Supplement 6 PUBLIC VERSION
CNO Docket No. UD-08-02

ENTERGY NEW ORLEANS

Supporting Technical Materials

2015 ENO Integrated Resource Plan

JUNE 2015

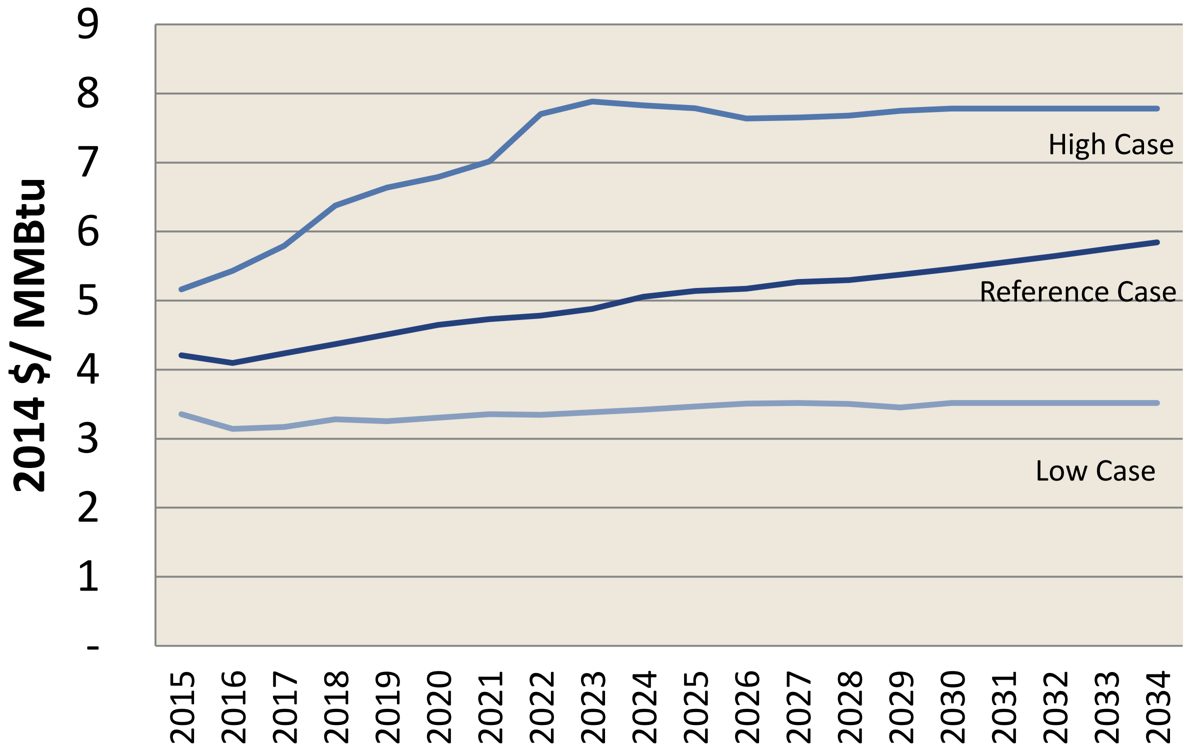
COMMODITY FORECASTS

HENRY HUB NATURAL GAS PRICE FORECAST

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

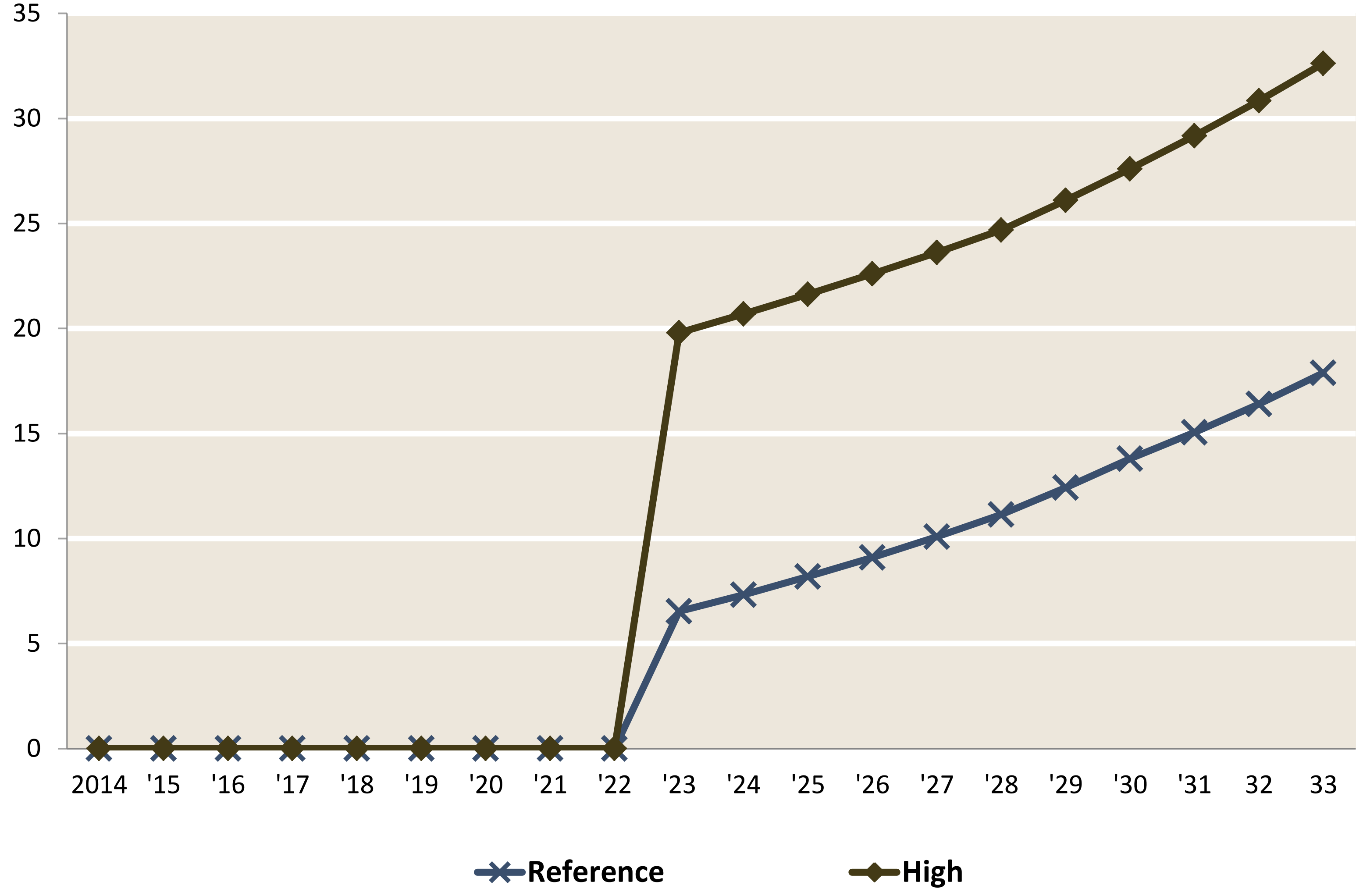
Process

- 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).



CO_2 PRICE FORECAST

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



HISTORIC LOAD AND LOAD FORECAST

ENO HISTORIC PEAK DEMAND AND ENERGY

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Peak (MW)	1,254	912	904	882	998	1,005	1,018	1,018	1,012	987
Load (MWh)	5,255,932	4,787,343	4,642,137	4,748,723	5,006,068	5,302,305	5,335,801	5,216,204	5,343,109	5,318,457

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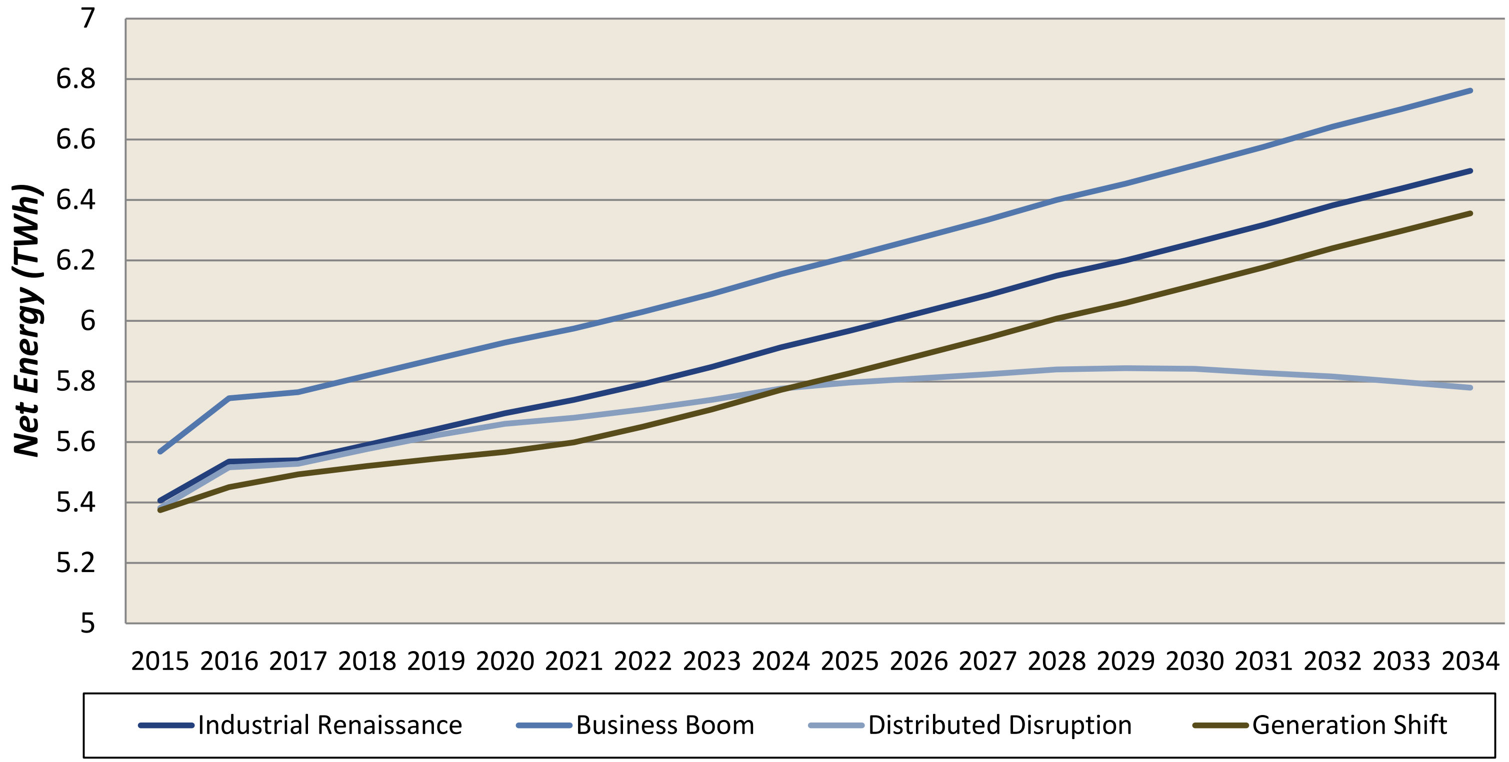
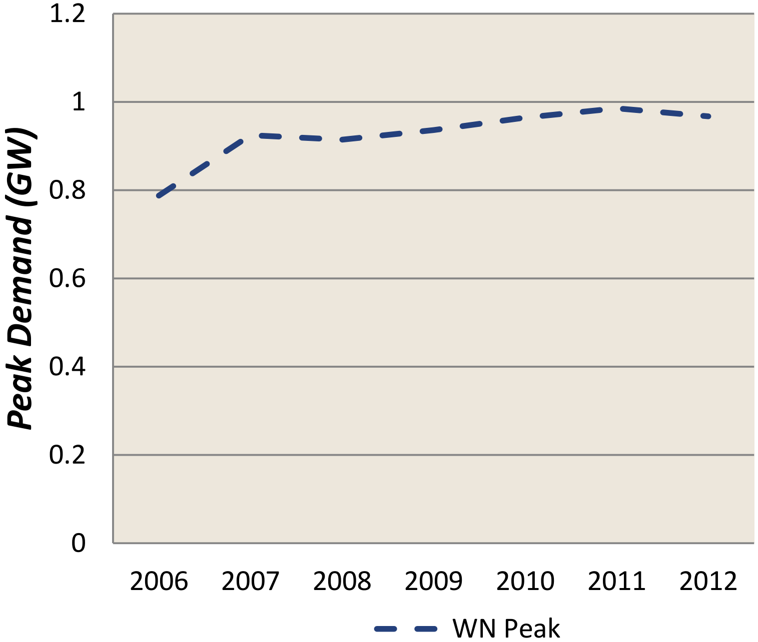
ENO TOTAL ENERGY LOAD FORECAST



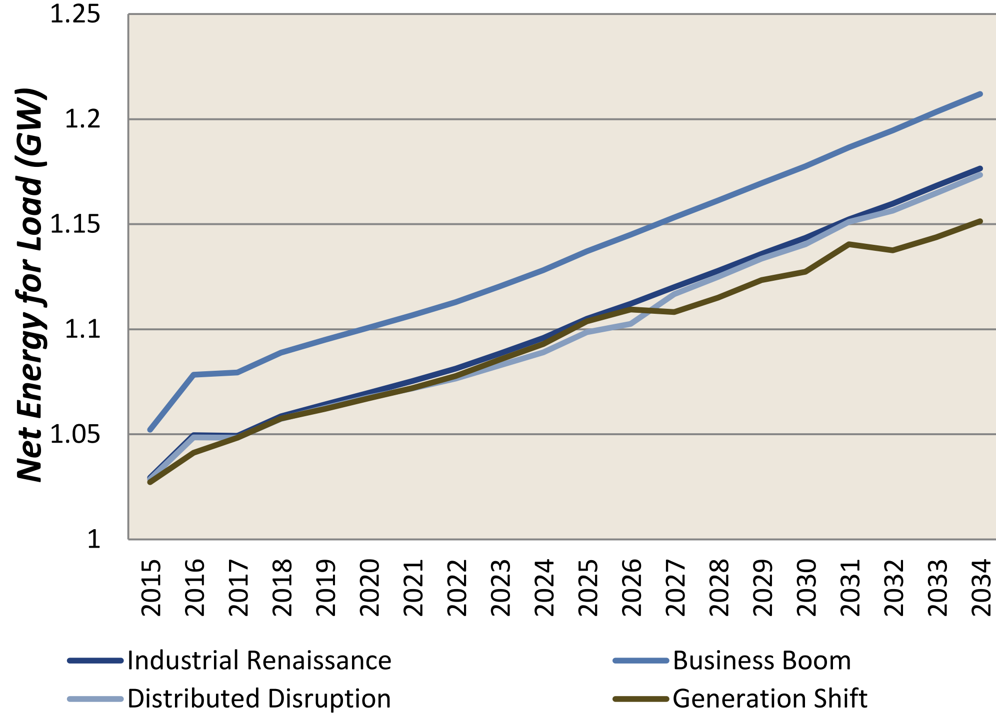
2015 Update	2015-2025 CAGR	2025-2034 CAGR
Industrial Renaissance	1.0%	0.9%
Business Boom	1.1%	0.9%
Distributed Disruption	0.7%	0.0%
Generation Shift	0.8%	0.9%

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



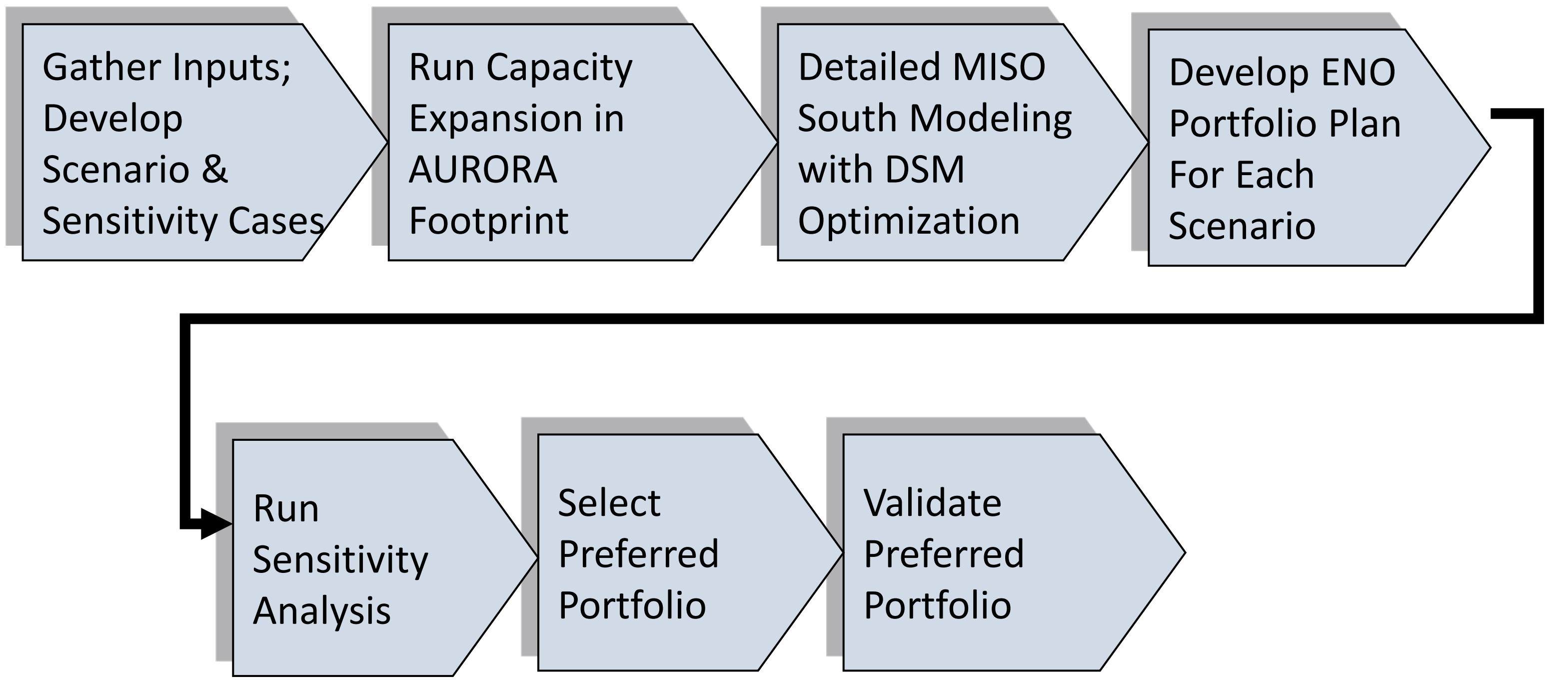
2015 Update	2015-2025 CAGR	2025-2034 CAGR
Industrial Renaissance	0.7%	0.6%
Business Boom	0.8%	0.6%
Distributed Disruption	0.7%	0.5%
Generation Shift	0.7%	0.6%

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

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 considered the following uncertainties:

- Natural gas prices
- Implementation of CO_2 cost**
- Gas and CO_2 combination**

SCENARIO STORYLINES

	Scenario 2 Business Boom	Scenario 3 Distributed Disruption	Scenario 4 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.

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

FLEET ASSUMPTIONS

ENO's GENERATION FLEET 2015

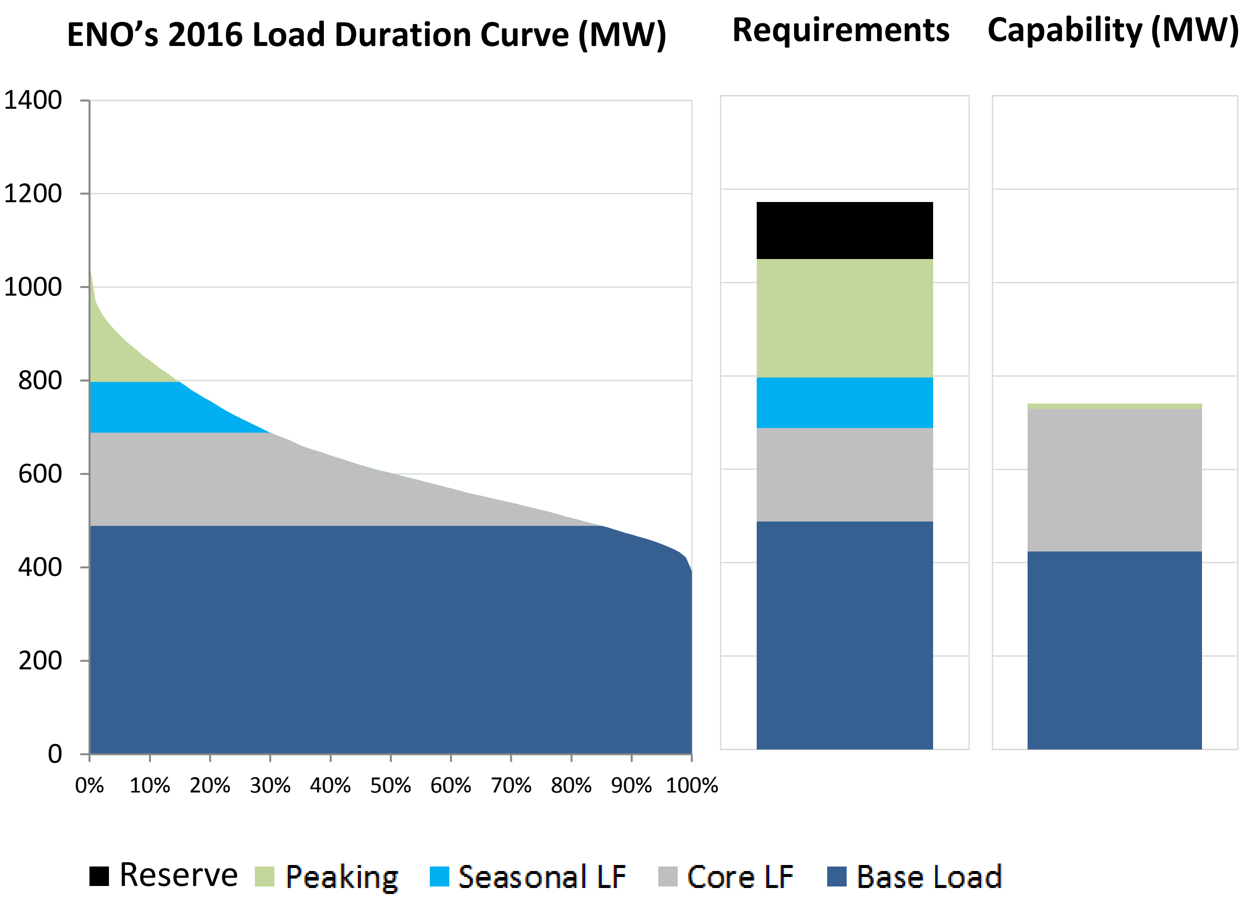
Unit	Fuel	Capability (MW)	Deactivation Assumption
Ninemile 6	Gas	112	N/A
Michoud 2	Gas	239	May 31, 2016
Michoud 3	Gas	542	May 31, 2016
ANO 1	Nuclear	23	N/A
ANO 2	Nuclear	27	N/A
Grand Gulf	Nuclear	247	N/A
Independence 1	Coal	7	N/A
White Bluff 1	Coal	12	N/A
White Bluff 2	Coal	13	N/A

ENO Resource Needs by Scenario by Year (MW)

	Industrial Renaissance	Business Boom	Distributed Disruption	Generation Shift
2015	165	140	166	168
2016	(639)	(671)	(638)	(630)
2017	(639)	(672)	(638)	(638)
2018	(649)	(683)	(648)	(648)
2019	(655)	(690)	(654)	(653)
2020	(662)	(696)	(659)	(659)
2021	(668)	(703)	(664)	(664)
2022	(674)	(710)	(669)	(671)
2023	(682)	(718)	(676)	(679)
2024	(691)	(727)	(683)	(688)
2025	(701)	(737)	(694)	(700)
2026	(709)	(746)	(698)	(706)
2027	(718)	(755)	(705)	(714)
2028	(727)	(764)	(712)	(723)
2029	(736)	(773)	(722)	(733)
2030	(744)	(782)	(726)	(741)
2031	(754)	(792)	(741)	(753)
2032	(762)	(801)	(738)	(759)
2033	(772)	(811)	(745)	(768)
2034	(781)	(821)	(753)	(778)

ENO Portfolio and Supply Role Needs

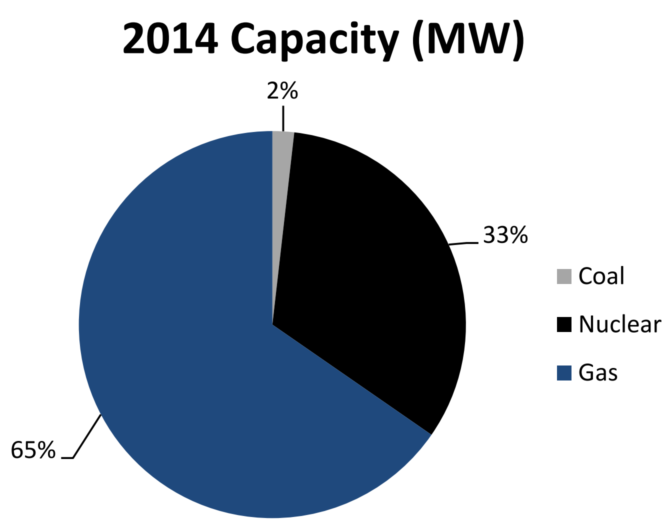
ENO's 2016 generation portfolio is projected to have adequate capacity for its Base Load and Core Load Following needs; however, additional peaking capacity is needed

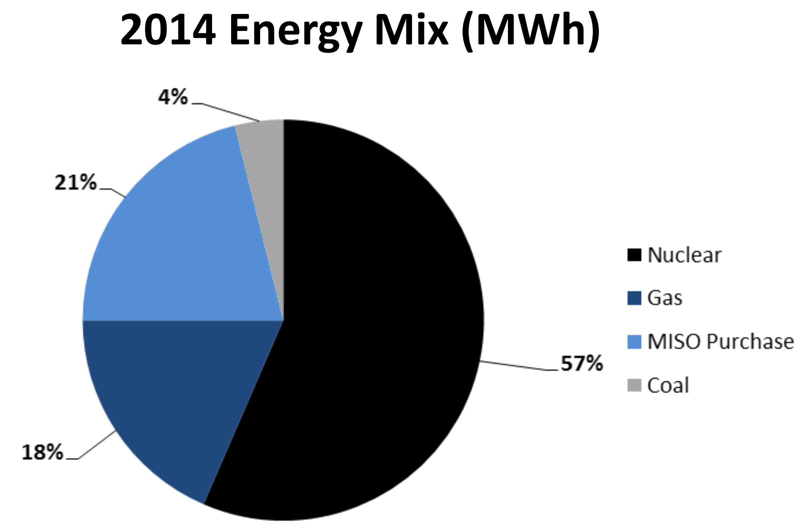


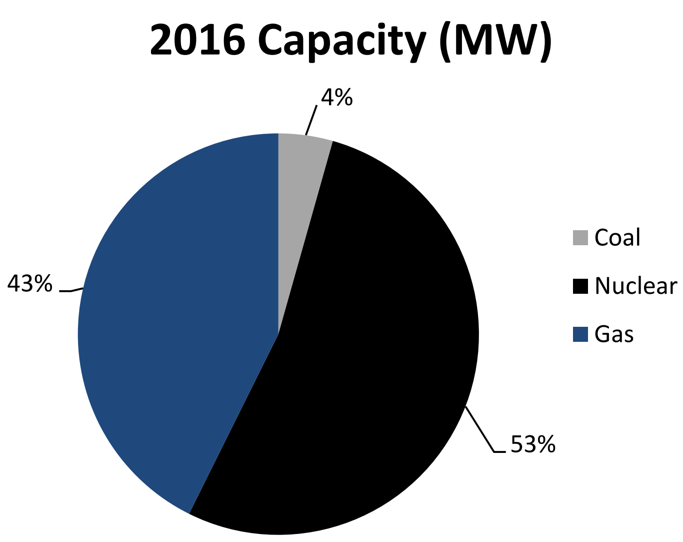
Unit	Fuel	Capability (MW)
Ninemile 6	Gas	112
Union	Gas	204
ANO 1	Nuclear	23
ANO 2	Nuclear	27
Grand Gulf	Nuclear	247
Independence 1	Coal	7
White Bluff 1	Coal	12
White Bluff 2	Coal	13

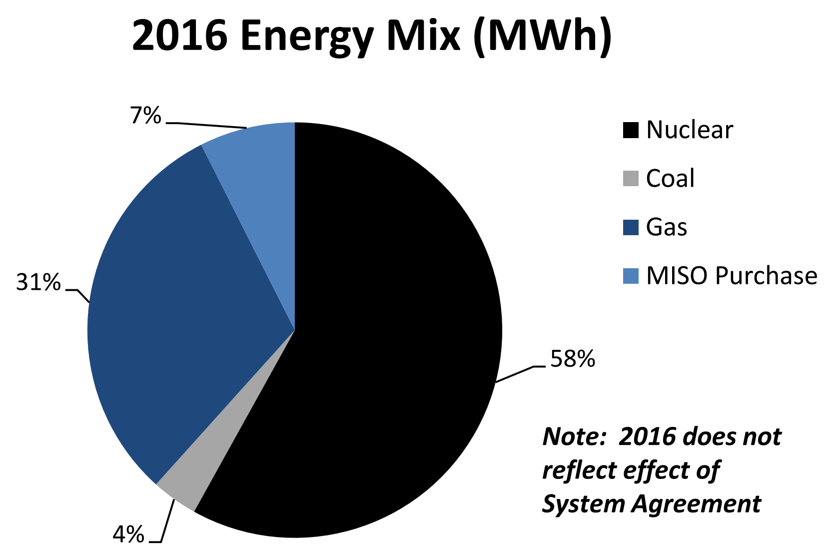
ENO'S CAPACITY & ENERGY MIX

With the planned deactivation of Michoud 2 and 3, nuclear and coal resources provide over 50% of capacity and over 60% of energy needs









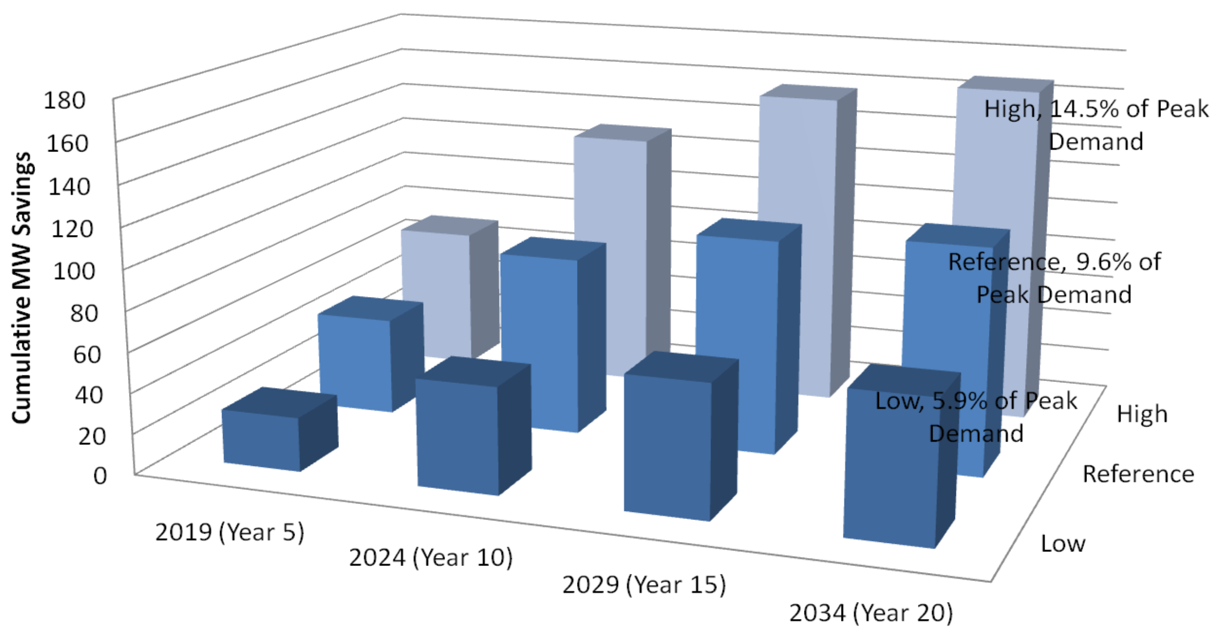
Note: 2016 does not reflect effect of System Agreement

DSM OVERVIEW

DSM POTENTIAL STUDY

- ICF conducted a DSM Potential Study to develop high-level, long run achievable DSM program potential estimates for ENO over the 20-year planning horizon (2015-2034).
  - In total, 24 DSM programs were considered cost effective with a Total Resources Cost ("TRC") ratio of 1.0 or better. ICF developed hourly loadshapes and program cost projections representing three levels – low, reference, and high – of achievable DSM program savings. These load shapes and costs are the demand side management inputs in the IRP analysis.

ENO Cumulative Net MW Savings Potential, by Scenario



AURORA Background and Construct

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.

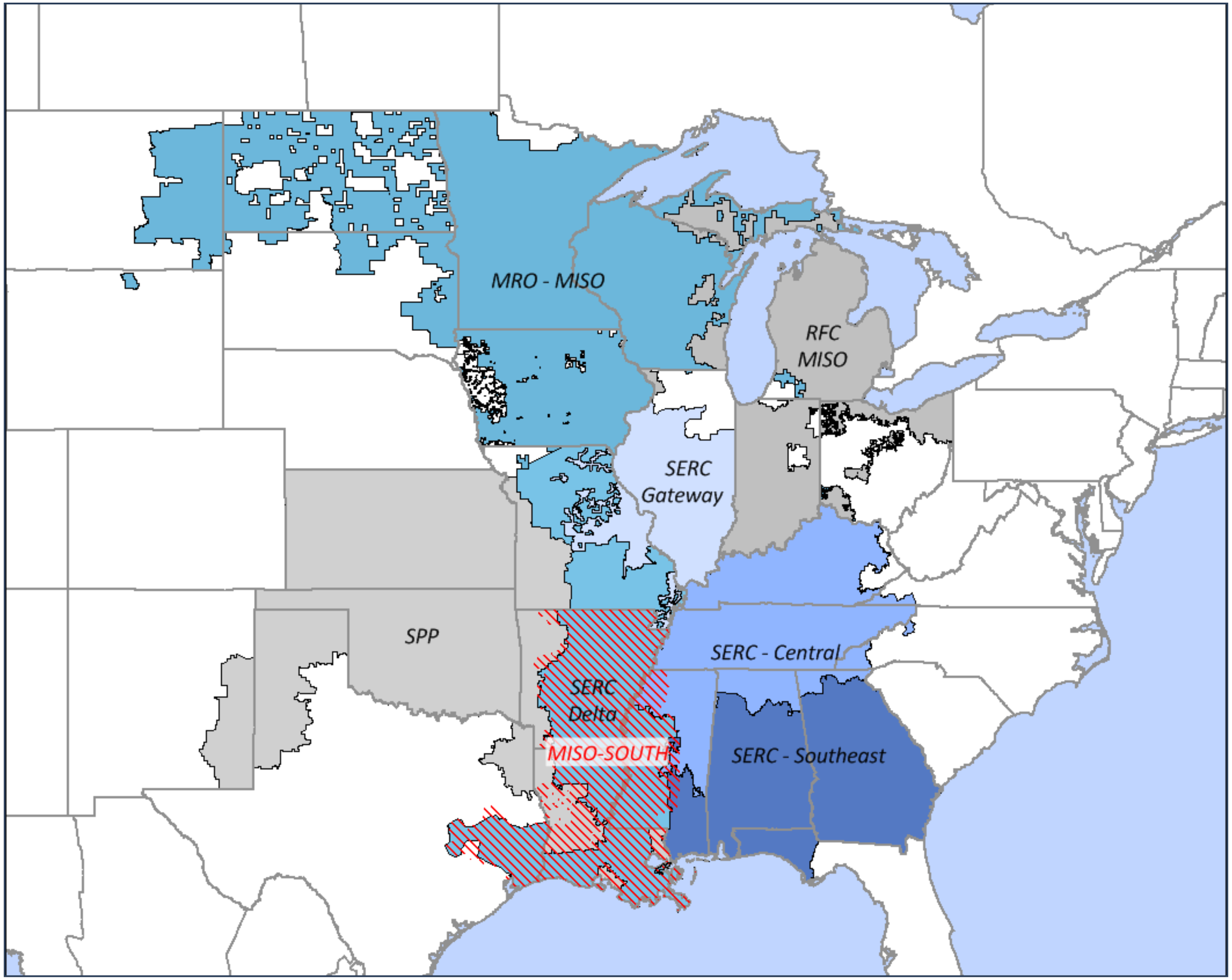
- The 2015 ENO IRP will utilize AURORA in scenario and sensitivity modeling. The 2015 AURORA Update Case has been created using the latest planning assumptions . This will serve as the foundation for ENO's IRP Scenario 1 modeling. Assumptions in the IRP work which materially differ from the 2015 Business 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 .



