

# SUPPLEMENT 10: DEMAND SIDE MANAGEMENT

## Existing DSM Programs

This purpose of this section is to discuss the historical performance of the Energy SMART program.

### ENERGY SMART (ENO)

Energy Smart New Orleans

Energy Smart is a comprehensive energy efficiency program developed by the New Orleans City Council, administered by Entergy New Orleans, Inc. and implemented by CLEARResult. Currently in its fifth program year on the Eastbank, the Energy Smart New Orleans Program (“New Orleans Program”) has helped over 32,000 New Orleans ratepayers with energy efficient measures to help manage their energy consumption.

In its first four years, Energy Smart consisted of the seven residential and two commercial programs, listed below.

**Table 1: Energy Smart Programs**

Program	Program Type
Home Performance with Energy Star	Residential
Energy Star Air Conditioning	Residential
Air Conditioning Tune-up	Residential
Energy Star New Homes	Residential
Low Income	Residential
Solar Water Heater Pilot	Residential
Compact Fluorescent Lighting Direct Install	Residential
Small Commercial Solutions	Commercial and Industrial
Large Commercial Solutions	Commercial and Industrial

The Energy Smart program has kWh savings approved yearly by the New Orleans City Council. In program years 1-4, the New Orleans Program achieved 109%, 124%, 96% and 96% of the approved kWh savings goals, respectively. These results were boosted by several programs that have consistently performed well. The Home Performance with Energy Star program and Low Income (or “Income Qualified”) generated kWh savings in excess of their specific goals in all four years. On the contrary, the Energy Star New Homes and Solar Water Heater Pilot programs struggled with participation.

Historical performance of Energy Smart is displayed in the following tables:

**Table 2: Energy Smart Program Year One**

PROGRAM NAME	KW GOAL	KWH GOAL	KW ACTUAL	KWH ACTUAL	PARTICIPANTS	MEASURES	KW	KWH
RESIDENTIAL SOLUTIONS	220	1,311,726	621	3,080,830	2,016	3,349	282.05%	234.87%
ENERGY STAR AIR CONDITIONING	260	651,656	50.5	134,655	218	262	19.42%	20.66%

A/C TUNE-UP	486	882,739	223.44	429,291	719	909	45.98%	48.63%
NEW HOMES	252	1,266,391	65	207,067	101	101	25.79%	16.35%
CFL DIRECT INSTALL	495	3,424,013	604	3,726,006	4,931	90,254	122.02%	108.82%
INCOME QUALIFIED	18	81,699	67	419,857	445	499	372.22%	513.91%
SOLAR WATER HEATER PILOT	39	259,785	1	5438	2	2	2.56%	2.09%
SMALL COMMERCIAL SOLUTIONS	322	2,230,328	432	2,231,265	78	78	134.16%	100.04%
LARGE COMMERCIAL SOLUTIONS	3000	4,130,464	895	5,578,546	24	42	29.83%	135.06%
TOTALS	5,092	14,238,801	2,958	15,812,955	8,534	95,496	58.10%	111.06%

**Table 3: Energy Smart Program Year Two**

PROGRAM NAME	KW GOAL	KWH GOAL	KW ACTUAL	KWH ACTUAL	PARTICIPANTS	MEASURES	KW	KWH
HOME PERFORMANCE WITH ENERGY STAR	293	868,874	832	3,802,170	2,352	31,975	283.96%	437.60%
ENERGY STAR AIR CONDITIONING	347	1,178,169	85	221,332	402	493	24.50%	18.79%
A/C TUNE-UP	648	1,176,985	224	442,136	958	1048	34.57%	37.57%
NEW HOMES	492	2,308,671	144	587,251	216	548	29.27%	25.44%
CFL DIRECT INSTALL	660	4,565,349	232	2,654,751	3,445	61,984	35.15%	58.15%
INCOME QUALIFIED	30	122,250	152	900,230	692	11,847	506.67%	736.38%
SOLAR WATER HEATER PILOT	0	0	0	0	0	0	0.00%	0.00%
SMALL COMMERCIAL SOLUTIONS	322	2,230,328	425	2,258,033	87	87	131.99%	101.24%
LARGE COMMERCIAL SOLUTIONS	636	4,130,464	1272	9,706,519	19	19	200.00%	235.00%
TOTALS	3,428	16,581,090	3,366	20,572,422	8,171	108,001	98.19%	124.07%

**Table 4: Energy Smart Program Year Three**

PROGRAM NAME	KW GOAL	KWH GOAL	KW ACTUAL	KWH ACTUAL	PARTICIPANTS	MEASURES	KW	KWH
HOME PERFORMANCE WITH ENERGY STAR	293	868,874	901	3,184,213	2,469	18,780	307.62%	366.48%
ENERGY STAR AIR CONDITIONING	347	1,178,169	79.95	227,754	349	416	23.04%	19.33%
A/C TUNE-UP	648	1,176,985	611.8	617,946	1038	1199	94.41%	52.50%
NEW HOMES	492	2,308,671	15.45	71,925	32	36	3.14%	3.12%
CFL DIRECT INSTALL	660	4,565,349	108.93	2,448,124	897	19,068	16.50%	53.62%
INCOME QUALIFIED	30	122,250	352.77	2,743,541	2,842	34,164	1175.90%	2244.21%
SOLAR WATER HEATER PILOT	0	0	0.84	4630	2	2	0.00%	0.00%
SMALL COMMERCIAL SOLUTIONS	322	2,230,328	356.3	2,108,012	89	89	110.65%	94.52%
LARGE COMMERCIAL SOLUTIONS	636	4,130,464	695.85	4,601,848	18	19	109.41%	111.41%
TOTALS	3,428	16,581,090	3,123	16,007,993	7,736	73,773	91.11%	96.54%

**Table 5: Energy Smart Program Year Four**

PROGRAM NAME	KW GOAL	KWH GOAL	KW ACTUAL	KWH ACTUAL	PARTICIPANTS	MEASURES	KW	KWH
HOME PERFORMANCE WITH ENERGY STAR	1,361	4,039,652	1,186	4,445,224	4,350	39,761	87.10%	110.00%
ENERGY STAR AIR CONDITIONING	115	389,773	79	237,416	224	260	68.70%	60.90%
A/C TUNE-UP	534	969,536	143	279,772	132	879	26.80%	28.90%
NEW HOMES	38	177,491	36	112,562	65	80	94.70%	63.40%
CFL DIRECT INSTALL	263	1,817,351	97	1,205,662	2,165	46,277	36.90%	66.30%
INCOME QUALIFIED	225	912,750	525	1,825,848	1,012	10,984	233.30%	200.40%
SOLAR WATER HEATER PILOT	4	27,191	-	-	-	-	-	-
SMALL COMMERCIAL SOLUTIONS	385	2,666,423	498	2,519,153	72	73	129.40%	94.50%
LARGE COMMERCIAL SOLUTIONS	945	6,138,592	831	5,823,379	23	23	87.90%	94.90%
TOTALS	3,870	17,138,155	3,395	16,449,016	8,034	98,337	87.70%	96.00%

**Savings Rates**

The ICF DSM Potential study includes analysis of the incremental savings potential in New Orleans. ICF estimated that incremental annual MWh potential savings in year 5 (2019) would be 0.4%, 0.7%, and 1.2% for the low, reference and high cases, respectively. Actual results through the first four years of Energy Smart are listed in the table below.

**Table 6: Energy Smart Incremental Savings**

	Program Year kWh Savings	Annual total sales	%
1	15,812,955	5,122,384,000	0.31%
2	20,572,422	5,011,659,000	0.41%
3	16,007,993	5,107,748,000	0.31%
4	16,449,016	5,232,742,000*	0.31%

\*represents the total annual sales in 2014

The savings percentage in year 2 was boosted by several large projects in the large commercial program. As illustrated, savings rates for 2011-2014 are consistent with the low case 2019 savings rate.

**Algiers**

The Energy Smart Algiers Program (“Algiers Program”) began in October 2012. The design and execution of the Algiers Program mirrored that of the New Orleans program. Although participation in Algiers has been tougher to garner, the Algiers Program has achieved similar success. Results from the first two “program years” of the Algiers Program are shown in the tables below.

**Table 7: The First 18 Months – Algiers**

<b>PROGRAM NAME</b>	<b>KWH Goal</b>	<b>KWH Actual</b>	<b>PARTICIPANTS</b>	<b>MEASURES</b>	<b>KWH</b>
HOME PERFORMANCE WITH ENERGY STAR	593,539	570497	484	5,653	96.12%
ENERGY STAR AIR CONDITIONING	105,302	33018	30	37	31.36%
A/C TUNE-UP	120,441	131854	102	350	109.48%
NEW HOMES	26,653	-	-	-	
CFL DIRECT INSTALL	1,102,303	821238	0	0	74.50%
INCOME QUALIFIED	94,273	928933	775	12,315	985.36%
SOLAR WATER HEATER PILOT	14,712	-	-	-	
SMALL COMMERCIAL SOLUTIONS	409,158	512925	15	15	125.36%
LARGE COMMERCIAL SOLUTIONS	646,897	209023	1	1	32.31%
<b>TOTALS</b>	<b>3,113,278</b>	<b>3,207,488</b>	<b>1,407</b>	<b>18,371</b>	<b>103.03%</b>

**Table 8: Program Year Two – Algiers**

<b>PROGRAM NAME</b>	<b>KWH Goal</b>	<b>KWH Actual</b>	<b>PARTICIPANTS</b>	<b>MEASURES</b>	<b>KWH</b>
HOME PERFORMANCE WITH ENERGY STAR	394,704	1,470,226	1,439	19,394	372.50%
ENERGY STAR AIR CONDITIONING	70,026	26,675	13	16	38.10%
A/C TUNE-UP	80,094	3,008	5	6	3.80%
NEW HOMES	17,725	-	-	-	-
CFL DIRECT INSTALL	733,032	164,915	240	6,487	22.50%
INCOME QUALIFIED	62,692	115,564	132	1,997	184.30%
SOLAR WATER HEATER PILOT	9,783	-	-	-	-
SMALL COMMERCIAL SOLUTIONS	272,090	215,680	9	9	79.30%
LARGE COMMERCIAL SOLUTIONS	430,187	24,576	1	1	5.70%
<b>TOTALS</b>	<b>2,070,333</b>	<b>2,020,644</b>	<b>1,839</b>	<b>27,910</b>	<b>97.60%</b>

### Savings Rate - Algiers

The savings rates in Algiers are listed in the table below.

**Table 9: Algiers Saving Rates**

	Program Year kWh Savings	Annual total sales	%
1	3,207,488	665,729,000	0.48%
2	2,020,644	453,248,000	0.45%

### Current Program Year

The current program year is off to a successful beginning. Program structure was revamped for both the New Orleans Program and the Algiers Program. Programs which were lagged in participation in previous years were removed or absorbed into more successful programs (allowing customers to still access some measures although they are not stand-alone programs). The current program mix for the Energy smart program is listed in the table below.

**Table 10: Energy Smart Current Program Mix**

Program	Program Type
Home Performance with Energy Star	Residential
Consumer Products	Residential
Low Income	Residential
A/C Tune Up and HVAC	Residential
School Kits and Education	Residential
Compact Fluorescent Lighting Direct Install	Residential
Small Commercial Solutions	Commercial and Industrial
Large Commercial Solutions	Commercial and Industrial

Savings and participation through the second quarter of the current program year are listed in the table below.

**Table 11: Energy Smart New Orleans**

PROGRAM NAME	KW GOAL	KWH GOAL	KW	KWH	PARTICIPANTS	MEASURES	KW	KWH
HOME PERFORMANCE WITH ENERGY STAR	260	732,674	480	1,797,749	571	945	184.62%	245.37%
CONSUMER PRODUCTS	290	942,765	46	99,444	178	187	15.86%	10.55%
LOW INCOME	201	518,876	6	16,443	3	17	2.99%	3.17%
A/C TUNE UP & HVAC	573	1,458,077	172	500,187	315	272	30.02%	34.30%
SCHOOL KITS AND EDUCATION	119	926,946	0	0	0	0	0.00%	0.00%
GREEN LIGHT	94	449,607	65	297,719	679	17,024	69.15%	66.22%
SMALL BUSINESS SOLUTIONS	950	3,692,306	168	1,159,620	121	220	17.68%	31.41%
LARGE COMMERCIAL SOLUTIONS	1265	7,561,766	213	2,213,093	21	34	16.84%	29.27%
TOTALS	3,752	16,283,017	1,150	6,084,255	1,888	18,699	30.65%	37.37%

**Table 12: Energy Smart Algiers**

PROGRAM NAME	KW GOAL	KWH GOAL	KW	KWH	PARTICIPANTS	MEASURES	KW	KWH
HOME PERFORMANCE WITH ENERGY STAR	21	59,989	16	45,446	245	104	76.19%	75.76%
CONSUMER PRODUCTS	23	75,368	1	720	4	5	4.35%	0.96%
LOW INCOME	18	45,946	3	10,595	4	11	16.67%	23.06%
A/C TUNE UP & HVAC	52	131,133	19	56,168	35	35	36.54%	42.83%
SCHOOL KITS AND EDUCATION	53	84,150	0	0	0	0	0.00%	0.00%
GREEN LIGHT	0	0	12	54,617	173	3,068	#DIV/0!	#DIV/0!
SMALL BUSINESS SOLUTIONS	87	339,555	0	0	0	0	0.00%	0.00%
LARGE COMMERCIAL SOLUTIONS	108	644,830	8	181,099	1	1	7.41%	28.08%
TOTALS	362	1,380,971	59	348,645	462	3,224	16.30%	25.25%

## Review of ICF Potential Study Methodology and Assumptions

## COMPARISON OF DSM POTENTIAL STUDIES FOR ARKANSAS AND NEW ORLEANS

In their comments on the ENO IRP, the Alliance for Affordable Energy stated that ICF's projections of achievable potential do not comport with the recent EAI IRP filings in Arkansas. "EAI is on track to achieve 1.27% annually, while ICF projects only 0.6% annually for the entire twenty-year period of the ENO IRP." The Advisors recommend that the draft IRP should have included a comparison and reconciled to the difference between EAI (1.27% annually) and ENO (.6% annually).

