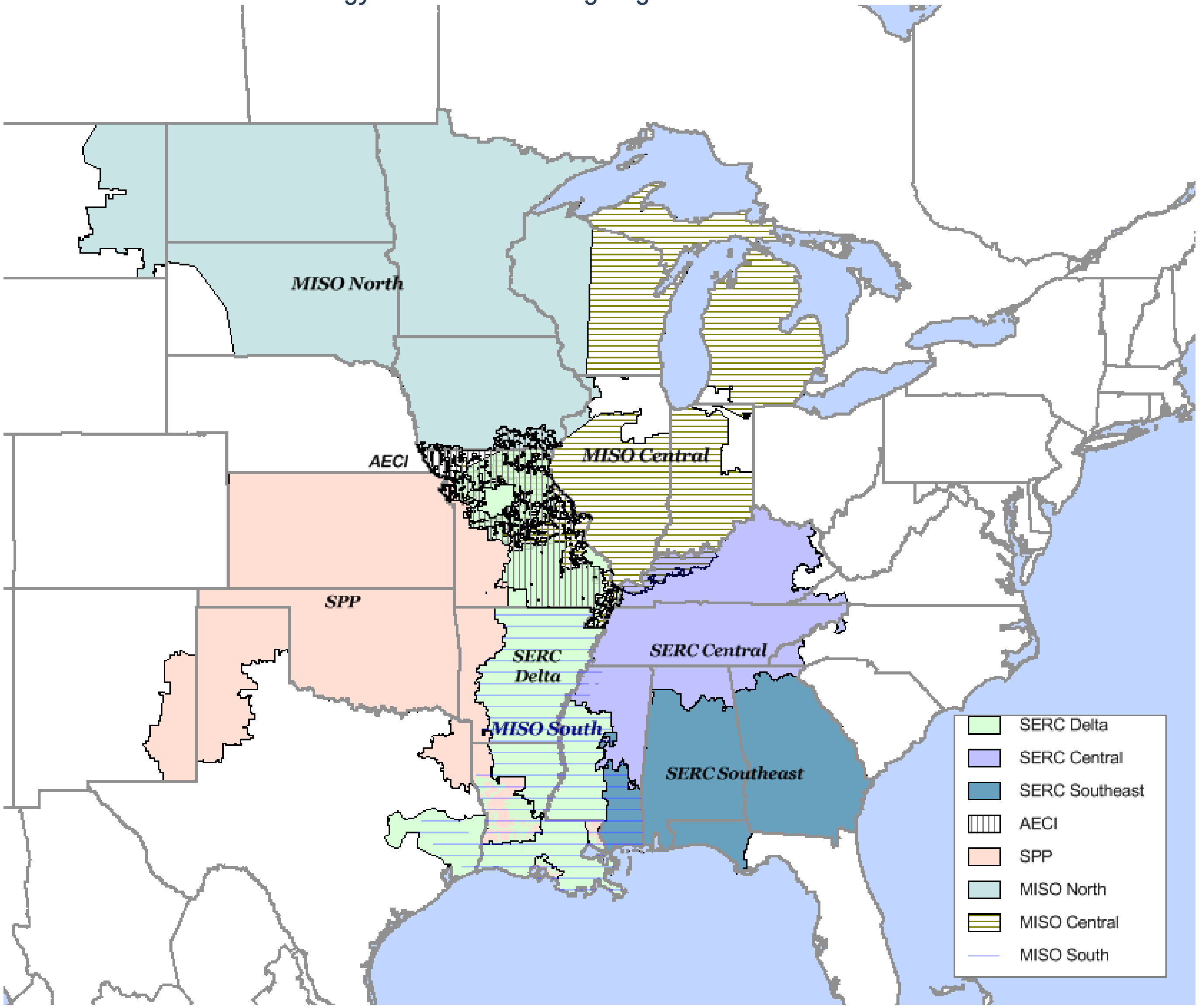
- The 2015 ENO IRP will utilize AURORA in scenario and sensitivity modeling. The 2015 AURORA Update Case has been created using the latest planning assumptions . This will serve as the foundation for ENO's IRP Scenario 1 modeling. Assumptions in the IRP work which materially differ from the 2015 Business Plan case will be noted in the IRP documents. The AURORA model has been calibrated to ensure accuracy of input data and output results. AURORA simulates the hourly operations of a power market over a projected study period. In this case, the model has been populated to allow studies for up to 20 years in length (1/1/2015 to 12/31/2034).