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

Fuel Price Methodologies Used In Modeling (Continued)

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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.

MARKET MODELING AND PORTFOLIO DESIGN

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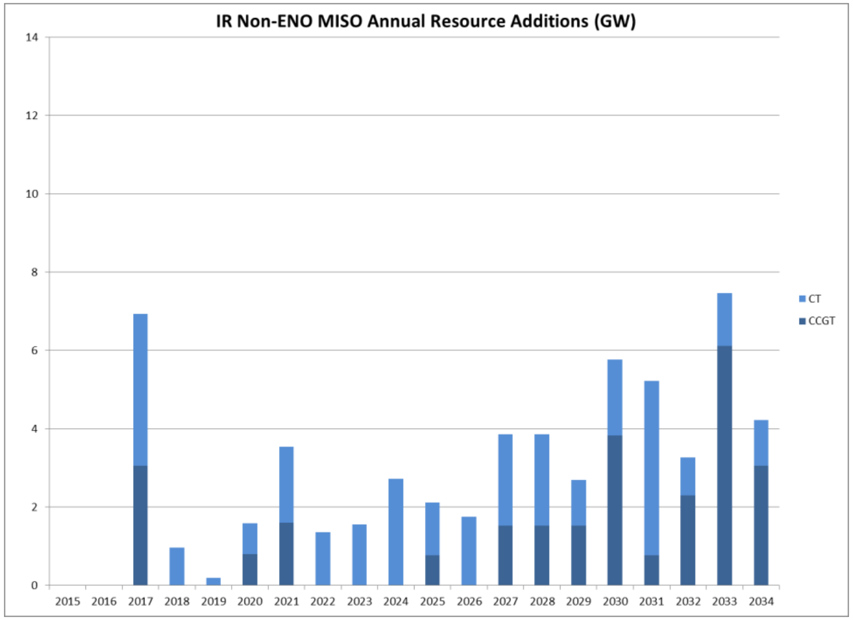
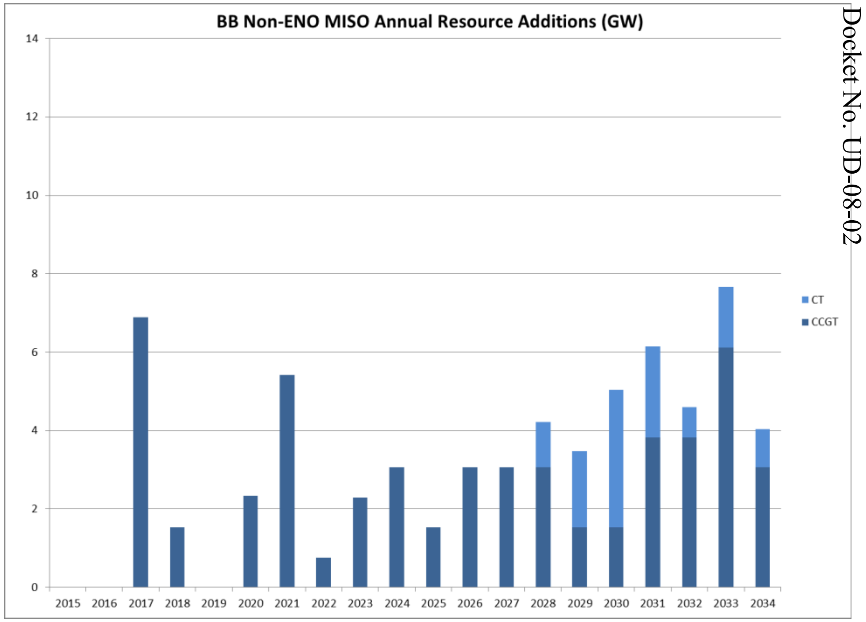
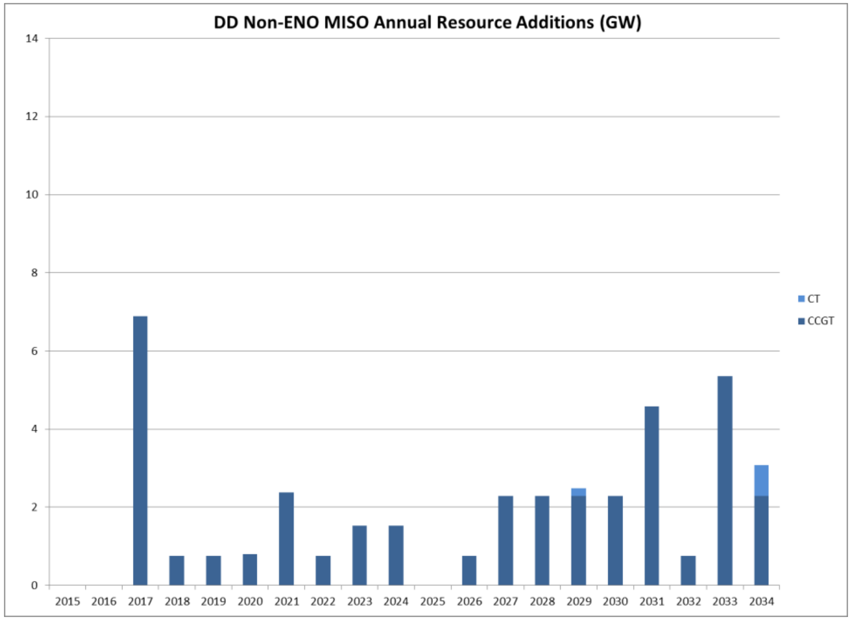
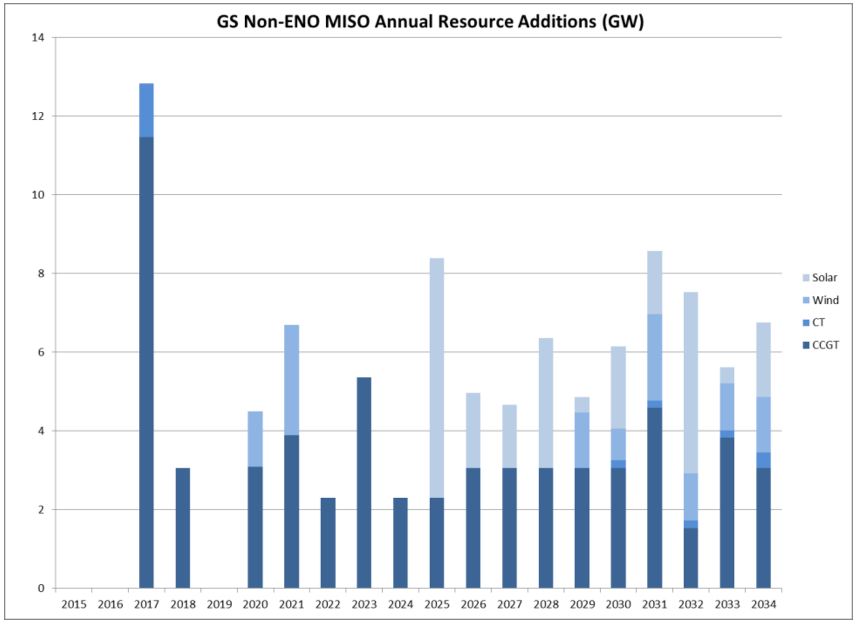
CNO Docket No. UD-08-02

PROJECTED MISO MARKET ADDITIONS BY YEAR







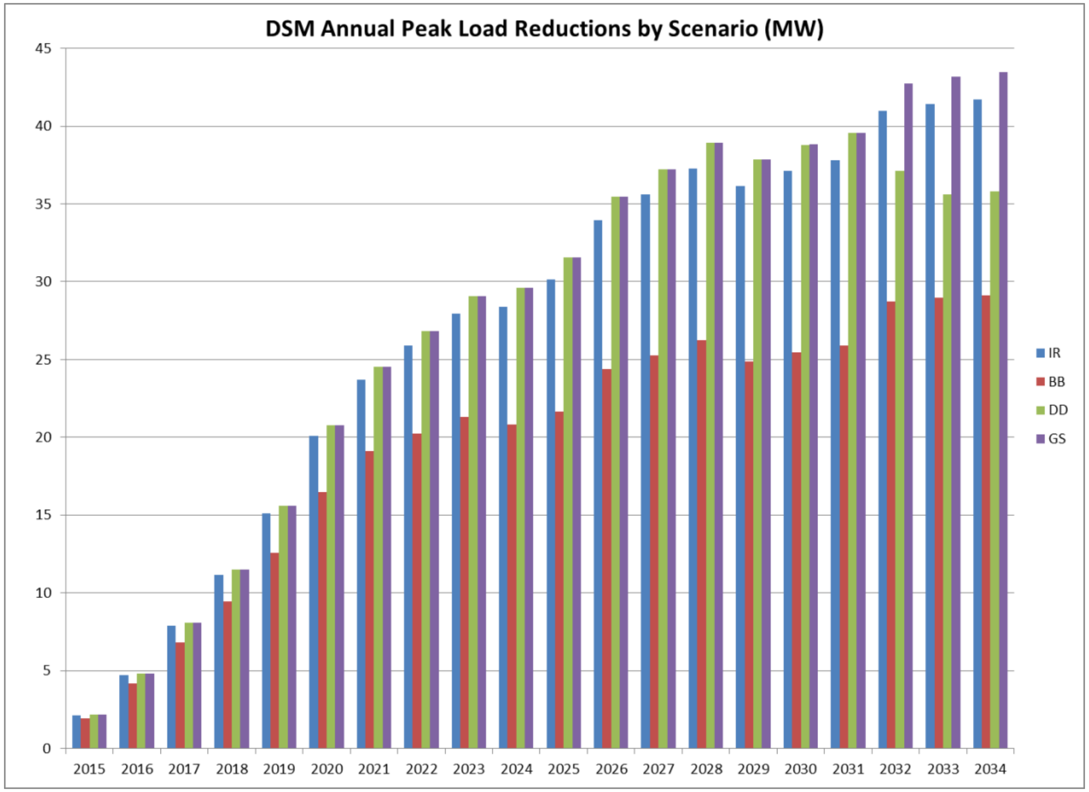


DSM OPTIMIZATION

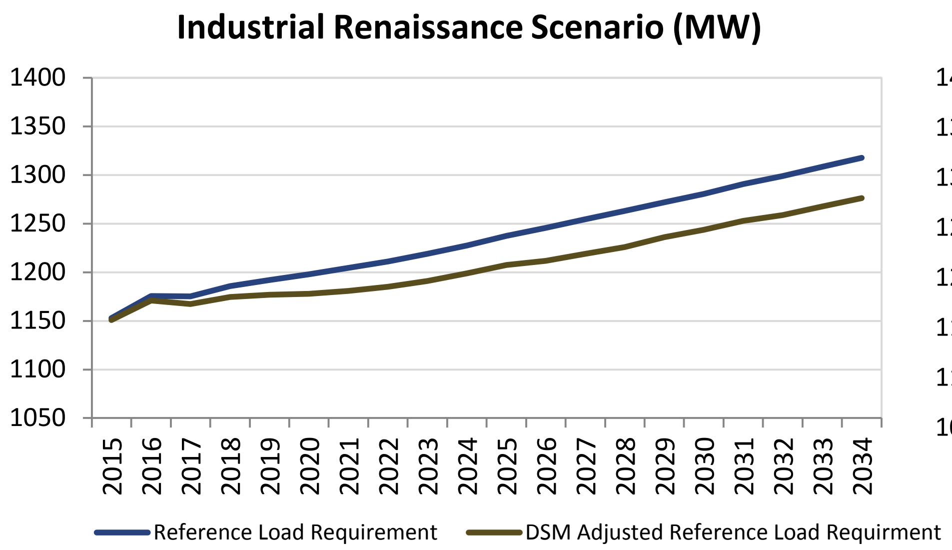
- The AURORA Capacity Expansion Model was used to develop a DSM portfolio for each of the scenarios.
- The result of this process was an optimal DSM portfolio for each scenario.

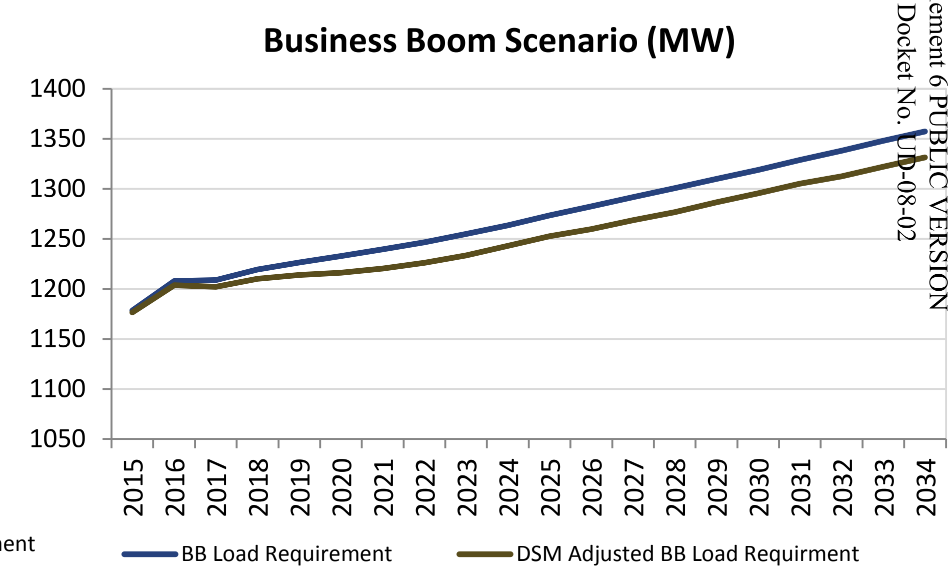
Portfolio Design Mix

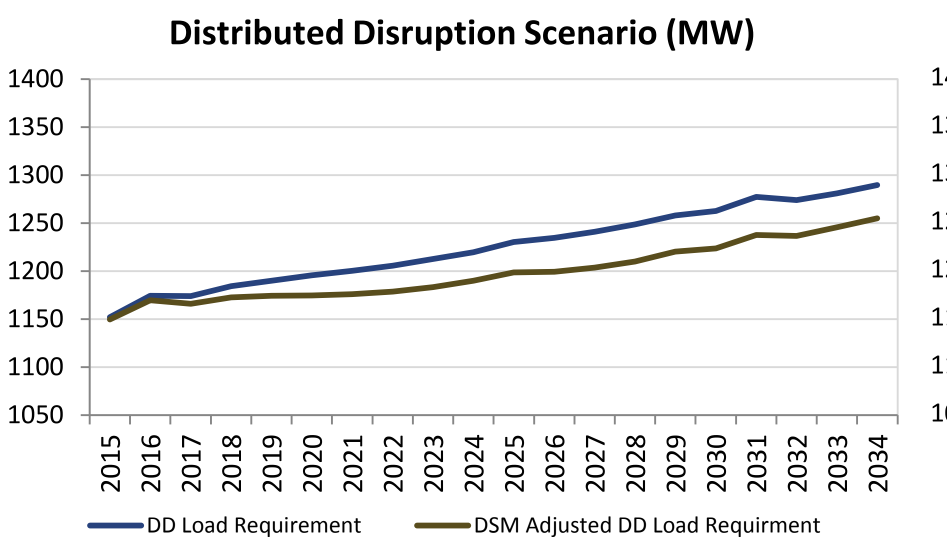
	IR Portfolio	BB Portfolio	DD Portfolio	GS Portfolio
DSM	14 Programs	12 Programs	16 Programs	17 Programs
DSM Maximum (MW)	41	26	40	43

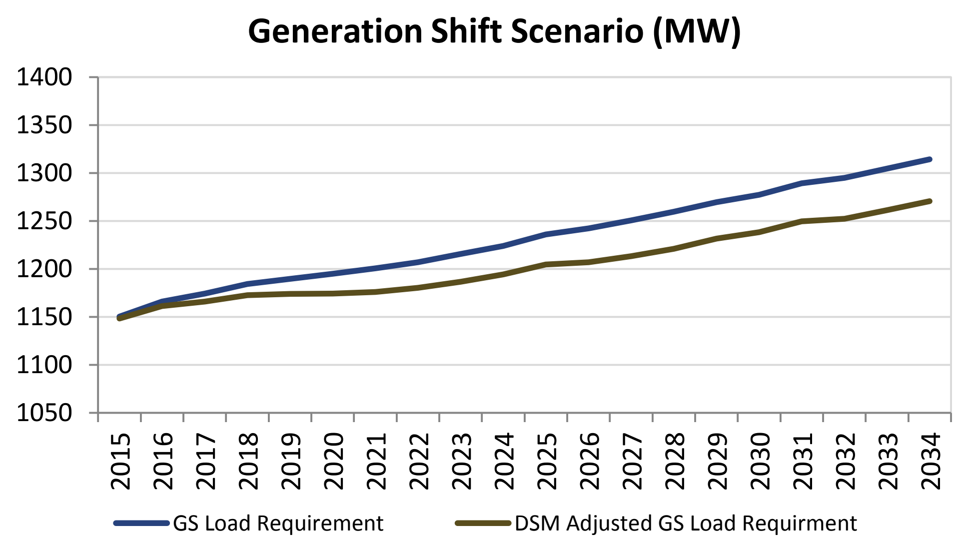


LOAD REQUIREMENTS FOR EACH SCENARIO

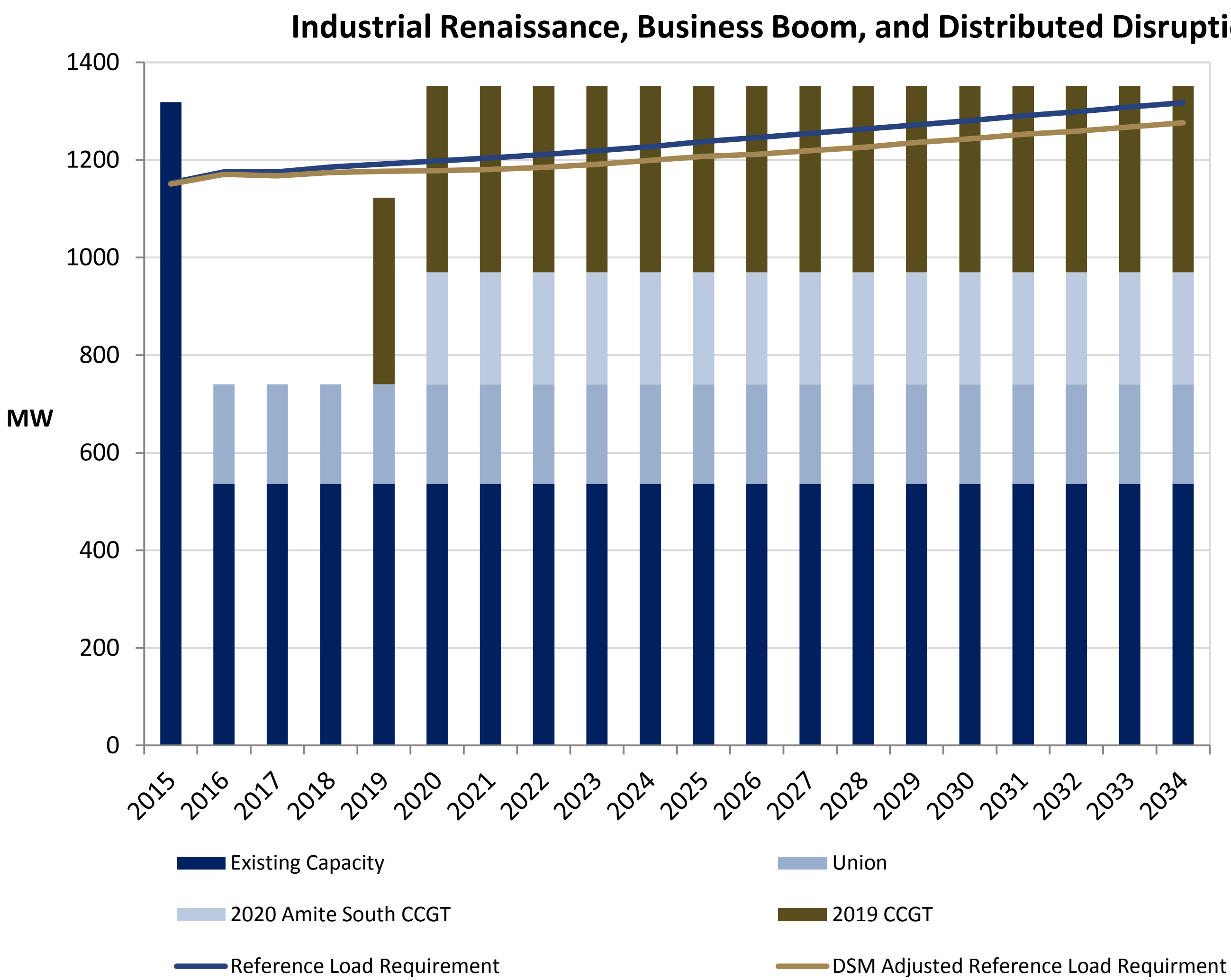








AURORA Capacity Expansion - Supply Side Portfolios



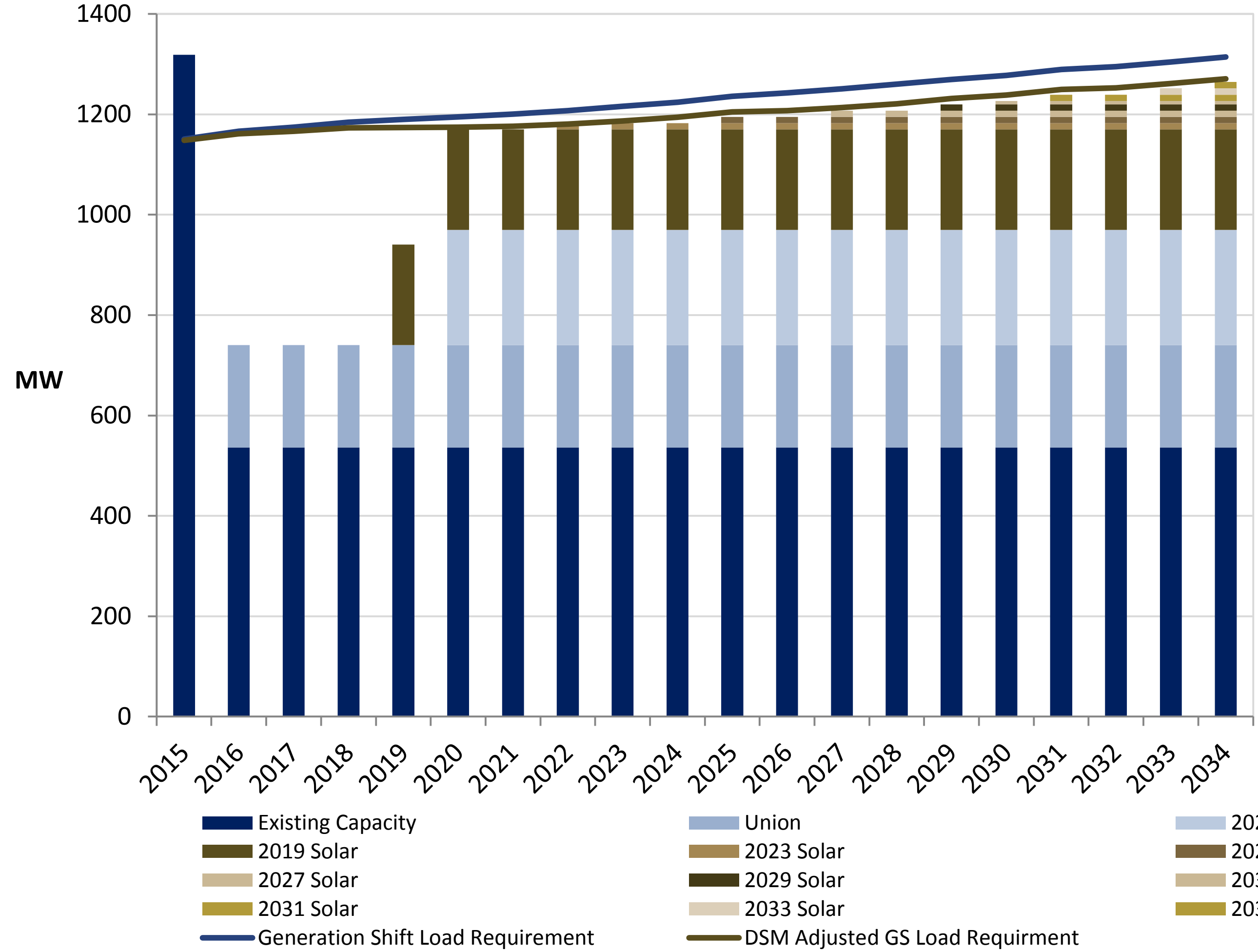
Resource Addition	Capacity (MW)
2019 CCGT	382

*Resources listed in blue are existing and planned resources. Resources additions listed in brown are the resources to be evaluated in the IRP.

Preliminary – Work in Progress

AURORA Capacity Expansion - Supply Side Portfolios

Generation Shift Portfolio

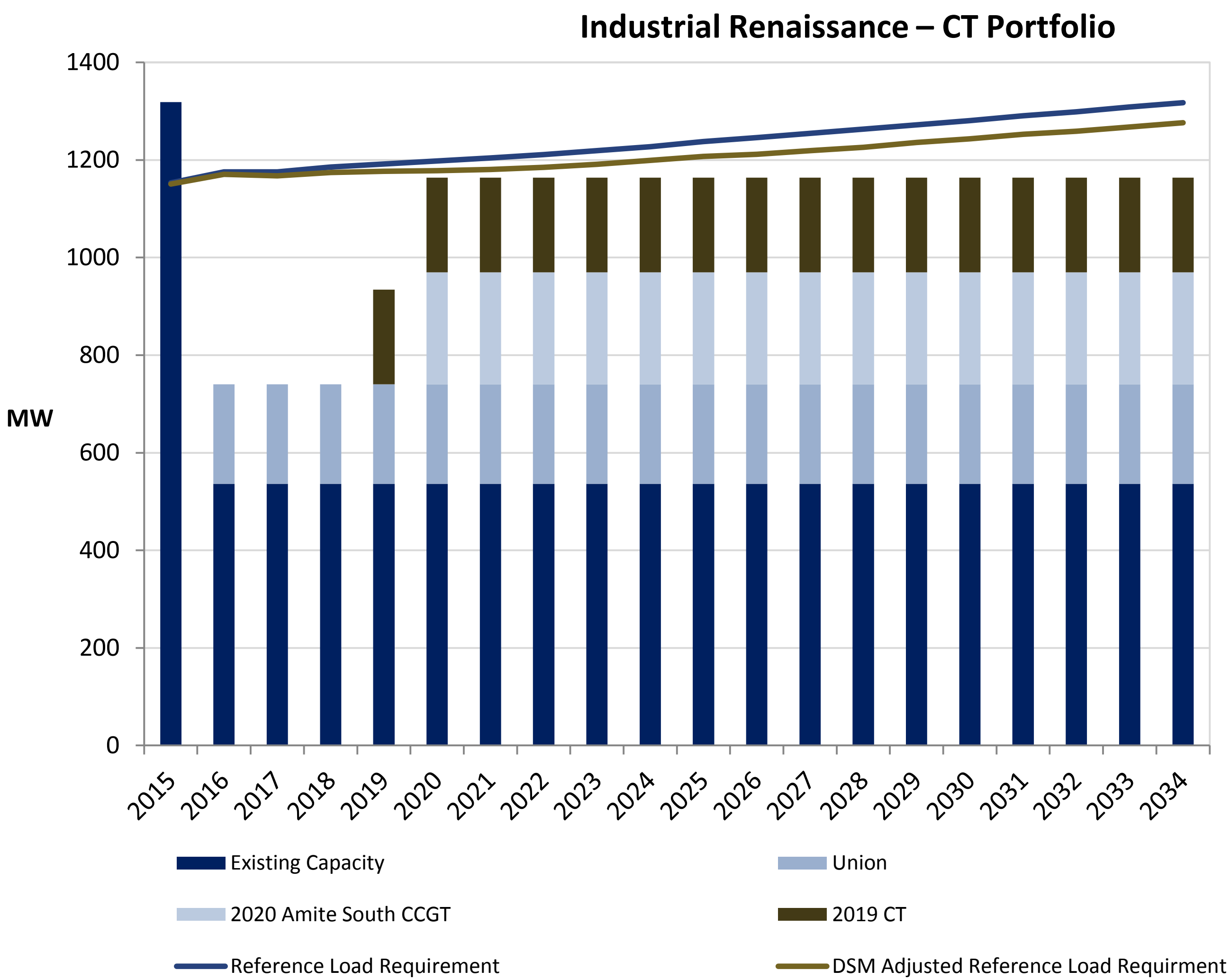


Resource Addition	Capacity (MW)	Effective Capacity (MW)
2019 Solar	800	200
2023 Solar	50	12.5
2025 Solar	50	12.5
2027 Solar	50	12.5
2029 Solar	50	12.5
2030 Wind	50	7
2031 Solar	50	12.5
2033 Solar	50	12.5
2034 Solar	50	12.5

*Resources listed in blue are existing and planned resources. Resources additions listed in brown are the resources to be evaluated in the IRP.

Preliminary – Work in Progress

MANUAL PORTFOLIOS - SUPPLY SIDE PORTFOLIOS

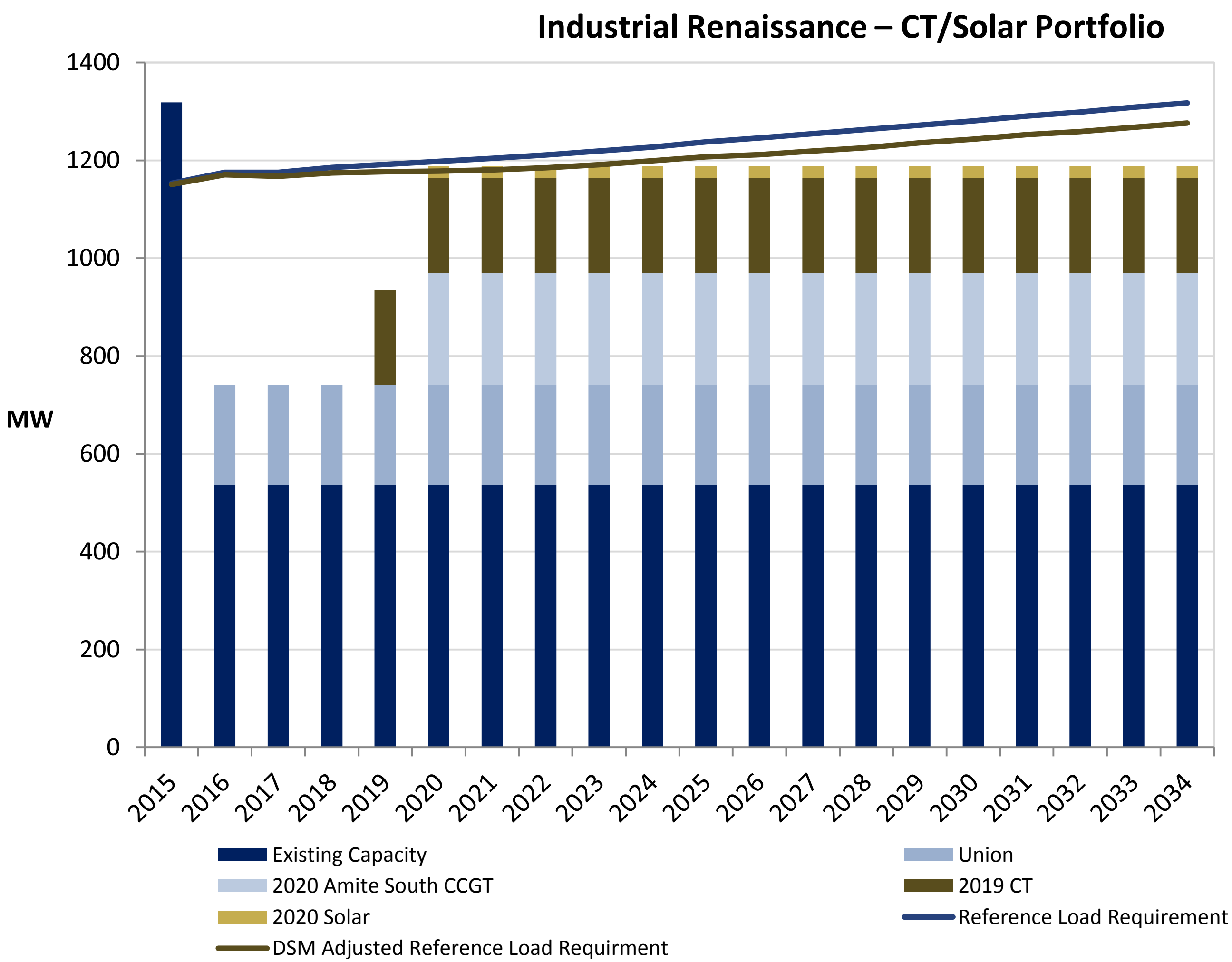


Resource Addition	Capacity (MW)
2019 CT	194

*Resources listed in blue are existing and planned resources. Resources additions listed in brown are the resources to be evaluated in the IRP.

Preliminary – Work in Progress

MANUAL PORTFOLIOS - SUPPLY SIDE PORTFOLIOS

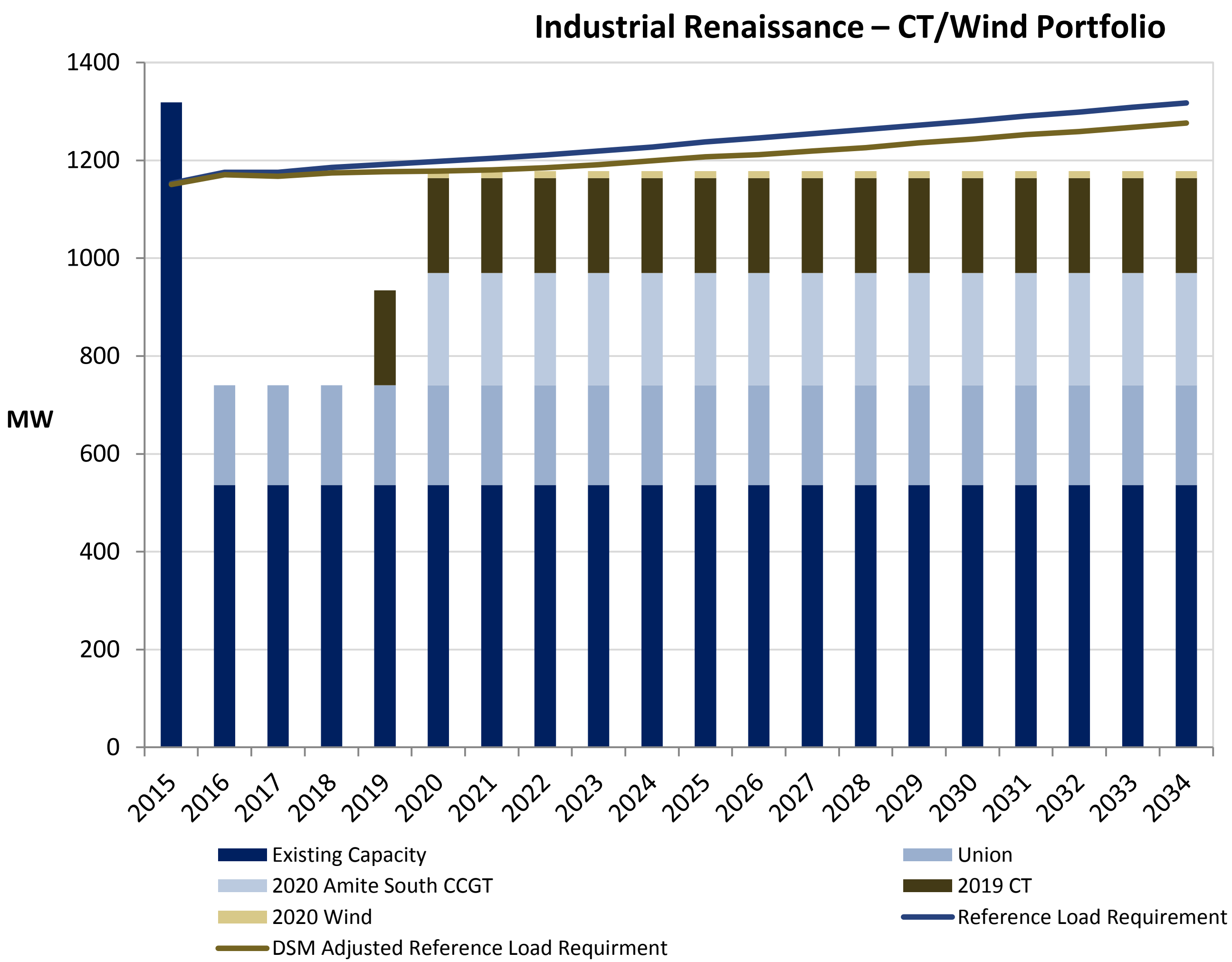


Resource Addition	Capacit y (MW)	Effective Capacity (MW)
2019 CT	194	194
2020 Solar	100	25

*Resources listed in blue are existing and planned resources. Resources additions listed in brown are the resources to be evaluated in the IRP.