### Response

The 1.27% value provided by the Alliance comes from an August 2015 presentation by EAI on its 2015 IRP in which EAI provided preliminary "proxy" values for their 2016 - 2018 DSM Program Plan, which EAI has not yet filed. EAI's final 2015 IRP can be found here: [http://www.energy-arkansas.com/content/transition\\_plan/07-016-U\\_49\\_1.pdf](http://www.energy-arkansas.com/content/transition_plan/07-016-U_49_1.pdf)

In the August 2015 presentation EAI shows that it used a placeholder value of 1.27% savings as a percent of sales for 2016, 2017 and 2018. However, in the same presentation, EAI states that their plan was subject to change based on APSC regulatory decisions, TRM, and EM&V updates. EAI also states in the same presentation that:

*"Since the Arkansas DSM Potential Study was still underway and no direction regarding future DSM Targets was available at the time, EAI assumed 0.9% of retail sales above forecast without DSM (above naturally occurring DSM) as the DSM proxy within the Sales and Load forecasts [in the 2015 IRP]."*

In summary, put into the context of the EAI presentation, there was is a high level of uncertainty around the 1.27% savings value, yet the Alliance misconstrued the 1.27% value by stating that EAI is on track to reach it. At the time necessary for EAI to make assumptions regarding DSM potential the Navigant DSM Potential Study for Arkansas had not yet been completed. Thus, in its final 2015 IRP, EAI used a lower savings value of 0.9%, as a placeholder, based on past and presumed future APSC goals. As discussed below, the Arkansas Potential Study conducted by Navigant has since been completed and the forecasted achievable long-term savings values in the potential study are in fact lower than the 0.9% savings EAI assumed in its 2015 IRP. In fact, the EAI potential High case for the next 20 years is never more than 0.9%. The reference case is between 0.6% and .08%. These results can be found on the APSC website at: [http://www.apscservices.info/EFilings/Docket\\_Search\\_Documents.asp?Docket=13-002-U&DocNumVal=222](http://www.apscservices.info/EFilings/Docket_Search_Documents.asp?Docket=13-002-U&DocNumVal=222).

The Alliance is also using the 1.27% proxy savings value in a misleading way because short-term program implementation plans and long-term potential studies are fundamentally different. As stated in the Executive Summary of the ENO Potential Study Report:

*"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.”*

To elaborate further on differences in measure mix, measures that constitute an important portion of EAI’s (and most other) short-term savings will not be available in the future due to the increased efficiency of baseline equipment. For example, as stated in Section 1.4.3 of the ENO 2015 Potential Study Report:

- *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 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. 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. 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.*

Since the ENO 2015 Potential Study is a long-term forecast, it makes more sense to compare those results to the now completed Arkansas Potential Study,<sup>1</sup> which includes a forecast of achievable energy efficiency potential over the 2016 to 2025 time horizon. The table below show’s Navigant’s forecast for achievable potential in Arkansas over this period, as well as annual program costs, for the Mid Level Funding Scenario, which is comparable to the Reference Case scenario developed by ICF for the ENO Potential Study.

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<sup>1</sup> Navigant. Arkansas Energy Efficiency Potential Study: Final Report. Prepared for the Arkansas Public Service Commission. June 2015.



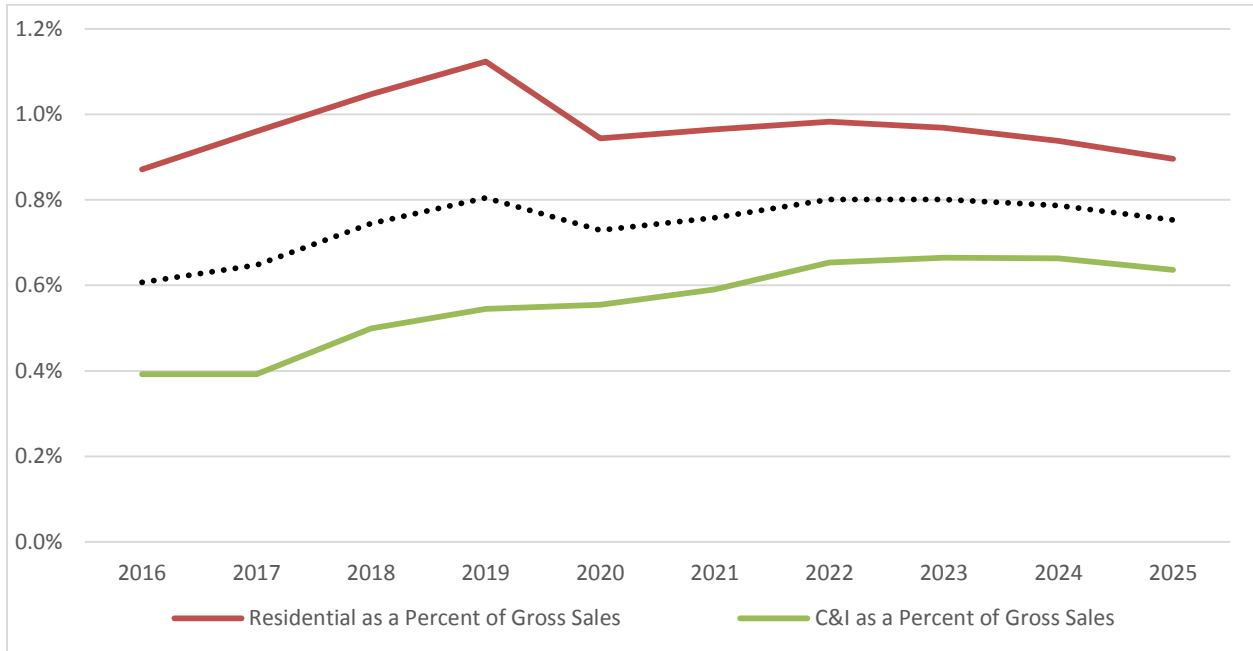
**Table 13: Arkansas DSM Potential Study**

Arkansas Potential Study				
Year	Mid Funding Scenario			
	Program Budget (Millions \$)	Cumulative GWh Savings	Incremental GWh Savings	Inc. GWh Savings as % of Gross Sales
2016	\$56	170	178	0.6%
2017	\$62	355	195	0.7%
2018	\$71	569	224	0.7%
2019	\$75	799	242	0.8%
2020	\$78	1010	224	0.7%
2021	\$81	1231	234	0.8%
2022	\$89	1465	246	0.8%
2023	\$92	1701	251	0.8%
2024	\$95	1935	249	0.8%
2025	\$97	2161	240	0.7%
			<b>Average</b>	<b>0.7%</b>

Source: Navigant. Arkansas Energy Efficiency Potential Study: Final Report. Prepared for the Arkansas Public Service Commission. June 2015. Tables ES-2, ES-4, ES-6, ES-8

Note that Arkansas statewide values are shown in the table above and average achievable annual incremental savings potential as a percent of sales over the 10 year forecast equals 0.7%. EAI specific data is shown below.

**Figure 1: EAI Incremental Achievable Potential as a Percent of Gross Sales**



**Table 14: EAI Potential (Medium Case GWh)**

Incremental Achievable Potential	GWh									
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Residential	81.36	93.83	103.17	111.08	93.88	96.34	98.71	97.93	95.54	91.86
C&I	45.00	47.12	60.50	66.26	67.77	72.53	80.69	82.57	83.04	80.16
All Sectors	126.36	140.95	163.67	177.34	161.64	168.87	179.40	180.50	178.58	172.02

**Table 15: EAI Potential (Medium Budget)**

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Total Portfolio	\$ 41,025,176	\$ 47,856,655	\$ 55,856,170	\$ 59,009,807	\$ 61,406,601	\$ 64,146,710	\$ 71,291,249	\$ 73,711,867	\$ 75,341,168	\$ 76,648,624

The table below shows similar information for the ENO 2015 Potential Study. While the ENO study covered the 2015 to 2034 time horizon, data was extracted from the study for the 2016 to 2025 period to make the ENO study forecast more comparable to the Arkansas study forecast.

**Table 16: ENO DSM Potential Study**

<b>ENO Potential Study</b>				
<b>Year</b>	<b>Reference Case Scenario</b>			
	<b>Program Budget (Millions \$)</b>	<b>Cumulative GWh Savings</b>	<b>Incremental GWh Savings</b>	<b>Inc. GWh Savings as % of Previous Years Sales</b>
2016	\$7	40	23	0.4%
2017	\$9	67	29	0.5%
2018	\$11	98	34	0.6%
2019	\$13	134	38	0.7%
2020	\$14	172	41	0.7%
2021	\$14	205	37	0.7%
2022	\$14	236	36	0.6%
2023	\$14	256	35	0.6%
2024	\$14	276	34	0.6%
2025	\$14	296	33	0.6%
			<b>Average</b>	<b>0.6%</b>

Source: ICF International. Long-Term Demand Side Management Potential in the Entergy New Orleans Service Area. Prepared for Entergy System Planning and Operations. June 2015.

In the ENO study forecast, average annual incremental savings as a percent of sales over the same 10 year period as the Arkansas forecast equal 0.6%. Given the uncertainties involved in a ten year forecast, the average savings levels of 0.6% for ENO and 0.7% for Arkansas are comparable.

Projected costs in the two studies are comparable as well. To perform the cost comparison we calculated a levelized cost per cumulative kWh saved. This was calculated by dividing the net present value of the program costs over 2016 to 2025 period by the net present value of the cumulative savings over the period. This is different than the traditional levelized cost calculation, which uses lifetime savings instead of cumulative savings to arrive at a “cost of conserved energy” or CCE. CCE was not calculated here because lifetime savings were not reported in the Arkansas study. The important fact here is that the costs below were derived using the same method and the same discount rate (the ENO discount rate provided by Entergy to ICF for the ENO 2015 Potential Study).

**Table 17: Levelized Cost per Cumulative kWh**

<b>Levelized Cost per Cumulative kWh (2016-2025)</b>			
<b>Study</b>	<b>NPV (Millions \$)</b>	<b>NPV GWh</b>	<b>Levelized Cost per Cumulative kWh (2016- 2025)</b>
Arkansas Potential Study	\$537	7073	\$0.08
ENO Potential Study	\$82	1124	\$0.07

These comparable cost levels serve to demonstrate that ICF’s cost forecasts in the ENO study are not in fact out of line with industry thinking about the future cost of energy efficiency for the region.

While comparing long-term forecasts makes more sense than comparing a short- to a long- term forecast, it is also important to note that there are differences between EAI’s service area, or Arkansas more generally and ENO’s service area. EAI has significantly more large C&I customers than does ENO. While some of these large C&I customers have “opted out” of EAI’s programs, large C&I savings make up a significant portion of EAI program savings. Further, EAI also has a large number of agricultural customers, whereas ENO does not; EAI’s Agricultural Solutions program is growing element of EAI’s DSM portfolio.

**MULTIFAMILY PROGRAMS**

The Advisors and the Alliance for Affordable Energy note that multifamily units represent a significant opportunity for DSM, and that programs for multifamily units should be available, comprehensive and clearly described.

**Response**

The multifamily sector is important and there are energy savings opportunities in this market in New Orleans. A comprehensive Multifamily Program was modeled for the ENO Potential Study as noted in section 1.5.1 of the potential study report.

Consistent with ICF multifamily program experience, in the Reference Case ICF assumed that 85% of multifamily units could be audited in the first 3 years of the forecast, and that over the same period 70% of units and buildings would have direct install and common area measures installed. Due the expectation that most units could be served by the program in the early years of the forecast, participation declines beginning in year four of the ICF forecast to a steady state that would serve the multifamily population for the remainder of the forecast period.

**Demand Response Overview**

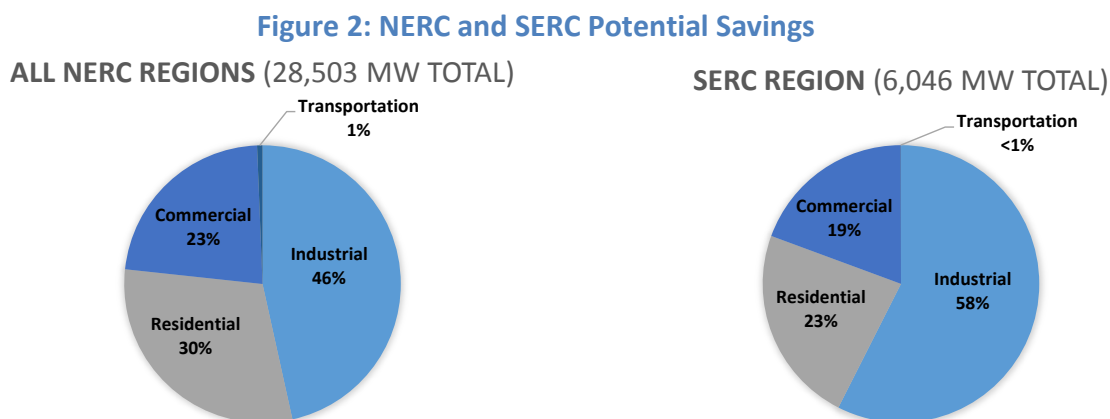
The purpose of this section is to review the state of the market of Demand Response resources as well as discuss its role in MISO. A high level overview of the cost and benefits of Advanced Metering Infrastructure will also be discussed.

## STATE OF THE MARKET

The state of the market for demand response (DR) programs is both growing and evolving, albeit unevenly, across the U.S. Levels of investment in Advanced Metering Infrastructure (AMI)—a technical requirement for most DR options—vary widely and are driven by myriad regulator, economic, political, technical, and resource factors. The most recent publicly available study covering DR across the U.S. was published by FERC in December 2014. According to FERC:<sup>2</sup>

- In 2013, MW savings as a % of peak demand due to Independent System Operation (ISO) and Regional Transmission Organization (RTO) DR programs equaled 6% across all ISOs/RTOs in the U.S.
  - DR programs in the Midcontinent Independent System Operator (MISO) area, which includes the Entergy New Orleans service area, saved 10% of MISO peak demand in 2012.
- U.S. demand response potential in 2012 from existing programs/tariffs increased 7% over 2011 levels to 28,503 MW.
  - Within the Southern Electric Reliability Subregion (SERC), which includes Entergy service areas, DR potential in 2012 increased 2% from 2011 levels 6,046 MW.