- The ENO IRP consider the years 2015-2034.

- The AURORA model as configured for IRP analysis uses a zonal representation of MISO and 1st Tier markets. The MISO modeling is broken down into two regions, MISO North and MISO South. The MISO North region represents the MISO RTO as it existed prior to Entergy joining the RTO. The MISO South region includes Entergy operating companies, Entergy co-owners, IPPs and Qualifying Facilities, and other non-Entergy companies (i.e. CLECO, LAFA, LEPA, LAGN, and SMEPA) within the Entergy footprint that began participation in the MISO market December 19, 2013. The 1st Tier markets consist of SPP, SERC – Central (TVA), and SERC – Southeast (SERCS).

Scope of AURORA Market Modeling

Entergy and surrounding regions will be modeled .



UNIT ASSUMPTIONS

- Unit Capacities
  - The ratings for Entergy owned resources are the GVTC ratings[1] provided to MISO.
- Unit Availability and Inclusion
  - Resources taken from the 2009 Summer RFP, 2010 Renewable RFP, and 2011 EAI RFP are included as Entergy owned acquisitions/contracts.
  - All Entergy legacy units are modeled with the proposed deactivations schedule from the 2015 Update. There are 320 MW (Total ETR Utility capacity) where the deactivation date is to be determined. This is because the year of planned deactivation is currently being studied.
  - At this time Entergy unit deactivations do not vary by scenario, but that assumption could change for some scenarios pending additional review.
  - Non-Entergy resources deactivations:
    - Coal Units[2]
      - Scenario One (Industrial Renaissance) - at Age 60 years
      - Scenario Two (Business Boom) - at 70 years
      - Scenario Thee (Distributed Disruption) - at 60 years
      - Scenario Four (Generation Shift) – at 50 years
    - Gas, Nuclear & Other (At Age 60 years, modern CT and CCGT at age 30 years)

[1]Generation Verification Test Capacity (this is an annual test required by MISO to determine a resource's maximum capability based on a real power test).

[2]Some coal units are retired in the 2014-2020 period before they reach age 60 due to environmental regulations, primarily the MATS rule.

UNIT ASSUMPTIONS (CONTINUED)

- Maintenance
  - Thirty years of scheduled maintenance data are input for Entergy owned resources. Operations Planning collects data from the plants and co-owners, which includes their assumptions for the first 5 years. The pattern of scheduled maintenance is replicated and carried out through 2034.

- Forced Outage Rates
  - Annual forced outage rates are developed and input into the model for each Entergy owned fossil unit. These rates are based on historical Generation Availability Data Reporting System ("GADRS") data for May 2009 through April 2012.
  - Operations Planning reviews significant outage events to determine if each event is recurring or non-recurring in nature. Based on this review some events are removed from the forced outage rate calculation.
  - For nuclear units, forced outages are modeled as derates to the resource capacity to reflect historical outage experience.

DSM Optimization

As required in Resolution R-14-224, ENO proposes the following for use in the DSM Optimization process as to reduce the number of model simulations to be evaluated in the IRP optimization. Therefore, potentially eliminating, or a least greatly reducing, the need to bundle measures.