Preliminary – Work in Progress

Manual Portfolios - Supply Side Portfolios

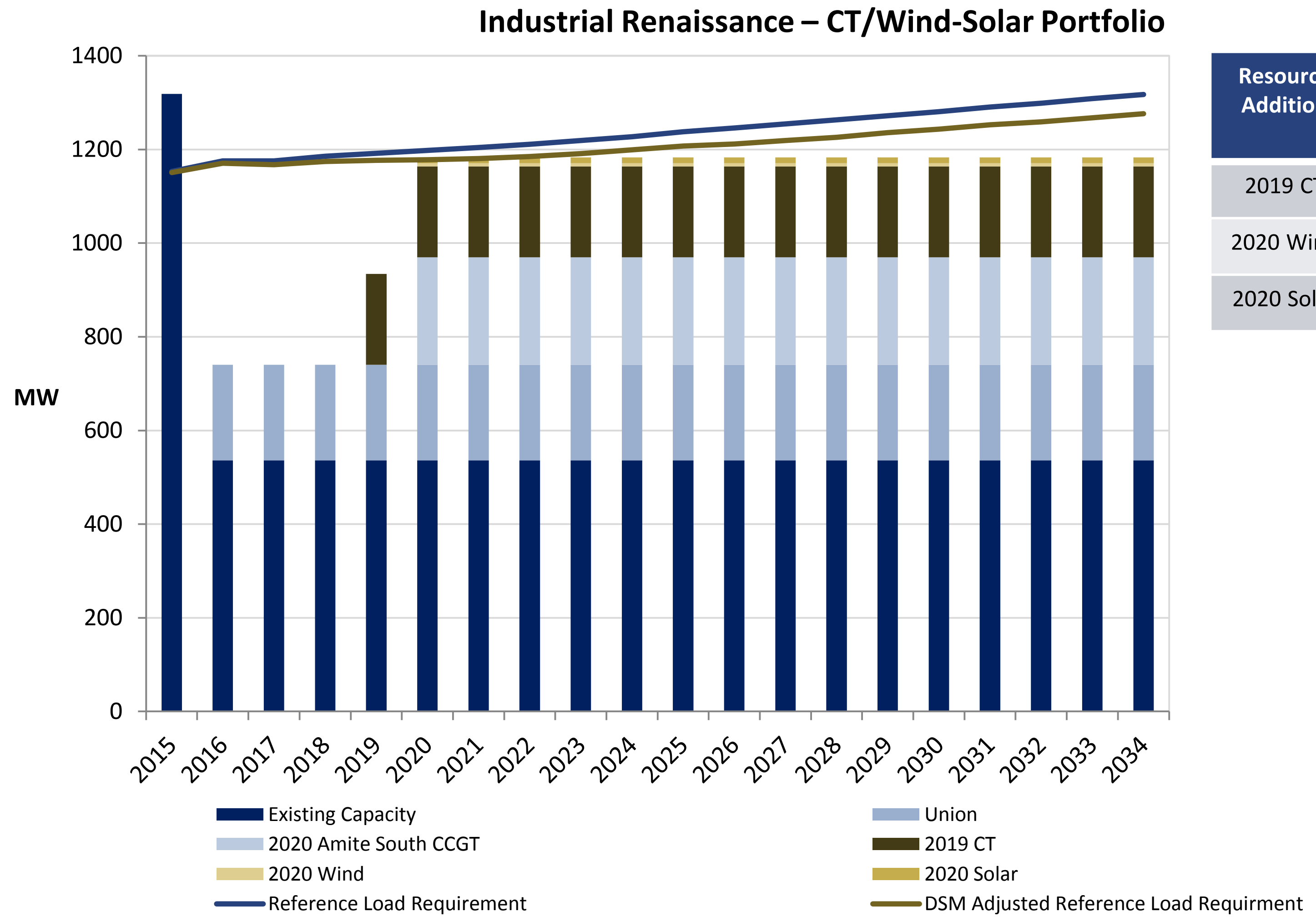


Resource Addition	Capacit y (MW)	Effective Capacity (MW)
2019 CT	194	194
2020 Wind	100	14

*Resources listed in blue are existing and planned resources. Resources additions listed in brown are the resources to be evaluated in the IRP.

Preliminary – Work in Progress

Manual Portfolios - Supply Side Portfolios

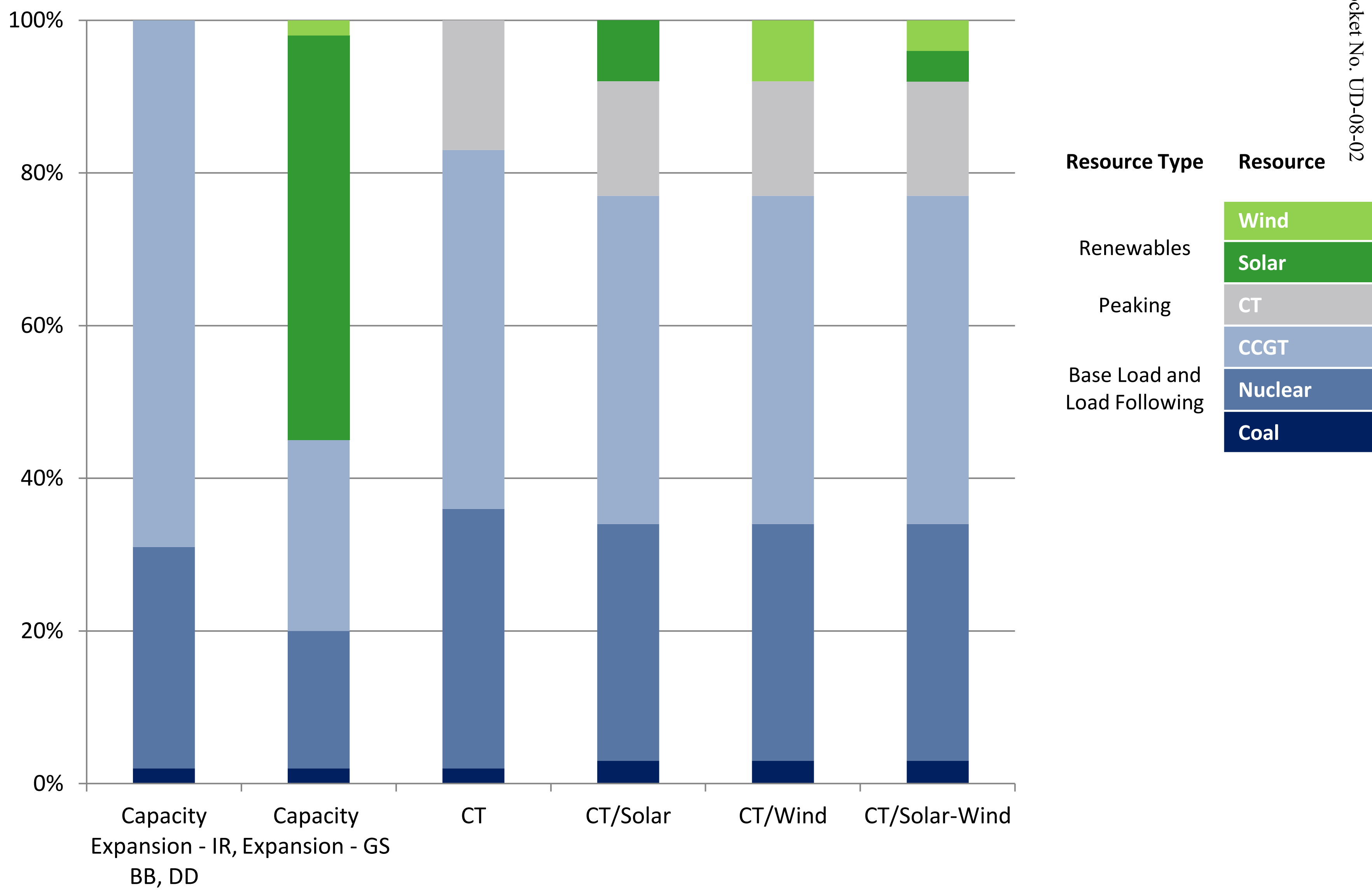


Resource Addition	Capacit y (MW)	Effective Capacity (MW)
2019 CT	194	194
2020 Wind	50	7
2020 Solar	50	12.5

*Resources listed in blue are existing and planned resources. Resources additions listed in brown are the resources to be evaluated in the IRP.

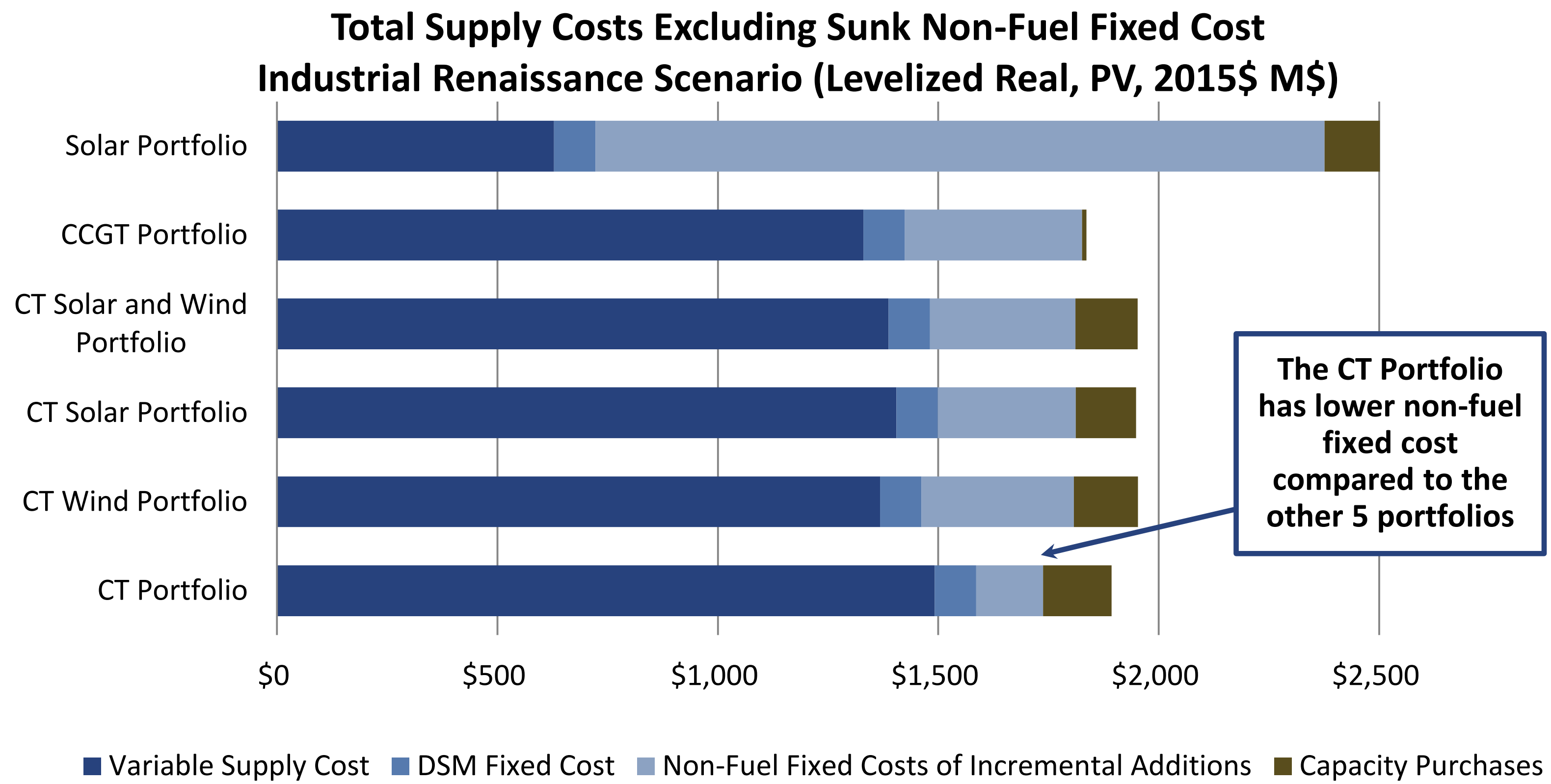
Preliminary – Work in Progress

INSTALLED CAPACITY MIX OF EACH PORTFOLIO IN 2034



PORTFOLIO COSTS & SENSITIVITIES

TOTAL SUPPLY COST COMPONENTS EXCLUDING SUNK NON-FUEL FIXED COST



Total Supply Costs Excluding Sunk Non-fuel Fixed Costs

Variable Supply Costs
+ DSM Fixed Costs
+ Non Fuel Fixed Costs of Incremental Additions
+ Capacity Purchases
+ Production Tax Credits (PTC) and Investment Tax Credit (ITC) (only included in the GS Scenario)

PORTFOLIO TOTAL SUPPLY COSTS

The CT Portfolio performs well in most scenarios, has lower risk, and complements ENO's existing portfolio

- The CCGT Portfolio ranks high, but has more risk because of higher fixed cost being offset by uncertain potential variable cost savings
- The Solar Portfolio is highly ranked in the Generation Shift Scenario due to continuation of ICT subsidiaries, high gas prices, and high CO2 prices, but ranks lowest in each of the other scenarios
- The addition of Wind and/or Solar to the CT Portfolio is only beneficial in the Generation Shift Scenario

Total Cost by Scenario
Levelized Real ($M)

Portfolios

	Ref - IR	*BB*	*DD*	*GS*
CT	$1,893	$1,687	$1,837	$2,374
CT Wind	$1,952	$1,765	$1,885	$2,310
CT Solar	$1,949	$1,756	$1,889	$2,343
CT Solar_Wind	$1,951	$1,760	$1,887	$2,326
CCGT	***$1,836***	***$1,538***	***$1,754***	$2,228
Solar	$2,501	$2,432	$2,403	***$2,100***

Ranking by Scenario

	Ref - IR	*BB*	*DD*	*GS*
CT	2	2	2	6
CT Wind	5	5	3	3
CT Solar	3	3	5	5
CT Solar_Wind	4	4	4	4
CCGT	***1***	***1***	***1***	2
Solar	6	6	6	***1***

Variance ($M)
relative to highest ranked portfolio

	Ref - IR	*BB*	*DD*	*GS*
CT	$57	$148	$84	$275
CT Wind	$116	$226	$132	$210
CT Solar	$113	$217	$135	$243
CT Solar_Wind	$114	$222	$133	$226
CCGT	***$0***	***$0***	***$0***	$128
Solar	$665	$893	$649	***$0***

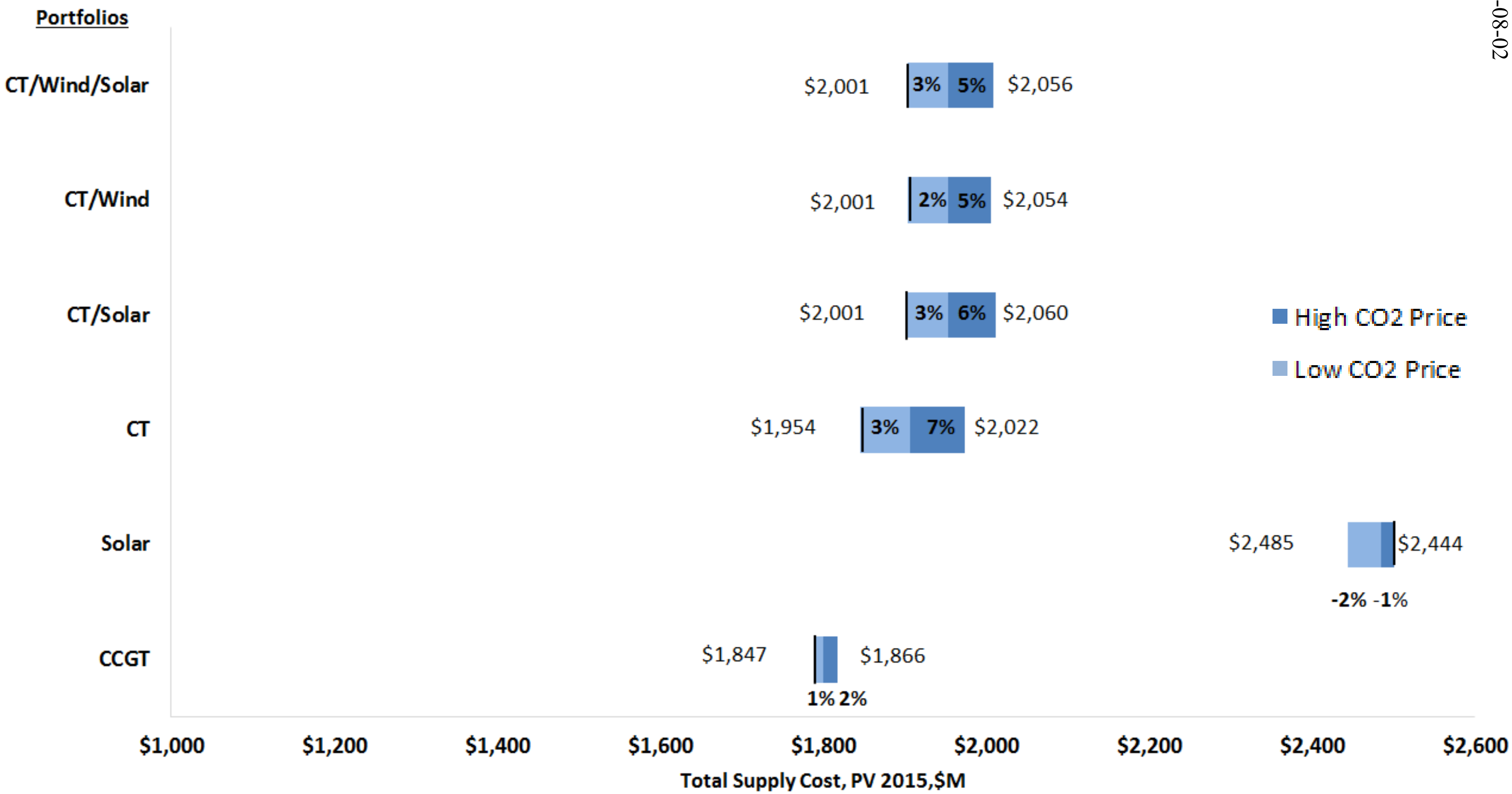
Although the CCGT and Solar Portfolios rank higher on a total cost basis, the CT Portfolio presents less risk while providing good economic performance.

Reference – IR Scenario Sensitivity: Natural Gas (PV $2015, $M)

Although the Solar Portfolio is less volatile, it is more costly than the other portfolios. The CCGT and CT Portfolios are similarly affected by changes in gas price assumptions.

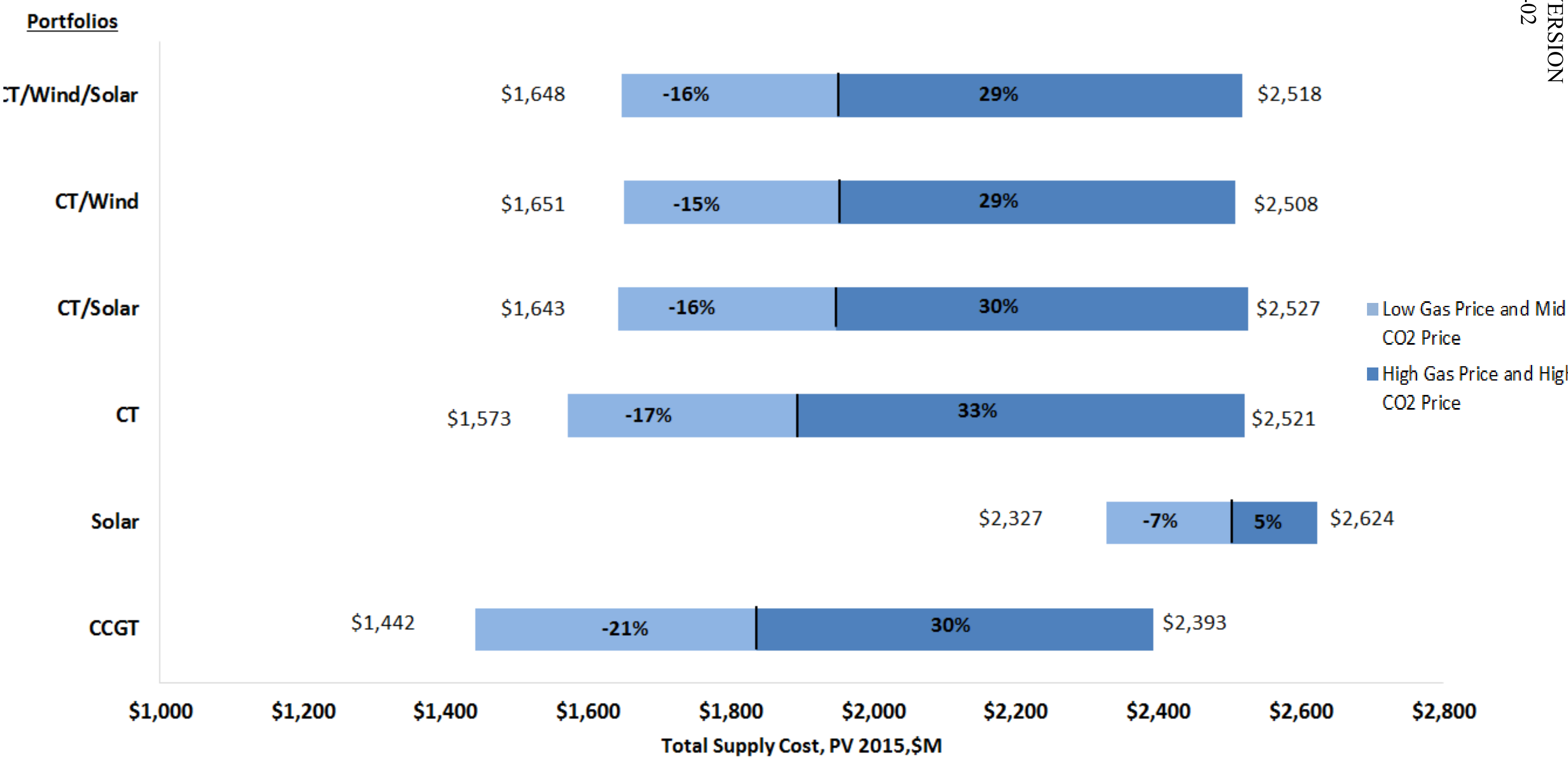
REFERENCE – IR SCENARIO SENSITIVITY: CO_2 (PV $2015, $M)

The CCGT Portfolio is relatively less affected by changes in carbon price assumptions; however, ENO existing portfolio is expected to have adequate Base Load and Core Load Following capacity.



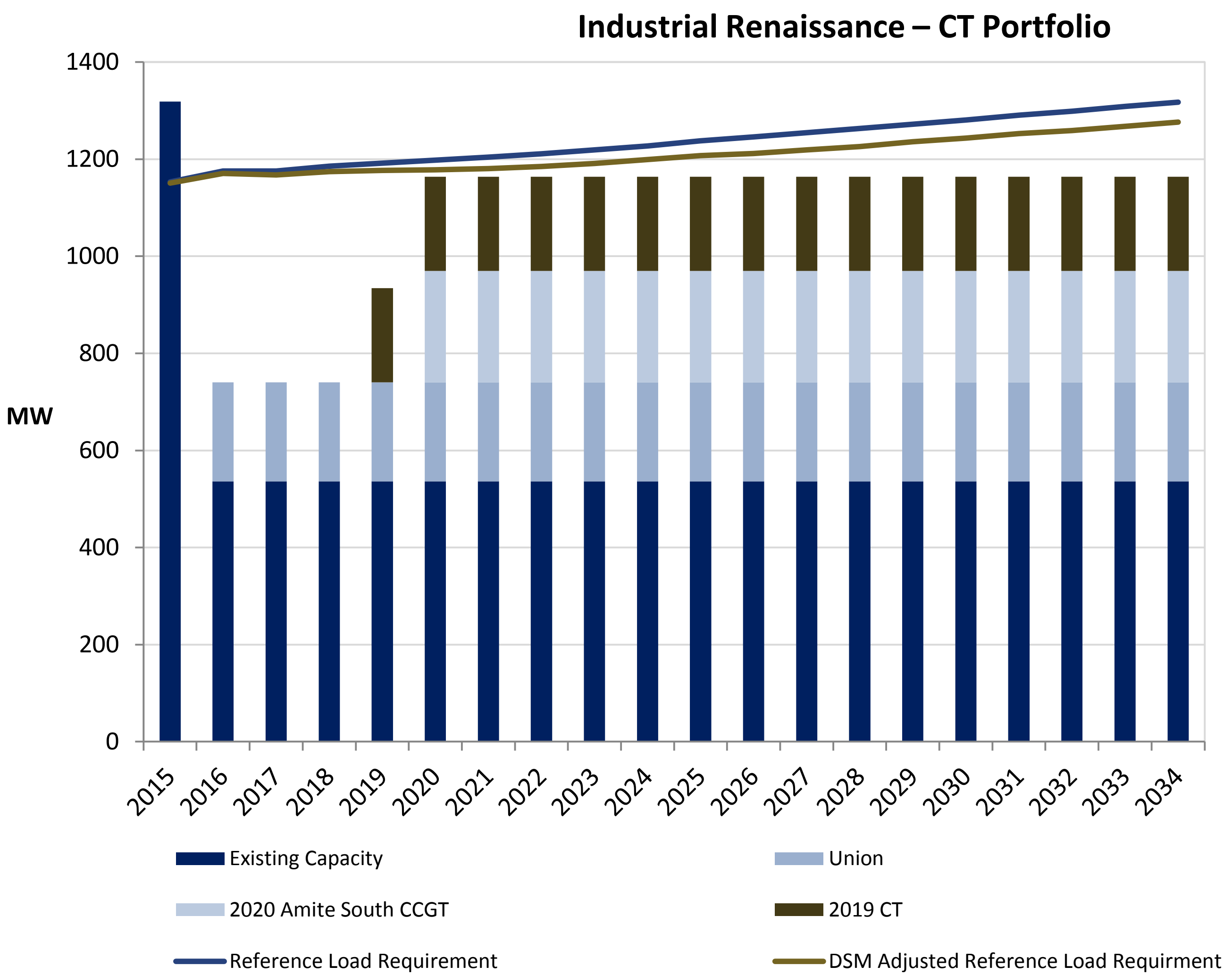
REFERENCE – IR SCENARIO SENSITIVITY: NATURAL GAS AND CO_2 (PV \$2015, \$M)

Although the Solar Portfolio is less volatile, it is more costly than the other portfolios. The CCGT and CT Portfolios are similarly affected by changes in gas price assumptions.



PREFERRED RESOURCE PLAN

PREFERRED RESOURCE PLAN



Resource Addition	Capacity (MW)
2019 CT	194

*Resources listed in blue are existing and planned resources. Resources additions listed in brown are the resources to be evaluated in the IRP.

Preliminary – Work in Progress

LOAD AND CAPABILITY OF ENO'S PREFERRED RESOURCE PLAN

Load & Capability 2015—2034

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Requirements																				
Peak Load	1,029	1,050	1,049	1,059	1,064	1,070	1,075	1,081	1,088	1,096	1,105	1,112	1,120	1,128	1,136	1,143	1,152	1,160	1,168	1,176
Reserve Margin (12%)	124	126	126	127	128	128	129	130	131	132	133	133	134	135	136	137	138	139	1401	141
Total Requirements	1,153	1,176	1,175	1,186	1,192	1,198	1,204	1,211	1,219	1,227	1,238	1,246	1,254	1,263	1,272	1,281	1,291	1,299	1,308	1,318
Resources																				
Existing Resources																				
Owned Resources	1,318	537	537	537	537	537	537	537	537	537	537	537	537	537	537	537	537	537	537	537
PPA Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LMRs	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Identified Planned Resources																				
Union	-	204	204	204	204	204	204	204	204	204	204	204	204	204	204	204	204	204	204	204
Amite South CCGT	-	-	-	-	-	229	229	229	229	229	229	229	229	229	229	229	229	229	229	229
Other Planned Resources																				
DSM	2	5	9	12	17	23	27	29	31	32	34	38	40	42	40	42	42	45	46	46
CT	-	-	-	-	194	194	194	194	194	194	194	194	194	194	194	194	194	194	194	194
Market Purchases	-	430	426	433	240	12	14	18	24	32	40	44	51	58	68	75	85	90	99	108
Total Resources	1,320	1,176	1,175	1,186	1,192	1,198	1,204	1,211	1,219	1,227	1,238	1,246	1,254	1,263	1,272	1,281	1,291	1,299	1,308	1,318

[1] Union plant acquisition is completed pending regulatory approvals.
[2] ENO share of the Amite South RFP is presently estimated at 229 MW. RFP responses are currently being evaluated. As a result, actual capacity may exceed 560 MW.
[3] Demand Side Management (DSM) total is grossed up for Planning Reserve Margin (12%) and transmission losses (2.4%).

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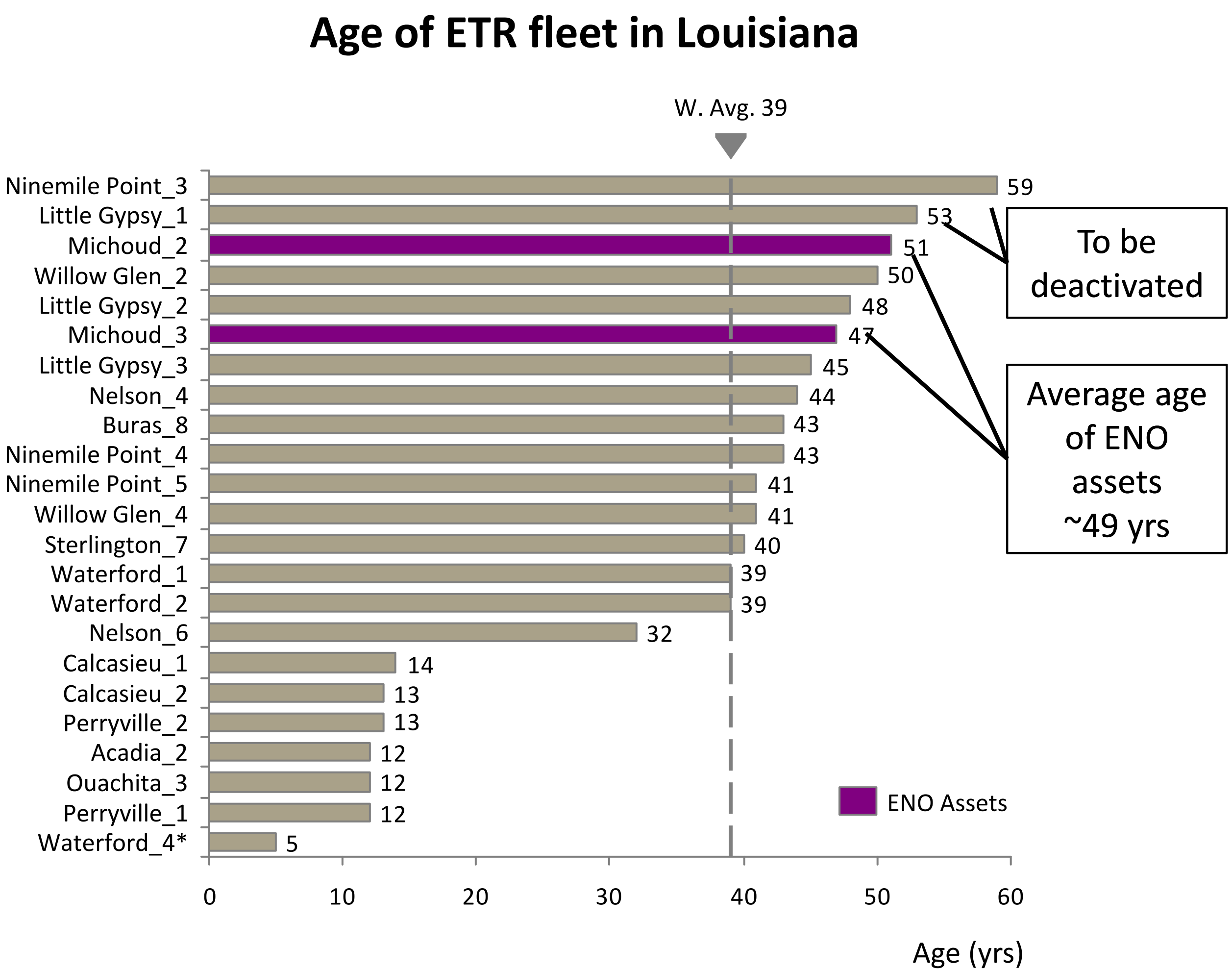
Planning to meet future needs must consider unit age and condition

Michoud 2 & 3 are among the oldest units in ETR's Louisiana fleet



Michoud 2 & 3 among the oldest active units in Entergy's Louisiana fleet

Michoud 2 & 3 are significantly older than the avg. age of the Louisiana fleet

Two units older than Michoud 2 already slated for deactivation

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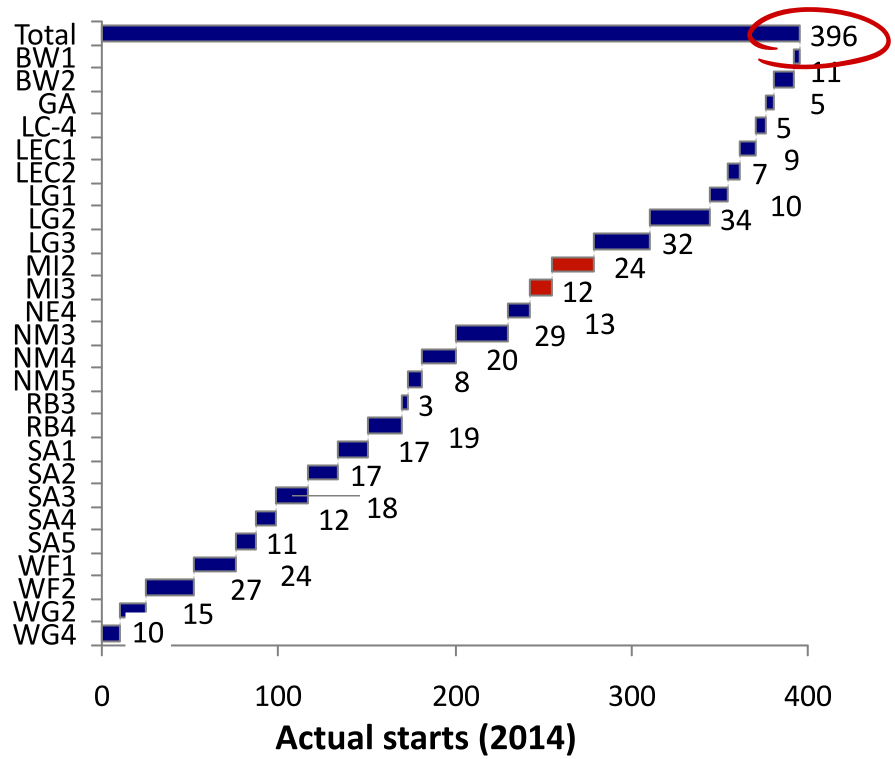
Steam generating fleet cycled more frequently in 2014



Year	2010	2011	2012	2013	2014
Steam unit start-stop cycles	246	236	227	216	396

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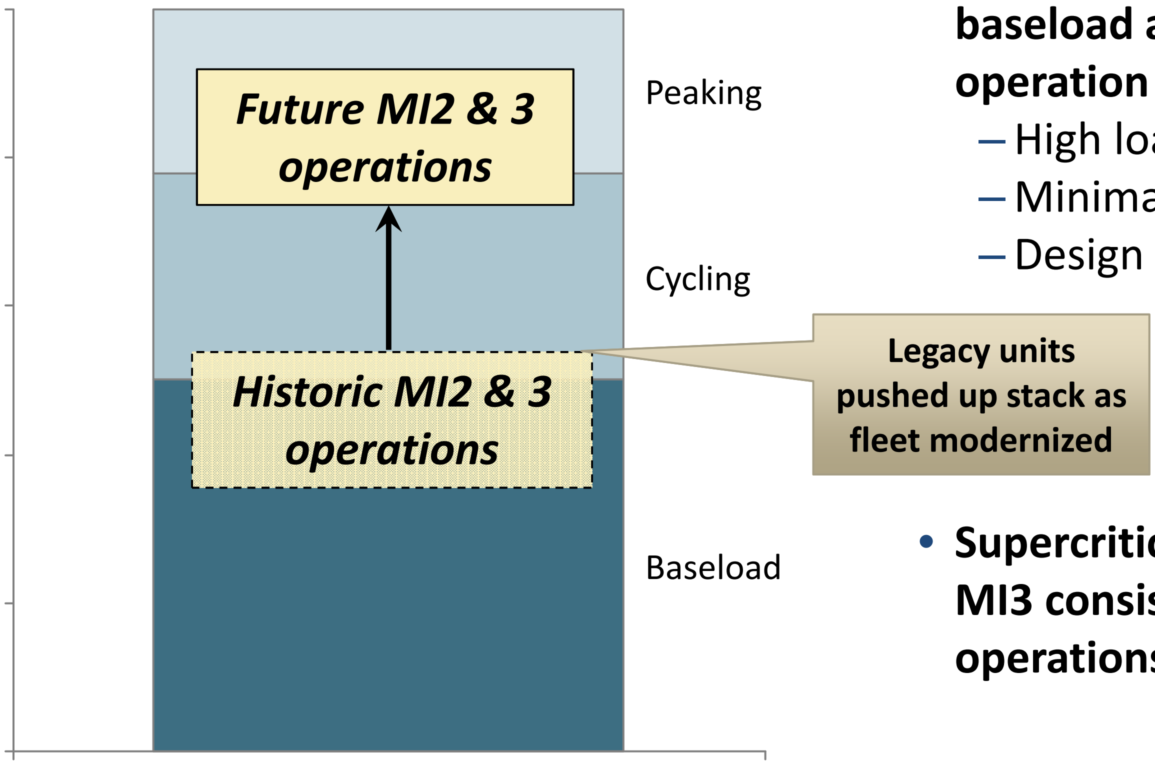
Entergy

Future dispatch of MI2 and MI3 driven by relative efficiency

Increased cycling will push the units beyond design basis as they near end of useful life

Projected increase in cycling consistent with peaking operational role…

Generation Capacity (MW)



…in contrast to original design basis

- **Michoud 2 & 3 were designed for baseload and load-following operation**
  - High load factor
  - Minimal starts per year
  - Design cycle efficiency
- **Supercritical pressure design basis of MI3 consistent with baseload operations**

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Overview of Michoud 2 (MI2)

Status and operational design characteristics

Unit 2 Facility Details	
Age	51 years (in operation since 1963)
Max. capacity	239 MW (Rankine cycle)
Technology overview	Steam Turbine and Drum Boiler: Drum style sub-critical pressure steam generator designed by Riley Stoker. The steam turbine is a General Electric Model F10 tandem-compound unit
Fuel	Natural gas (previously capable of co-fired gas / oil)
Current Role	Intermediate annual must-run
Heat Rate (5 year avg.)	10,960 Btu / kWh
Start-stops (5 year avg.)	10 start-stops / year
Operational context	• Run in brackish water environment • Units were flooded during Katrina in 2005 • Transmission interconnection – 115kV

Among the oldest assets in the ETR fossil fleet

Steam turbine technology – approaching asset design life

Relatively high heat rate versus newer technologies

Operating in challenging environmental conditions

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MI2 would require significant refurbishment to continue to operate reliably

Specific Examples Include…

Condenser Condition

Phase I Condenser Tube sheet Replacement

Extensive condenser tube sheet cracking and tube wall thinning due to corrosion

Cast iron water boxes have to be mechanically patched – patches are not reliable.