The distribution of savings potential by sector in retail DR programs in 2012 NERC-wide, and in SERC specifically are shown below:



Two-way (utility to customer and vice versa) communication through Advanced Meters (or “AMI meters”) is required for most DR program options beyond traditional DR options such as direct load control (DLC) programs, which are largely are operated via one way pager networks.

- The saturation of AMI meters in the U.S. increased about six-fold between 2007 and 2013, or from 5% to 32% of total meters in 2013.<sup>3</sup>
- AMI meter saturation in the SERC region was 21% in 2012.<sup>4</sup>

<sup>2</sup> U.S. Federal Energy Regulatory Commission (FERC). Assessment of Demand Response and Advanced Metering Staff Report. December 2014.

<sup>3</sup> Id.

- More than half the households in the U.S. are likely have a smart meter by the end of 2015.<sup>5</sup>
- The number of customers in incentive- and time-based DR programs NERC-wide, and in SERC specifically, are shown below.<sup>6</sup>

**Table 18: DR Customer Enrollment by Program type**

DR Program Type	Customer Enrollments in DR Programs in 2012 (Millions)	
	NERC-Wide	SERC
<b>Incentive-based</b> (direct load control, interruptible, demand bidding/buyback, emergency DR, capacity market, and ancillary services)	5.4	0.7
<b>Time-based</b> (real-time pricing, critical peak pricing, variable peak pricing, and time of use rates)	<u>3.7</u>	<u>0.2</u>
<b>Total</b>	<b>9.2</b>	<b>0.9</b>

Since the market for DR is evolving quickly, it is worthwhile to note here a few of the key trends impacting the market for DR.

- Convergence of Energy Efficiency (EE) and DR. There are an increasing number of companies providing services that combine EE and DR elements. The EE elements are usually behavioral in nature, whereas the DR options range from traditional DLC options to thermostat aggregation in the market. OPower’s Thermostat Platform and Converge’s Intellisource Demand Response Management System are two examples of such EE/DR services.<sup>7</sup>
- Increased Distributed Energy Resources (DER). DERs present a number of opportunities to provide wholesale services including energy, generation capacity, transmission capacity deferral, and ancillary services necessary to operate the power system. These services would be sourced through a combination of time varying rate designs, energy efficiency and demand response programs, and utility procurements.<sup>8</sup>

### DEMAND RESPONSE IN MISO

Currently, there are four demand response classifications in MISO, each with its own registration and performance requirements. These four classifications are Demand Response Resource (DRR) Type I, DRR Type II, Load Modifying Resource (LMR) and Emergency Demand Response (EDR).

<sup>4</sup> Id.

<sup>5</sup> The Edison Foundation. Institute for Electric Efficiency. Utility-Level Smart Meter Deployments: Plans and Proposals. May 2012.

<sup>6</sup> FERC 2014.

<sup>7</sup> Greentech Efficiency. Technology Choice is Finally Coming to Residential Demand Response. Katherine Tweed. January 30, 2014.

<sup>8</sup> ICF International. On the Grid’s Bleeding Edge: The California, New York, and Hawaii Power Market Revolution. Whitepaper. 2015.

DRRs are demand resources that can participate in the Day-Ahead and/or Real-Time energy markets. They are economically dispatched by MISO and are paid the locational marginal price for the energy they provide to the Energy and Operating Reserve Market via physical load reduction or behind-the-meter generation. DRR-Type I resources are only capable of supplying a fixed, pre-specified quantity of energy whereas Type II resources are capable of supplying energy to the market through commitment and dispatch similar to generation resources and complying with MISO’s set-point instructions. DRRs can also participate in the capacity market. If a DRR clears the annual capacity auction and receives capacity credit, it carries the must offer obligation in the Day-Ahead Market for every hour of every day on that Planning Year.

LMRs and EDRs only provide emergency energy services to MISO. LMRs will receive capacity credit in the annual capacity auction if it meets the following requirements:

- Maximum 12 hours’ notice
- Maintain target level of load reduction for four continuous hours Obligated to respond to emergency events for at least the first five times during the summer season
- Must be greater than or equal to 100 kW (grouping of multiple demand resources is allowed)
- Able to achieve the target level associated with capacity credit

A summary of the markets each demand response resource type can participate in is summarized in the Table 19.

**Table 19: MISO Demand Response Classifications**

<b>MISO Demand Response Classifications</b>				
	<b>Energy Market</b>	<b>Ancillary Services</b>	<b>Capacity Market</b>	<b>Emergency Energy</b>
<b>DRR – Type I</b>	✓	✓	✓	✓
<b>DRR – Type II</b>	✓	✓	✓	✓
<b>LMR</b>			✓	✓
<b>EDR</b>				✓

## Summary of Advanced Metering Infrastructure (AMI) Activities and Trends

Advanced Metering Infrastructure (AMI)<sup>9</sup> began to be considered as the next generation of automated meter reading in the early 2000's and accelerated after passage of the 2005 Energy Policy Act that included requirement for states to evaluate time based metering and related communications to enable time varying rates. This led to an increasing number of state utility commissions to require their Investor Owned Utilities (IOUs) to investigate the viability and benefits of adopting (AMI). The resulting business cases that were positive led to the initial wave of implementation beginning around 2008 in California, Oregon and Pennsylvania, for example.

### CURRENT STATE OF PENETRATION OF AMI IN THE U.S.

The U.S. penetration rate of AMI meters in 2014 was 36.3 percent, a 30 percent increase from 2008 data<sup>10</sup>. Installation of more than 50 million advanced meters cover about 43 percent of US residences, according to July 2014 data from the Edison Foundation Institute for Electric Innovation. During the past year, state governments, retail rate regulators and individual utilities supported installation efforts of AMI and often within the context of grid modernization efforts. Table 20 and Figure 3 show states with high AMI installations as well as the expected total deployment through 2015 across the country<sup>11</sup>.

**Table 20 AMI Installations by State – July 2014**

(>2,000,000 meters/state)

State	Total Smart Meters Installed
California	12,479,730
Florida	5,614,700
Georgia	3,182,150
Pennsylvania	2,698,716
Arizona	2,061,760

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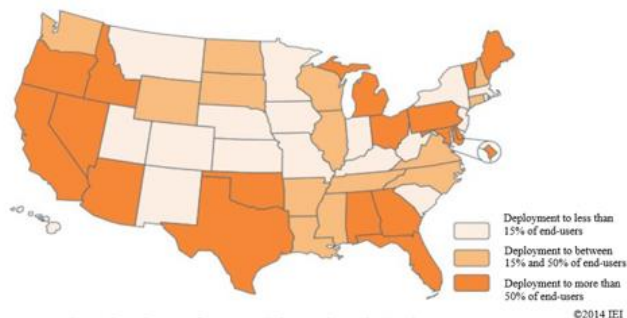
<sup>9</sup> Advanced Metering Infrastructure (AMI) provides bi-directional communication between meters on customers' premises and a utility's back office to enable automated reading of energy usage, voltage and outage events recorded in the meter, and enable remote service connect/disconnection (if optional switch is included in meter). These basic functions enable a range of operational benefits beyond the obvious meter reading labor savings.

<sup>10</sup> U.S. Federal Energy Regulatory Commission (FERC). Assessment of Demand Response and Advanced Metering Staff Report. December 2015.

<sup>11</sup> Edison Foundation Institute for Electric Innovation. Utility-Scale Smart Meter Deployments: Building Block of the Evolving Power Grid. September 2014.



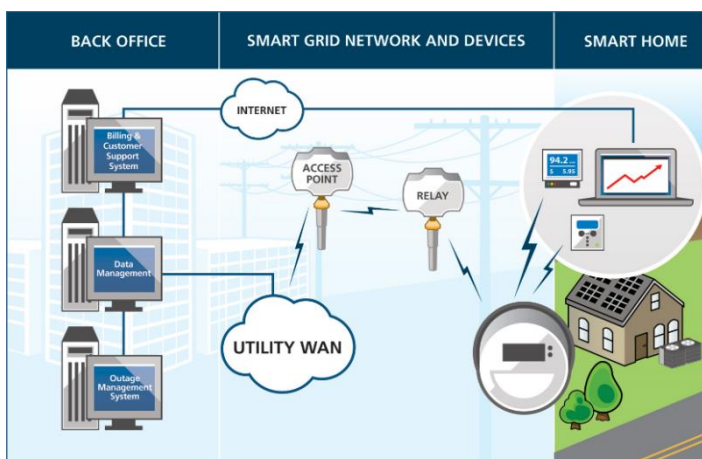
**Figure 3: Smart Meter Deployment by State 2015**



### GENERAL COMPONENTS AND COST OF AMI DESIGNS

AMI generally refers to meters that allow two-way communication between the utility and the meter at the customers' premises. The changes from electromechanical meters are (a) utilization of a communication card within the meter to link with a communications network, (b) a communication system typically comprised of a field area network (FAN) and wide area network (WAN) to transmit the data, and (c) a meter data management system (MDMS) to perform data validation, estimation and editing to create billing determinants to send to a customer billing system. The basic components are shown in Figure 4.

**Figure 4: Basic System Components of an Advanced Metering Infrastructure System**



For the communication system, alternative approaches are typically evaluated from wireless radio-mesh narrowband networks, Power Line Carrier (PLC), and cellular broadband systems using wireless carriers such as AT&T and Verizon.

### DSM Program Selection

The purpose of this section is to review the updated analysis that was performed in the selection of economic DSM programs found in the preferred portfolio that was done in response to stakeholder feedback after the filing of the Draft IRP in June 2015. The updated analysis includes an addition of

three demand response programs, and a trailing benefits analysis of programs that were initially not selected in the preferred portfolio. As a result of this analysis, two more DSM programs were included.

### DSM BREAKEVEN ANALYSIS

Figure 5 below shows the benefit/cost ratio of all 24 DSM programs. If the benefit/cost ratio was greater than 1, meaning that the benefits were greater than the cost over the 20-year evaluation period, the DSM program was selected to be included in each of the portfolios. If the benefit/cost ratio was less than 1, it was initially not selected but later analyzed in the trailing benefits analysis. This breakeven analysis resulted in 17 programs being selected, including 3 DR programs, and 7 programs that were not selected. The net incremental benefit can be seen in Figure 6 and Table 21 below.