- ICF to evaluate 192 measures at three funding levels
- ICF's Potential Study to determine the most cost effective DSM measures, which generally refers to measures with a TRC of at least 1.0
- Evaluate ICF's results to determine most efficient funding level (low, medium, and high) for each measure
- Assess selected programs in AURORA

SPO PLANNING ANALYSIS

GENERATION TECHNOLOGY ASSESSMENT

Technology Cost & Performance

Milestone 2 Public Technical Conference

OCTOBER 30, 2014

NOTE: ALL IRP MATERIALS ARE PRELIMINARY & SUBJECT TO CHANGE PRIOR TO THE FINAL REPORT FILING.

TECHNOLOGY ASSESSMENT PROCESS & OVERVIEW

- An understanding of generation technology capital cost, operating cost, feasibility, commercial availability, and performance is a necessary input to planning and decision support activities. SPO Planning Analysis monitors and assesses generation alternatives on an on-going basis. This analysis uses a generic long-term capital structure of 11.0% Return on Equity and 7.0% cost of long-term debt and assumes 50% equity and 50% debt.

- The process has two main steps. First a screening level analysis is performed and then a detailed analysis is performed.

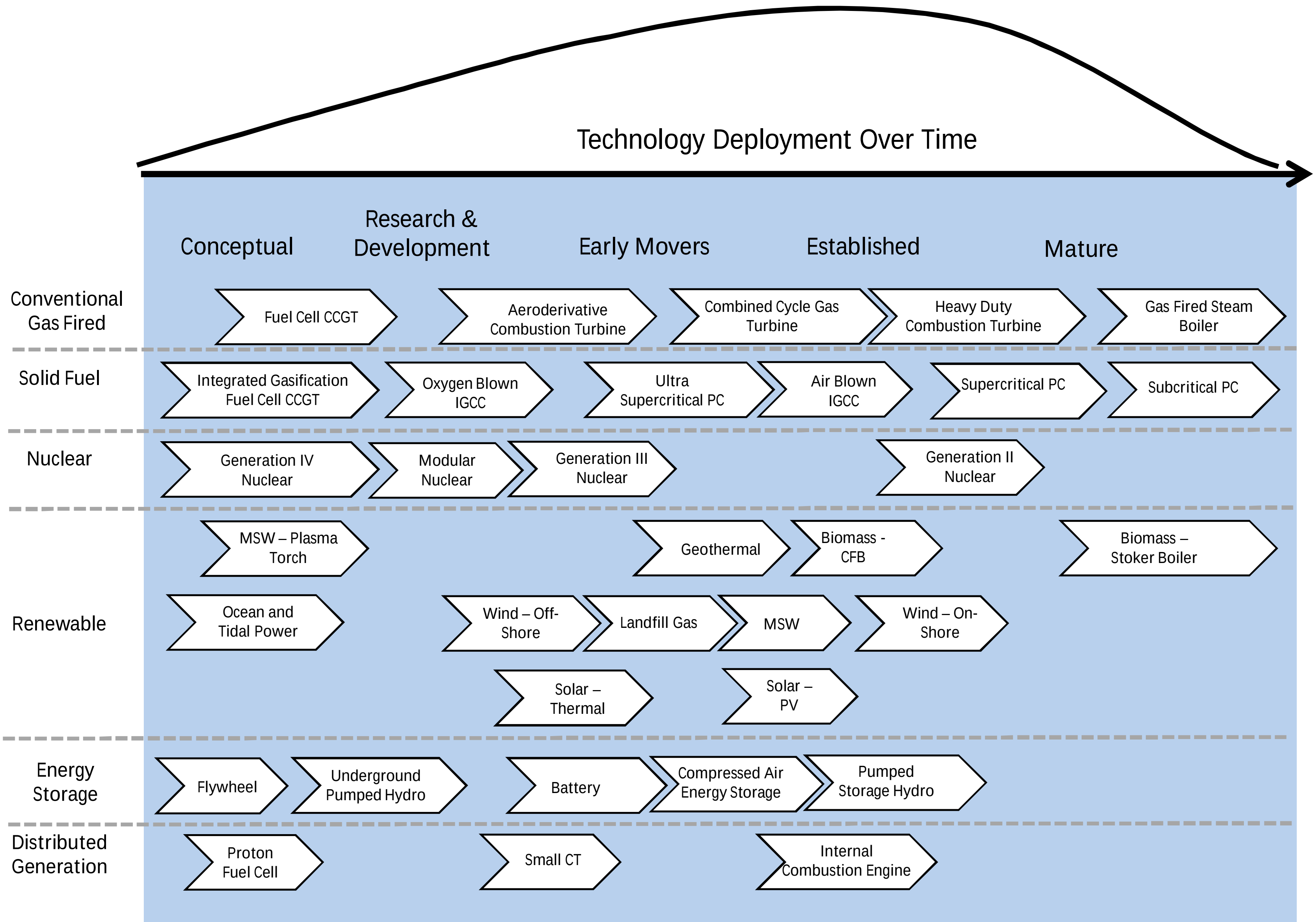
- The 2014 Generation Technology Assessment began by surveying available utility-scale electricity generation technologies, generally those that are two (2) megawatts or greater. The objective is to identify a reasonably wide a range of generation technologies for further modeling. The initial list was subject to a screening analysis to identify generation technologies that are technologically mature and could reasonably be expected to be operational in or around the Entergy utility service areas within the IRP planning horizon.