Generator Rotor risk increasing

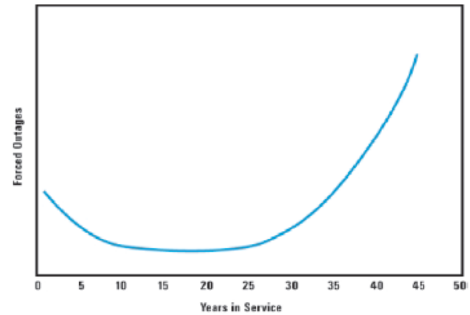


Figure 2a. Turbine-generator reliability trend

"Unit 2 has accumulated approximately 350,000 operating hours, or about 40 operating years through early October 2010. Increasing risk of rotor failure.

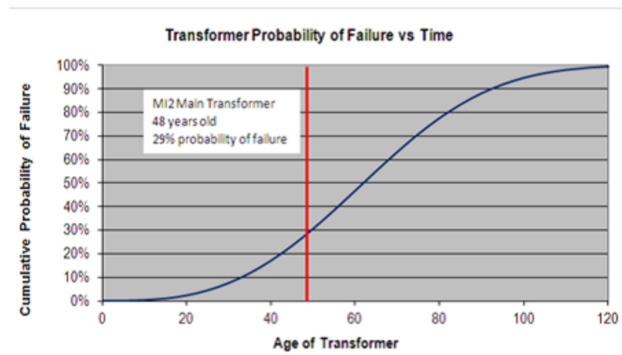
High Pressure Boiler Component Condition

Phase II Economizer Inlet Header Replacement

Figure 3.8: Economizer Inlet Header Closer View of Header Nipple Weld and Tube Surface Conditions

Figure 3.9: Economizer Inlet Header Assembly 2 Tube B Tube Stub Through-Wall Crack (Refer to Subsequent Figure 3.10)

Transformer failure risk is increasing



High risk of transformer failure based on fleet experience.

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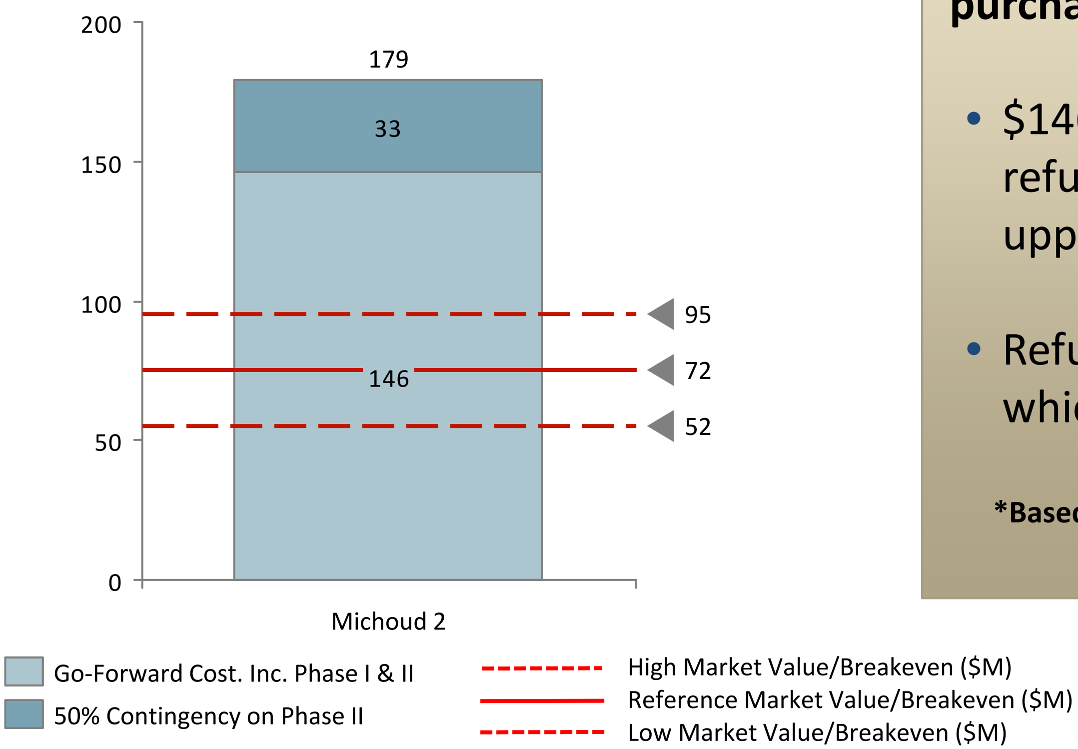
Prior analysis indicated refurbishing MI2 was not economic

Maintaining MI2 more costly than purchasing capacity

Refurbish Rev. Req. vs. capacity market cost (PV, 2013 $M)



Revenue requirement of refurbishing MI2 significantly greater than the cost of purchasing capacity from the MISO market*

- $146M revenue requirement for MI2 refurbishment significantly greater than upper bound of cost to purchase capacity
- Refurbishment could have contingencies which further increase costs

***Based on forecast of MISO Capacity prices over 2013-2026 produced at the time of MI2 analysis**

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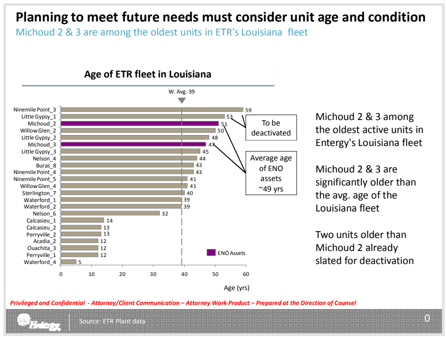
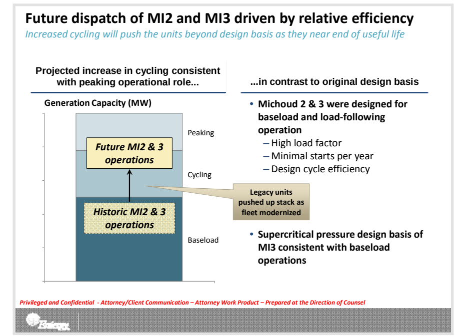
Analysis from multiple dimensions supports the decision to deactivate Michoud 2

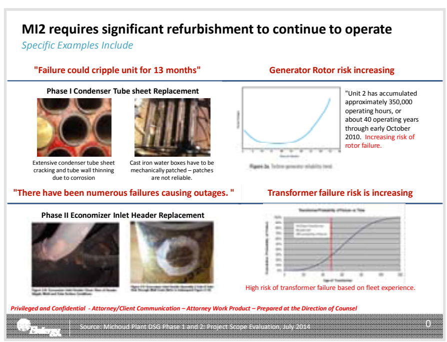
MI2 nearing end of useful life and significantly older than avg for LA fleet



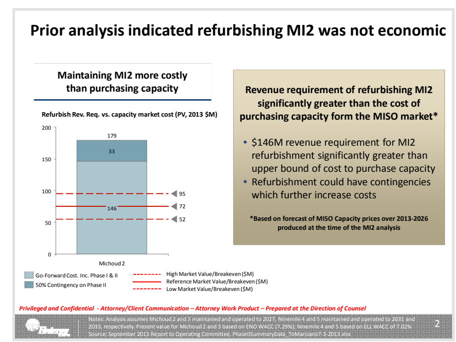
Steam units formerly in load following role may incur higher ongoing cost & reliability fatigue associated with more start up shut down cycles in peaking service



Putting it at increased risk of major component failures and in need of critical repairs



Cost of known repairs are significant and far exceed the near-term projected cost of capacity in MISO



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Overview of Michoud 3 (MI3)

Status and operational design characteristics

Unit 3 Facility Details	
Age	47 years (in operation since 1967)
Max. capacity	542 MW (Rankine cycle)
Technology overview	Steam Turbine and Supercritical Boiler: Once-through supercritical steam generator Steam turbine is a GE tandem-compound unit
Fuel	Natural gas (previously capable of co-fired gas / oil)
Current Role	Intermediate annual must-run
Heat Rate (5 year avg.)	11,520 Btu / kWh
Start-stops (5 year avg.)	12 start-stops / year
Operational context	• Run in brackish water environment • Units were flooded during Katrina in 2005 • Transmission interconnection – 230kV

Among the oldest assets in the ETR fossil fleet

Steam turbine technology – approaching asset design life

Relatively high heat rate versus newer technologies

Operating in challenging environmental conditions

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MI3 major components exhibit high risk of failure

Basic Infrastructure

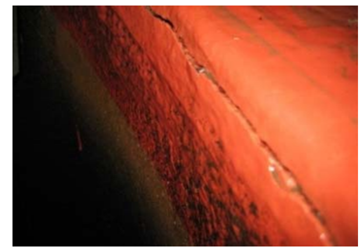
Boiler stack

Broken radial angle iron, failed seam weld


Major Pumps

Circulating water pump casings

Discharge joint cracking, temporary epoxy

Boiler Pressure Parts

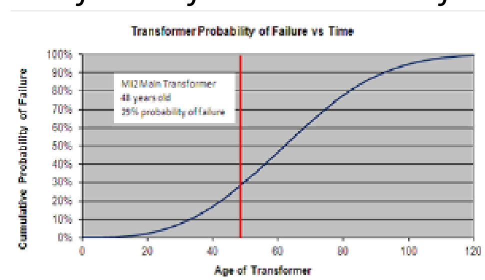
Finishing superheater elements & headers

Bore hole cracking, areas of exfoliation & indication

Transformer failure risk is increasing

Main Transformer

High risk of transformer failure based on fleet experience



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Ongoing risk of unknowns in aging, heavily utilized unit

Example: Routine LP Rotor inspection identified need for replacement

Routine inspections continue to identify additional issues...

- LP turbine rotor deterioration found during scheduled turbine inspection
- Due to limited testing capability, prior inspections by GE did not indicate that corrosion pitting was significant
- Subsequent maintenance allowed for more detailed inspection finding corrosion pitting had accelerated beyond previous test results

Figure 8: Entergy Michoud LPA - Removing Buckets

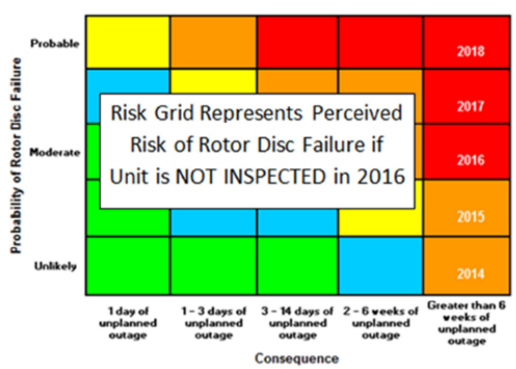
Figure 9: Entergy Michoud LPA - As Found Dovetails

... which were not factored in previous URS and EPRI cost studies

"...a disc failure can result in a complete bucket liberation and catastrophic failure. This **failure could result in significant damage to downstream buckets and stationary components and pose significant safety risks for plant personnel**."

– Fleet Maintenance , Jan. 2014

Estimated replacement cost: ~$25 million



LP rotor replacement driving timing of MI3 deactivation in 2016

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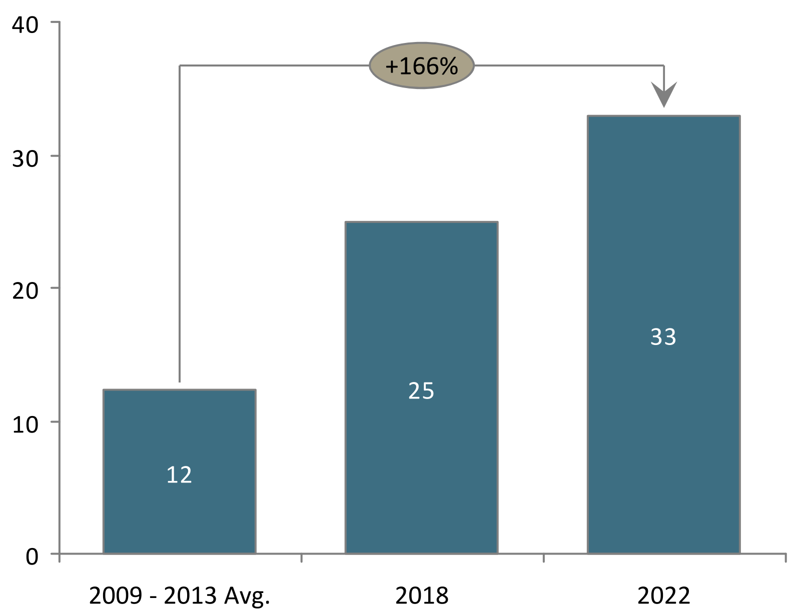
Future dispatch of MI3 driven by relative efficiency

MI3 expected to cycle more frequently over time as generating fleet is modernized

Significant projected increase in cycling of Michoud 3...

Projected annual start-stops for Michoud 3



...leading to uncertainty in the cost to operate and maintain MI3

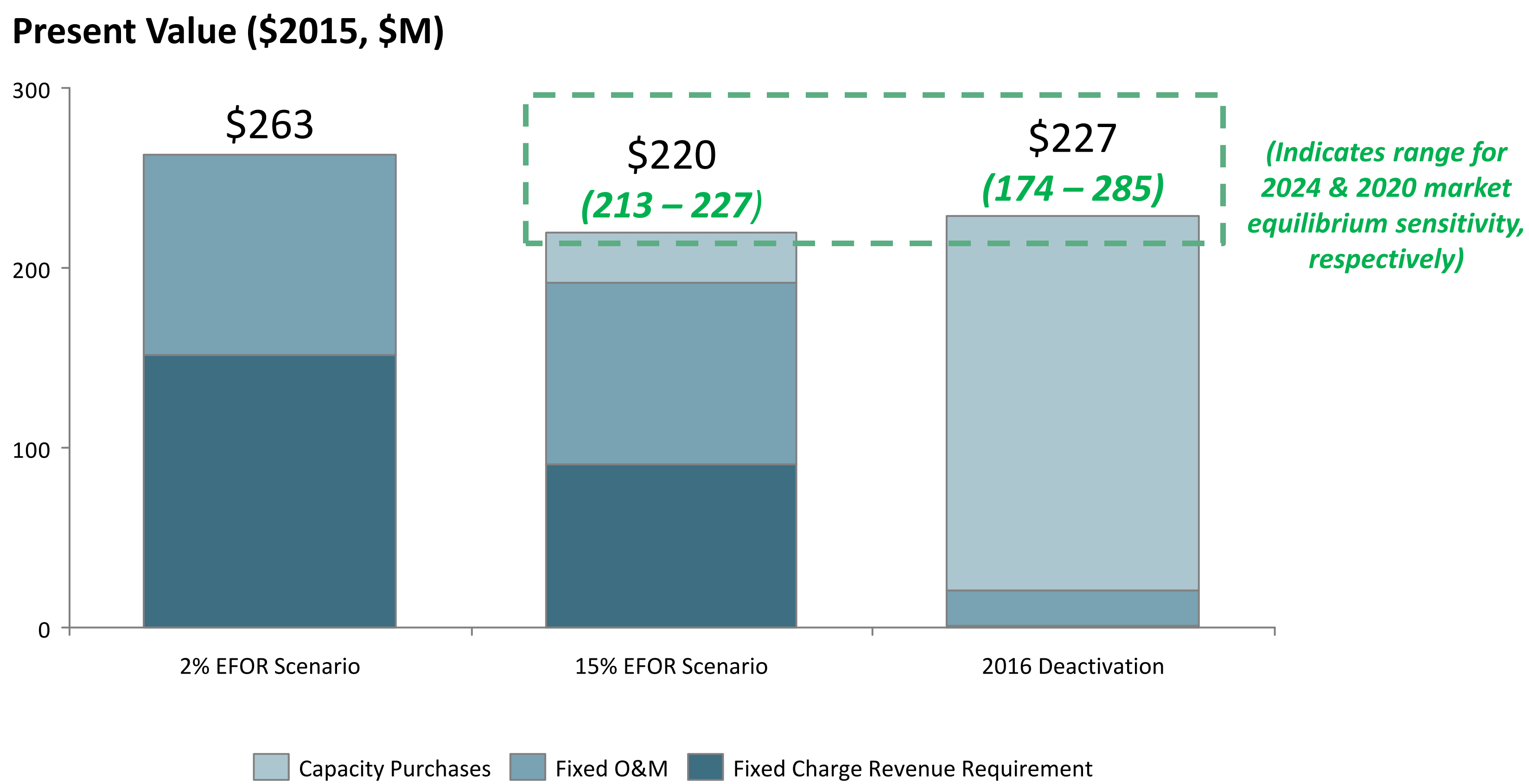
- **Potential consequences of ~2.5x increase in cycling per year**
  - Acceleration of major component deterioration
  - Need to repair/replace unidentified components
  - Increase in cost to operate and maintain
  - Increased forced outage rate / derates

- **Risks associated with these consequences**
  - Volatility in O&M cost
  - Exposure to the real-time energy market
  - Ability to recover production costs in MISO market

MI3 being asked to 'do more' as it nears the end of useful life

Economics of MI3 refurbishment vs. deactivation comparable…

Cost to deactivate MI3 in line with cost to refurbish at 15% EFOR



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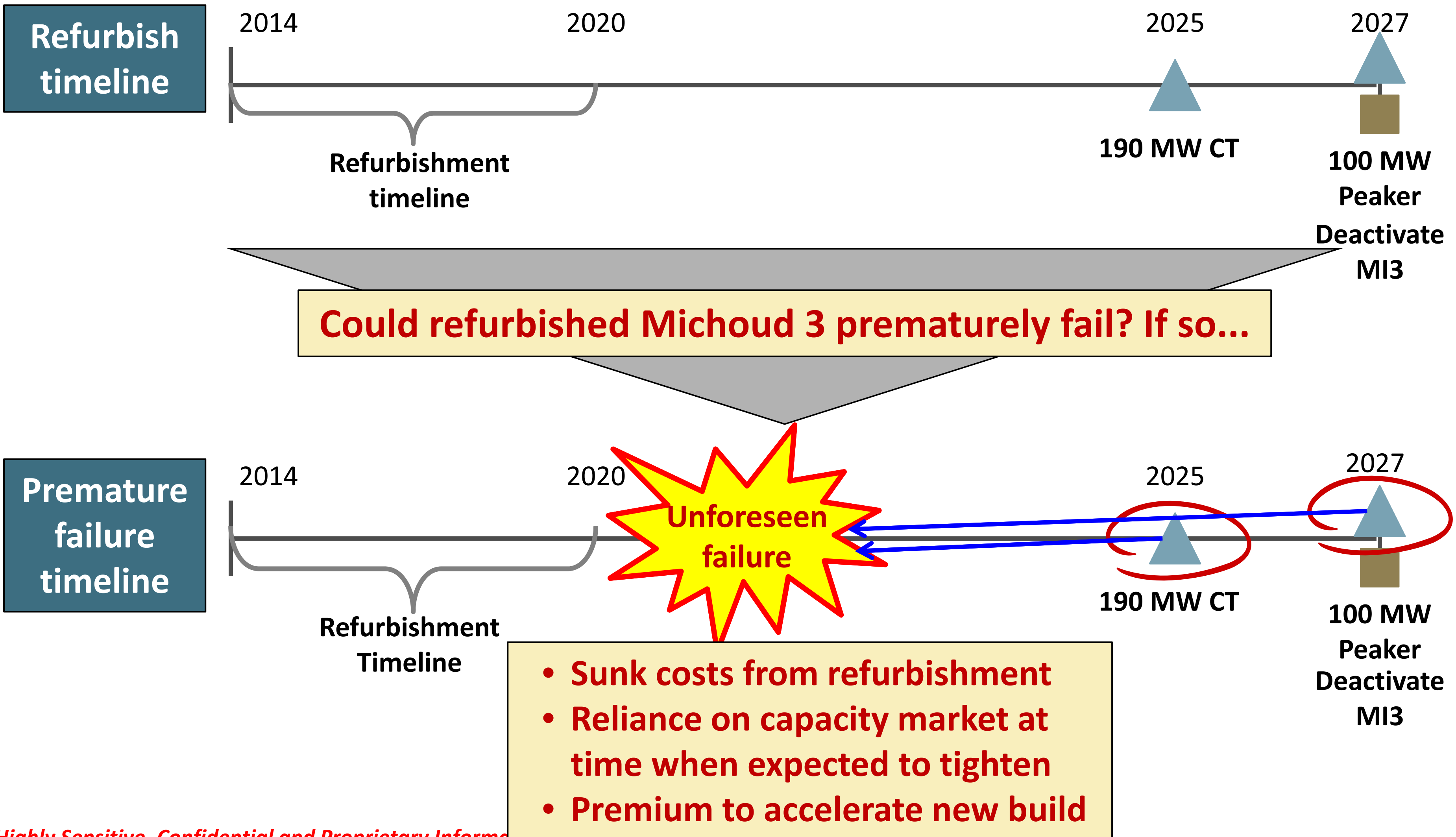
...but economics of MI3 refurb require unit to operate until 2027

Refurbished MI3 may fail prematurely leading to increased cost to customers



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Premature failure of MI3 will lead to increased cost to customers

Customer costs under deactivation more predictable, less volatile

Cost of Premature Failure	Est. Supply Cost Impact[1]	Rationale
Sunk capital and O&M	$193 – 263 M	• Capital and O&M to refurbish already incurred if MI3 breaks down early • Customers still pay to fund refurbishment
Short term capacity purchases	$27 – 167 M	• Sufficient capacity must be purchased until new generation in service • Capacity may not even be available if market constrained
Premium to accelerate new build	$55 – 82 M	• At least 20 – 30% premium on new assets expected in order to accelerate build
Customer cost	**$275 – 512 M**	• Compares to $227M to deactivate in 2016

Uncertainty and risk associated with MI3 refurbishment suggests deactivation and new-build is optimal

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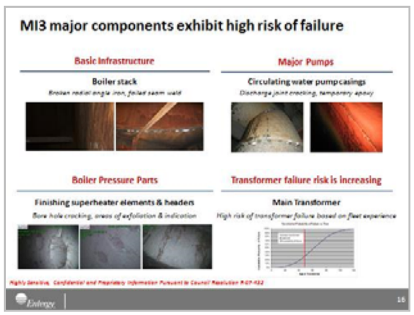
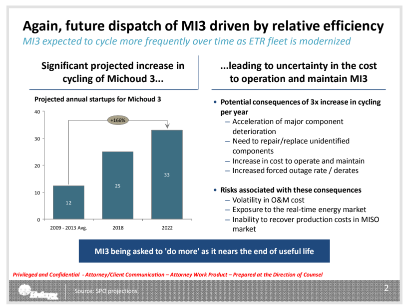
Investment in Michoud 3 involves increased risks vs. deactivation

Major components refurbished to original design basis – risk of failure will increase with time

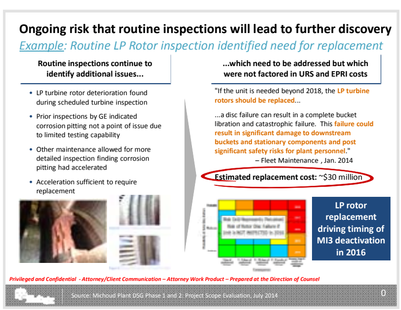
Major components must be replaced or repaired



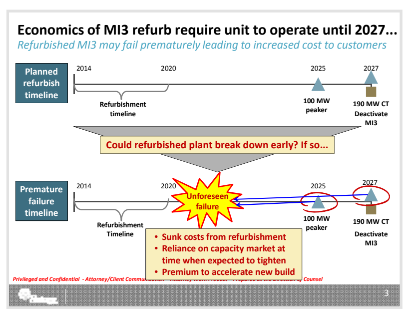
Even if refurbished, future operating role will increase cost and volatility of O&M



Other components not yet identified may need to be replaced



Risk of premature failure is real, adversely affecting cost to customers



Importantly, operating MI3 beyond 2016 will not eliminate the need to build new resources, but may defer that decision for a period of time.

Given the relative comparability of the economics of deactivating vs. refurbishing MI3, and the higher risk associated with refurbishment, investment in new resources will reduce the uncertainty of future supply costs.

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CNO Docket No. UD-08-02

Entergy

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New Orleans, LA 70161-1000
Tel 504 576 6571
Fax 504 576 5579

Timothy S. Cragin
Assistant General Counsel
Legal Services - Regulatory

September 18, 2015

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:

Enclosed please find an original and three copies of Entergy New Orleans, Inc.'s ("ENO") 2015 Integrated Resource Plan ("IRP") Updates for the Final IRP Report. This presentation provides updates regarding the following: (1) the effects of the reallocation of the Union Power Station resource from a power purchase agreement to the acquisition of Power Block 1; (2) the economic evaluation of demand-side management programs; and (3) the total supply cost of the evaluated portfolios, including updated load and capability data for the preferred CT portfolio. 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

TSC/tm
Enclosures
cc: Official Service List UD-08-02 *(via electronic mail)*

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SEP 18 2015
BY: KB

CERTIFICATE OF SERVICE
Docket No. UD-08-02

I hereby certify that I have this 18th day of September 2015, served the required number of copies of the foregoing report upon all other known parties of this proceeding, by: ☒ electronic mail, ☐ facsimile, ☐ overnight mail, ☐ hand delivery, and/or ☐ United States Postal Service, postage prepaid.

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Council of the City of New Orleans
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New Orleans, Louisiana, this 18th day of September, 2015.

Timothy S. Cragin

2015 ENO IRP

Updates for the Final IRP

SEPTEMBER 18, 2015

Entergy®

OBJECTIVES

The following topics will be discussed:

- Effects of Union Reallocation on ENO Supply Plan
  - Supply Role Capacity Analysis
  - Energy Mix Analysis
  - ENO Carbon Intensity
- DSM Economic Evaluation
  - Cost/Benefit and Breakeven Calculation
  - Demand Response Timing Optimization
  - Incremental Load Reduction from Demand Response
  - Diminishing Return Effect
- Total Supply Cost and Preferred Portfolio
  - Updated Total Supply Costs
  - Renewable Sensitivity Breakeven Analysis
  - Updated Load and Capability of Preferred Portfolio

Effects of Union Reallocation on ENO Supply Plan

OVERVIEW

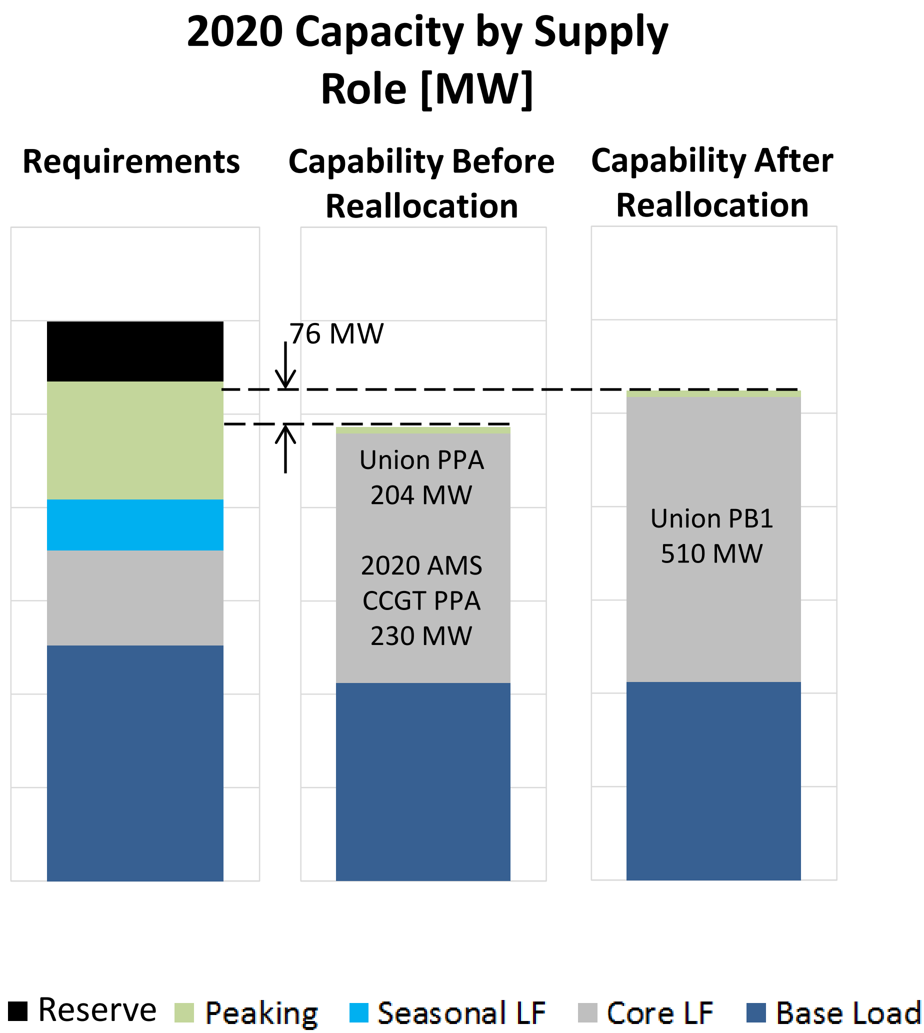
This section addresses the updates to the ENO IRP that relate to the reallocation of Union Power Block 1 (PB1). Two analyses were performed in order to understand the effects of the reallocation. Overall, the reallocation did not change the objective of the IRP, which is to identify the most economic way to meet the remaining peaking/reserve resource need.

- Capacity by Supply Role

- ENO Energy Mix
  - ENO Carbon Intensity

ENO PORTFOLIO AND SUPPLY ROLE NEEDS

Prior to and following the reallocation of Union PB1 and the 2020 Amite South CCGT, ENO's 2020 generation portfolio is projected to have adequate capacity for its Base Load and Core Load Following needs. However, additional peaking capacity is needed both before and after the reallocation. Union PB1 is economically suited to meet both load-following and peaking needs.