Figure 5: Total Benefit/Cost Ratio of DSM Programs

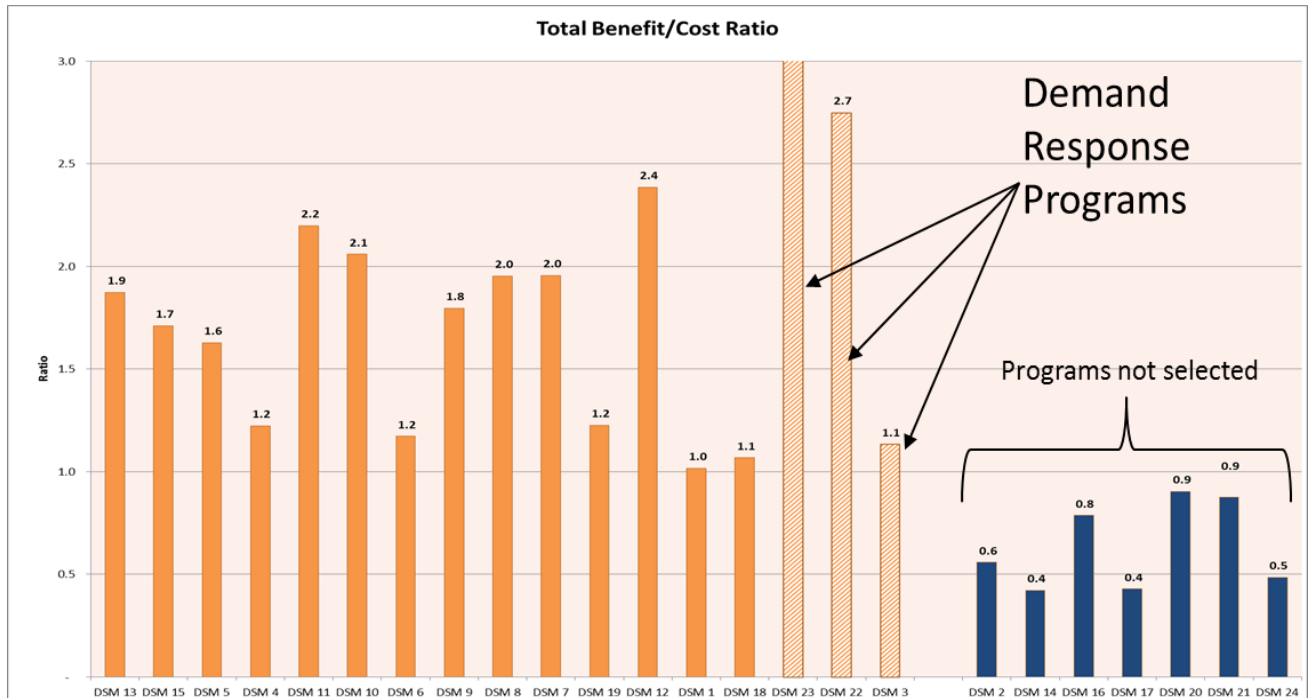


Figure 6: DSM Incremental Net Benefit

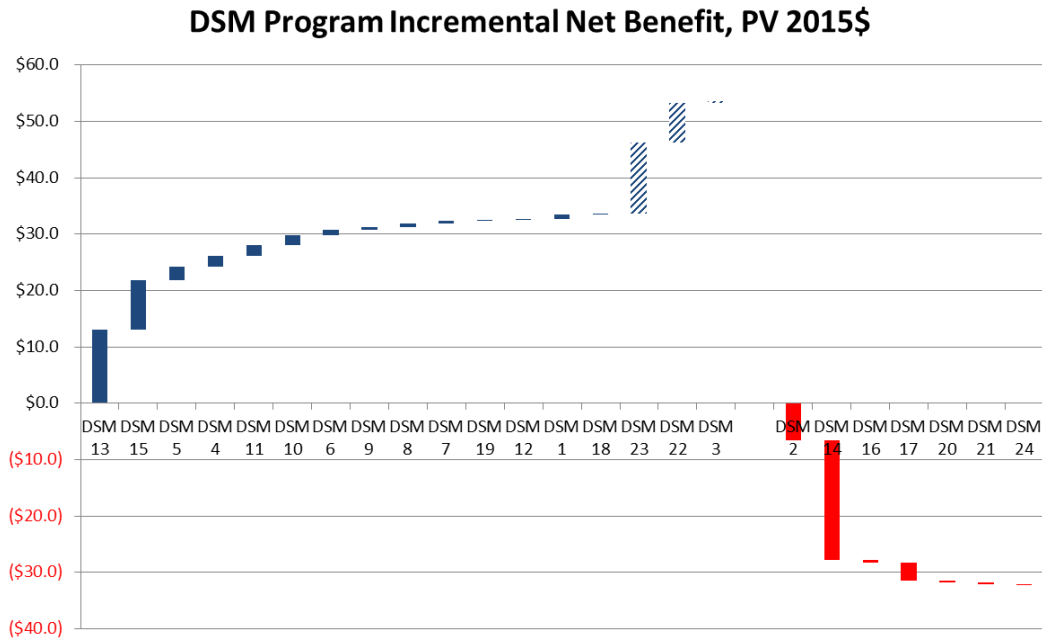


Table 21: DSM Incremental Net Benefit

Net Benefit of DSM Programs (Including DR) [M\$]																	
	DSM 13	DSM 15	DSM 5	DSM 4	DSM 11	DSM 10	DSM 6	DSM 9	DSM 8	DSM 7	DSM 19	DSM 12	DSM 1	DSM 18	DSM 23	DSM 22	DSM 3
<b>Benefit:</b>																	
Energy Revenue	\$22.5	\$11.3	\$5.4	\$8.5	\$2.8	\$2.9	\$5.1	\$1.0	\$0.9	\$0.8	\$1.1	\$0.2	\$45.0	\$0.2	\$0.0	\$0.0	\$0.0
Load Reduction Capacity Value	\$5.6	\$9.9	\$0.8	\$1.6	\$0.6	\$0.7	\$1.1	\$0.2	\$0.2	\$0.2	\$0.1	\$0.1	\$8.0	\$0.1	\$12.9	\$11.1	\$3.4
<b>Total Benefit</b>	<b>\$28.1</b>	<b>\$21.1</b>	<b>\$6.2</b>	<b>\$10.1</b>	<b>\$3.4</b>	<b>\$3.6</b>	<b>\$6.2</b>	<b>\$1.3</b>	<b>\$1.1</b>	<b>\$1.0</b>	<b>\$1.2</b>	<b>\$0.3</b>	<b>\$53.0</b>	<b>\$0.3</b>	<b>\$12.9</b>	<b>\$11.1</b>	<b>\$3.4</b>
<b>Cost:</b>																	
Total Program Cost	\$15.0	\$12.4	\$3.8	\$8.3	\$1.6	\$1.7	\$5.3	\$0.7	\$0.6	\$0.5	\$1.0	\$0.1	\$52.2	\$0.3	\$0.4	\$4.0	\$3.0
<b>Net Benefit:</b>																	
Net Benefit	<b>\$13.1</b>	<b>\$8.8</b>	<b>\$2.4</b>	<b>\$1.8</b>	<b>\$1.9</b>	<b>\$1.8</b>	<b>\$0.9</b>	<b>\$0.6</b>	<b>\$0.5</b>	<b>\$0.5</b>	<b>\$0.2</b>	<b>\$0.2</b>	<b>\$0.8</b>	<b>\$0.0</b>	<b>\$12.6</b>	<b>\$7.1</b>	<b>\$0.4</b>
Breakeven Year	2023	2025	2026	2023	2023	2023	2028	2024	2024	2023	2023	2024	2034	2032	2020	2022	2035

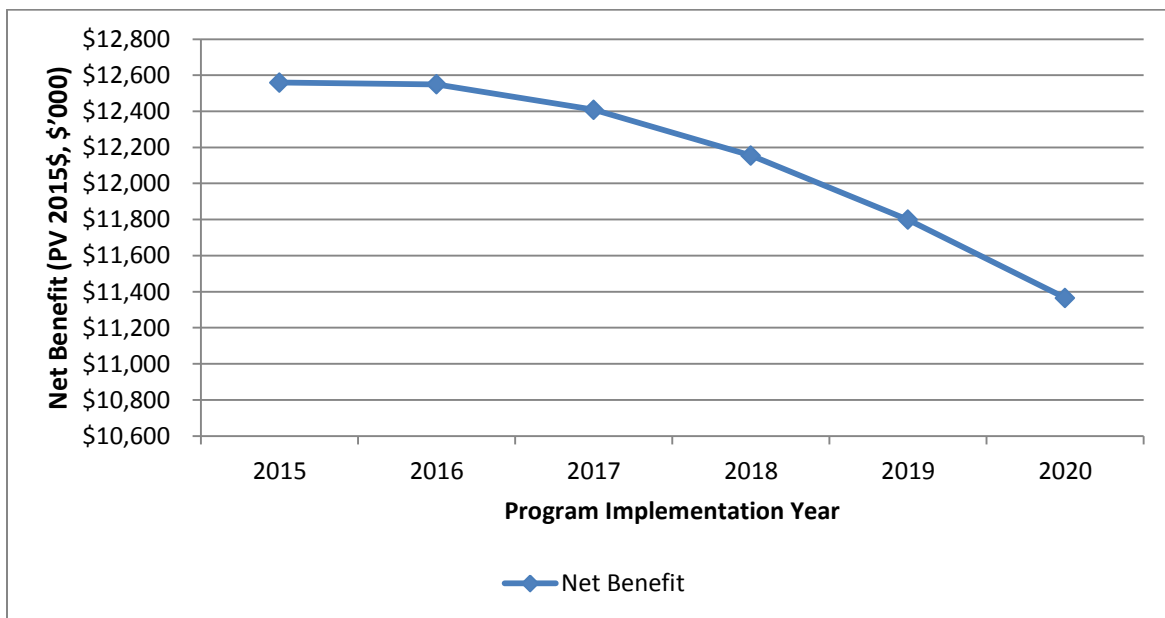
**ADDITIONAL ANALYSIS OF TRAILING BENEFITS**

In response to Advisor and stakeholder concerns that the benefits of the DSM programs were not being fully accounted, ENO did further analysis on the seven remaining programs that were not selected in the initial DSM breakeven study. This analysis incorporated the trailing benefits (kWh savings) that a program would exhibit beyond the 20-year evaluation period. It was assumed that further investment into the DSM measures would no longer occur after 2035, thus making the cost of DSM beyond the evaluation period zero for each program. The trailing benefits declined at different rates for each program, affecting the amount of kWh savings and how long the benefits endured after 2035. By incorporating these trailing benefits at zero cost into a new breakeven study, two DSM programs were found to breakeven. These programs were the Water Heating program and the Pool Pump program and were included in all the portfolios in the Stakeholder Input Case supplement.

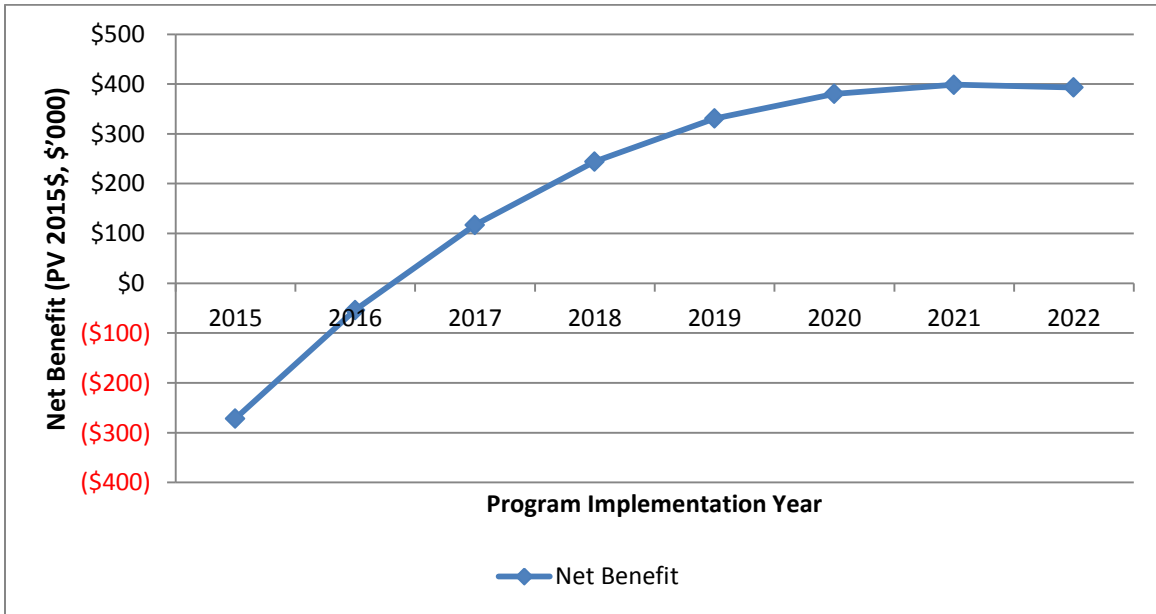
## DEMAND RESPONSE ANALYSIS

Out of the 24 DSM programs identified by ICF International, 3 were classified as demand response (DR) programs. These programs were Dynamic Pricing for residential customers, Non-Residential Dynamic Pricing, and Direct Load Control. The assumption is that the DR programs could be registered as LMRs in MISO and would receive capacity credit equal to their estimated annual peak load reduction grossed up for reserve margin, thus the net benefit is estimated to be the capacity credit net of the annual cost. It was assumed that all 3 DR programs would only be called on to provide energy during MISO declared emergencies and the energy would be made up in other non-emergency hours and therefore had an energy neutral effect in the market, and thus provided no net energy benefit. In addition, an annual sensitivity analysis was performed to determine the optimal implementation year for each program. As shown in Figures 7 – 9 the maximum net benefit for Dynamic Pricing (DSM 23) is estimated to be provided based on program implementation in 2015, Non-Residential Dynamic Pricing (DSM 3) is estimated to be provided based on program implementation in 2021, and Direct Load Control (DSM 22) is estimated to be provided based on program implementation in 2019. All 3 DR programs were determined to have a net benefit to customers and were included in the Preferred Portfolio for a projected reduction of peak load by approximately 35 MW by 2034 as shown in Figure 10. The net benefits of all three DR programs combined were projected to be over \$20M in NPV and are summarized in Table 22.

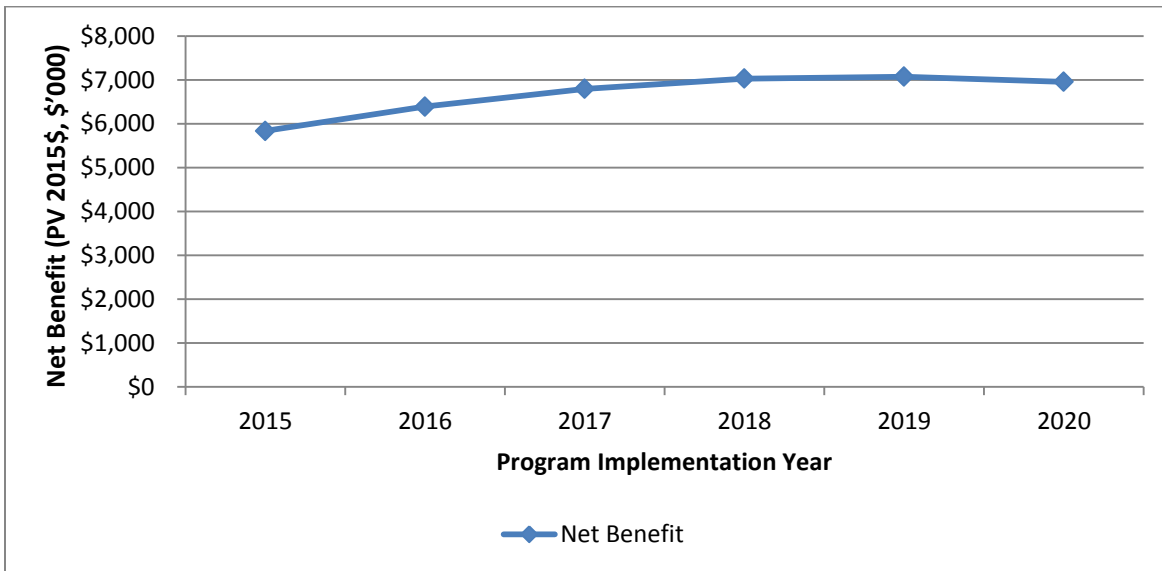
**Figure 7: Annual Sensitivity for Dynamic Pricing Program Implementation (DSM 23)**



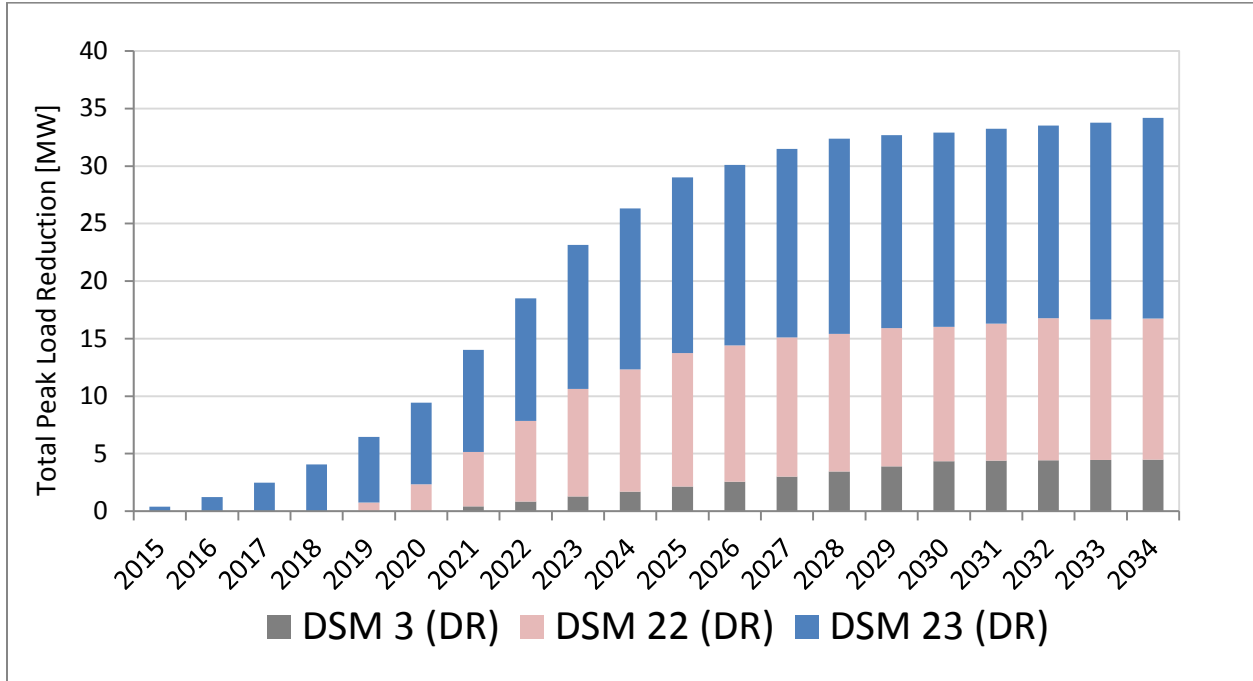
**Figure 8: Annual Sensitivity for Non-Residential Dynamic Pricing Program Implementation (DSM 3)**