- ENO along with the other Entergy Operating Companies (EOCs) prefer technologies that are proven viable on a commercial scale. Some technologies identified in this document lack the commercial track record to demonstrate their technical and operational feasibility at a utility-scale. A cautious approach to technology development and deployment is therefore reasonable and appropriate in order to maintain System reliability and to protect ENO customers from unnecessary risks and higher costs. It should also be noted that ENO and the other EOCs do not plan to be "first movers" with respect to the adoption of emerging, unproven technologies.

- Through this first level technology screen, System Planning & Analysis (SPO) has selected certain traditional and renewable generation technology alternatives which may reasonably be expected to meet primary objectives of cost minimization, risk mitigation, and reliability. For each selected technology SPO developed the necessary cost and performance parameter inputs for the detailed IRP modeling.

- SPO and ENO will continue to monitor the technologies eliminated as a result of this initial screen and incorporate changes into future technology assessments and IRPs.

A VARIETY OF SUPPLY SIDE RESOURCES ALTERNATIVES ARE AVAILABLE



TECHNOLOGIES SCREENED

- Renewable Technologies
  - Biomass
  - Solar Photovoltaic (Fixed Tile and Tracking)
  - Solar Thermal
  - Wind Power
  - Municipal Solid Waste
  - Landfill Gas
  - Geothermal
  - Ocean & Tidal
- Combustion Turbine / Combined Cycle / Other Natural Gas
  - Combustion Turbine
  - Combined Cycle
  - Large & Small Scale Aeroderivative
  - Steam Boiler
- Fuel Cells
  - Molten Carbonate
  - Solid Oxide
  - Phosphoric Acid
  - Proton Exchange Membrane
  - Fuel Cell Combined Cycle
- Pulverized Coal
  - Subcritical Pulverized Coal
  - Supercritical Pulverized Coal
  - Ultra Supercritical Pulverized Coal
- Fluidized Bed
  - Atmospheric Fluidized Bed
  - Pressurized Fluidized Bed
- Integrated Gasification ("IGCC")
  - Oxygen-Blown IGCC
  - Air-Blown IGCC
  - Integrated Gasification Fuel Cell Combined Cycle
- Nuclear
  - Advanced Boiling Water Reactor
  - Generation IV
  - Modular Reactors
- Energy Storage
  - Pumped Hydro
  - Underground Pumped Hydro
  - Battery
  - Flywheel
  - Compressed Air Energy Storage

Technologies Selected For Detailed Analysis

The following technologies are being carried forward for development of detailed planning assumptions