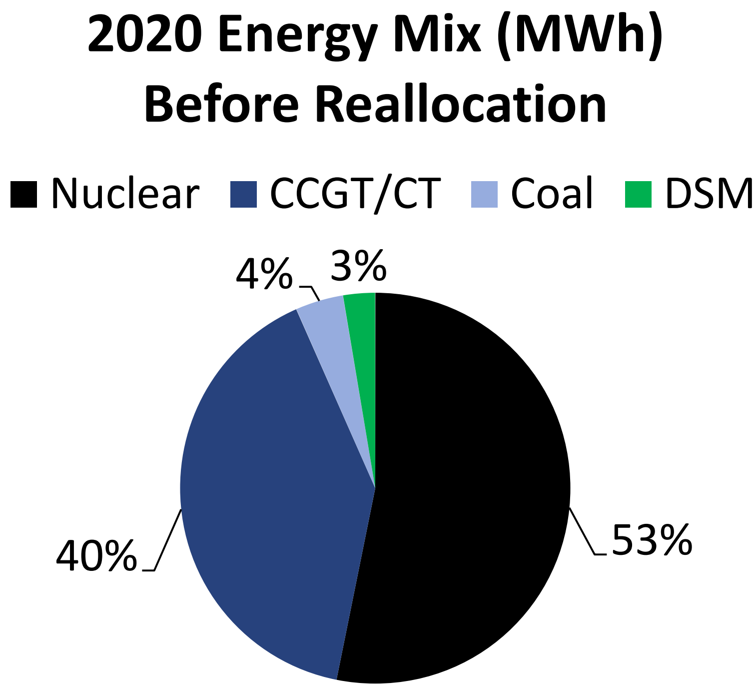


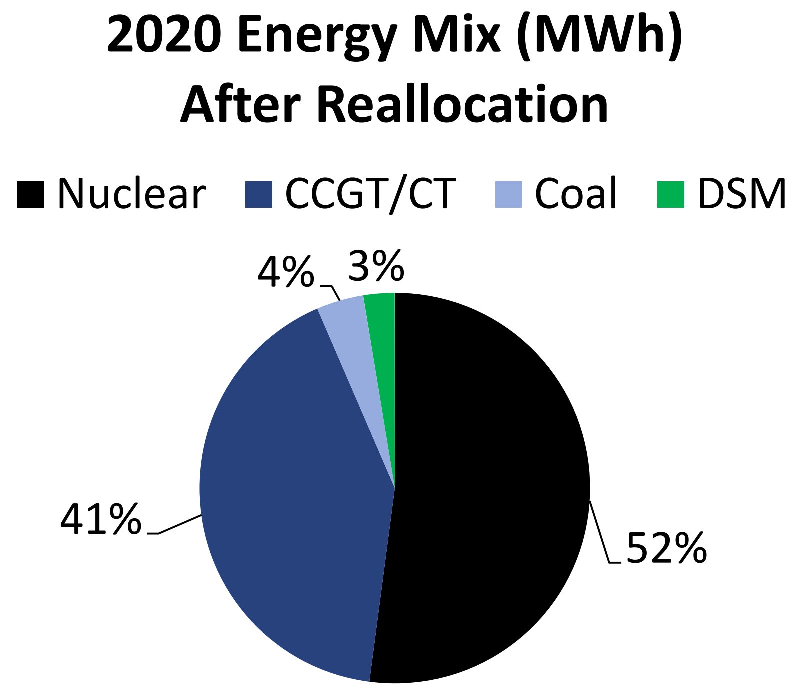
Capability After Reallocation

Unit	Fuel	Capability (MW)
Ninemile 6	Gas	112
Union	Gas	510
ANO 1	Nuclear	23
ANO 2	Nuclear	27
Grand Gulf	Nuclear	247
Independence 1	Coal	7
White Bluff 1	Coal	12
White Bluff 2	Coal	13

ENO'S ENERGY MIX

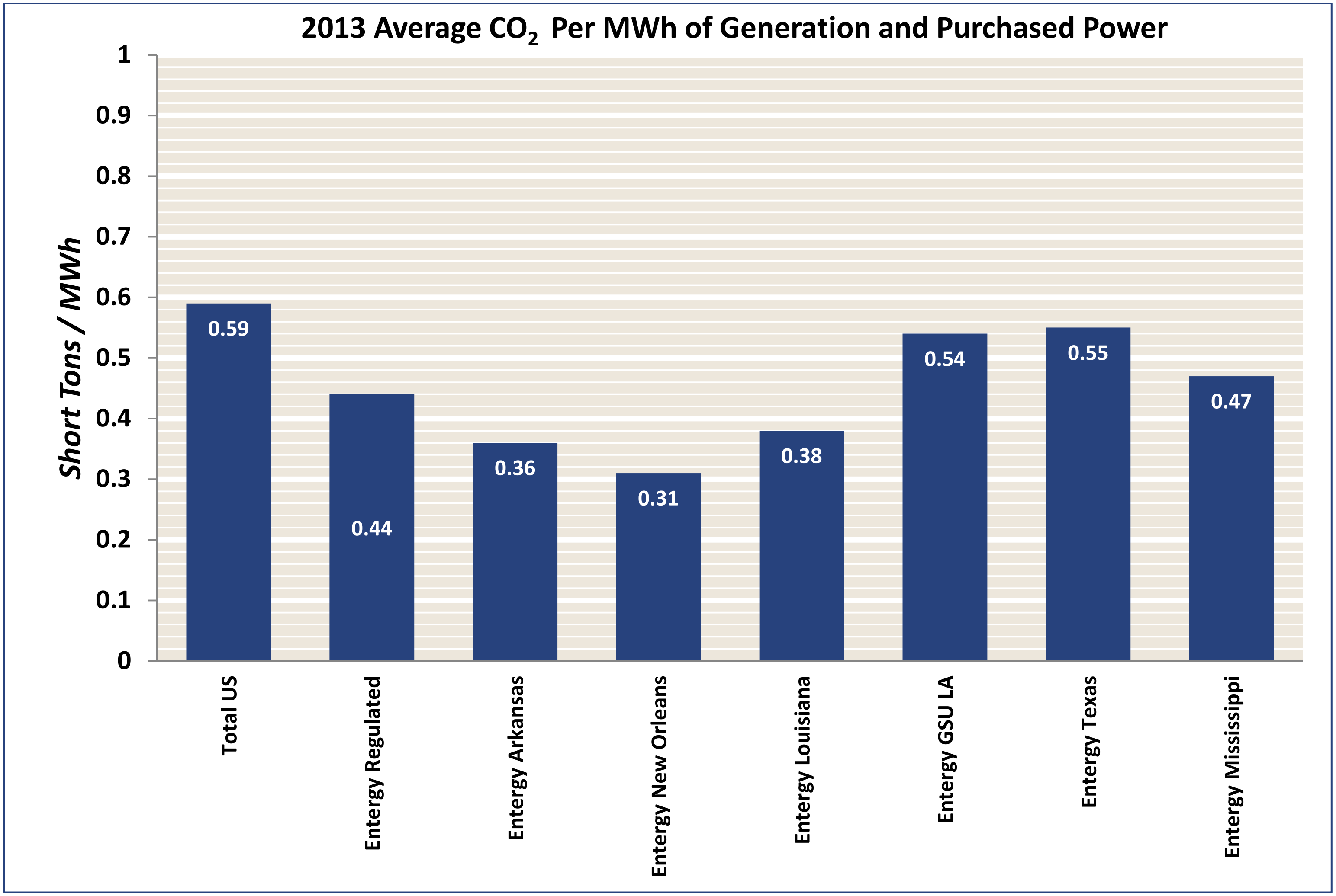
The projected energy mix for ENO by the year 2020 is consistent prior to and after the reallocation of Union PB1. ENO retains the same energy diversity with Union PB1 as it did with Union PB3&4 and 2020 Amite South PPAs. Over half of ENOs projected energy needs will be met with zero carbon emission stabled-priced baseload nuclear energy.





ENO'S CARBON INTENSITY

ENO's generation portfolio produced approximately 50% fewer CO2 emissions than the average US utility in 2013.



DSM ECONOMIC EVALUATION

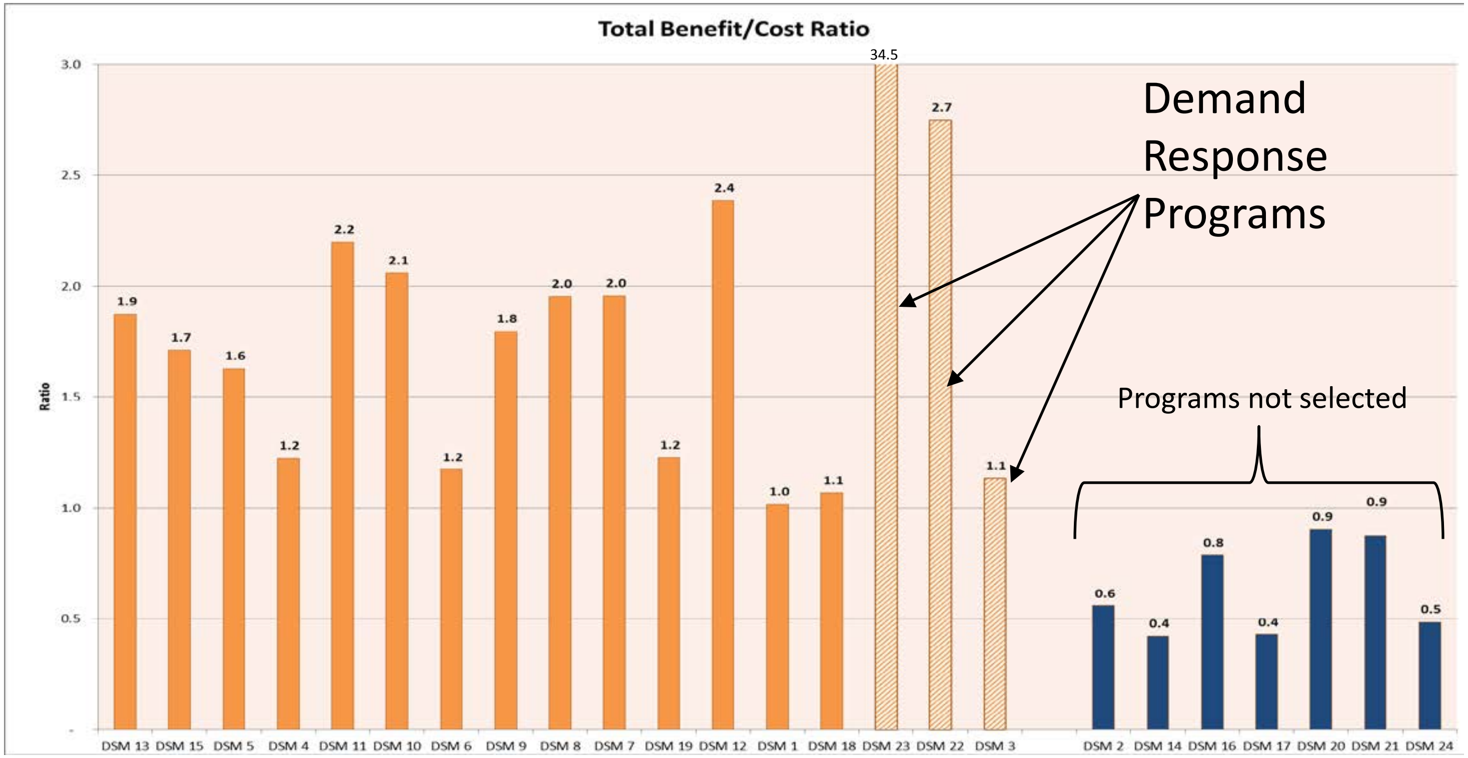
OVERVIEW

This section addresses the updated economic evaluation of the DSM programs. Major changes include updated costs for ENO incentives, updated load shapes, and updated cost/benefit analysis. All programs previously selected in the draft IRP were again selected in the updated analysis. In addition, three demand response programs were selected, contributing to an additional 35 MW in load reduction by 2034.

- Cost/Benefit and Breakeven Calculation
- Demand Response Timing Optimization
- Incremental Load Reduction from Demand Response
- Diminishing Return Effect

TOTAL BENEFIT TO COST RATIO

Selected DSM Program Summary, PV 2015$ M$, 2015 - 2034			
Total Benefit	Cost	Net Benefit	# of Programs
$164.3M	$110.8 M	$53.5M	17



DSM Program Net Benefit, PV 2015$ (M$)																								
M$	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	DSM 2	DSM 14	DSM 16	DSM 17	DSM 20	DSM 21	DSM 24
PV 2015$	13.1	8.8	2.4	1.8	1.9	1.8	0.9	0.6	0.5	0.5	0.2	0.2	0.8	0.0	12.6	7.1	0.4	(6.7)	(21.2)	(0.3)	(3.3)	(0.2)	(0.3)	(0.0)

*For all programs highlighted in red, total costs exceed total benefit.
**DSM Program has a benefit:cost ratio of 34.5.
***ENO's discount rate as of YE 12/31/14 is 6.93%.

NET BENEFIT/BREAKEVEN FOR DSM PROGRAMS, PV 2015$

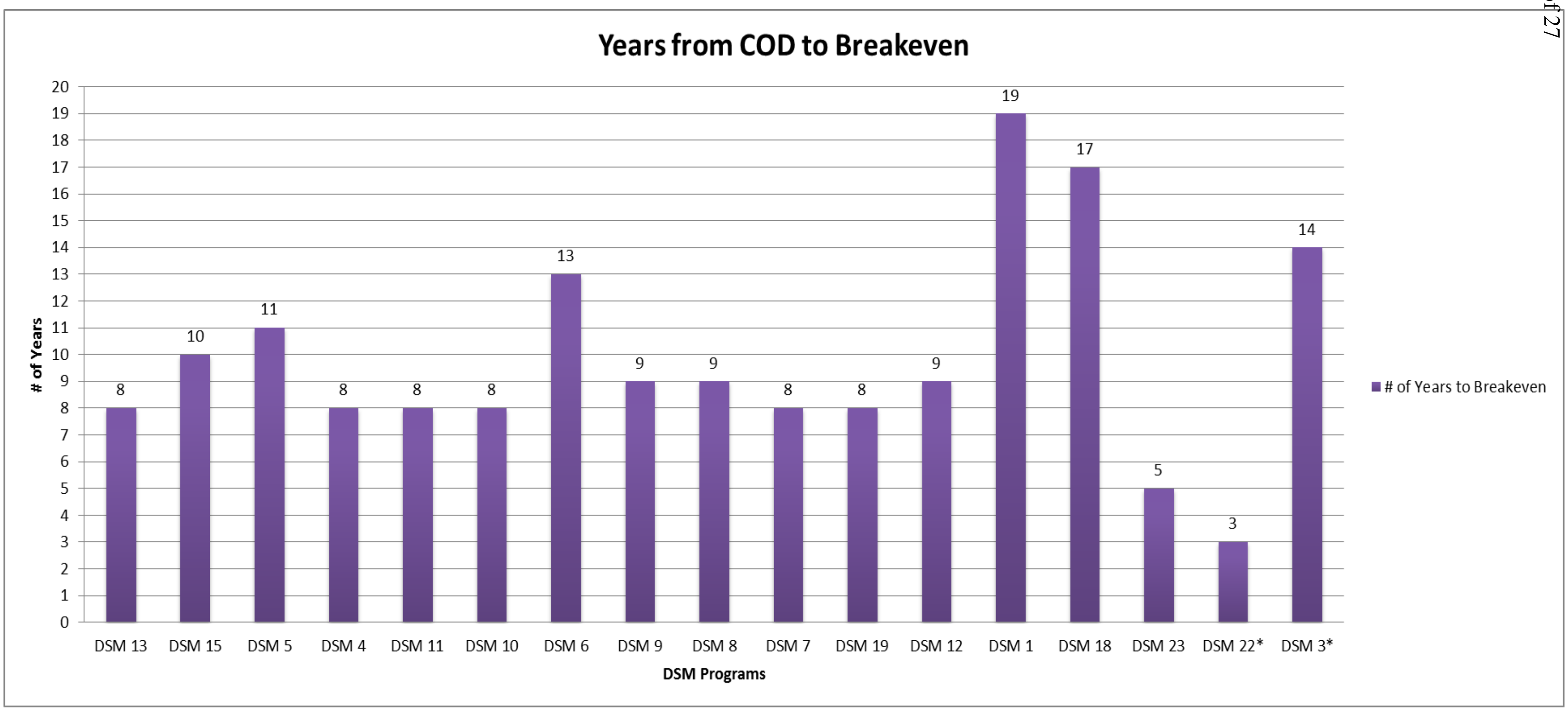
DSM breakeven net benefit illustrates that cost-effective programs break even within the evaluation period 2015 – 2034.

Benefit:		**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**
Energy Revenue	*M$*	$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	$0.0
Load Reduction Capacity Value	*M$*	$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	$3.4
Total Benefit	*M$*	$28.1	$21.1	$6.2	$10.1	$3.4	$3.6	$6.2	$1.3	$1.1	$1.0	$1.2	$0.3	$53.0	$0.3	$12.9	$11.1	$3.4
Cost:																		
Total Program Cost	*M$*	$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	$3.0
Net Benefit	*M$*	**$13.1**	**$8.8**	**$2.4**	**$1.8**	**$1.9**	**$1.8**	**$0.9**	**$0.6**	**$0.5**	**$0.5**	**$0.2**	**$0.2**	**$0.8**	**$0.0**	**$12.6**	**$7.1**	**$0.4**
Breakeven Year		2023	2025	2026	2023	2023	2023	2028	2024	2024	2023	2023	2024	2034	2032	2020	2022	2035

*The Net Benefit Breakeven is calculated using the rolling net benefit, defined as revenue minus cost. The rolling cumulative net benefit is then calculated on a PV basis over the evaluation period until revenues exceed costs.
**The effect of the peak and energy reduction is cumulative in the sense that each successive program added is in addition to the previous programs that were selected.
***DSM programs were added in the order shown above from left to right.

DSM Program Breakeven Year

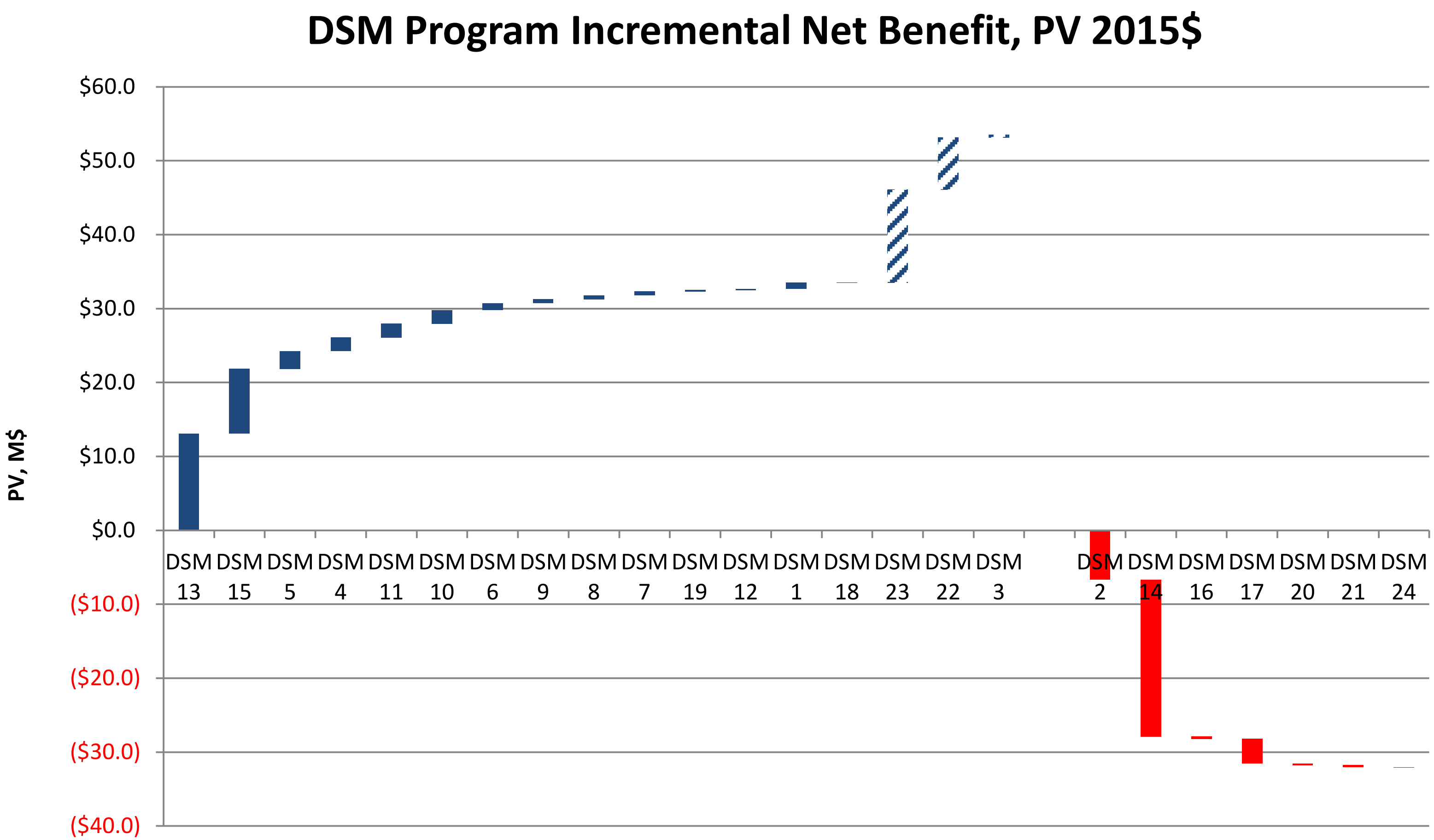
Of the 17 cost-effective DSM programs, 13 programs breakeven (76%) by 2026.



*DSM 3 starts in 2021 and DSM 22 starts in 2019. All other programs start in 2015.
**The Net Benefit Breakeven is calculated using the rolling net benefit, defined as revenue minus cost. The rolling cumulative net benefit is then calculated on a PV basis over the evaluation period until revenues exceed costs.
***The effect of the peak and energy reduction is cumulative in the sense that each successive program added is in addition to the previous programs that were selected.

INCREMENTAL NET BENEFIT

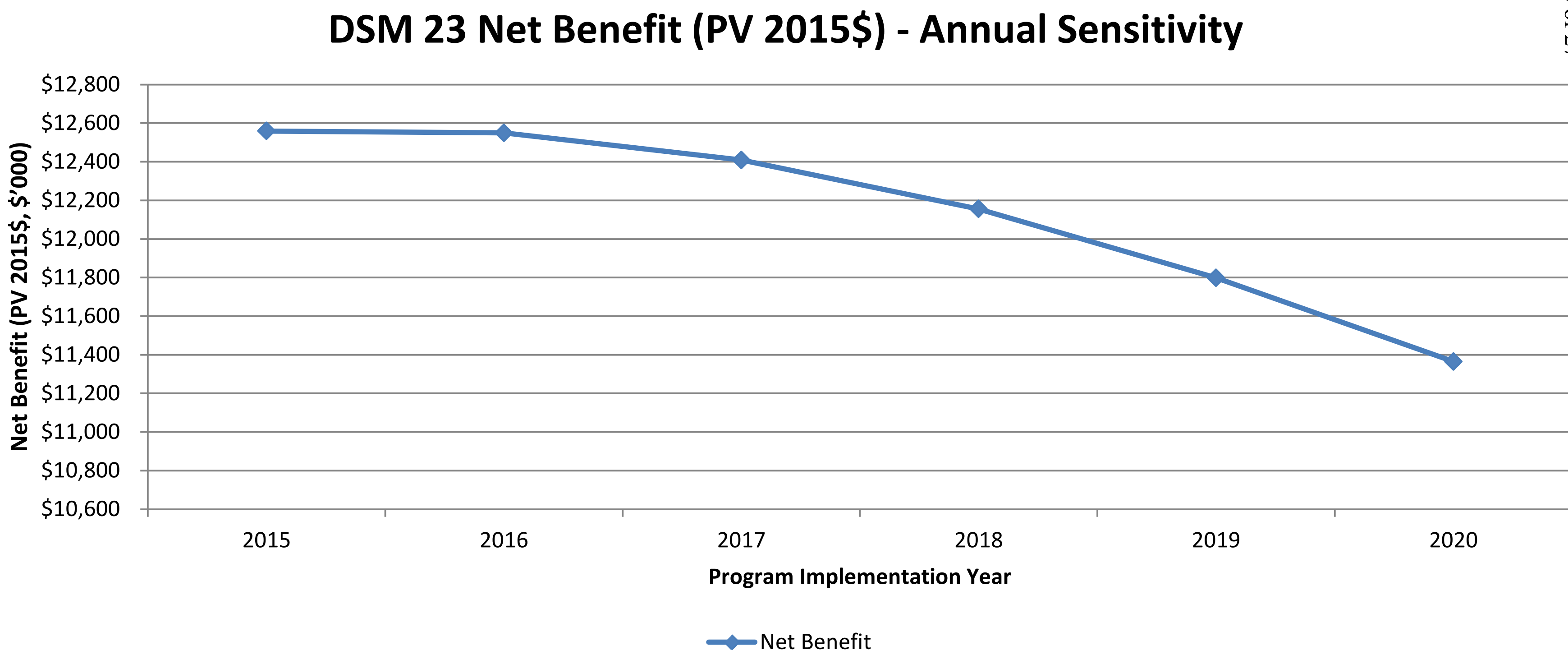
Below represents the net benefit of each individual DSM program; together, the total cumulative net benefit of the <u>Cost-Effective</u> DSM programs is $53.5M.



*ENO's discount rate as of YE 12/31/14 is 6.93%.
*Striped bars represent Demand Response programs

DEMAND RESPONSE – DSM PROGRAM 23

DSM Program 23 is Dynamic Pricing. The most net benefit received for DSM Program 23 occurs with implementation in 2015.



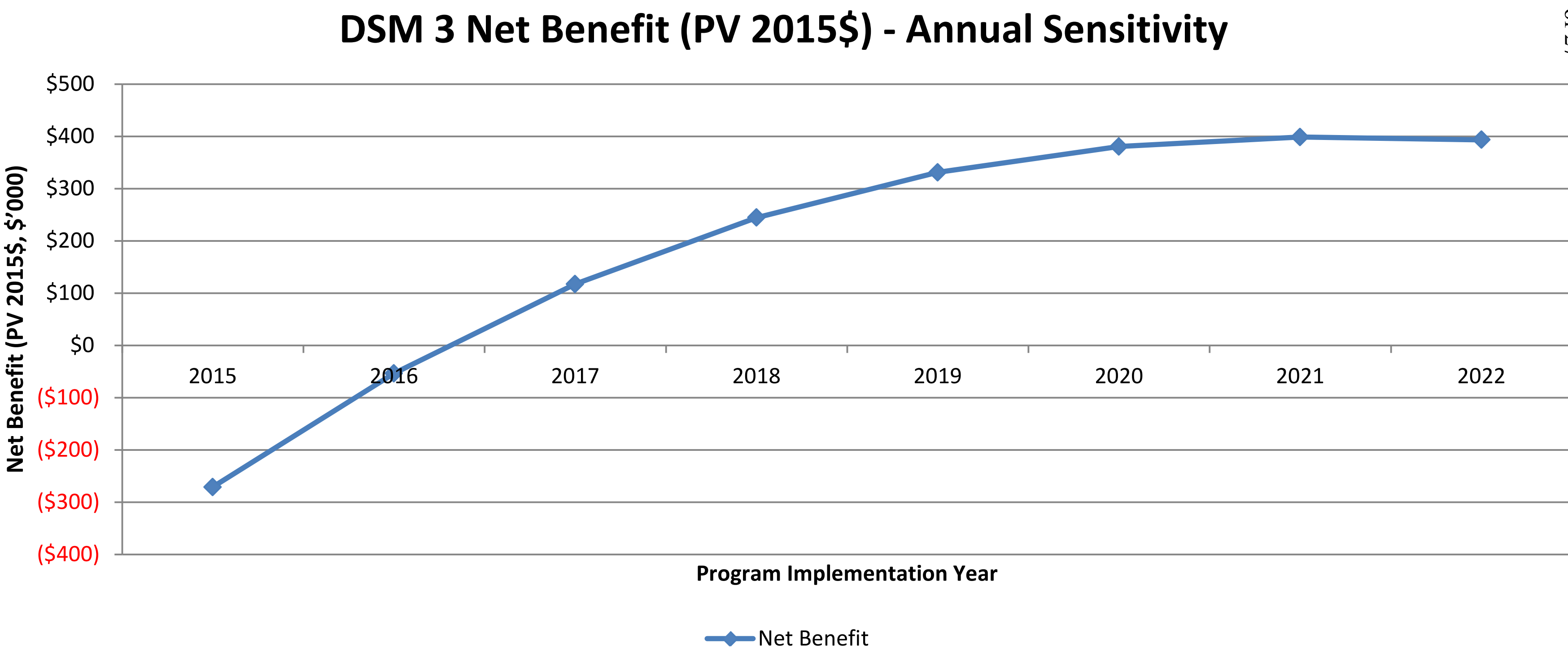
DSM 23	2015	2016	2017	2018	2019	2020
Total Benefit	$12,934	$12,907	$12,750	$12,481	$12,109	$11,661
Total Cost	$375	$358	$341	$326	$311	$296
Net Benefit	**$12,559**	**$12,549**	**$12,409**	**$12,155**	**$11,799**	**$11,365**

*The Net Benefit measures the Present Value (PV) of the benefits minus costs over a 20 year evaluation period. The data points assumes the program is implemented in the respective year and the program lasts 20 years after implementation.

**ENO WACC - 6.93%

DEMAND RESPONSE – DSM PROGRAM 3

DSM Program 3 is Non-Residential Dynamic Pricing. The most net benefit received for DSM Program 3 occurs with implementation in <u>2021.</u>

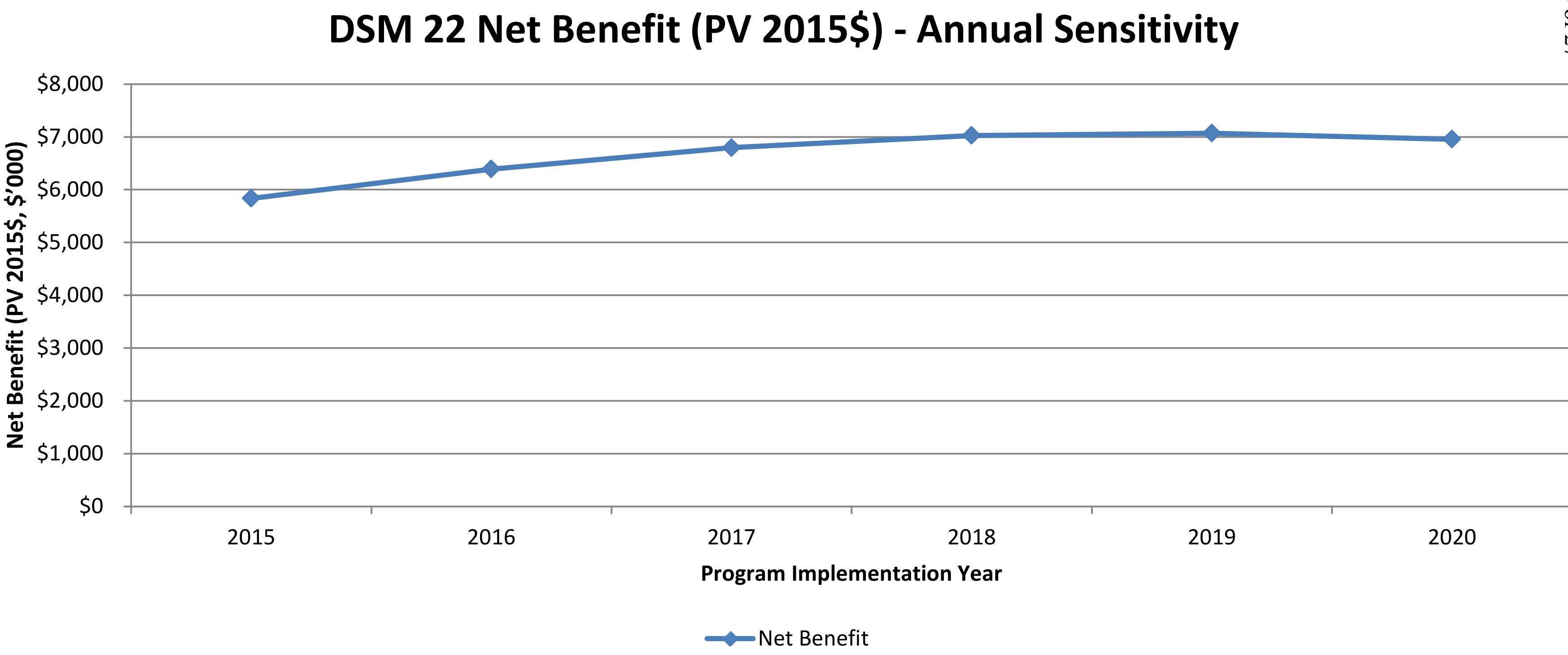


DSM 3	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Total Benefit	$3,708	$3,742	$3,738	$3,698	$3,625	$3,522	3396	$3,252
Total Cost	$3,979	$3,795	$3,620	$3,453	$3,294	$3,142	2997	$2,859
Net Benefit	**($271)**	**($54)**	**$117**	**$245**	**$331**	**$380**	**$399**	**$393**

*The Net Benefit measures the Present Value (PV) of the benefits minus costs over a 20 year evaluation period. The data points assumes the program is implemented in the respective year and the program lasts 20 years after implementation.
**ENO WACC - 6.93%

DEMAND RESPONSE – DSM PROGRAM 22

DSM Program 22 is Direct Load Control. The most net benefit received for DSM Program 22 occurs with implementation in 2019.



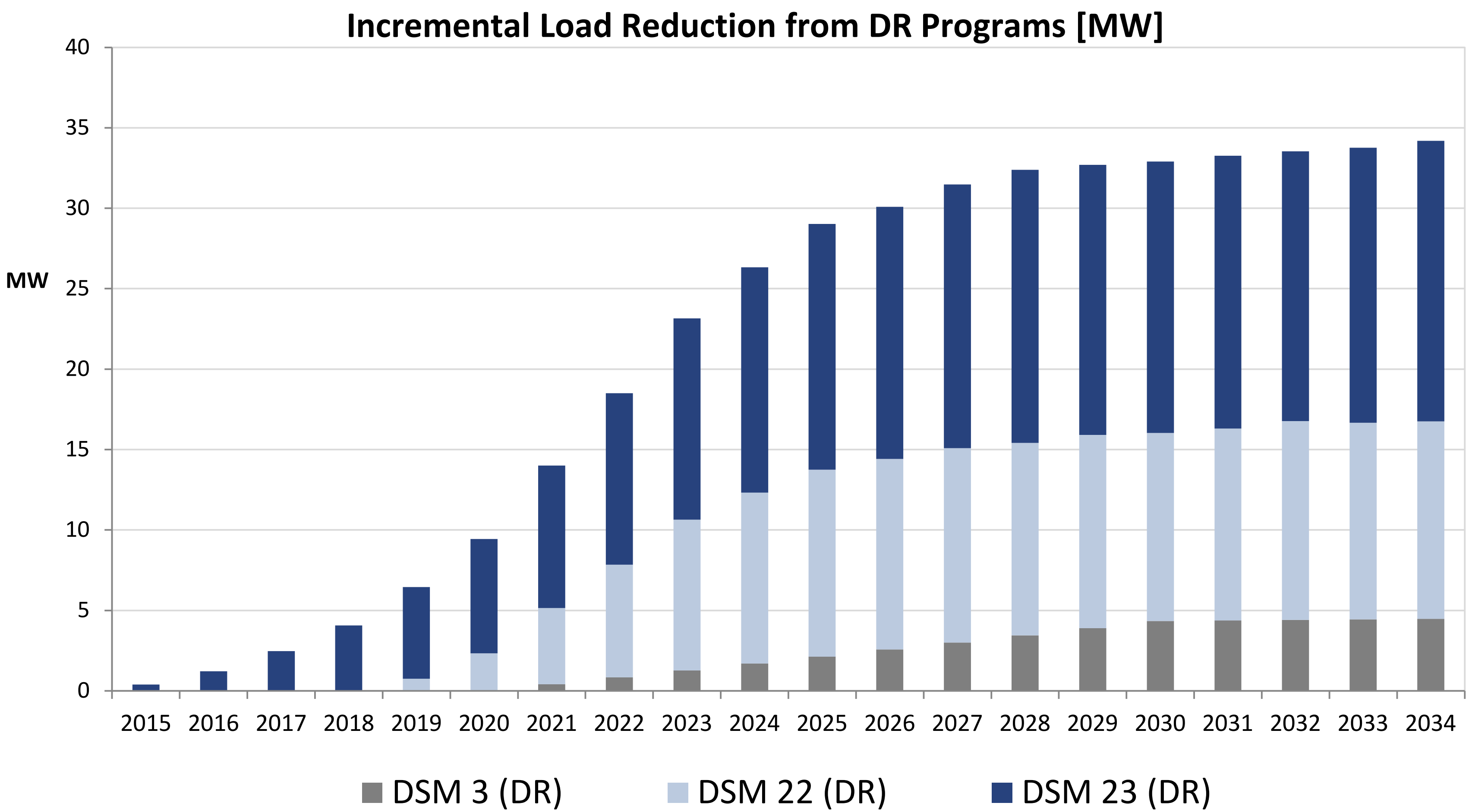
DSM 22	2015	2016	2017	2018	2019	2020
Total Benefit	$10,717	$11,048	$11,238	$11,264	$11,112	$10,812
Total Cost	$4,883	$4,658	$4,443	$4,238	$4,042	$3,856
Net Benefit	**$5,834**	**$6,391**	**$6,795**	**$7,026**	**$7,070**	**$6,956**

*The Net Benefit measures the Present Value (PV) of the benefits minus costs over a 20 year evaluation period. The data points assumes the program is implemented in the respective year and the program lasts 20 years after implementation.