**Figure 9: Annual Sensitivity for Direct Load Control Program Implementation (DSM 22)**



**Figure 10: Contribution of DR Programs to Peak Load Reduction**



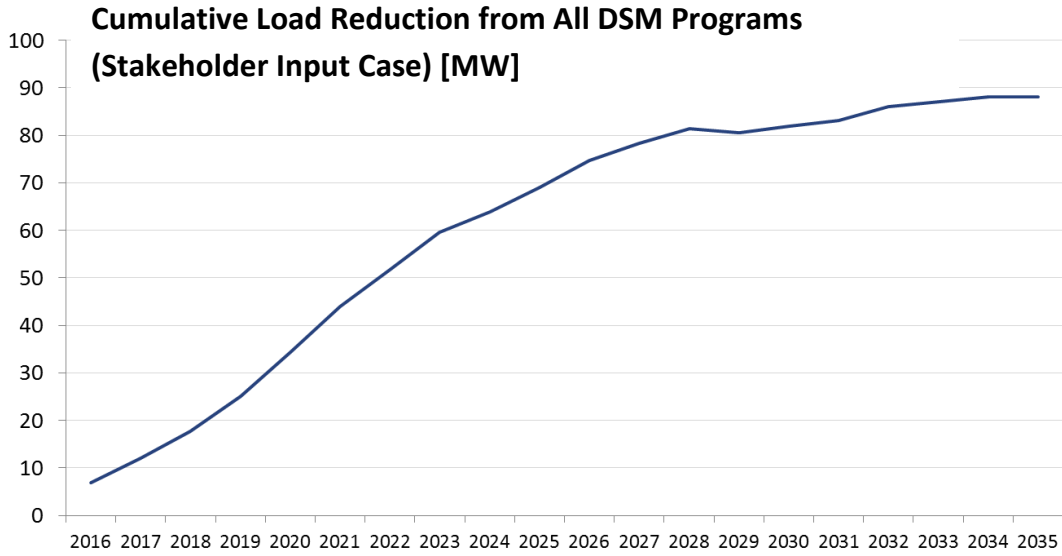
**Table 22: Net Benefit of DR Programs PV (2015, \$)**

Net Benefit of DR Programs			
	DSM 23	DSM 22	DSM 3
<b>Benefit:</b>			
Energy Revenue [M\$]	\$0.0	\$0.0	\$0.0
Load Reduction Capacity Value [M\$]	\$12.9	\$11.1	\$3.4
Total Benefit [M\$]	\$12.9	\$11.1	\$3.4
<b>Cost:</b>			
Total Program Cost [M\$]	\$0.4	\$4.0	\$3.0
<b>Net Benefit:</b>			
Net Benefit [M\$]	\$12.6	\$7.1	\$0.4
Breakeven Year	2020	2022	2035

**SUMMARY OF DSM PORTFOLIO**

The table below outlines the complete list of DSM programs that were selected for each portfolio in the Stakeholder Input Case supplement. The figure below shows the cumulative load reduction from all 19 DSM programs over the 20-year evaluation period.

**Figure 11: Cumulative Load Reduction from All DSM Programs (MW)**



**Table 23: ENO Preferred Portfolio of DSM Programs**

Sector	Program Name	Number	Maximum Peak Load Reduction (MW)
Commercial	Commercial Prescriptive & Custom	DSM 1	12.4
Commercial	Retro Commissioning	DSM 4	1.3
Commercial	Commercial New Construction	DSM 5	1.6
Commercial	Data Center	DSM 6	1.4
Industrial	Machine Drive	DSM 7	0.3
Industrial	Process Heating	DSM 8	0.3
Industrial	Process Cooling and Refrigeration	DSM 9	0.3
Industrial	Facility HVAC	DSM 10	0.9
Industrial	Facility Lighting	DSM 11	0.8
Industrial	Other Process/Non-Process Use	DSM 12	0.1
Residential	Residential Lighting & Appliances	DSM 13	6.1
Residential	ENERGY STAR Air Conditioning	DSM 15	15.3
Residential	Efficient New Homes	DSM 18	0.2
Residential	Multifamily	DSM 19	0.0

Commercial	Non-Residential Dynamic Pricing (DR)	DSM 3	4.5
Residential	Direct Load Control (DR)	DSM 22	12.3
Residential	Dynamic Pricing (DR)	DSM 23	17.4
Residential	Water Heating	DSM 20	0.8
Residential	Pool Pump	DSM 21	0.9
<b>Total</b>			<b>88</b>

## Non-Energy Impacts of Residential Efficiency Measures

A wide array of secondary data on the non-energy impacts (NEIs) of residential efficiency measures is currently available and can be categorized into four non-energy impact categories, listed below. Note, however, that the sources for these NEIs have not been examined to determine whether the data available could be normalized to conditions in New Orleans (e.g., for weather, cost of labor, etc). Any NEIs developed using secondary data considered for inclusion in ENO program benefit-cost analyses would need to be examined to determine if (a) the published values are precise enough to justify inclusion in benefit-cost testing, and (b) can be adapted to New Orleans. Then, for each such suitable NEI, adapted or “normalized” values would need to be calculated.

### PROPERTY VALUE/MARKETABILITY/AFFORDABILITY

NEIs that have an impact on the property value, the marketability of the property or the affordability of the property can be classified separately as unique set of NEIs. An increase in property value and marketability are frequently recognized as benefits to energy efficiency programs that participants express in “ease of selling” or “increased resale value.” Massachusetts, for example, has developed program-level NEI values for property value increases related to low-income and non-low-income programs.”

### DURABILITY AND MAINTENANCE

The largest quantity of NEIs in the secondary literature relate to the cost, performance and durability of efficient equipment or housing. State Technical Resource Manuals typically include operations and maintenance (O&M) costs, or deferred O&M costs, water and/or sewage savings. O&M costs can often be directly calculated so they are often more acceptable as an NEI compared to less tangible NEIs, such as participants “valuation” of the durability of home.

### HEALTH AND COMFORT

Health and Comfort NEIs contain a number of important and high profile values that can be categorized at the societal, utility, or participant perspective. Example of NEIs in this category are briefly described below.



Building Thermal/Pressure Envelope: A Thermal Comfort NEI related to building shell and HVAC measures is quantified on a program basis for the Massachusetts Program Administrators' whole house retrofit program.<sup>12</sup>

Air Quality: This NEI is interpreted to be indoor air quality related to health of the participant. Only NYSERDA and Massachusetts have quantified values from the participant perspective. Societal NEIs related to air quality and health have been applied in some states though not always as NEIs.

Lighting: NEIs are often positive cost savings, however they can also include negative impacts. Lighting is one of the few NEIs to have negative impacts associated with Health and Comfort. The relative value of the NEI of a CFL to incandescent lights is net negative; the net value of turn on delay, and warm up delay (negative) with heat generated and bulb lifetime (positive) was net negative.<sup>13</sup> Several sources provide NEIs for LEDs, however the secondary research for lighting has resulted in more NEIs for CFLs, since CFLs have been much more common measures until more recently when LEDs have started to be a larger share of the market.

## ENVIRONMENTAL, SOCIETAL, AND GOVERNMENT IMPACTS

These NEIs accrue almost entirely to society, and in a few cases, to the utility. Appliance Recycling has a large number of quantified NEI values as this is a common utility program and has quantifiable environmental benefits from avoided GHG emissions from recycling, reclaimed oils, metals, plastics, glass, mercury, foam and fiberglass.<sup>14</sup>

Air emissions: Avoided electricity and natural gas use due to energy efficiency also results in air emissions avoided. Some jurisdictions include avoided CO<sub>2</sub> values in avoided electricity and natural gas avoided costs. The recently adopted Federal Clean Power Plan rule may impact CO<sub>2</sub> values in many states in the long-run. Other emissions avoided with readily quantified values include SO<sub>x</sub>, NO<sub>x</sub> and particulate matter.

Infill over Greenfield Building: This category has impacts that include property value increases for the neighborhood and also reduced transportation costs for the occupants of the infill residence. While EPA does not monetize the impacts, they state "Infill housing can also raise surrounding property values, increase a community's tax base, and attract more retail to serve the larger resident population." For example, two studies show an increase in property value based on either new residential infill (ranging from \$670<sup>15</sup> to \$4500<sup>16</sup> per home within 150 ft.) or through rehabilitation of residences (estimated at \$2000 per home within 300 ft.).

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<sup>12</sup> NMR Group and Tetra Tech, 2011, *Massachusetts Special and Cross-Sector Studies Area, Residential and Low-Income Non-Energy Impacts (NEI) Evaluation*.

<sup>13</sup> Summit Blue Consulting, LLC, 2006. *Non-Energy Impacts (NEI) Evaluation on behalf of NYSERDA*.

<sup>14</sup> Cadmus, 2013. *Appliance Recycling Program Process Evaluation and Market Characterization - Volume 1*.

<sup>15</sup> Simons, Robert A., Roberto G. Quercia, and Ivan Maric. 1998. The Value of New Residential Construction and Neighborhood Disinvestment on Residential Sales Prices. *Journal of Real Estate Research*, 147-163.

<sup>16</sup> Ding, Chengri, Robert Simons and Esmail Baku. 2000. Effect of Residential Investment on Nearby Property Values: Evidence From Cleveland, Ohio. *Journal of Real Estate Research*, 23-48.

### **IMPROVED SAFETY (IMMINENT DANGERS)**

NEIs associated with Ambient Air Carbon Monoxide Levels and Gas Leaks/Fires make up the majority of this category of NEIs. NEI estimates can be found in association with the following measures: air sealing, combustion testing, heating repair, heating replacement, boiler, furnace, ventilation fan, insulation, ENERGY STAR HVAC Equipment, and whole home. Wisconsin also developed one NEI value for the Safety of Home for the low-income participant.<sup>17</sup>

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<sup>17</sup> Skumatz Economic Research Associates, 2005. *The Non-energy Benefits of Wisconsin's Low-income Weatherization Assistance Program: Revised Report.*

## SUPPLEMENT 11: STAKEHOLDER INPUT CASE

In response to stakeholder and Advisor concerns regarding dated assumptions used in the draft IRP, ENO performed additional production cost analysis using updated assumptions in support of the Final ENO 2015 IRP. A new Stakeholder Input Case scenario was created using the best available information regarding load, commodity prices and generator status. Using this new Stakeholder Input Case, 6 additional AURORA simulations for each of the portfolios previously evaluated using the Industrial Renaissance (Reference Case), Business Boom Case, Distributed Disruption Case and Generation Shift Case were conducted. It is important to note that Stakeholder Input case results are not in any way comparable with the results of the aforementioned four cases.

The scope of the additional analysis is as follows: The total supply cost excluding sunk non-fuel costs for the six portfolios (CCGT, Solar, CT, CT/Solar, CT/Wind, and CT/Solar/Wind) was determined based on re-running AURORA using the best available information regarding load, commodity prices, CO<sub>2</sub> and generator ratings, deactivations, and technology costs. The analysis was performed for 2016 – 2035 as opposed to the original 2015 – 2034 period. 19 of 24 DSM programs were selected for the Stakeholder Input Case. This includes the 14 that were selected in the Industrial Renaissance scenario, three Demand Response programs, and 2 DSM programs selected in the trailing benefit analysis. All 19 programs were selected for each portfolio in the Stakeholder Input Case. The 2015 ICF DSM Potential Study was used as the source of program costs and benefits with the exception that the costs and benefits were assumed to begin in 2016 as opposed to 2015. For any portfolio that included an ENO CT, it was modeled as a Mitsubishi simple-cycle G machine (250 MW) consistent with the updated load and capability projections with and without DSM. For any portfolio that includes a CCGT, it was modeled as a Mitsubishi G Frame technology (450 MW) consistent with the updated load and capability projections with and without DSM. ENO worked with IHS CERA to determine the most recent projections of installed costs for solar resources are available. Capacity expansion and sensitivity analyses included for the other four scenarios were not replicated.

### Assumptions

In addition to creating the four scenarios (Industrial Renaissance, Business Boom, Distributed Disruption, and Generation Shift), a Stakeholder Input Case scenario was created based on the most up to date assumptions available to ENO as of December 2015. The evaluation period for the Stakeholder Input Case is 2016-2035. The various assumption changes are detailed below.

### TECHNOLOGY ASSESSMENT

The Stakeholder Input Case scenario modeled four main technology types. Frame CT and Frame CCGT technology was based on the Mitsubishi Heavy Industries G Frame turbines. G Frame technologies have a lower heat rate than the F Frame technologies, as well as higher capacity. As part of the Stakeholder Input case, the cost curve of the Solar PV technology was updated based on the October 2015 IHS CERA Solar Report and is a region specific forecast (MISO South). Figure 1 and 2 below shows how solar cost estimates changed over time throughout the IRP process and how IHS CERA estimates compares to other industry standards. Table 1 provides a brief summary of technology assumptions for the Stakeholder Input Case.