- Renewable Technologies
  - Biomass
  - Wind Power
  - Solar PV (Fixed Tilt and Tracking)
- Battery Storage
- Natural Gas Fired
  - Combustion Turbine ("CT")
  - Combined Cycle Gas Turbine ("CCGT")
  - Large Scale Aeroderivative CT
  - Small Scale Aeroderivative CT
  - Internal Combustion Engine

- Nuclear
  - Advanced Boiling Water Reactor
- Pulverized Coal
  - Supercritical Pulverized Coal with carbon capture and storage*

**Proposed EPA regulations on CO_2 have basically eliminated all new coal plants without carbon capture.*

TECHNOLOGY ASSUMPTIONS FOR COMBINED CYCLE APPLICATION

Cost & Performance Appropriate For Technology Deployment in MISO South		2x1 F Frame CCGT	2x1F Frame w/ Supplemental Capacity	2x1 G Frame CCGT	2x1G Frame w/ Supplemental Capacity
Net Max Capacity (Summer)	(MW)	587	764	746	932
Installed Cost, 2014 (Summer)	($/kW)[1]	$1,300	$1,045	$1,190	$985
Full Load Heat Rate (Summer)	(Btu/kWh)	6,750	7,180	6,620	7,030
Net Max Capacity (ISO)	(MW)	624	800	769	980
Installed Cost, 2014 (ISO)	($/kW)[1]	$1,220	$1,000	$1,155	$940
Full Load Heat Rate (ISO)	(Btu/kWh)	6,600	7,035	6,550	7,030
Typical Capacity Factor	(%)	65%-85%	65%-85%	65%-85%	65%-85%
Fixed O&M (Summer)	($/kW-yr.)	$25.90	$20.10	$24.00	$19.90
Variable O&M (Summer)	($/MWh)	$1.50	$1.15	$1.50	$1.15
Inlet Air Conditioning Assumption		Evaporative Coolers			
NOx Control Technology		SCR	SCR	SCR	SCR
NOx emissions, post control	(lbs./MMBtu)	0.01	0.01	0.01	0.01

- Levelized 30 year gas price (reference case, real terms) is $4.94/mmbtu
- Supplemental capacity (duct firing) is valued at $250/kW

Technology Assumptions for Peaking Applications

Cost & Performance Appropriate For Technology Deployment in MISO South		F Frame CT	F Frame CT w/ SCR	E Frame CT	Large Aeroderivative CT	Internal Combustion
Net Max Capacity (Summer)	(MW)	194	194	76	102	18.8
Installed Cost, 2014	($/kW)[1]	$820	$915	$1,035	$1,275	$1,360
Full Load Heat Rate – Summer	(Btu/kWh)	10,200	10,400	13,200	9,125	8,440
Net Max Capacity (ISO)	(MW)	217	217	83	104	18.8
Installed Cost, 2014 (ISO)	($/kW)[1]	$735	$820	$950	$1,250	$1,360
Full Load Heat Rate (ISO)	(Btu/kWh)	9,931	10,130	11,800	8,960	8,325
Typical Capacity Factor	(%)	0%-10%	0%-40%	0%-5%	0%-40%	0%-40%
Fixed O&M	($/kW-yr.)	$11.80	$12.80	$8.35	$13.20	$29.30
Variable O&M	($/MWh)	$0.50	$1.00	$0.50	$1.00	$2.25
Inlet Air Conditioning Assumption		-	-	-	Inlet Chillers	-
NOx Control Technology		Dry Low NOx burners	SCR	Dry Low NOx burners	SCR	SCR
NOx emissions, post control	(lbs./MMBtu)	0.03	0.01	0.03	0.01	0.01