**ENO WACC - 6.93%

INCREMENTAL LOAD REDUCTION FROM DR PROGRAMS

With the inclusion of the three DR programs, ENO peak load could be reduced by an additional 35 MW by 2034. Total reduction of load from all DSM programs by 2034 is projected to be 86 MW[1].



[1]The implementation of cost-effective DSM requires consistent, sustained regulatory support and approval. ENO's investment in DSM must be supported by a reasonable opportunity to timely recover all of the costs, including lost contribution to fixed cost, associated with those programs.

DEMONSTRATION OF DSM DIMINISHING MARGINAL RETURNS

The table below demonstrates that with each additional DSM program selected by AURORA, the benefit of the other previously selected programs is decreased.

MWh-Weighted Program Benefit by Iteration (PV, 2015$)				
Program	**Iteration 1**	**Iteration 2**	**Iteration 3**	**Iteration 4**
DSM13 - Residential Lighting & Appliances	615.03	614.71	614.68	614.29
DSM15 - ENERGY STAR Air Conditioning	N/A	697.51	697.34	696.82
DSM4 - RetroCommissioning	N/A	N/A	566.81	566.41

Notes:

1. Program benefit includes both avoided energy and capacity.

2. The values in this analysis do not reflect the actual avoided energy and capacity of each DSM program. Because of the small size of each program relative to the entire MISO system, the effect of each program on energy pricing is very small. Thus, it is difficult to demonstrate the effect of diminishing marginal returns within the precision of the AURORA model. To demonstrate proof of concept, hourly load reductions for each of the three programs were increased by a factor of 10.

3. Iteration refers to the iterative process employed in the AURORA capacity expansion algorithm

4. "N/A" values indicate a program was not in the system for that iteration. Each iteration, the program with the next highest net benefit is selected to be included in the system, in addition to all programs previously selected.

Total Supply Cost and Preferred Portfolio

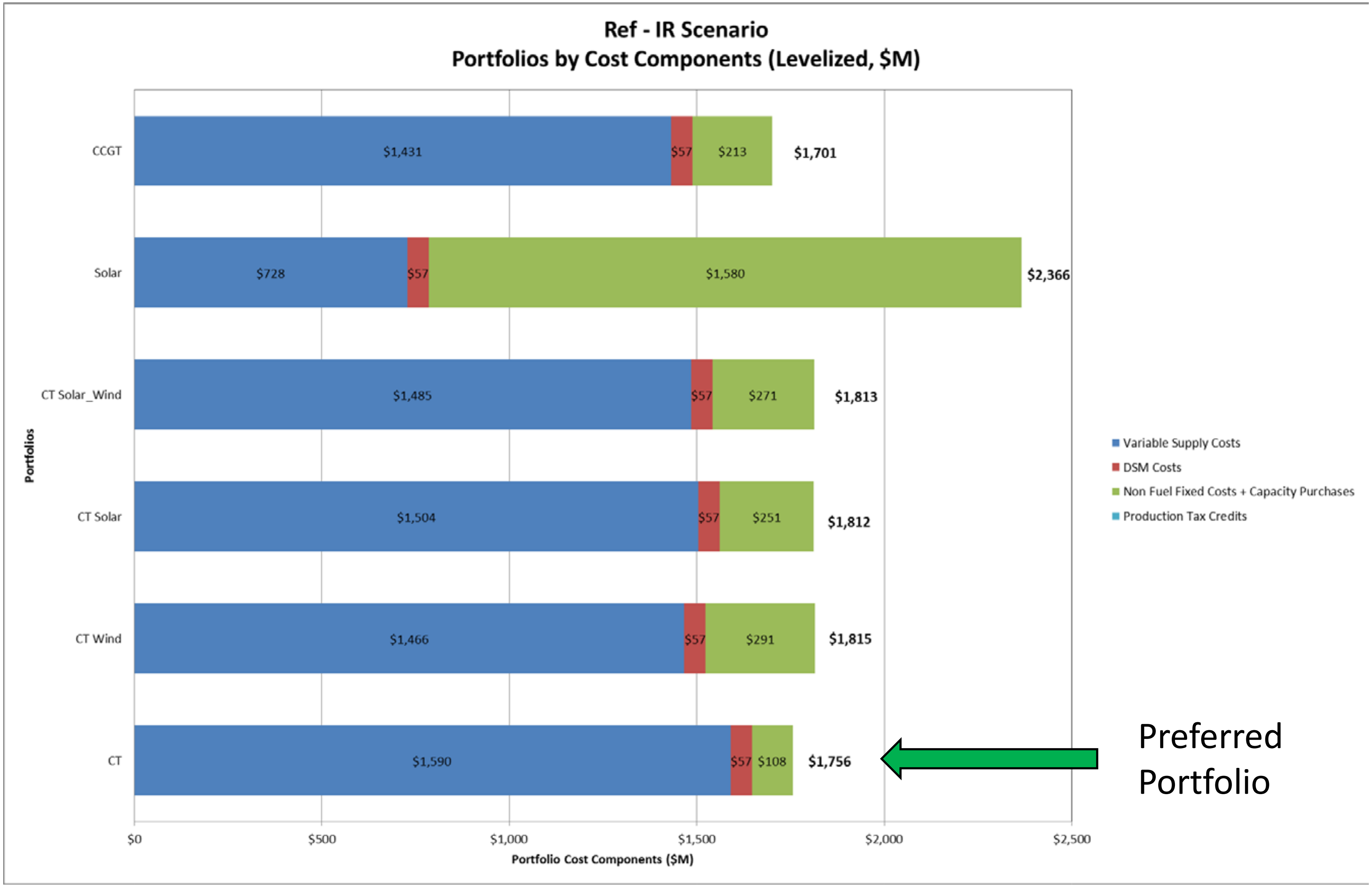
OVERVIEW

This sections addresses the necessary updates to the total supply cost of the evaluated portfolios. In addition, a sensitivity study was performed on the estimated install costs of solar and wind resources. This was done to determine at what point the CT Wind, CT Solar, and CT Solar_Wind portfolios would have an equal total supply cost to the preferred CT portfolio. Lastly, the updated load and capability chart is shown for the preferred portfolio.

- Total Supply Cost Comparison
- Renewable Install Cost Sensitivity Analysis
- Updated Load and Capability chart for ENO’s preferred portfolio

TOTAL SUPPLY COSTS EXCLUDING NON-FUEL FIXED COSTS

After the reallocation of Union PB1 and the re-evaluation of the DSM programs, the CT portfolio is still the preferred portfolio for ENO.



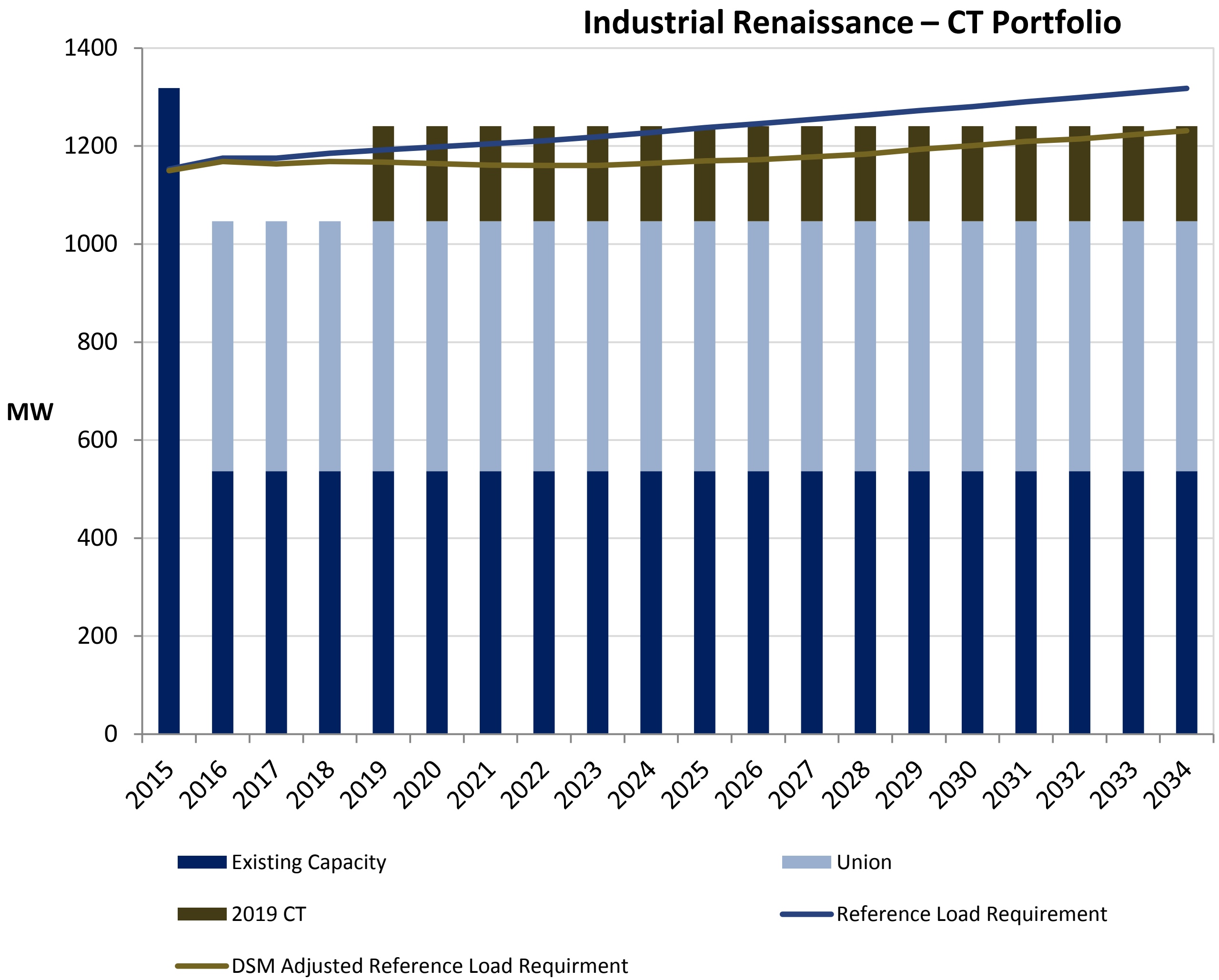
RENEWABLE RESOURCE COMPARISON TO PREFERRED PORTFOLIO

In order for the CT Wind, CT Solar, and CT Solar_Wind portfolios to be competitive with the CT Portfolio, the installed cost of wind and solar resources would have to be approximately 30-40% less than the current installed cost estimates. Thus, the CT Portfolio is still the preferred portfolio. Renewable installation costs will continue to be monitored for planning purposes going forward.

ENO IRP Breakeven Wind and Solar Installed Cost

Portfolio		**CT Wind**	**CT Solar**	**CT Solar_Wind**
Original Installed Cost (2020)	*$/kW*	$2,291 (Wind)	$2,076 (Solar)	$2,291 (Wind) $2,076 (Solar)
Breakeven (BE) Installed Cost	*$/kW*	$1,513 (Wind)	$1,250 (Solar)	$1,455 (Wind) $1,318 (Solar)
BE as % of Original Installed Cost	%	66%	60%	64%

ENO'S PREFERRED PORTFOLIO UPDATED



*Resources listed in blue are existing and planned resources. Resources additions listed in brown are the resources to be evaluated in the IRP.

Table 1: IRP Additions

Resource Addition	Capacity (MW)
2019 CT	194

Table 2: Additional Capacity Needs After IRP Additions (Reference Load)

Year	Capacity Need (Surplus) [MW]
2020	(42)
2021	(36)
2022	(30)
2023	(22)
2024	(13)
2025	(3)
2026	5
2027	14
2028	23
2029	32
2030	40
2031	50
2032	58
2033	68
2034	77

SPO PLANNING ANALYSIS

2015 ENO IRP

Portfolio Composition and Results

MAY 27, 2015

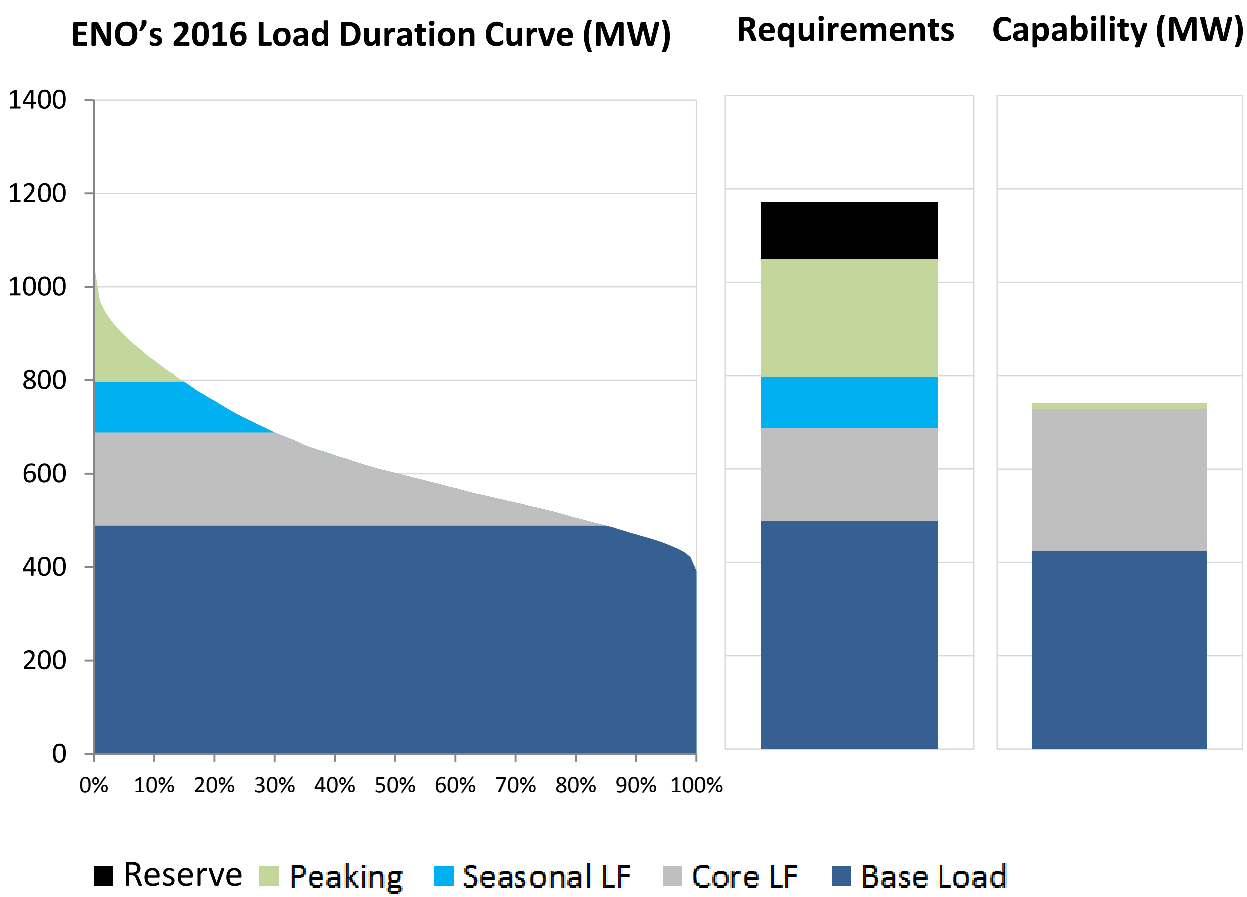
OBJECTIVES

The following topics will be discussed:

- ENO Supply Role Needs and Portfolio Mix
- Scenario Assumptions
- Portfolio Composition
- Portfolio Costs
- Environmental and Commodity Sensitivities

ENO PORTFOLIO AND SUPPLY ROLE NEEDS

ENO's 2016 generation portfolio is projected to have adequate capacity for its Base Load and Core Load Following needs; however, additional peaking capacity is needed



Unit	Fuel	Capability (MW)
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Union	Gas	204
ANO 1	Nuclear	23
ANO 2	Nuclear	27
Grand Gulf	Nuclear	247
Independence 1	Coal	7
White Bluff 1	Coal	12
White Bluff 2	Coal	13

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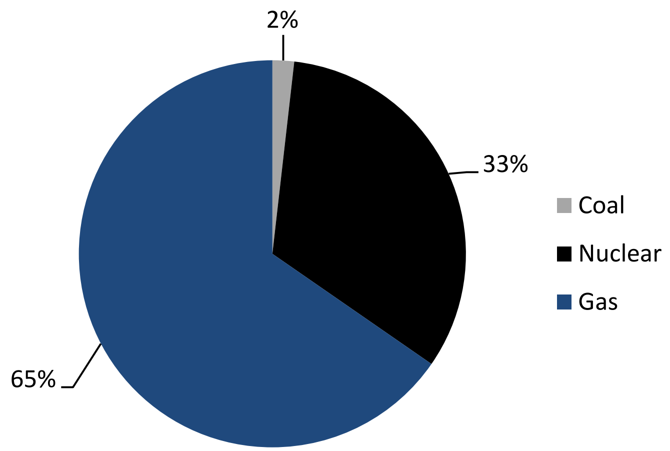
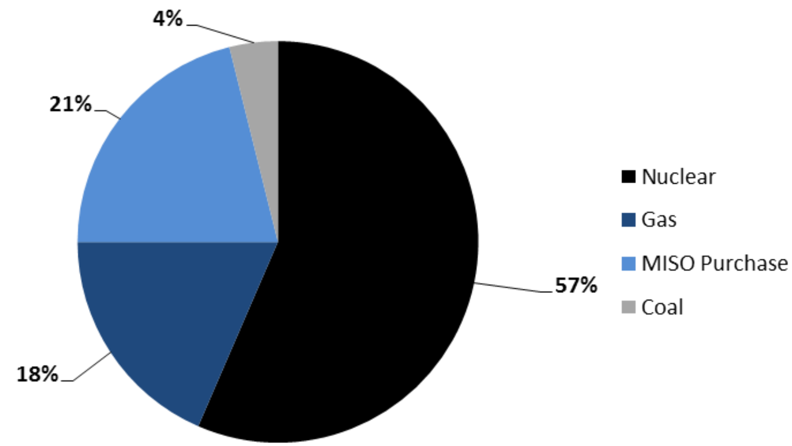
ENO'S CAPACITY & ENERGY MIX

With the planned deactivation of Michoud 2 and 3, nuclear and coal resources provide over 50% of capacity and over 60% of energy needs

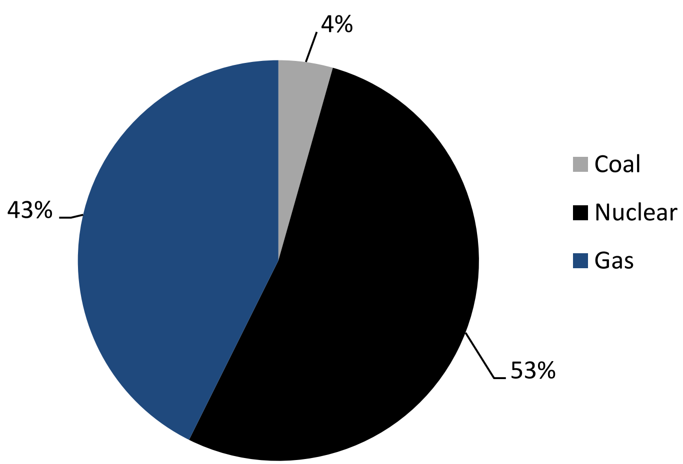
2014 Capacity (MW)



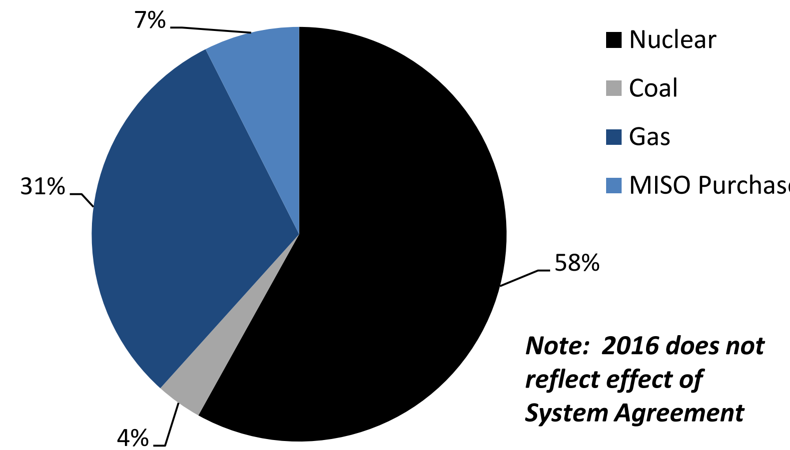
2014 Energy Mix (MWh)



2016 Capacity (MW)



2016 Energy Mix (MWh)



Note: 2016 does not reflect effect of System Agreement

CNO Docket No. UD-08-02
Supplement 9

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 (Years)*	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

PORTFOLIO COMPOSITION – DSM PROGRAMS

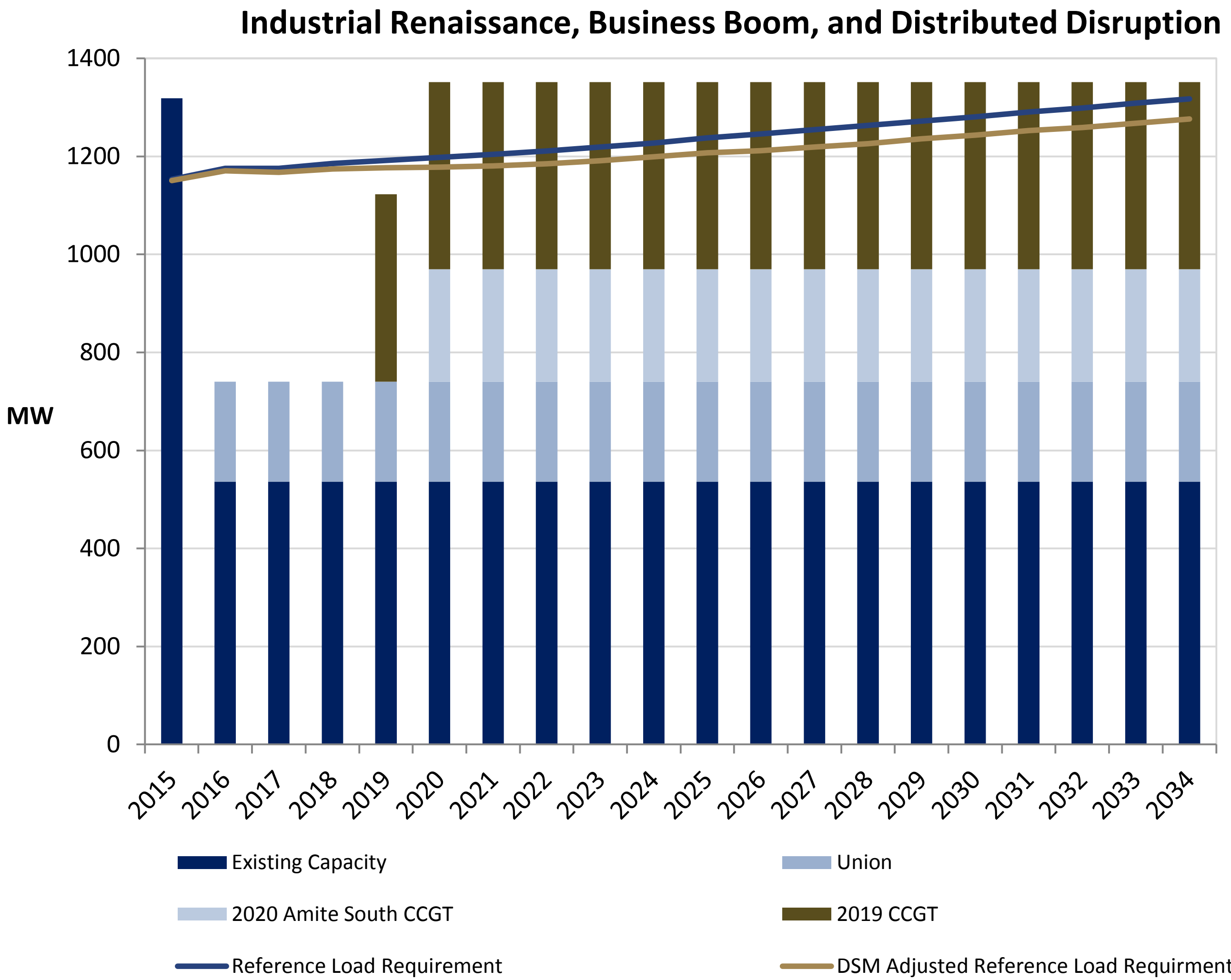
- The AURORA Capacity Expansion Model was used to develop a DSM portfolio for each of the scenarios.
- The result of this process was an optimal DSM portfolio for each scenario.

Portfolio Design Mix

	IR Portfolio	BB Portfolio	DD Portfolio	GS Portfolio
DSM	14 Programs	12 Programs	15 Programs	17 Programs
DSM Maximum (MW)	41	26	40	43

AURORA DSM Portfolios by Scenario			
Industrial Renaissance	**Business Boom**	**Distributed Disruption**	**Generation Shift**
DSM1 - Commercial Prescriptive & Custom		DSM1 - Commercial Prescriptive & Custom	DSM1 - Commercial Prescriptive & Custom
DSM4 - RetroCommissioning	DSM4 - RetroCommissioning	DSM4 - RetroCommissioning	DSM4 - RetroCommissioning
DSM5 - Commercial New Construction	DSM5 - Commercial New Construction	DSM5 - Commercial New Construction	DSM5 - Commercial New Construction
DSM6 - Data Center	DSM6 - Data Center	DSM6 - Data Center	DSM6 - Data Center
DSM7 - Machine Drive	DSM7 - Machine Drive	DSM7 - Machine Drive	DSM7 - Machine Drive
DSM8 - Process Heating	DSM8 - Process Heating	DSM8 - Process Heating	DSM8 - Process Heating
DSM9 - Process Cooling and Refrigeration	DSM9 - Process Cooling and Refrigeration	DSM9 - Process Cooling and Refrigeration	DSM9 - Process Cooling and Refrigeration
DSM10 - Facility HVAC	DSM10 - Facility HVAC	DSM10 - Facility HVAC	DSM10 - Facility HVAC
DSM11 - Facility Lighting	DSM11 - Facility Lighting	DSM11 - Facility Lighting	DSM11 - Facility Lighting
DSM12 - Other Process/Non-Process Use	DSM12 - Other Process/Non-Process Use	DSM12 - Other Process/Non-Process Use	DSM12 - Other Process/Non-Process Use
DSM13 - Residential Lighting & Appliances	DSM13 - Residential Lighting & Appliances	DSM13 - Residential Lighting & Appliances	DSM13 - Residential Lighting & Appliances
DSM15 - ENERGY STAR Air Conditioning	DSM15 - ENERGY STAR Air Conditioning	DSM15 - ENERGY STAR Air Conditioning	DSM15 - ENERGY STAR Air Conditioning
			DSM16 - Home Energy Use Benchmarking
DSM18 - Efficient New Homes		DSM18 - Efficient New Homes	DSM18 - Efficient New Homes
DSM19 - Multifamily	DSM19 - Multifamily	DSM19 - Multifamily	DSM19 - Multifamily
		DSM20 - Water Heating	DSM20 - Water Heating
			DSM21 - Pool Pump

AURORA CAPACITY EXPANSION - SUPPLY SIDE PORTFOLIOS



Resource Addition	Capacity (MW)
2019 CCGT	382

*Resources listed in blue are existing and planned resources. Resources additions listed in brown are the resources to be evaluated in the IRP.

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Preliminary – Work in Progress

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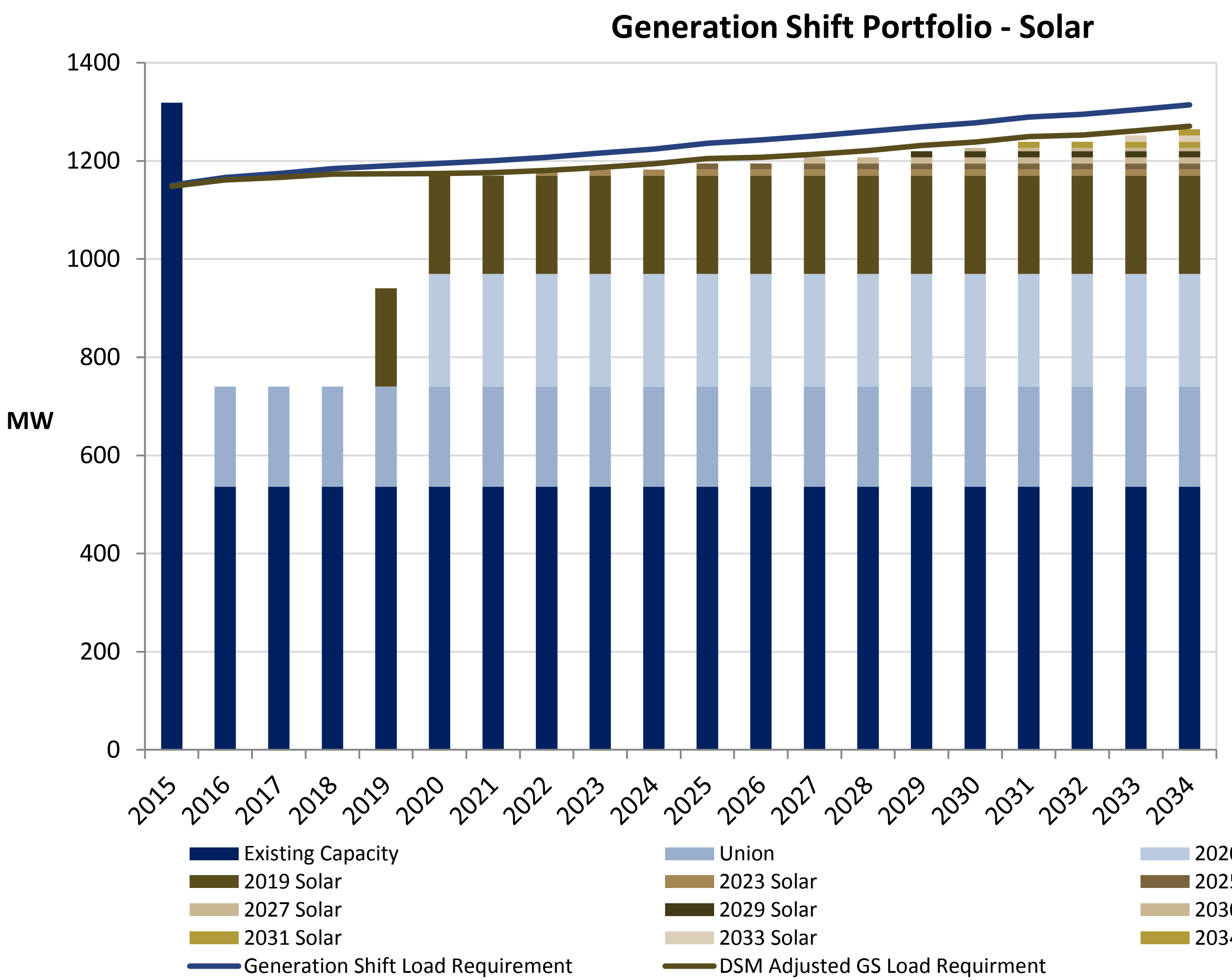
AURORA CAPACITY EXPANSION - SUPPLY SIDE PORTFOLIOS

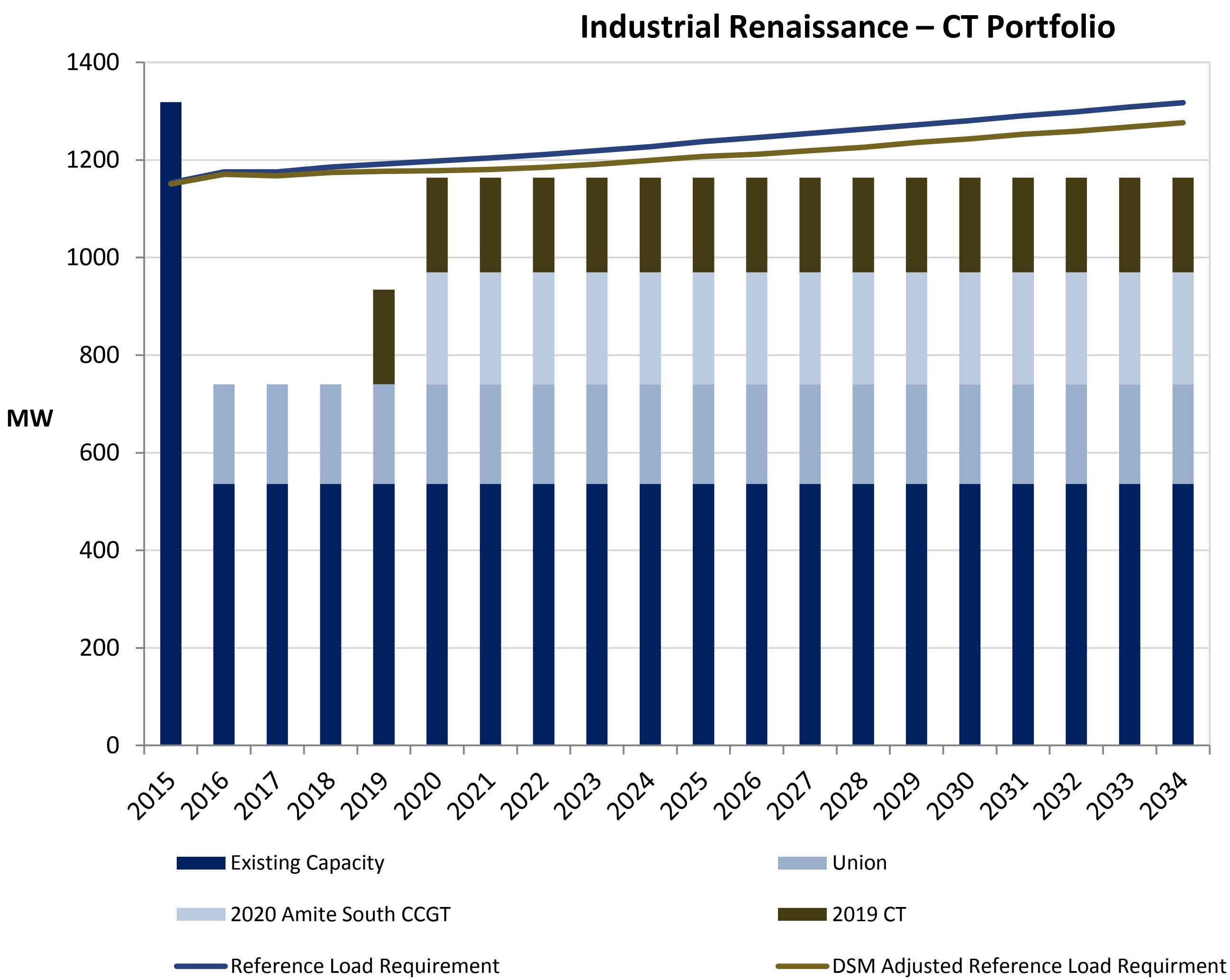


Resource Addition	Capacity (MW)	Effective Capacity (MW)
2019 Solar	800	200
2023 Solar	50	12.5
2025 Solar	50	12.5
2027 Solar	50	12.5
2029 Solar	50	12.5
2030 Wind	50	7
2031 Solar	50	12.5
2033 Solar	50	12.5
2034 Solar	50	12.5

*Resources listed in blue are existing and planned resources. Resources additions listed in brown are the resources to be evaluated in the IRP.