**Table 1: Stakeholder Input Case Technology Assumptions**

<b>Stakeholder Input Case Technology Assumptions</b>		
<b>Technology</b>	<b>Capacity (MW)</b>	<b>Capital Cost (\$/kW)<sup>18</sup></b>
G Frame CT	250	\$734
1x1 G Frame CCGT	450	\$1139
Wind	Variable <sup>19</sup>	\$2087
Solar PV (tracking)	Variable <sup>20</sup>	\$1838

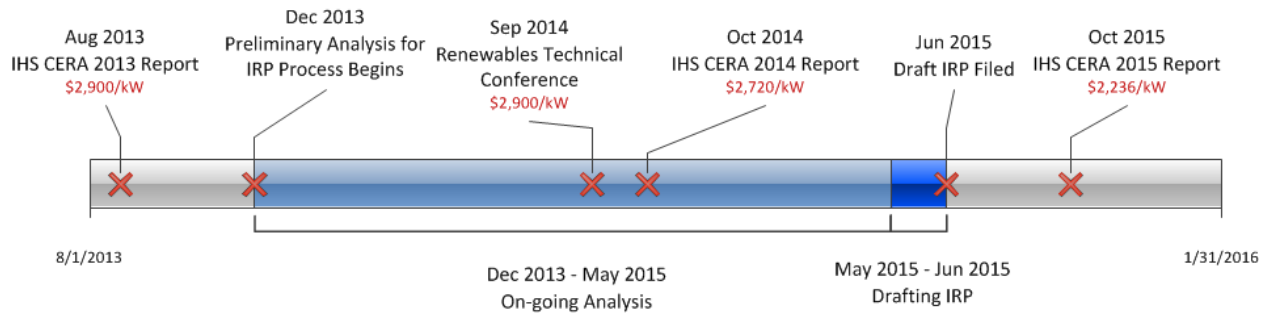
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<sup>18</sup> 2016 Nominal Cost.

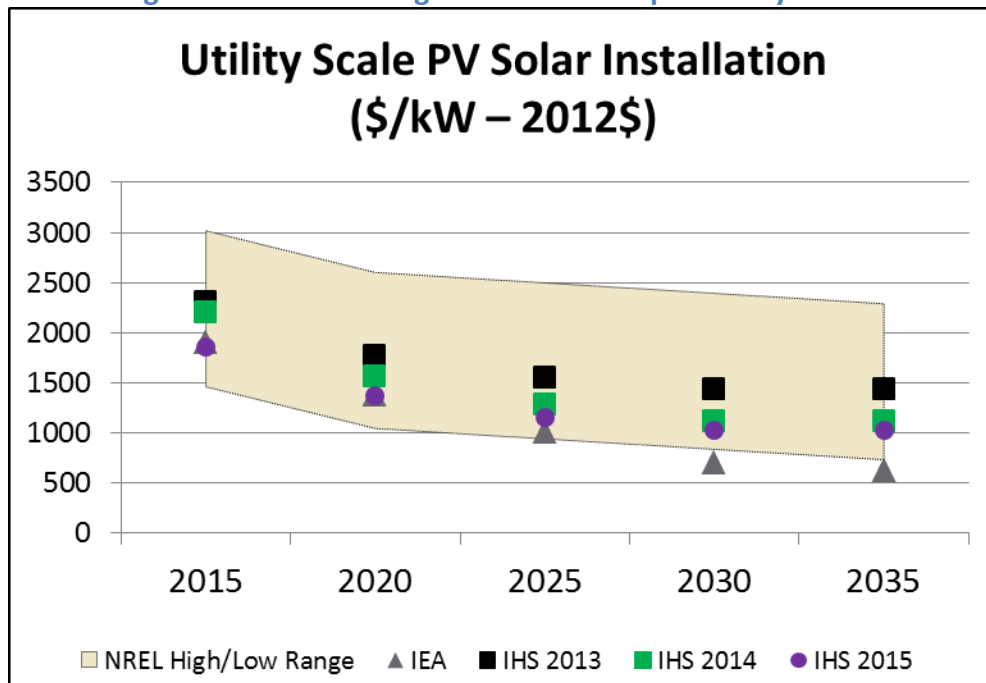
<sup>19</sup> Effective capacity of a wind installment is based on MISO's 15/16 capacity credit of 14.7%

<sup>20</sup> Effective capacity of a solar installment is based on MISO's 15/16 capacity credit of 25%

**Figure 1: Timeline of Solar Tracking Install Costs (2013\$/kW)**



**Figure 2: Solar Tracking Install Cost Comparison by Source**



**DEMAND SIDE MANAGEMENT**

In an update to the draft IRP, filed on September 18, 2015, certain updates to the DSM component of the IRP were included. To reflect input from the Advisors regarding Council-approved incentives available to ENO for years 5 and 6 of Energy Smart, ENO included the assumption that the incentives would be available associated with the long-term DSM potential identified in the IRP, and were modeled as part of the total cost of the DSM programs. In addition, updated load reduction information for three demand response programs not included in the draft IRP were provided by ICF and re-evaluated for inclusion in the Final IRP. These three programs were the Dynamic Pricing Program, Non-Residential Dynamic Pricing Program, and Direct Load Control Program. Through the updated analysis, it was

determined that all three of these programs were cost-effective, and are now included in the Preferred Portfolio.

In addition to the changes made on September 18, 2015, the Stakeholder Input Case includes a secondary analysis of DSM programs that did not break even in the 20-year evaluation period. This analysis incorporated the trailing benefits (kWh savings) that a program would exhibit beyond the 20-year evaluation period. It was assumed that further investment into the DSM measures would no longer occur after 2035, thus making the cost of DSM beyond the evaluation period zero for each program. The trailing benefits declined at different rates for each program, affecting the amount of kWh savings and how long the benefits endured after 2035. These trailing benefits were included in a new breakeven analysis to determine if more DSM programs would be selected, resulting in the potential for an additional 2 DSM programs not previously included to become cost-beneficial when including trailing benefits.

### NATURAL GAS PRICE

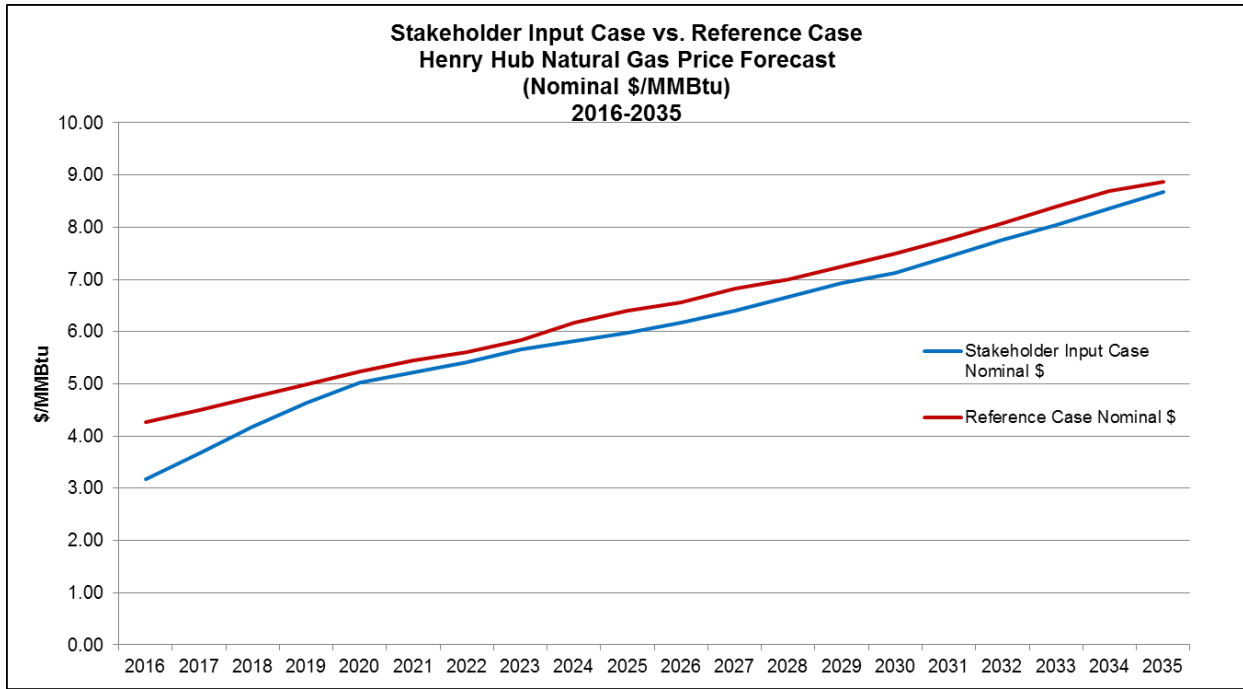
The natural gas price forecast for the Stakeholder Input Case was lower than the reference case forecast used in the Industrial Renaissance scenario. This forecast was influenced by historically strong production driven by the continued economics of Northeast shale gas combined with mild weather. These factors have created a supply and storage glut. This oversupply is expected to continue in the near-term and put downward pressure on prices, assuming normal weather patterns. Long-term structural demand increases (LNG exports, exports to Mexico, power demand) are expected to continue to develop, holding off potential price decreases in the long-run.

**Table 2: Stakeholder Input Case Natural Gas Price Forecast**

<b>Henry Hub Natural Gas Prices</b>		
	<b>Nominal \$/MMBtu</b>	<b>Real 2014\$/MMBtu</b>
Real Levelized <sup>21</sup> (2016-2035)	\$5.54	\$4.57
Average (2016- 2035)	\$6.12	\$4.76
20-Year CAGR	5.2%	3.2%

<sup>21</sup> “Real levelized” prices refer to the price in 2014\$ where the NPV of that price grown with inflation over the 2016-2035 period would equal the NPV of levelized nominal prices over the 2016-2035 period.

Figure 3: Stakeholder Input Case Natural Gas Price Forecast

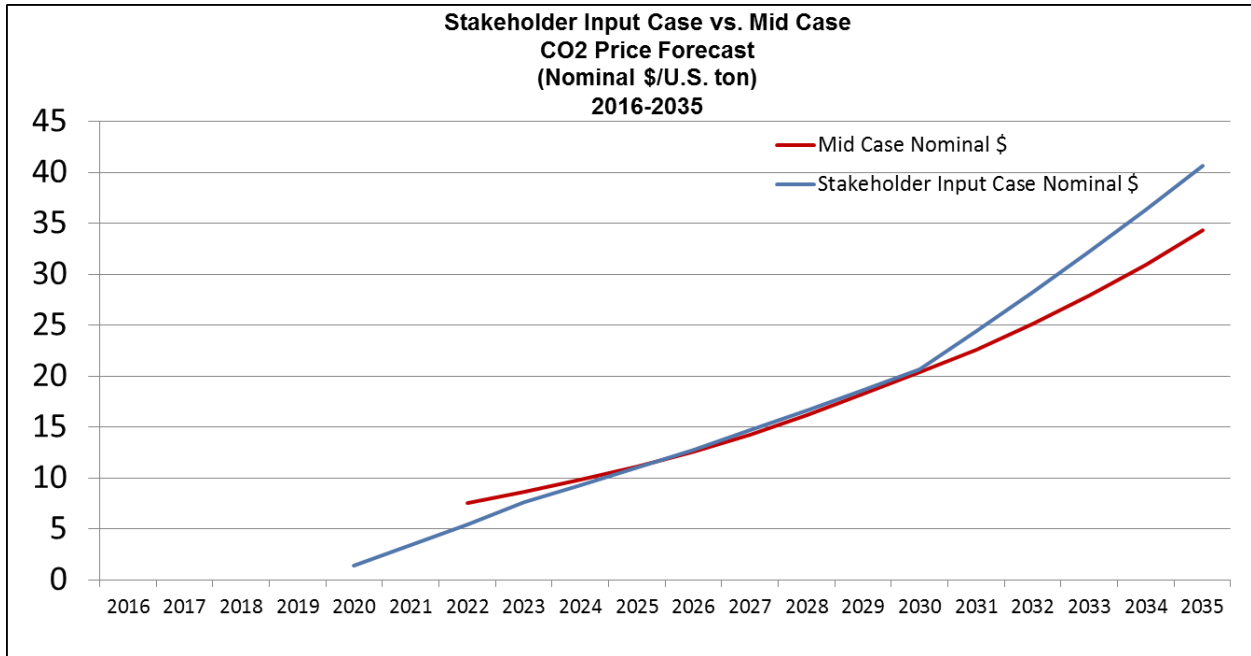


### CO<sub>2</sub> PRICE

The Stakeholder Input Case CO<sub>2</sub> price forecast was taken from Entergy corporate CO<sub>2</sub> POV developed in March 2015. The basis for Entergy corporate POV for the mid-price forecast shown below is based on the ICF 1Q 2015 Reference Case. The Stakeholder Input case forecast shows CO<sub>2</sub> prices that begin in 2020 at \$1.39/U.S. ton and escalate more quickly than the mid-price forecast. The 2016-2035 levelized cost in 2014\$ for the Stakeholder Input Case is \$8.00/U.S. ton.<sup>22</sup>

<sup>22</sup> Includes discount rate of 7.12%

**Figure 4: Stakeholder Input Case CO<sub>2</sub> Price Forecast**



**Current Fleet & Projected Needs: Stakeholder Input Case**

Due to the changes that were filed September 18, 2015 and the creation of the Stakeholder Input Case, the differences in the current fleet assessment and projected needs assessment are documented below.

**CURRENT FLEET**

ENO received Council approval for the transfer of Algiers from ELL to ENO in May 2015, which transaction closed on September 1, 2015. The resources available to ENO through the Algiers PPA were included in the portfolio of the existing fleet of the Stakeholder Input Case, resulting in an increase of 117 MW from 537 MW to 654 MW of owned resources and affiliate power purchase agreements in 2016.