- Levelized 30 year gas price (reference case, real terms) is $4.94/mmbtu

Technology Assumptions for Solid Fuel & Renewable Applications

		PC With 90% CCS	Biomass	Nuclear	Wind	Solar PV (fixed tilt)	Solar PV (tracking)	Battery Storage (Lead Acid Batteries)
Net Max Capacity	(MW)	800	100	1,310	200	100	100	50
Installed Cost, 2014	($/kW)[1]	$4,900	$4,760	$8,000	$2,050	$2,600	$2,900	$2,400
Full Load Heat Rate – Summer	(Btu/kWh)	13,200	12,900	10,200	-	-	-	-
Levelized Fuel Cost	($/MMBtu)	$3.12	$3.04	$0.90	-	-	-	-
Typical Capacity Factor	(%)	85%	85%	90%	34%	18%	21%	20%
Fixed O&M	($/kW-yr.)	$140.00	$104.60	$115.60	$22.10	$19.00	$23.00	$0.00
Charging Cost	($/MWh)	n/a	n/a	n/a	n/a	n/a	n/a	$25.00
Expected Useful Life		40	30	40	20	25	25	20

- Capacity for these technologies is not significantly affected by ambient air temperature
- All O&M is considered fixed.

LIFECYCLE RESOURCE COST, LEVELIZED NOMINAL $/MWH FOR 2015 RESOURCES

Based on Generic Cost of Capital[4]		No CO_2			With CO_2		
Technology	Capacity Factor	Reference Fuel	High Fuel	Low Fuel	Reference Fuel	High Fuel	Low Fuel
F Frame CT	10%	$198	$224	$179	$204	$230	$184
F Frame CT w/ SCR	20%	$141	$167	$121	$146	$173	$126
E Frame CT	10%	$240	$274	$215	$247	$281	$222
Large Aeroderivative CT	40%	$108	$131	$91	$113	$136	$95
Small Aeroderivative CT	40%	$125	$150	$106	$130	$156	$112
Internal Combustion	40%	$115	$137	$99	$120	$141	$104
2x1 F Frame CCGT	65%	$79	$97	$67	$83	$100	$70
2x1 F Frame CCGT w/ Supplemental	65%	$75	$93	$61	$78	$97	$65
2x1 G Frame CCGT	65%	$76	$93	$63	$79	$96	$67
2x1 G Frame CCGT with Supplemental	65%	$72	$90	$59	$76	$94	$63
1x1 F Frame CCGT	65%	$82	$100	$69	$86	$104	$73
PC With CCS	85%	$163	$230	$94	$165	$232	$96
Biomass	85%	$175	$321	$142	$175	$321	$142
Nuclear	90%	$157	$169	$157	$157	$169	$157
Wind (No Subsidy)[1]	34%	$115	$115	$115	$115	$115	$115
Wind (Ten Yr. $22/MWh PTC)[1]	34%	$102	$102	$102	$102	$102	$102
Solar PV with 30% ITC (fixed tilt)[2]	18%	$190	$190	$190	$190	$190	$190
Solar PV with 30% ITC (tracking)[2]	21%	$179	$179	$179	$179	$179	$179
Battery Storage[3]	20%	$217	$217	$217	$217	$217	$217

1. Includes capacity match-up cost $47.88/MWh due to wind's 14.1% capacity value in MISO
2. Includes capacity match-up cost of $23.57/MWh assuming a 25.0% capacity value in MISO
3. Includes cost of $25/MWh required to charge batteries.
4. Includes capacity Levelized Nominal Lifecycle Cost of Resources Deployed in 2015, $/MWh
5. CO_2 Beginning 2023 $7.54/U.S. Ton Nominal $, Reaches $66.44/ton in 2043

ADDITIONAL SUPPLY CONSIDERATIONS

Schedule and location can influence which technology is preferred for a given application