Preliminary – Work in Progress

Manual Portfolios - Supply Side Portfolios

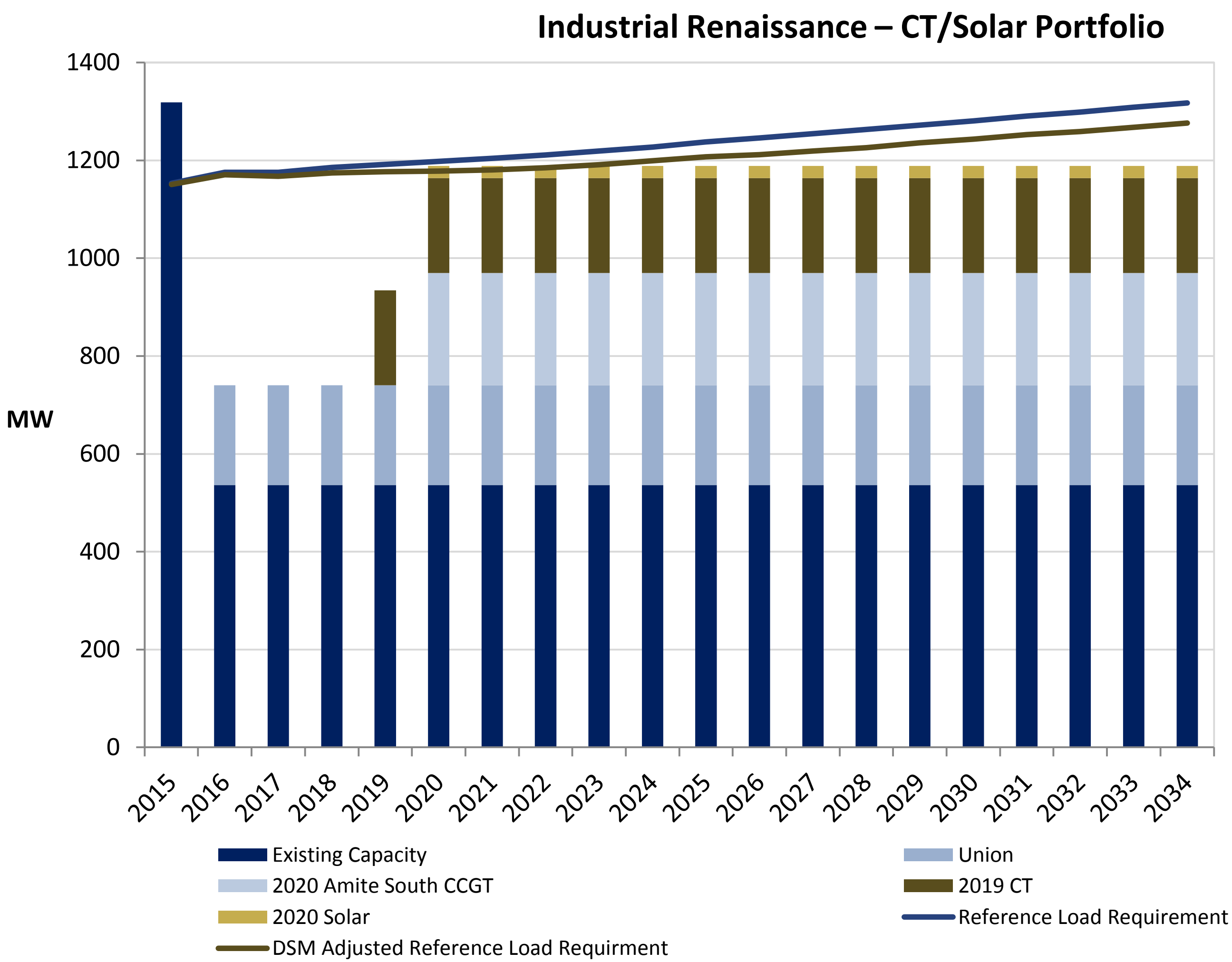


Resource Addition	Capacity (MW)
2019 CT	194

*Resources listed in blue are existing and planned resources. Resources additions listed in brown are the resources to be evaluated in the IRP.

Preliminary – Work in Progress

MANUAL PORTFOLIOS - SUPPLY SIDE PORTFOLIOS

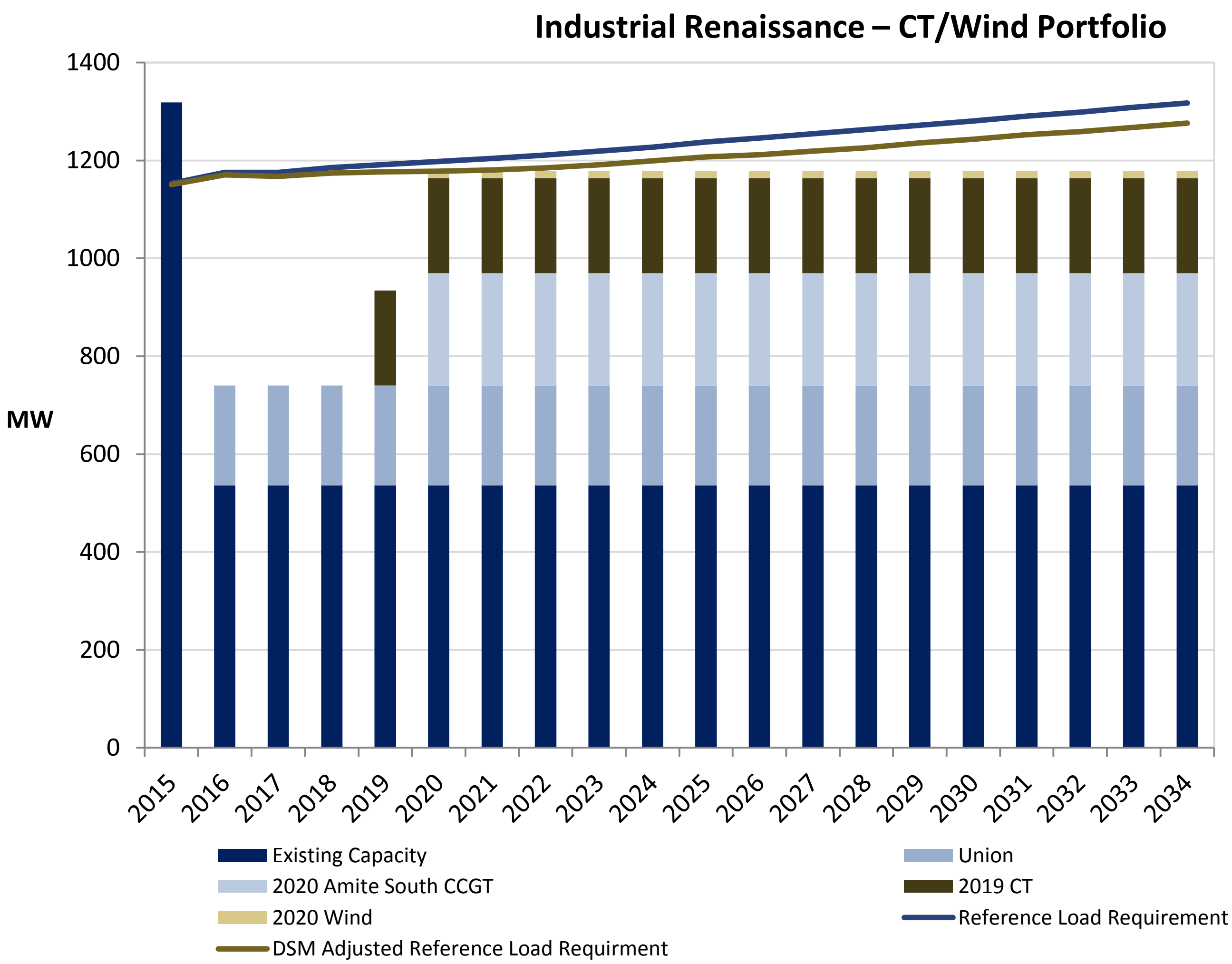


Resource Addition	Capacity (MW)	Effective Capacity (MW)
2019 CT	194	194
2020 Solar	100	25

*Resources listed in blue are existing and planned resources. Resources additions listed in brown are the resources to be evaluated in the IRP.

Preliminary – Work in Progress

MANUAL PORTFOLIOS - SUPPLY SIDE PORTFOLIOS



Resource Addition	Capacity (MW)	Effective Capacity (MW)
2019 CT	194	194
2020 Wind	100	14

*Resources listed in blue are existing and planned resources. Resources additions listed in brown are the resources to be evaluated in the IRP.

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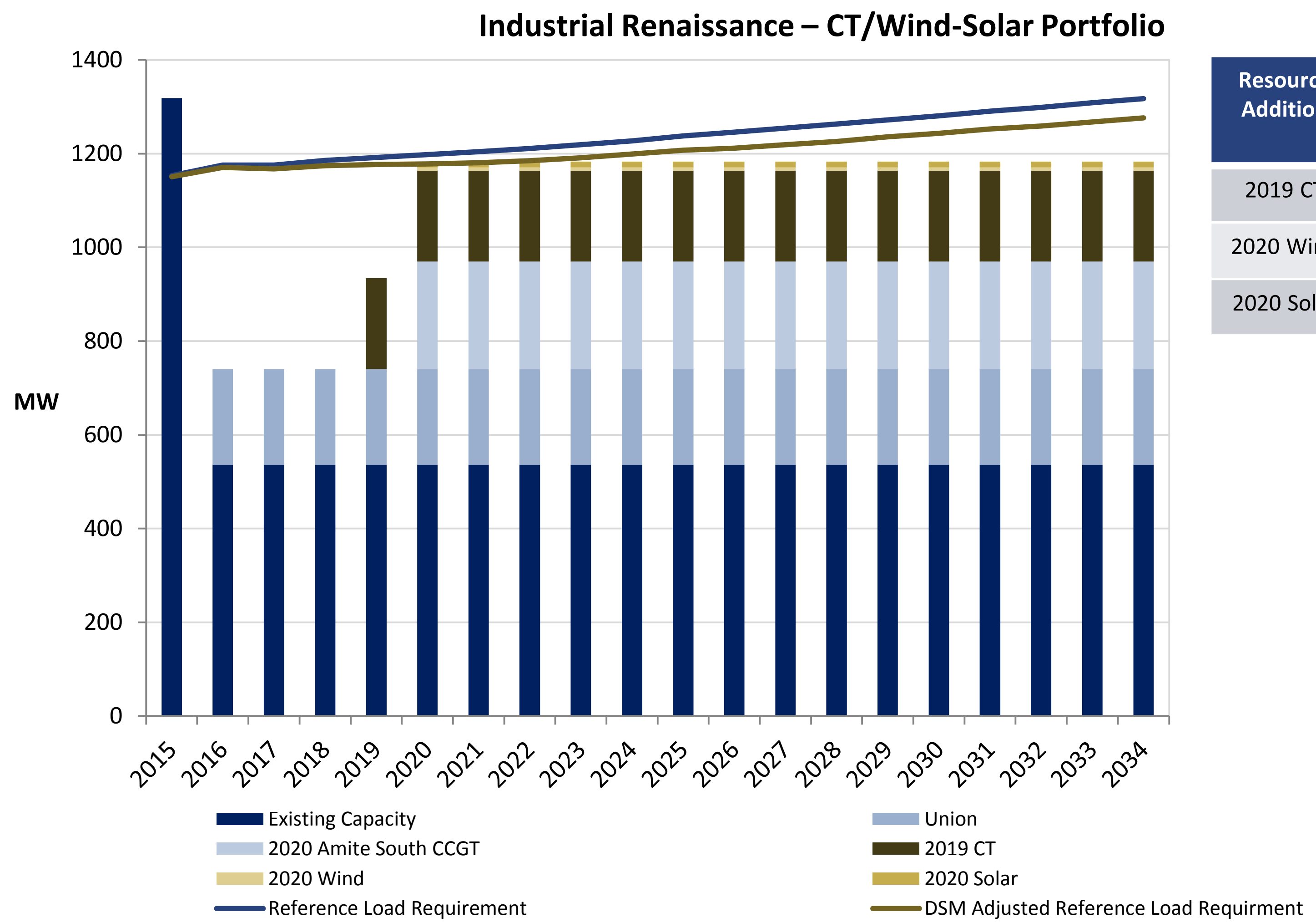
Preliminary – Work in Progress

MANUAL PORTFOLIOS - SUPPLY SIDE PORTFOLIOS



Resource Addition	Capacity (MW)	Effective Capacity (MW)
2019 CT	194	194
2020 Wind	50	7
2020 Solar	50	12.5

*Resources listed in blue are existing and planned resources. Resources additions listed in brown are the resources to be evaluated in the IRP.

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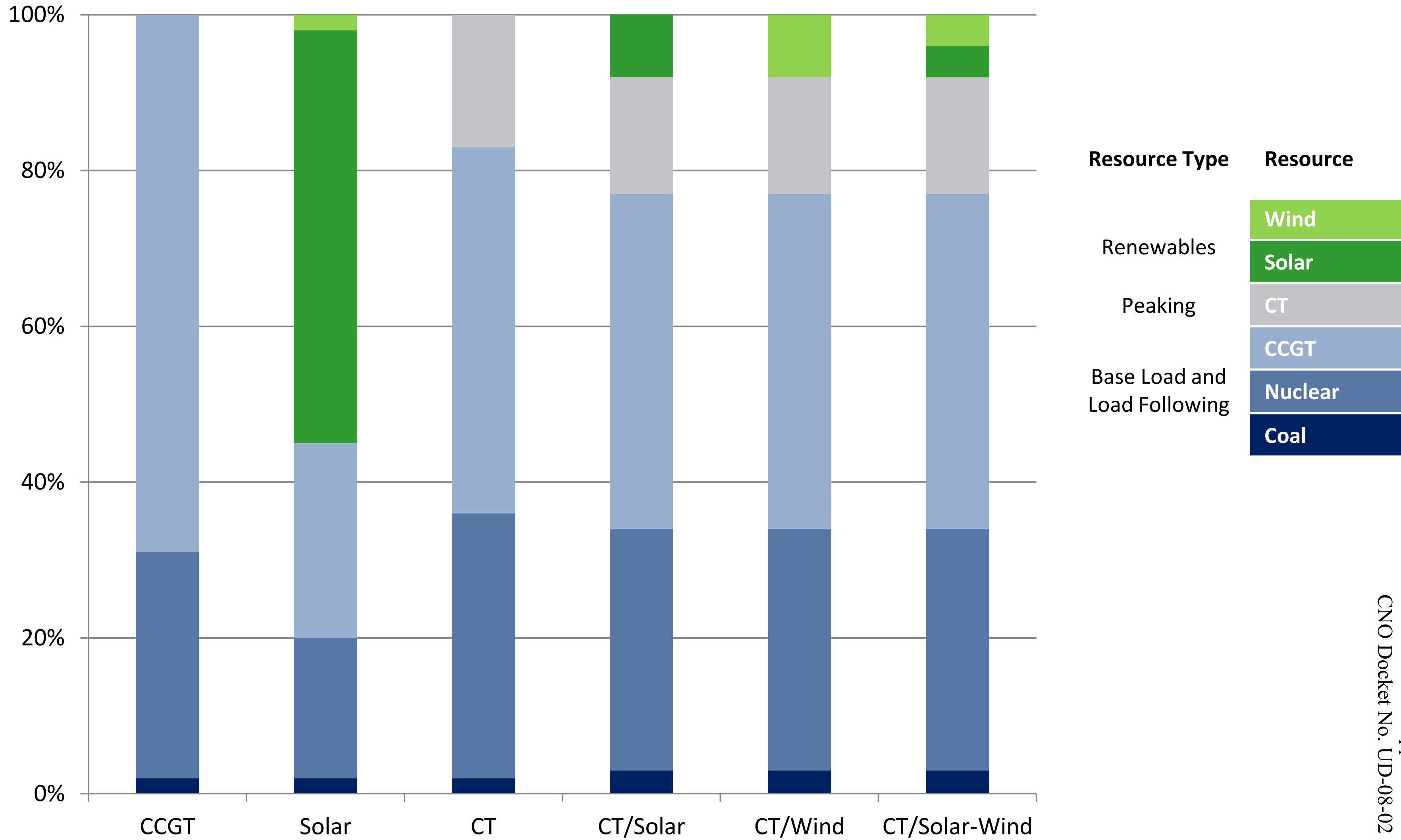
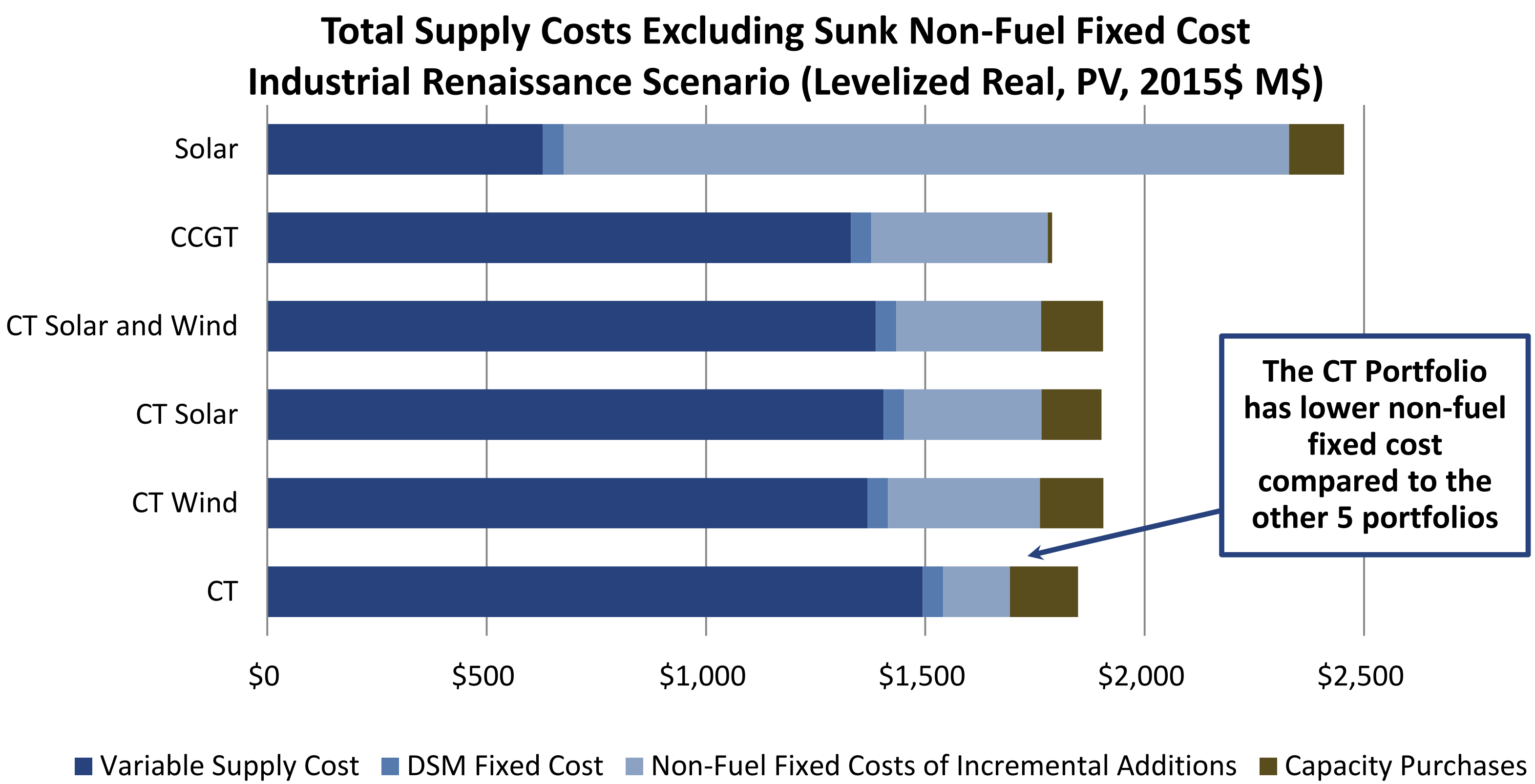
Preliminary – Work in Progress

INSTALLED CAPACITY MIX OF EACH PORTFOLIO IN 2034



TOTAL SUPPLY COST COMPONENTS EXCLUDING SUNK NON-FUEL FIXED COST



Total Supply Costs Excluding Sunk Non-fuel Fixed Costs

Variable Supply Costs
+ DSM Fixed Costs
+ Non Fuel Fixed Costs of Incremental Additions
+ Capacity Purchases
+ Production Tax Credits (PTC) and Investment Tax Credit (ITC) (only included in the GS Scenario)

PORTFOLIO TOTAL SUPPLY COSTS

The CT Portfolio performs well in most scenarios, has lower risk, and complements ENO's existing portfolio

- The CCGT Portfolio ranks high, but has more risk because of higher fixed cost being offset by uncertain potential variable cost savings
- The Solar Portfolio is highly ranked in the Generation Shift Scenario due to continuation of ICT subsidiaries, high gas prices, and high CO2 prices, but ranks lowest in each of the other scenarios
- The addition of Wind and/or Solar to the CT Portfolio is only beneficial in the Generation Shift Scenario

Total Cost by Scenario
Levelized Real ($M)

Portfolios

	Ref - IR	*BB*	*DD*	*GS*
CT	$1,846	$1,675	$1,789	$2,323
CT Wind	$1,905	$1,753	$1,837	$2,259
CT Solar	$1,902	$1,744	$1,840	$2,292
CT Solar_Wind	$1,903	$1,749	$1,838	$2,275
CCGT	***$1,789***	***$1,527***	***$1,705***	$2,177
Solar	$2,454	$2,420	$2,354	***$2,049***

Ranking by Scenario

	Ref - IR	*BB*	*DD*	*GS*
CT	2	2	2	6
CT Wind	5	5	3	3
CT Solar	3	3	5	5
CT Solar_Wind	4	4	4	4
CCGT	***1***	***1***	***1***	2
Solar	6	6	6	***1***

Variance ($M)
relative to highest ranked portfolio

	Ref - IR	*BB*	*DD*	*GS*
CT	$57	$148	$84	$275
CT Wind	$116	$226	$132	$210
CT Solar	$113	$217	$135	$243
CT Solar_Wind	$114	$222	$133	$226
CCGT	***$0***	***$0***	***$0***	$128
Solar	$665	$893	$649	***$0***

Although the CCGT and Solar Portfolios rank higher on a total cost basis, the CT Portfolio presents less risk while providing good economic performance.

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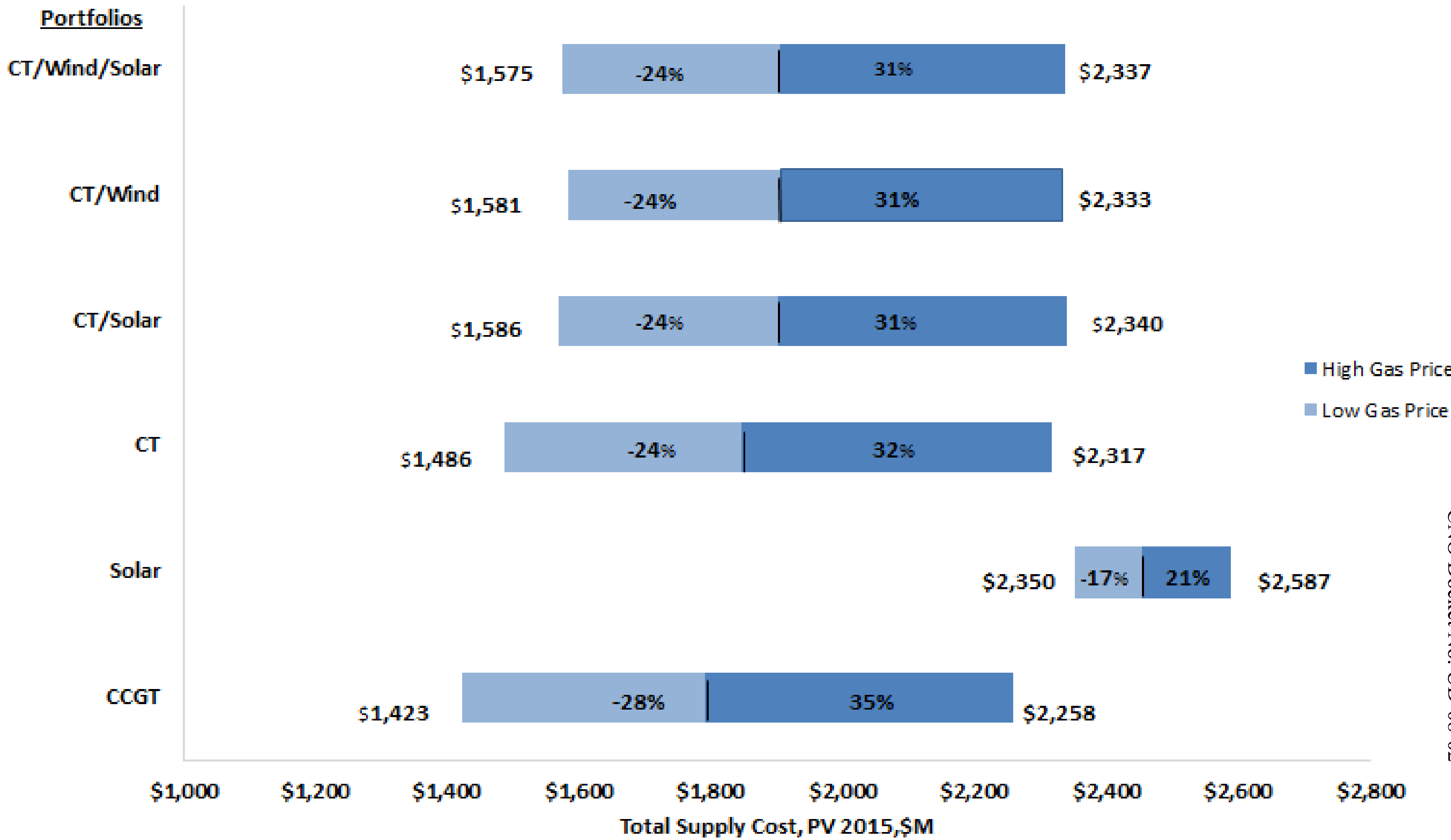
REFERENCE – IR SCENARIO SENSITIVITY: NATURAL GAS (PV $2015, $M)

Although the Solar Portfolio is less volatile, it is more costly than the other portfolios. The CCGT and CT Portfolios are similarly affected by changes in gas price assumptions.



CNO Docket No. UD-08-02
Supplement 9

REFERENCE – IR SCENARIO SENSITIVITY: CO_2 (PV $2015, $M)

The CCGT Portfolio is relatively less affected by changes in carbon price assumptions; however, ENO existing portfolio is expected to have adequate Base Load and Core Load Following capacity.

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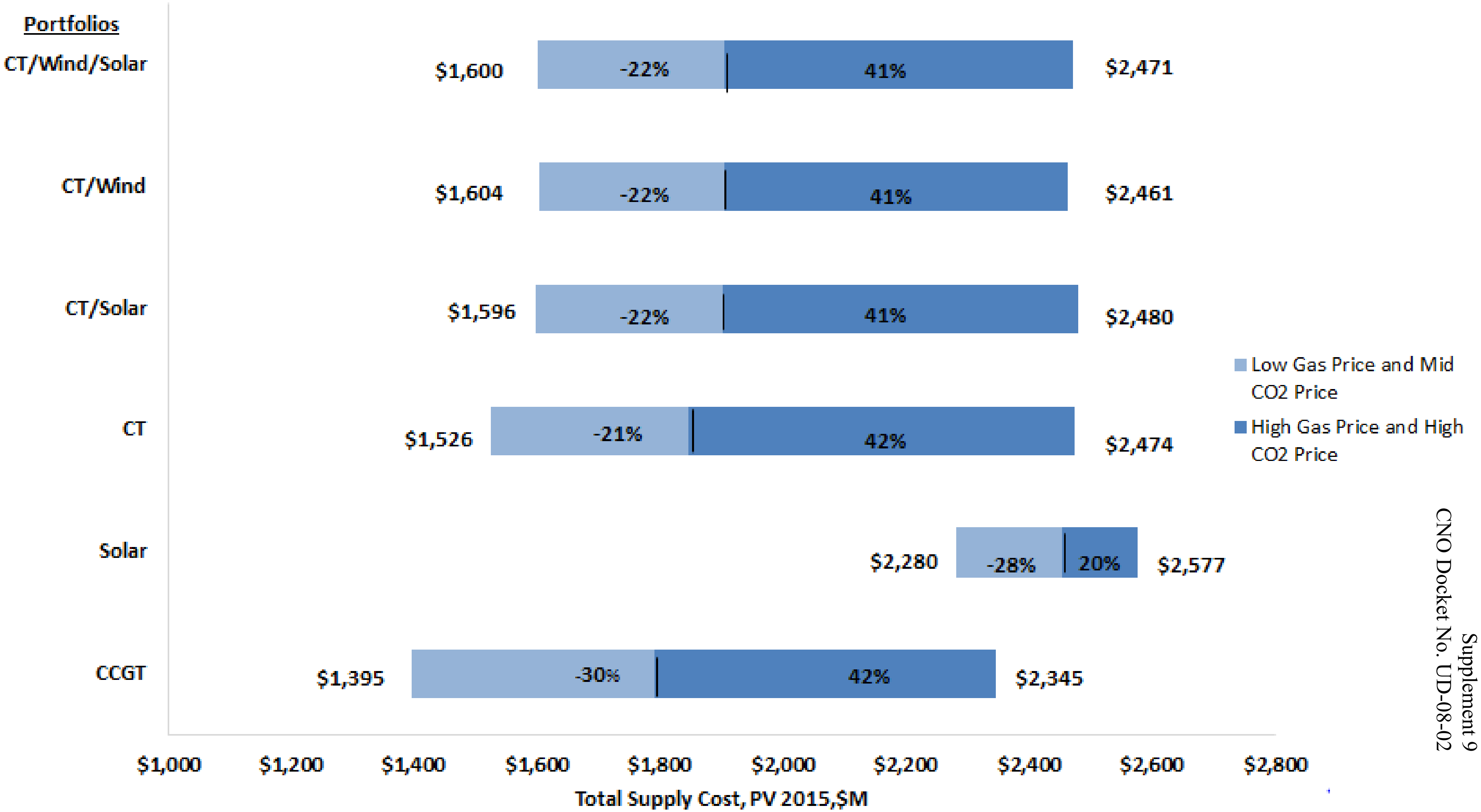
REFERENCE – IR SCENARIO SENSITIVITY: NATURAL GAS AND CO_2 (PV \$2015, \$M)

Although the Solar Portfolio is less volatile, it is more costly than the other portfolios. The CCGT and CT Portfolios are similarly affected by changes in gas price assumptions.



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Next steps

The following activities are planned:

- Identify reference portfolio plan and action plan
- Draft IRP Report is due in June 2015

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 CLEAResult. 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

PROGRAM NAME	KWH Goal	KWH Actual	PARTICIPANTS	MEASURES	KWH
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%
TOTALS	3,113,278	3,207,488	1,407	18,371	103.03%

Table 8: Program Year Two – Algiers

PROGRAM NAME	KWH Goal	KWH Actual	PARTICIPANTS	MEASURES	KWH
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%
TOTALS	2,070,333	2,020,644	1,839	27,910	97.60%

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.entergy-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.

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,[1] 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.

[1] 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%
			Average	**0.7%**

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

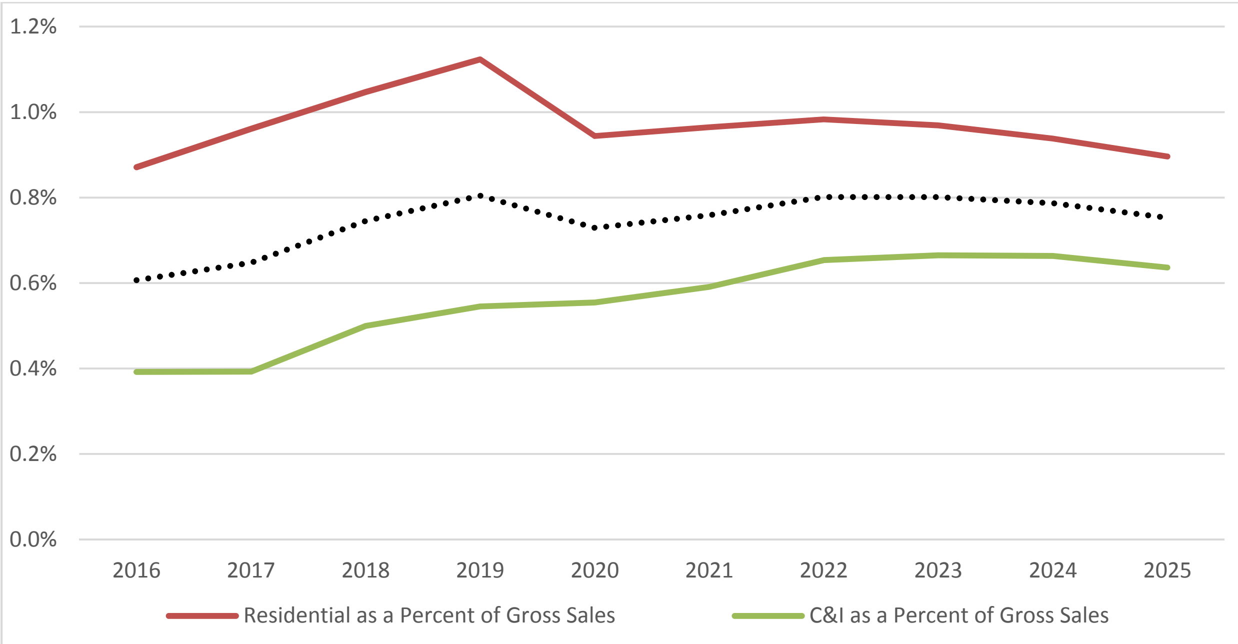


Table 14: EAI Potential (Medium Case GWH)

	GWh									
Incremental Achievable Potential	**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

ENO Potential Study				
Year	Reference Case Scenario			
	Program Budget (Millions $)	Cumulative GWh Savings	Incremental GWh Savings	Inc. GWh Savings as % of Previous Years Sales
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%
			Average	**0.6%**

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

Levelized Cost per Cumulative kWh (2016-2025)			
Study	**NPV (Millions $)**	**NPV GWh**	**Levelized Cost per Cumulative kWh (2016-2025)**
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.

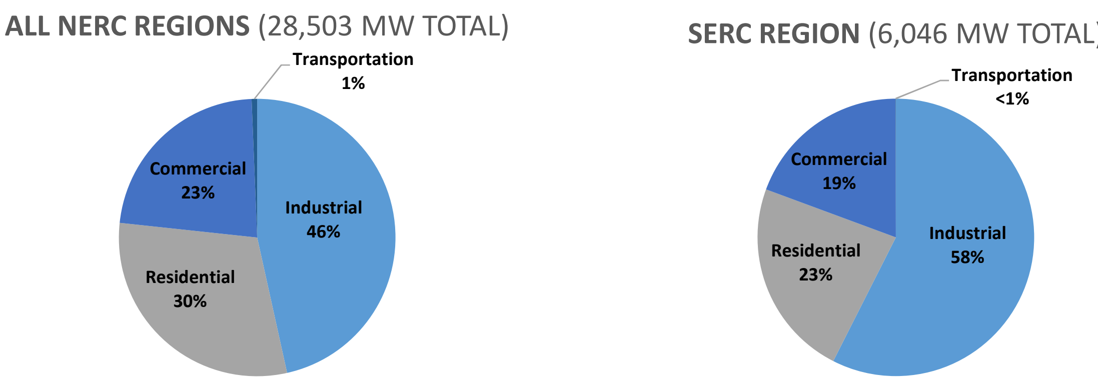
STATE OF THE MARKET

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:[2]

- 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.
    - o 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.
    - o 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:

Figure 2: NERC and SERC Potential Savings



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.[3]
- AMI meter saturation in the SERC region was 21% in 2012.[4]

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[2] U.S. Federal Energy Regulatory Commission (FERC). Assessment of Demand Response and Advanced Metering Staff Report. December 2014.
[3] Id.

- More than half the households in the U.S. are likely have a smart meter by the end of 2015.[5]

The number of customers in incentive- and time-based DR programs NERC-wide, and in SERC specifically, are shown below.[6]

Table 18: DR Customer Enrollment by Program type

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

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 Comverge's Intellisource Demand Response Management System are two examples of such EE/DR services.[7]
- 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.[8]

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).

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[4] Id.

[5] The Edison Foundation. Institute for Electric Efficiency. Utility-Level Smart Meter Deployments: Plans and Proposals. May 2012.

[6] FERC 2014.

[7] Greentech Efficiency. Technology Choice is Finally Coming to Residential Demand Response. Katherine Tweed. January 30, 2014.

[8] 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

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

Summary of Advanced Metering Infrastructure (AMI) Activities and Trends

Advanced Metering Infrastructure (AMI)[9] 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[10]. 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[11].