**Table 3: Incremental Capacity from Algiers Transfer (MW)**

Resource Name	Resource Type	MW
Acadia	CCGT	7
Buras 8	Legacy Gas	0.2
Grand Gulf	Nuclear	3
Little Gypsy 2	Legacy Gas	8
Little Gypsy 3	Legacy Gas	10
Ninemile 4	Legacy Gas	13
Ninemile 5	Legacy Gas	13

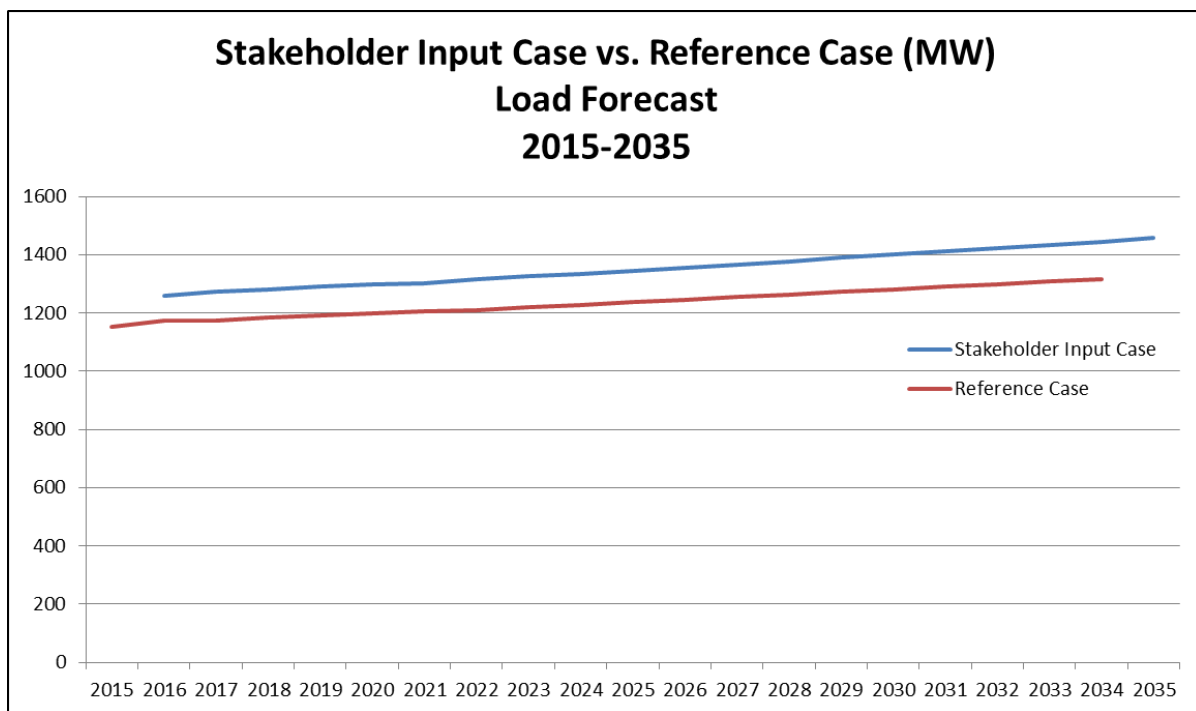


Perryville 1	CCGT	2
Perryville 2	CT	1
Riverbend	Nuclear	4
Waterford 1	Legacy Gas	7
Waterford 2	Legacy Gas	8
Waterford 3	Nuclear	21
Waterford 4	Oil	1
Sterlington 7	CCGT	1
Ninemile 6	CCGT	6
Oxy-Taft	CCGT	9
Toledo Bend	Hydro	0.4
Vidalia	Hydro	2
Total		117

### LOAD FORECAST

For the Stakeholder Input case, the load was changed to reflect the load forecast of the most current business plan, which also included the Algiers transfer. This resulted in an increase of 84 MW in the total resource requirement in 2016 compared to the Final IRP reference case load.

Figure 5: Stakeholder Input Case Load Forecast



## RESOURCE NEEDS

Resource needs changed in the Stakeholder Input Case due to changes in the load forecast as well as the addition of incremental capacity from the Algiers transfer. Planned resource additions also changed from the affiliate PPA's of the Union and Amite South resources to the ownership of Union Power Block 1. This change is highlighted in Table 4 below. Despite these changes to the Stakeholder Input case, ENO's needs were determined to be similar to the reference case: ENO largely meets their base load/core load following need while still being deficient in peaking capacity and overall capacity.

**Table 4: Reallocation of Planned Resource Additions**

Reallocation of Planned Resource Additions			
Resource	IR/BB/DD/GS Scenarios (MW)	Stakeholder Input Case (MW)	Change
Union	204	510	306
Amite South	229	0	(229)
Totals	433	510	77

**Table 5: Stakeholder Input Case Projected Peak Forecast Increase by 2035**

Stakeholder Input Case (MW)		
2016	2035	Increase
1,125	1,301	176

**Table 6: Stakeholder Input Case ENO Resource Needs (MW)**

Capacity Surplus/(Need) (Before IRP Additions)	
By 2025	(685)
By 2035	(901)

**Table 7: Projected Resource Needs in 2035 by Supply Roles (Stakeholder Input Case)**

	Need	Resources	Surplus/(Deficit)	Planned Additions	Surplus/(Deficit)
Base Load and Load Following (MW)	1043	526	(517)	510	(7)
Peaking & Reserve (MW)	414	30	(384)	0	(384)
Totals	1457	556	(901)	510	(391)

## Stakeholder Input Case Portfolios

### PORTFOLIO DESIGN

ENO created a Stakeholder Input Case scenario using the assumptions outlined in the Assumptions section. Once the Stakeholder Input Case was established, ENO ran six additional AURORA simulations for each of the portfolios derived from the same market modeling and manual portfolio design process established earlier in this report. Additional analysis was also done in the selection of DSM programs from the Potential Study. This analysis consisted of determining the optimal implementation year of three demand response programs based on dynamic pricing and load control as well as a terminal value assessment of programs initially shown not to breakeven. If the residual benefits of these programs that extended beyond the evaluation period resulted in the programs becoming cost effective, they were added to the portfolio. All six portfolios under the Stakeholder Input Case contain a total of 19 DSM programs. More information on the DSM analysis can be found in the DSM supplement.

**Table 8: Portfolio Design Mix – Installed Capacity**

Design Mix – Installed Capacity						
	AURORA Capacity Expansion Portfolios		Alternative Portfolios			
	CCGT Portfolio	Solar Portfolio	CT Portfolio	CT/Solar Portfolio	CT/Wind Portfolio	CT/Wind/Solar Portfolio
<b>DSM Programs</b>	19 Programs	19 Programs	19 Programs	19 Programs	19 Programs	19 Programs
<b>CCGTs</b>	450	0	0	0	0	0
<b>CTs</b>	0	0	250	250	250	250
<b>Solar</b>	0	1200	0	100	0	50
<b>Wind</b>	0	0	0	0	100	50