Technology	Time to Market	Environmental	Gas Supply	Flexibility
CCGT	◑	●	◑	◑
Frame CT w/ SCR	◕	●	◑	◑
Small Aeroderivative	●	●	○	◕
Large Aeroderivative	◕	●	○	◕
Internal Combustion Engine	●	◑	●	●
Nuclear	○	◕		○
Coal	◔	○		●
Wind	●	●		○
Solar	●	●		○
Biomass	◑	●		◑
Considerations included in category	• Permitting Requirements • Lead time of major components • Engineering Required • Installation Time	• Impact of Non-Attainment Zone • NOx Emissions • SOx Emissions • CO_2 Emissions • Residual Fuel	• Gas Pressure Required	• Ramp Rate • Turndown Ratio • Start Time • Performance at Part Load

● ◕ ◑ ◔ ○

Relatively best — Relatively worst

Considerations are scored relative to each other

Capital Cost Projections

Capital Cost Installed (Nominal)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
F Frame CT	$820	$838	$860	$885	$918	$951	$982	$1,001	$1,027	$1,040	$1,056	$1,077
F Frame CT with SCR	$915	$935	$960	$988	$1,024	$1,061	$1,095	$1,117	$1,146	$1,160	$1,179	$1,202
E Frame CT	$1,035	$1,058	$1,086	$1,118	$1,158	$1,200	$1,239	$1,264	$1,296	$1,312	$1,333	$1,360
Small Aeroderivative	$1,550	$1,585	$1,626	$1,674	$1,735	$1,797	$1,856	$1,893	$1,941	$1,966	$1,997	$2,036
Large Aeroderivative	$1,275	$1,303	$1,337	$1,377	$1,427	$1,478	$1,526	$1,557	$1,597	$1,617	$1,642	$1,675
Internal Combustion	$1,360	$1,390	$1,400	$1,425	$1,476	$1,537	$1,580	$1,624	$1,670	$1,710	$1,751	$1,786
2x1 F Frame CCGT	$1,300	$1,329	$1,347	$1,379	$1,432	$1,492	$1,538	$1,577	$1,616	$1,639	$1,751	$1,786
2x1 F Frame CCGT w/ supplemental	$1,045	$1,068	$1,083	$1,108	$1,151	$1,199	$1,237	$1,268	$1,299	$1,317	$1,669	$1,702
2x1 G Frame CCGT	$1,190	$1,217	$1,233	$1,262	$1,311	$1,366	$1,408	$1,443	$1,479	$1,500	$1,342	$1,368
2x1 G Frame CCGT w/ supplemental	$985	$1,007	$1,020	$1,045	$1,085	$1,131	$1,166	$1,195	$1,224	$1,242	$1,528	$1,558
1x1 F Frame CCGT	$1,350	$1,380	$1,398	$1,432	$1,487	$1,549	$1,597	$1,638	$1,678	$1,702	$1,733	$1,768
PC With CCS	$4,905	$5,015	$5,043	$5,130	$5,308	$5,524	$5,673	$5,836	$6,009	$6,176	$6,335	$6,462
Biomass	$4,760	$4,867	$4,894	$4,978	$5,152	$5,361	$5,505	$5,664	$5,831	$5,993	$6,148	$6,271
Nuclear	$8,000	$8,179	$8,391	$8,638	$8,953	$9,276	$9,578	$9,769	$10,020	$10,145	$10,305	$10,511
Wind (no subsidy) [1]	$2,050	$2,075	$2,087	$2,061	$2,131	$2,203	$2,279	$2,334	$2,408	$2,472	$2,537	$2,588
Solar PV (fixed tilt)[2]	$2,600	$2,361	$2,178	$2,050	$1,976	$1,914	$1,861	$1,819	$1,785	$1,760	$1,738	$1,723
Solar PV (tracking)[2]	$2,900	$2,633	$2,429	$2,286	$2,204	$2,135	$2,076	$2,029	$1,991	$1,963	$1,939	$1,922
Battery Storage	$2,400	$2,453	$2,471	$2,515	$2,605	$2,712	$2,789	$2,865	$2,946	$3,017	$3,090	$3,151

1. Does not include any Production Tax Credits
2. Includes Investment Tax Credit of 30%