Figure 6: Stakeholder Input Case Scenario CT Portfolio

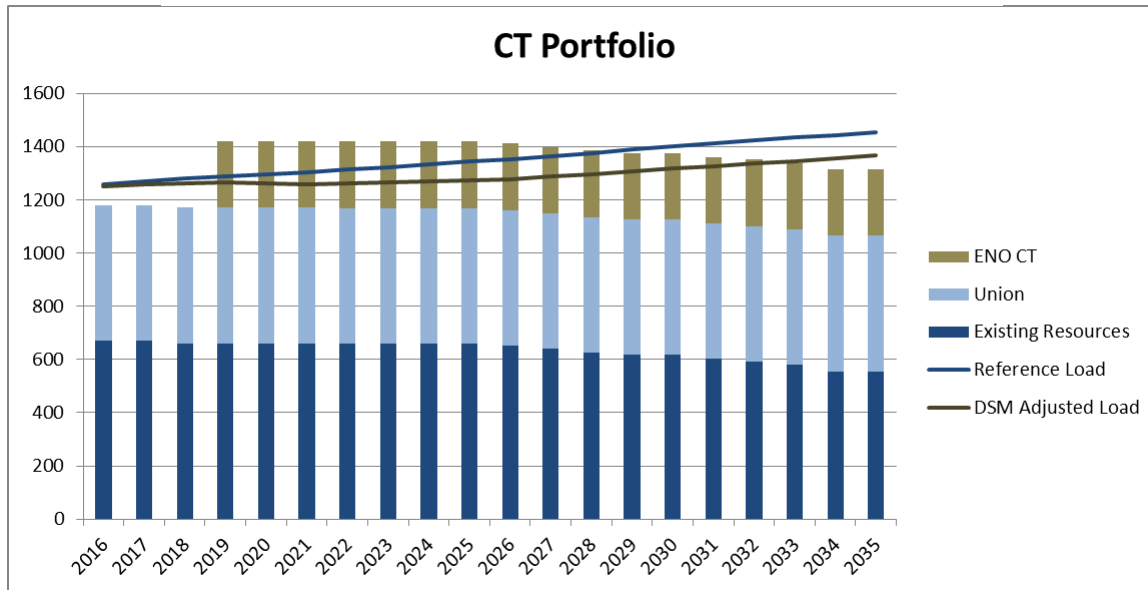


Figure 7: Stakeholder Input Case Scenario CT/Wind Portfolio

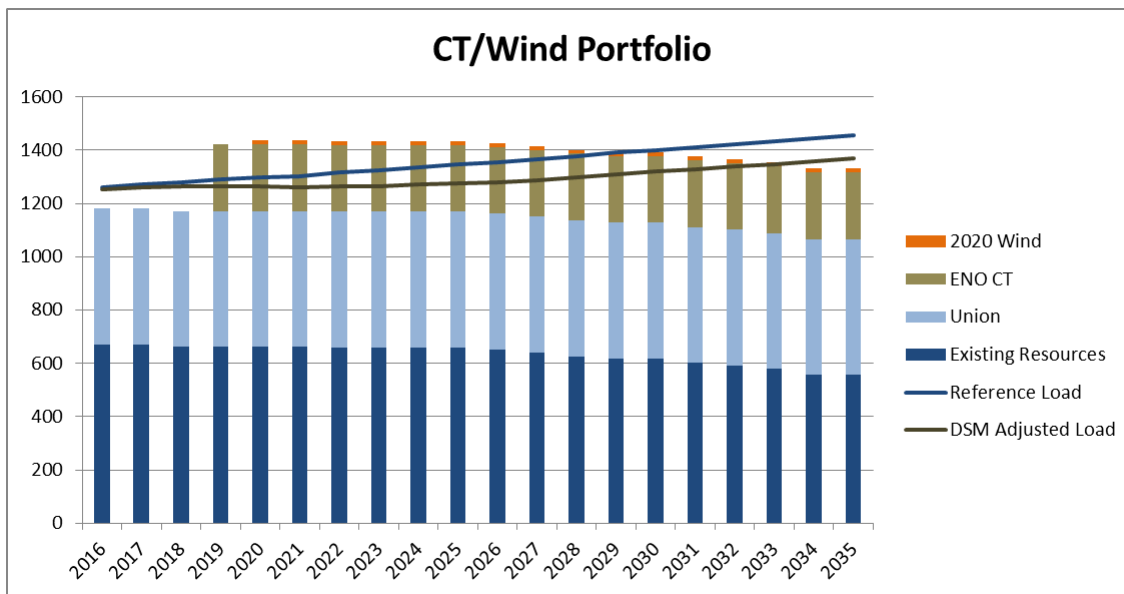


Figure 8: Stakeholder Input Case Scenario CT/Solar Portfolio

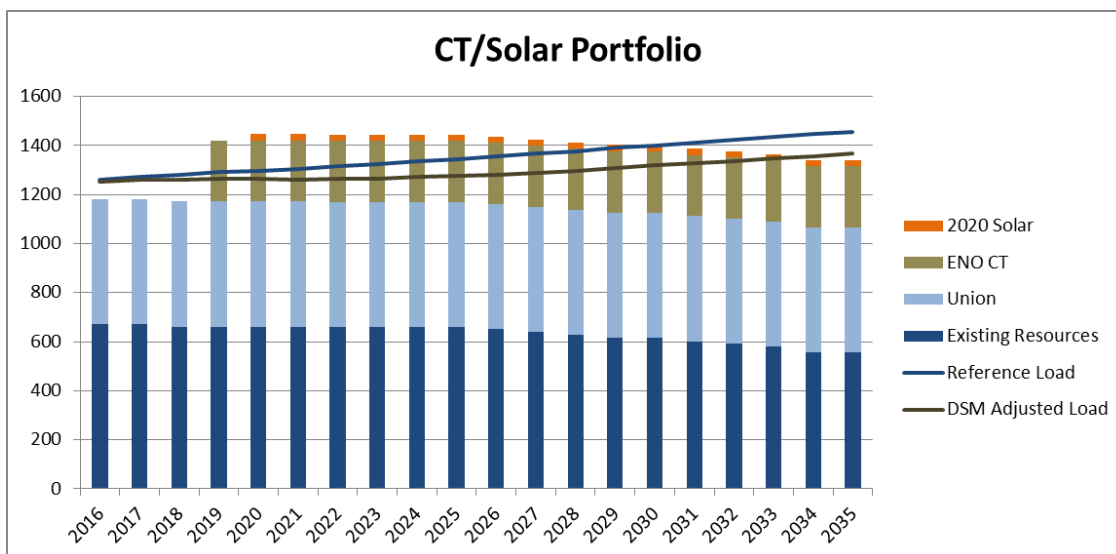


Figure 9: Stakeholder Input Case Scenario CT/Solar/Wind Portfolio

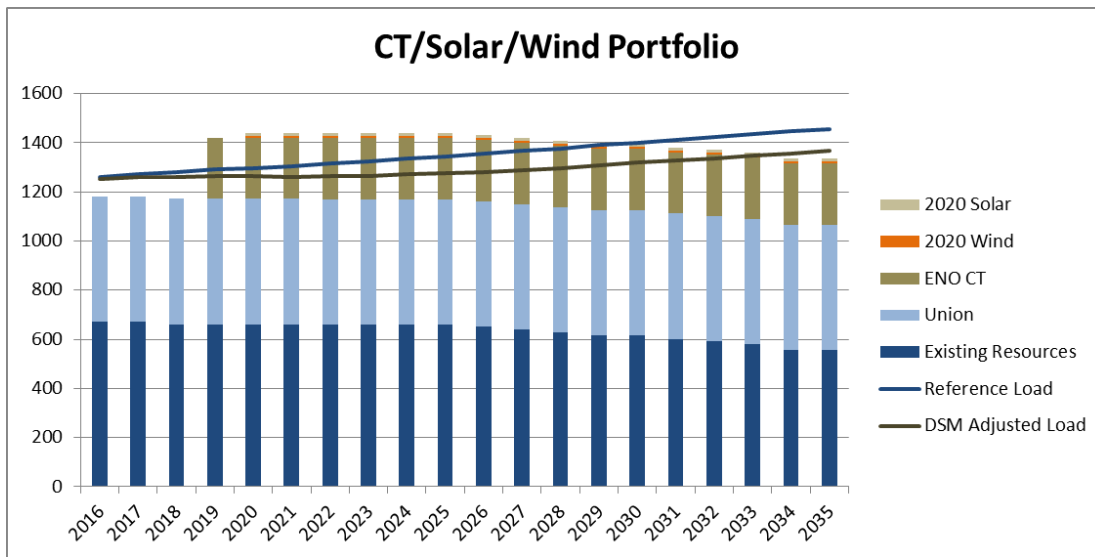


Figure 10: Stakeholder Input Case Scenario CCGT Portfolio

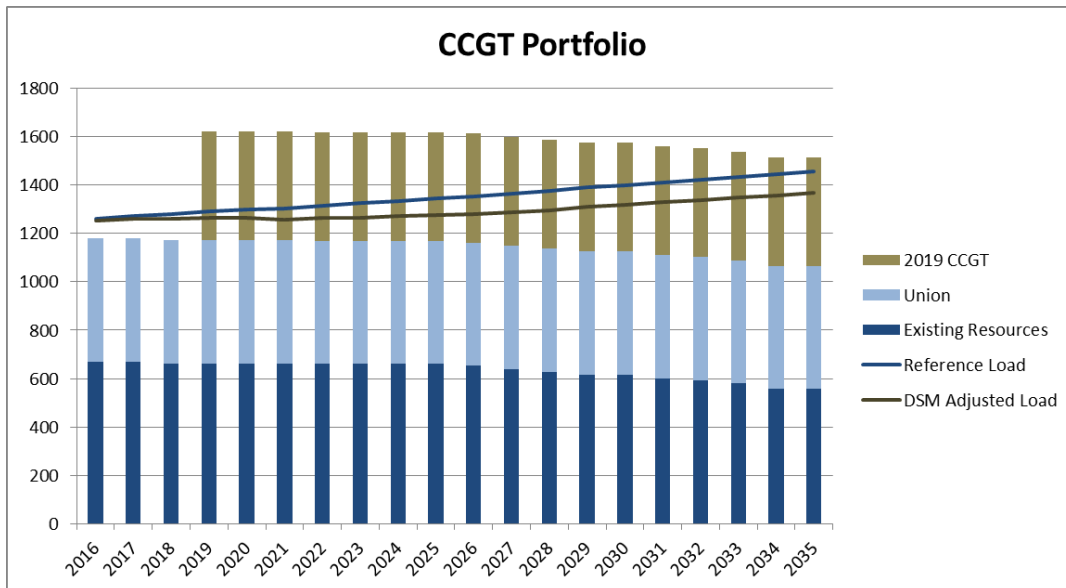
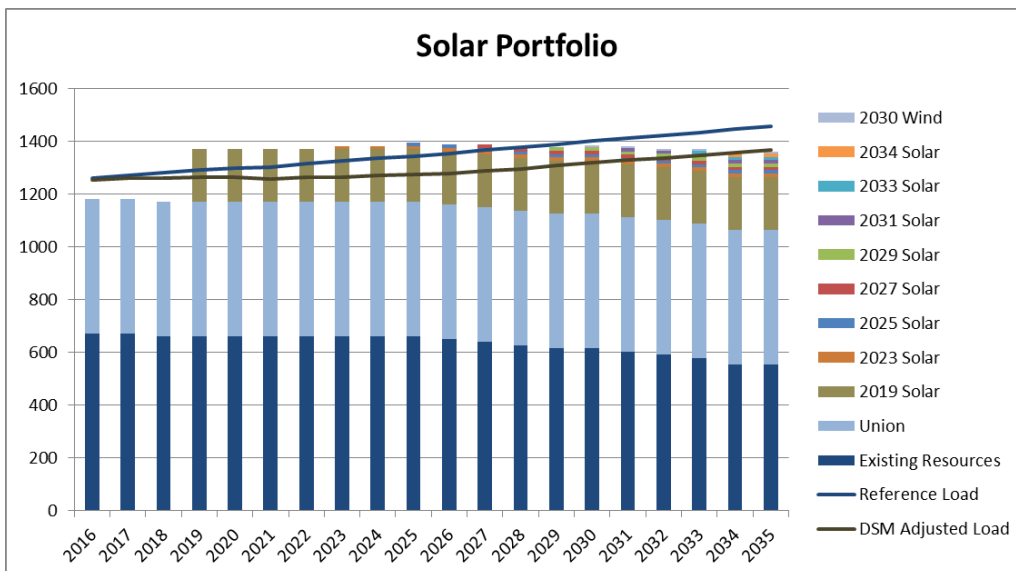


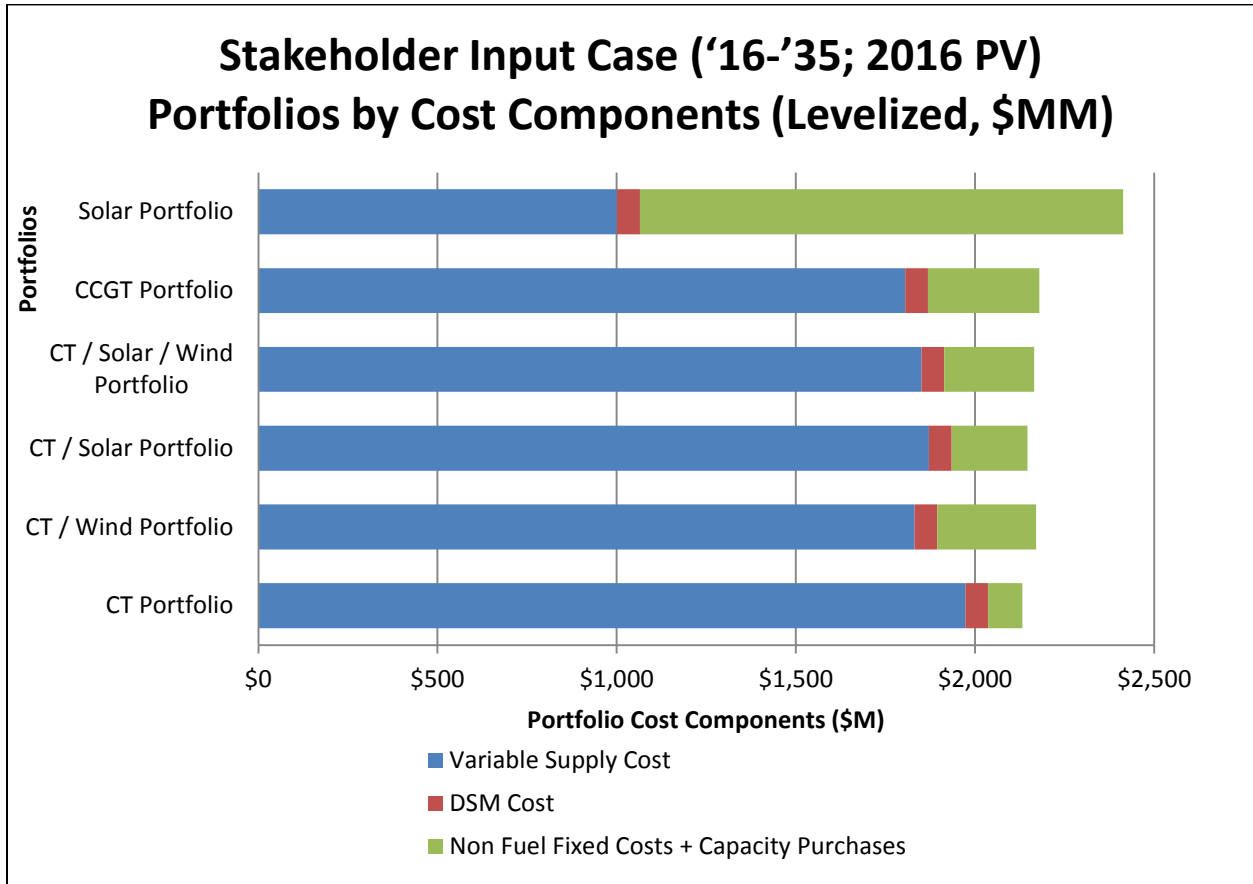
Figure 11: Stakeholder Input Case Scenario Solar Portfolio



## TOTAL SUPPLY COST

Figure 12 below shows the total supply cost excluding sunk non-fuel fixed cost for each of the six portfolios broken out by variable supply cost, DSM cost, and fixed cost. The CT portfolio is the lowest cost portfolio driven by low fixed cost. When renewables are added to the CT portfolio, they did not improve the performance on a cost basis.

**Figure 12: Total Supply Costs Excluding Sunk Non-Fuel Fixed Costs in the Industrial Renaissance Scenario**



**Table 9: Portfolio Ranking by Total Supply Cost**

Total Supply Cost Portfolio Rankings for Stakeholder Input Case		
Portfolios	Total Relevant Supply Cost Levelized Real (\$MM)	Ranking
Solar	\$2,413	6
CCGT	\$2,180	5
CT Solar_Wind	\$2,165	3
CT Solar	\$2,146	2
CT Wind	\$2,171	4

CT	\$2,132	1
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## Preferred Portfolio and Conclusions

### RATE EFFECTS

The estimated typical bill effects associated with the cost to meet customer’s needs through the Preferred Portfolio over the next two decades are modest. Over time, inflation in the broader economy tends to drive prices up for all goods and services, and in general the average annual growth rate in projected customer bills (reflected in the last column in Table 11) during the IRP planning horizon are expected to grow below inflation expectations.

**Table 10: ENO Average Residential Customer Electric Bill (Preferred Portfolio)<sup>23</sup>**

Projected ENO Residential Customer Bill and Energy Usage				
Customer Segment	Actual 2014 Usage (KWh/mo.)	Actual 2014 Average Monthly Bill	Projected 2035 Usage (KWh/mo.)	Projected 2035 Average Monthly bill
Residential (Legacy)	1,081	\$109	1,332	\$147
Residential (Algiers)			1,561	\$149

**Table 11: Rate Effects – ENO Preferred Portfolio (Stakeholder Input Case)**

Projected ENO Average Monthly Customer Bill				
Customer Segment	2016	2026	2035	CAGR <sup>24</sup>
Residential (Legacy)	\$110	\$127	\$147	1.5%
Commercial (Legacy)	\$1,095	\$1,111	\$1,135	0.2%
Industrial (Legacy)	\$1,302	\$1,151	\$1,009	(-1.3%)
Government (Legacy)	\$3,377	\$3,815	\$4,096	1.0%
Residential (Algiers)	\$100	\$132	\$149	2.0 %
Commercial (Algiers)	\$628	\$836	\$922	1.9%
Industrial (Algiers)	\$234	\$348	\$406	2.8%
Government (Algiers)	\$1,282	\$1,775	\$2,050	2.4%

<sup>23</sup> Includes benefits associated with the optimal (cost-effective) level of DSM identified through the DSM Optimization.

<sup>24</sup> Compound Annual Growth Rate (“CAGR”) measures the average annual rate of growth in typical customer bills over the planning horizon.

Table 12: ENO Preferred Portfolio Stakeholder Input Case--Load & Capability 2016-2035 (All values in MW)<sup>27</sup>

Load & Capability 2016—2035																				
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
<b>Requirements</b>																				
Peak Load	1,125	1,136	1,143	1,153	1,159	1,163	1,175	1,183	1,193	1,201	1,209	1,220	1,230	1,241	1,251	1,261	1,271	1,281	1,291	1,301
Reserve Margin (12%)	135	136	137	138	139	140	141	142	143	144	145	146	148	149	150	151	153	154	155	156
<b>Total Requirements</b>	<b>1,260</b>	<b>1,273</b>	<b>1,280</b>	<b>1,291</b>	<b>1,298</b>	<b>1,303</b>	<b>1,316</b>	<b>1,325</b>	<b>1,336</b>	<b>1,345</b>	<b>1,355</b>	<b>1,366</b>	<b>1,378</b>	<b>1,390</b>	<b>1,401</b>	<b>1,412</b>	<b>1,424</b>	<b>1,435</b>	<b>1,446</b>	<b>1,457</b>
<b>Resources</b>																				
<b>Existing Resources</b>																				
Owned Resources	642	642	642	642	642	642	641	641	641	641	633	621	608	598	598	585	575	562	539	539
PPA Contracts	11	11	2	2	2	2	2	2	2	2	2	2	2	2	2	-	-	-	-	-
LMRs	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17
<b>Identified Planned Resources</b>																				
Union <sup>25</sup>	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510
<b>Other Planned Resources</b>																				
DSM <sup>26</sup>	7	12	18	25	34	44	52	60	64	69	75	78	81	80	82	83	86	87	88	88
CT	-	-	-	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
Market Purchases (Sales)	73	80	91	(156)	(158)	(162)	(156)	(154)	(148)	(144)	(133)	(112)	(90)	(67)	(58)	(33)	(15)	9	42	53
<b>Total Resources</b>	<b>1,260</b>	<b>1,273</b>	<b>1,280</b>	<b>1,291</b>	<b>1,298</b>	<b>1,303</b>	<b>1,316</b>	<b>1,325</b>	<b>1,336</b>	<b>1,345</b>	<b>1,355</b>	<b>1,366</b>	<b>1,378</b>	<b>1,390</b>	<b>1,401</b>	<b>1,412</b>	<b>1,424</b>	<b>1,435</b>	<b>1,446</b>	<b>1,457</b>

<sup>25</sup>Union plant acquisition is completed pending regulatory approvals.

<sup>26</sup>Demand Side Management (DSM) total is grossed up for Planning Reserve Margin (12%) and transmission losses (2.4%).

<sup>27</sup>Includes Algiers Transfer