Table 20 AMI Installations by State – July 2014

(>2,000,000 meters/state)

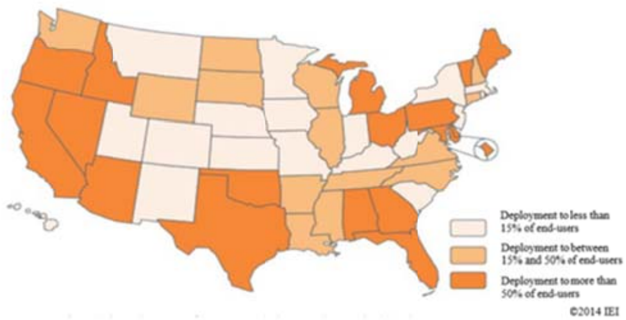
State	Total Smart Meters Installed
California	12,479,730
Florida	5,614,700
Georgia	3,182,150
Pennsylvania	2,698,716
Arizona	2,061,760

[9] 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.

[10] U.S. Federal Energy Regulatory Commission (FERC). Assessment of Demand Response and Advanced Metering Staff Report. December 2015.

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

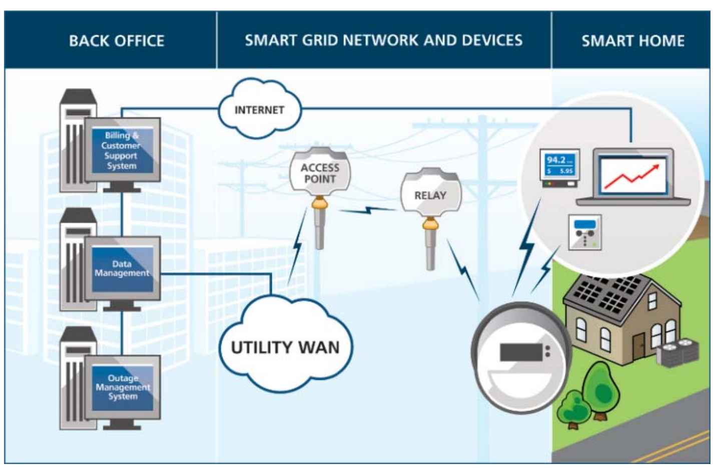
Figure 3: Smart Meter Deployment by State 2015



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

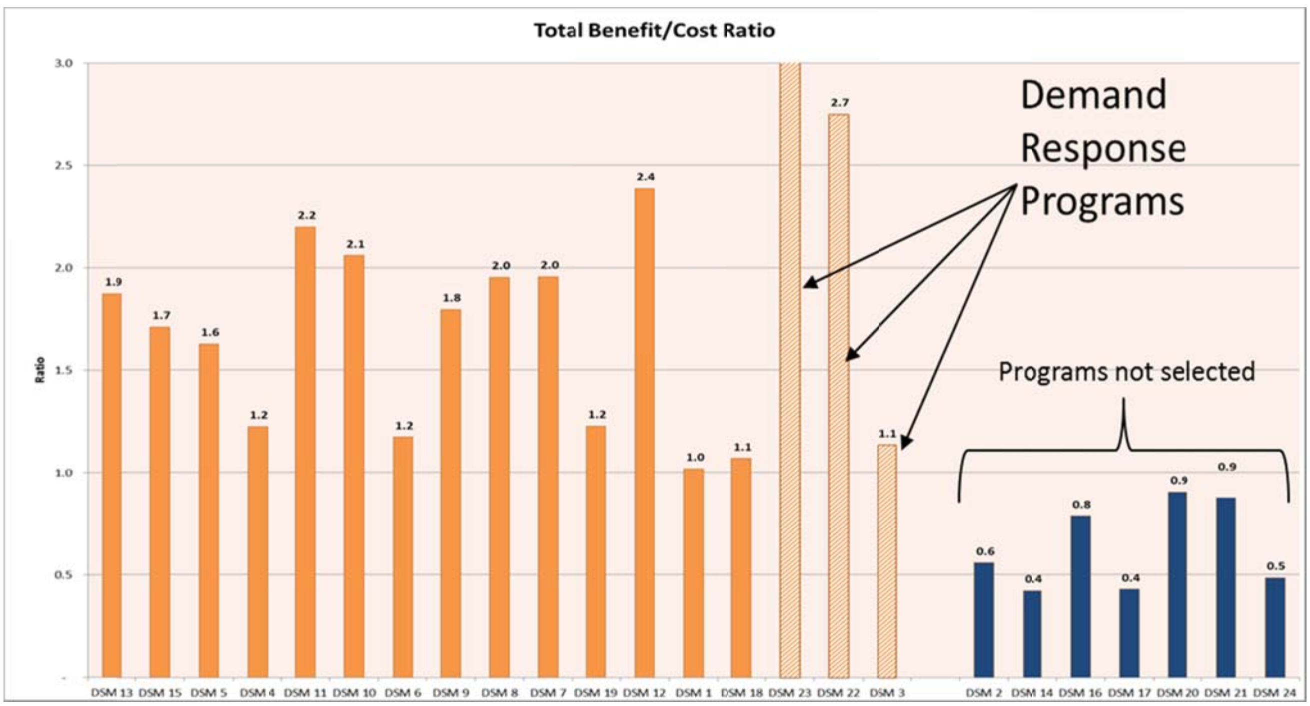


Figure 6: DSM Incremental Net Benefit

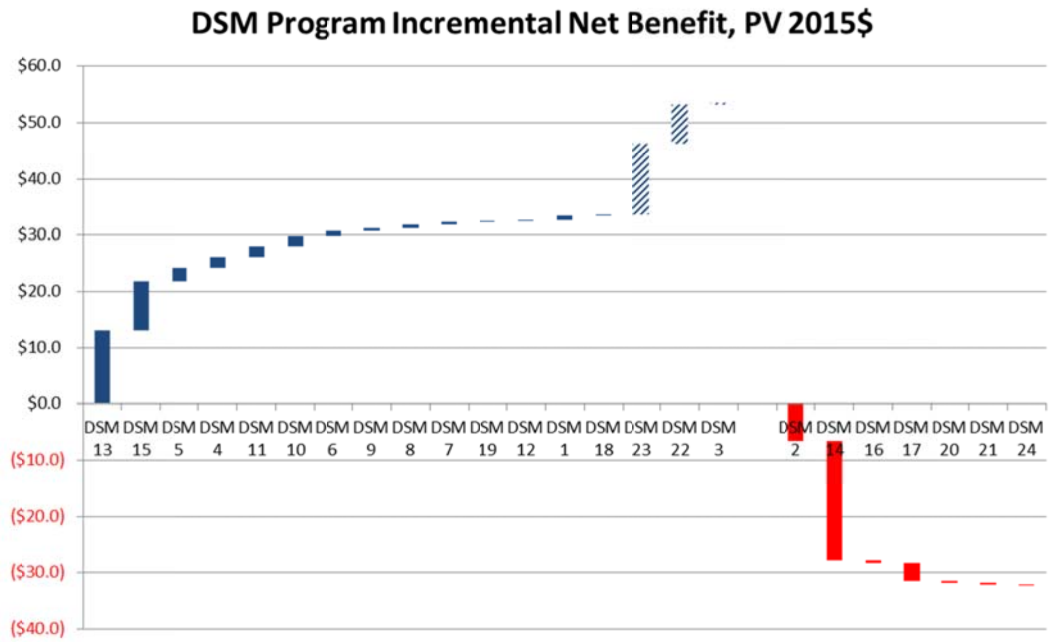


Table 21: DSM Incremental Net Benefit

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
Benefit:																	
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
Total Benefit	$28.1	$21.1	$6.2	$10.1	$3.4	$3.6	$6.2	$1.3	$1.1	$1.0	$1.2	$0.3	$53.0	$0.3	$12.9	$11.1	$3.4
Cost:																	
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
Net Benefit:																	
Net Benefit	**$13.1**	**$8.8**	**$2.4**	**$1.8**	**$1.9**	**$1.8**	**$0.9**	**$0.6**	**$0.5**	**$0.5**	**$0.2**	**$0.2**	**$0.8**	**$0.0**	**$12.6**	**$7.1**	**$0.4**
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)

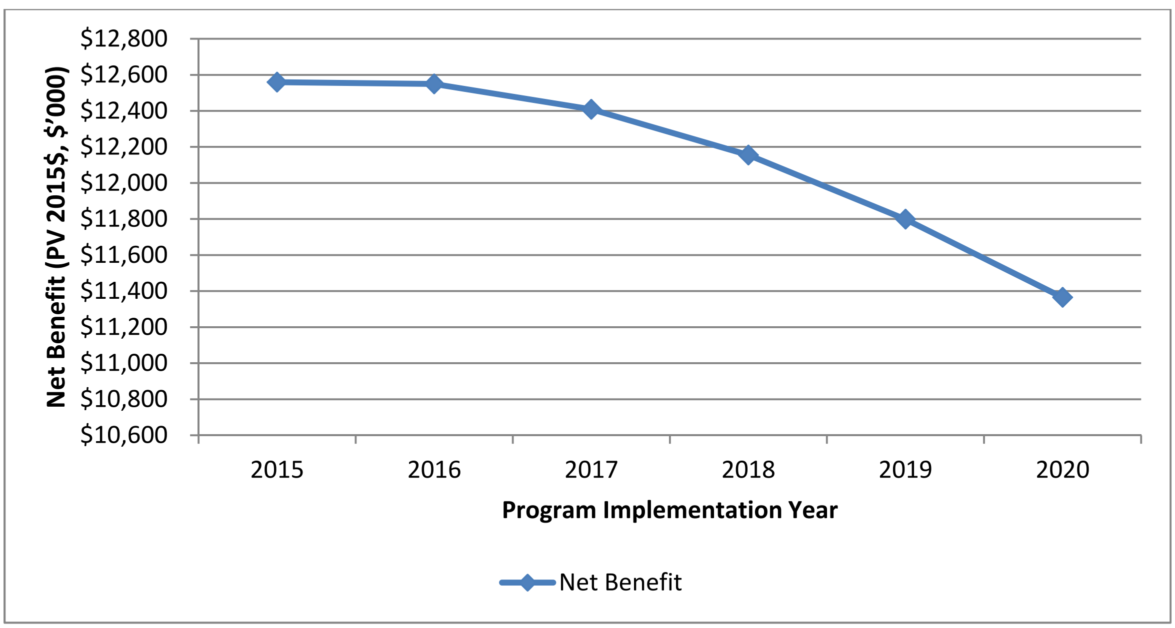


Figure 8: Annual Sensitivity for Non-Residential Dynamic Pricing Program Implementation (DSM 3)

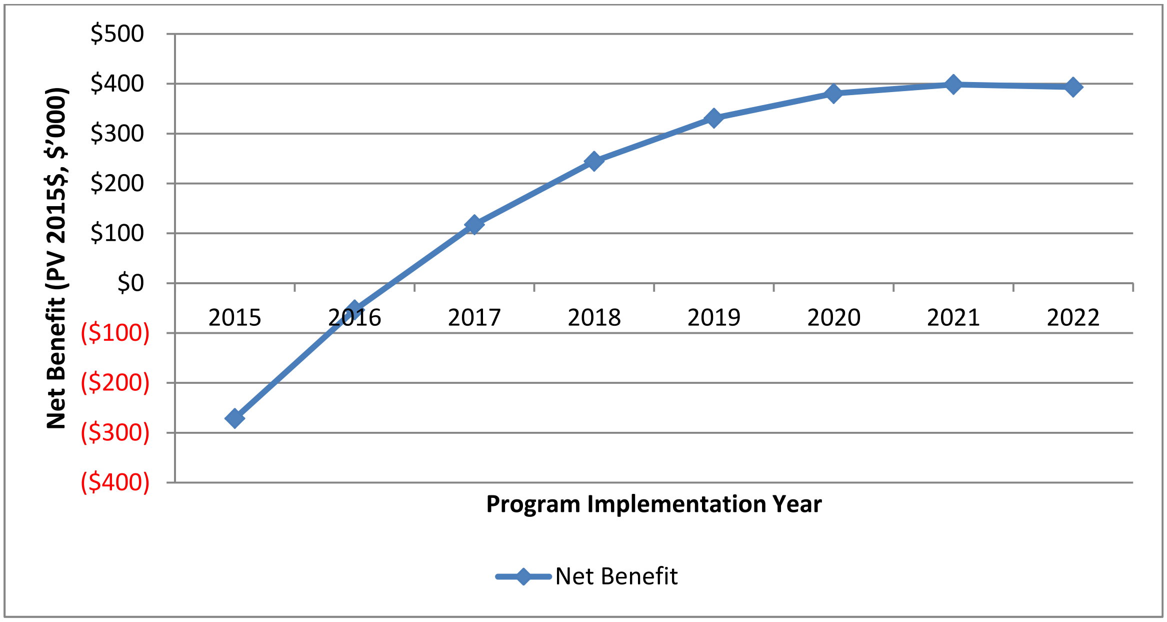


Figure 9: Annual Sensitivity for Direct Load Control Program Implementation (DSM 22)

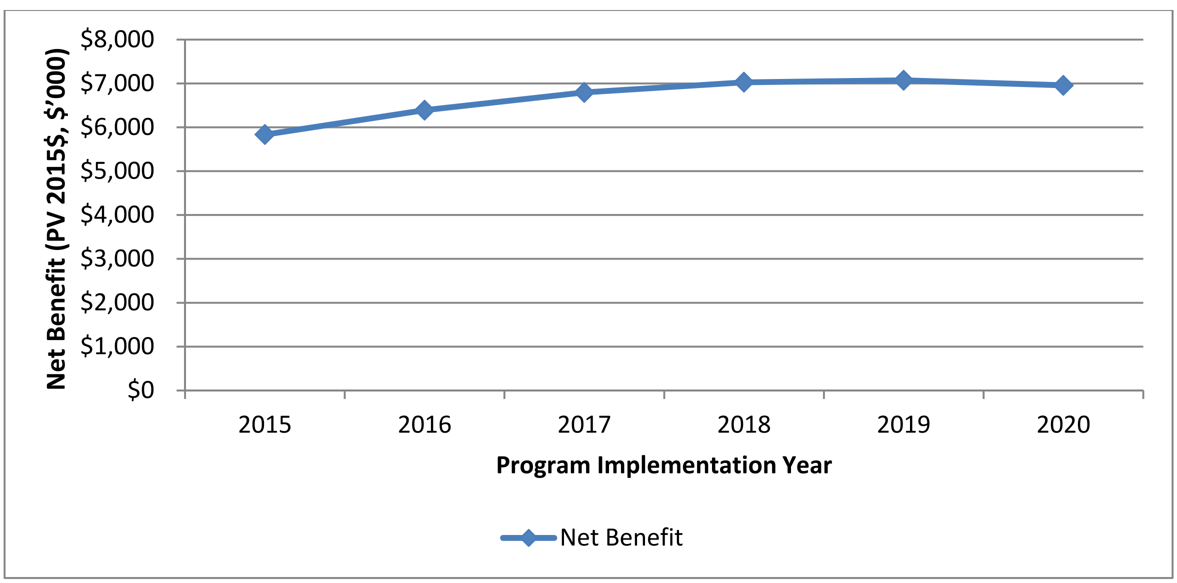


Figure 10: Contribution of DR Programs to Peak Load Reduction

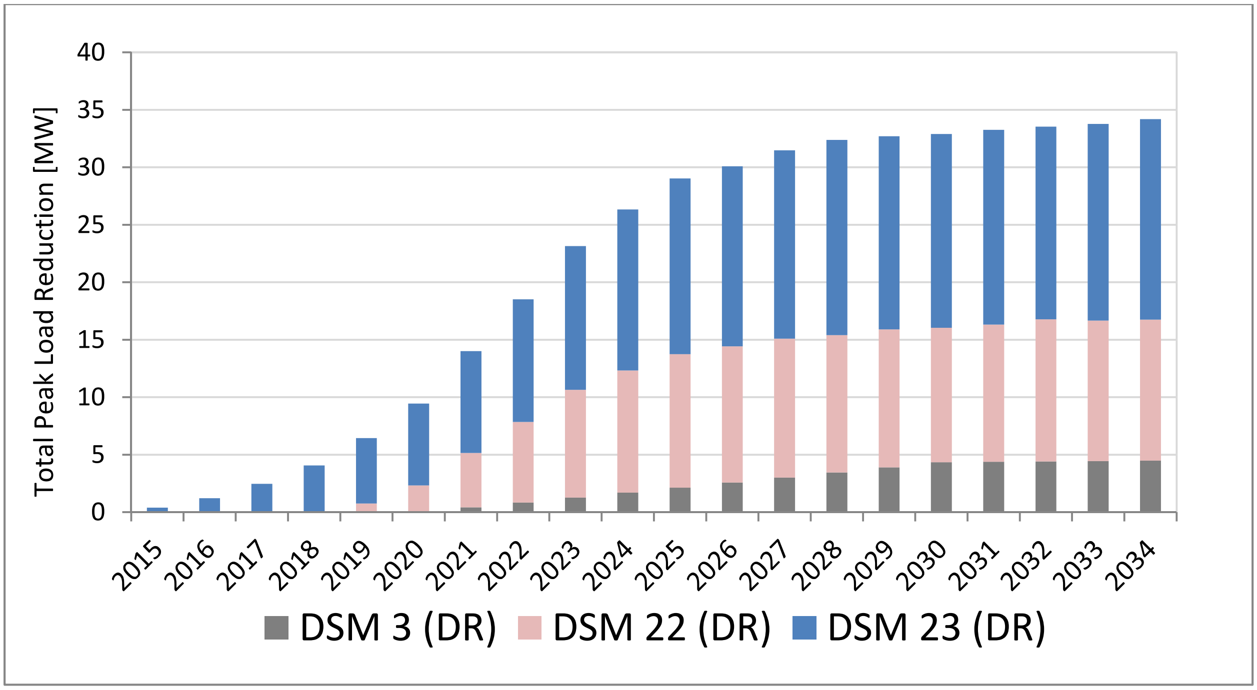


Table 22: Net Benefit of DR Programs PV (2015, $)

Net Benefit of DR Programs			
	DSM 23	**DSM 22**	**DSM 3**
Benefit:			
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	$3.4
Cost:			
Total Program Cost *[M$]*	$0.4	$4.0	$3.0
Net Benefit:			
Net Benefit *[M$]*	$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)

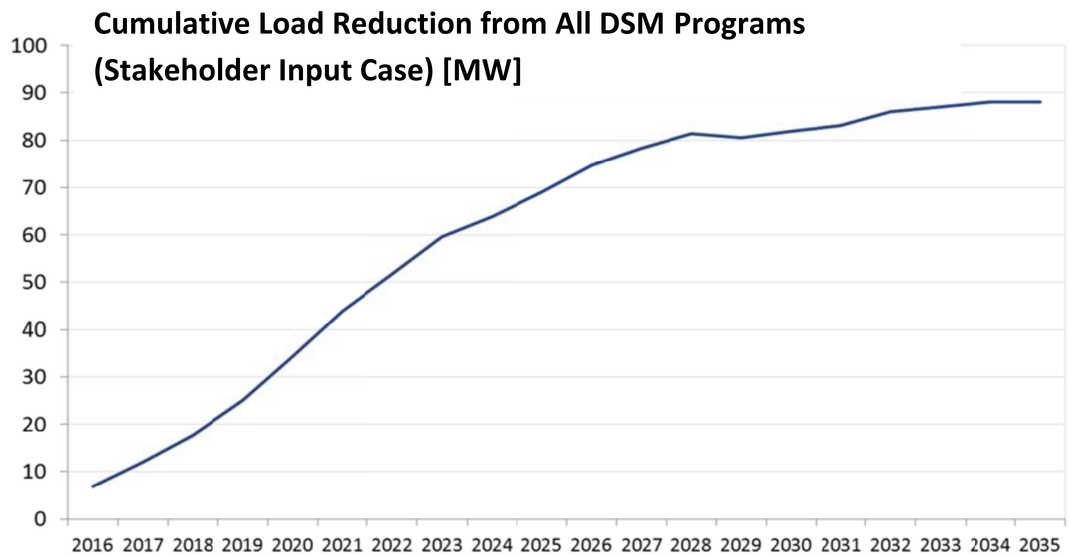


Table 23: ENO Preferred Portfolio of DSM Programs

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
Total			**88**

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.[12]

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.[13] 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.[14]

Air emissions: Avoided electricity and natural gas use due to energy efficiency also results in air emissions avoided. Some jurisdictions include avoided CO_2 values in avoided electricity and natural gas avoided costs. The recently adopted Federal Clean Power Plan rule may impact CO_2 values in many states in the long-run. Other emissions avoided with readily quantified values include SO_x, NO_x 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[15] to $4500[16] per home within 150 ft.) or through rehabilitation of residences (estimated at $2000 per home within 300 ft.).

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

[13] Summit Blue Consulting, LLC, 2006. *Non-Energy Impacts (NEI) Evaluation on behalf of NYSERDA.*

[14] Cadmus, 2013. *Appliance Recycling Program Process Evaluation and Market Characterization - Volume 1.*

[15] 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.

[16] 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.[17]

[17] 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_2 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

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

[18] 2016 Nominal Cost.
[19] Effective capacity of a wind installment is based on MISO's 15/16 capacity credit of 14.7%
[20] 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)

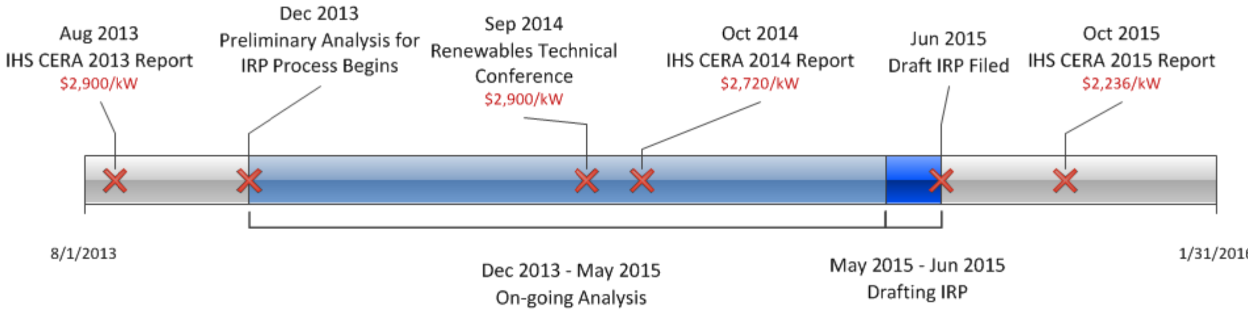
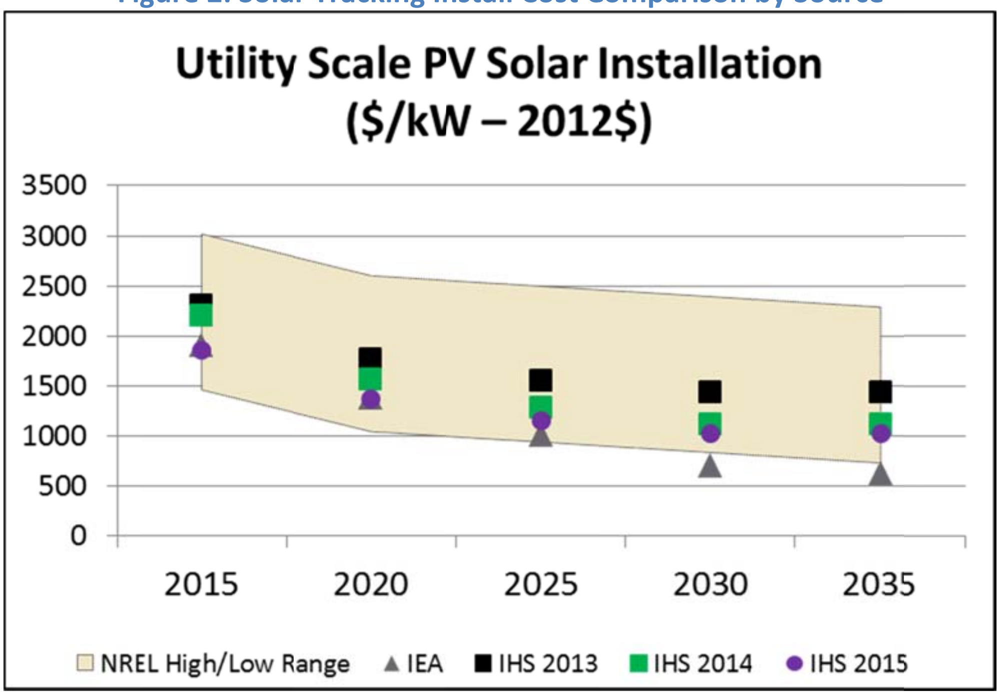


Figure 2: Solar Tracking Install Cost Comparison by Source



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

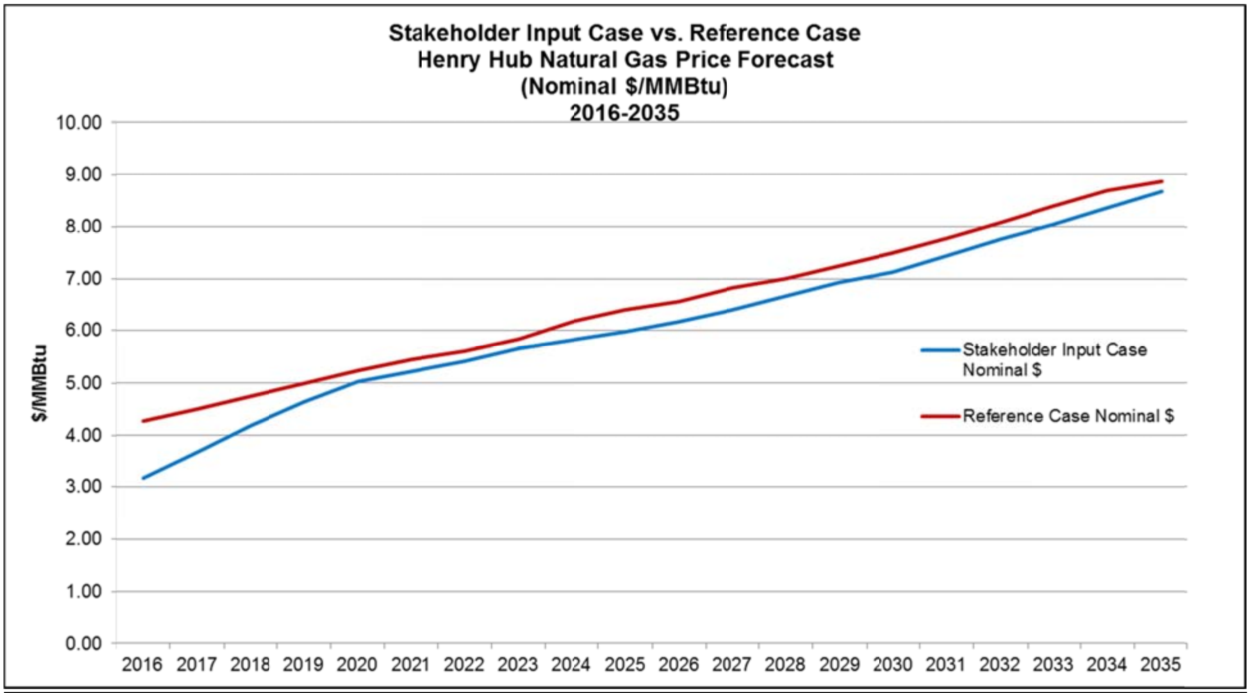
The natural gas price forecast for the Stakeholder Input Case was lower than the reference case forecast used in the Industrial Renaissance scenario. This forecast was influenced by historically strong production driven by the continued economics of Northeast shale gas combined with mild weather. These 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

Henry Hub Natural Gas Prices		
	Nominal $/MMBtu	**Real 2014$/MMBtu**
Real Levelized[21] (2016-2035)	$5.54	$4.57
Average (2016-2035)	$6.12	$4.76
20-Year CAGR	5.2%	3.2%

[21] "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

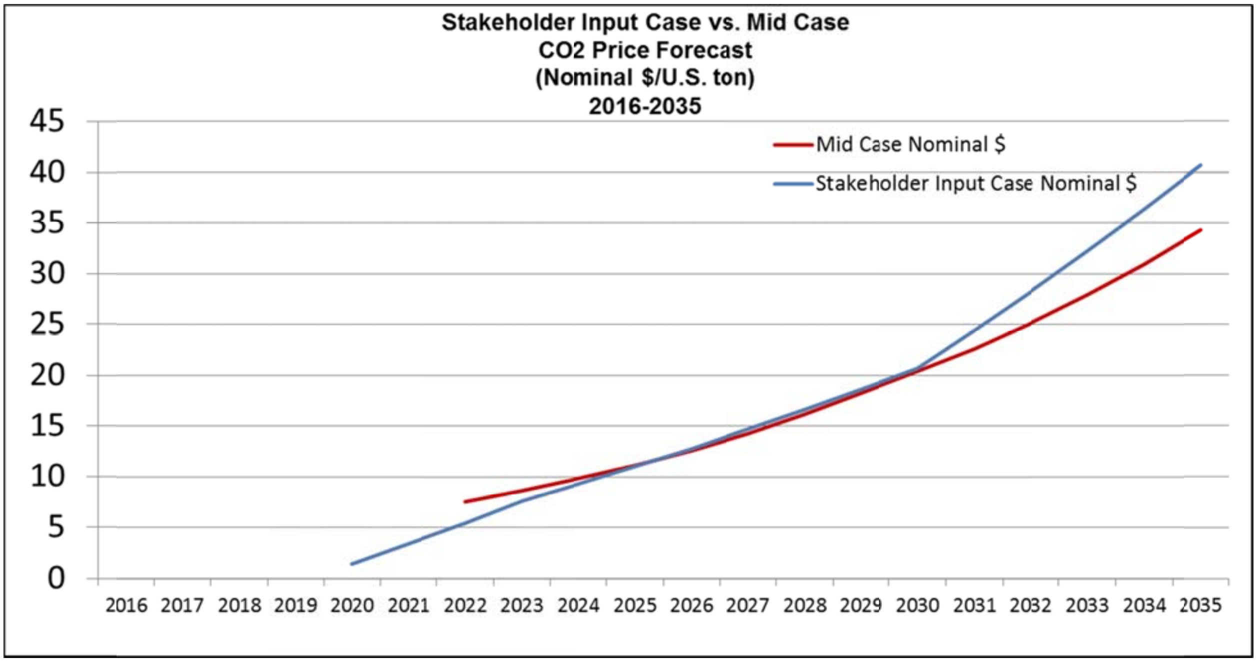


CO_2 PRICE

The Stakeholder Input Case CO_2 price forecast was taken from Entergy corporate CO_2 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_2 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.[22]

[22] Includes discount rate of 7.12%

Figure 4: Stakeholder Input Case CO_2 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)

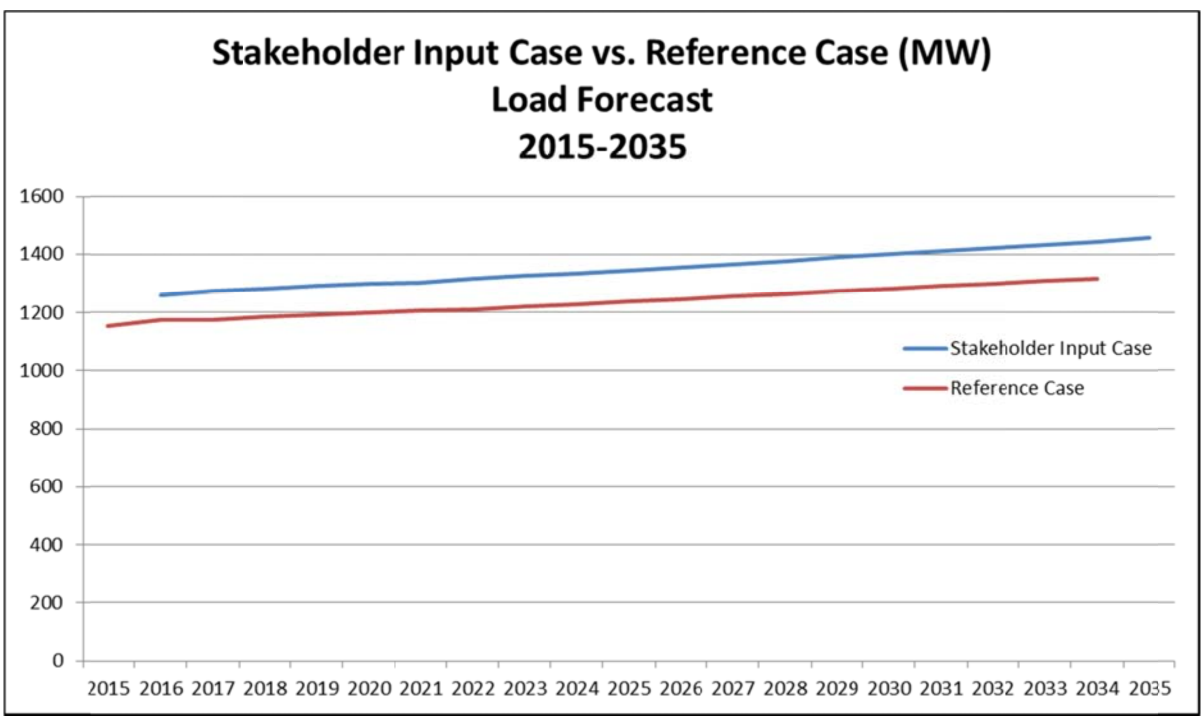
Resource Name	Resource Type	MW
Acadia	CCGT	7
Buras 8	Legacy Gas	0.2
Grand Gulf	Nuclear	3
Little Gypsy 2	Legacy Gas	8
Little Gypsy 3	Legacy Gas	10
Ninemile 4	Legacy Gas	13
Ninemile 5	Legacy Gas	13

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
DSM Programs	19 Programs	19 Programs	19 Programs	19 Programs	19 Programs	19 Programs
CCGTs	450	0	0	0	0	0
CTs	0	0	250	250	250	250
Solar	0	1200	0	100	0	50
Wind	0	0	0	0	100	50

Figure 6: Stakeholder Input Case Scenario CT Portfolio

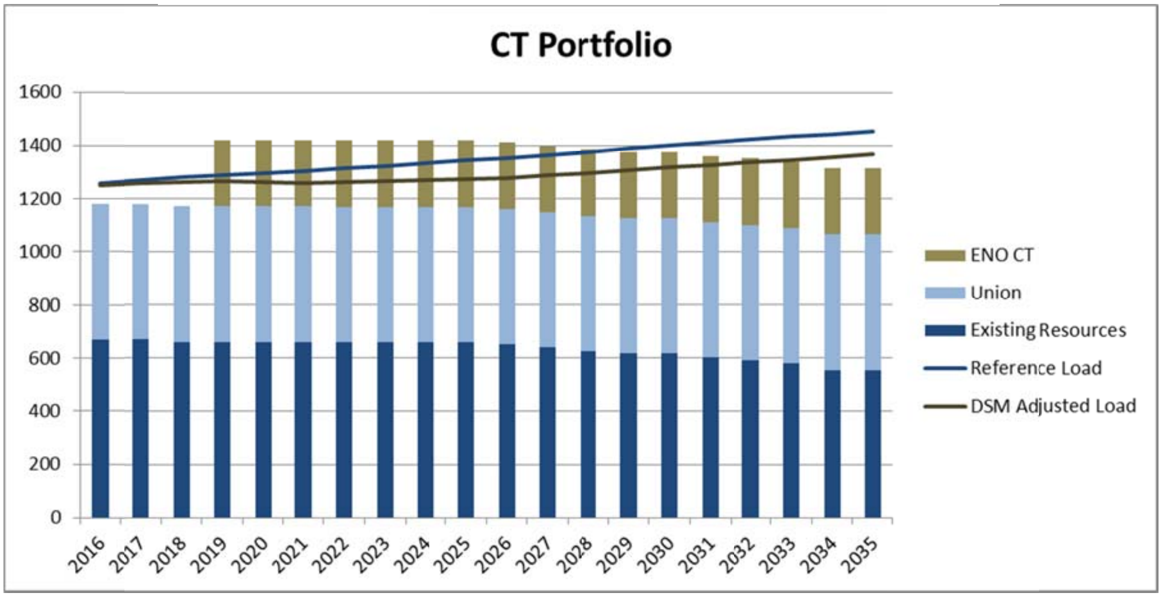


Figure 7: Stakeholder Input Case Scenario CT/Wind Portfolio

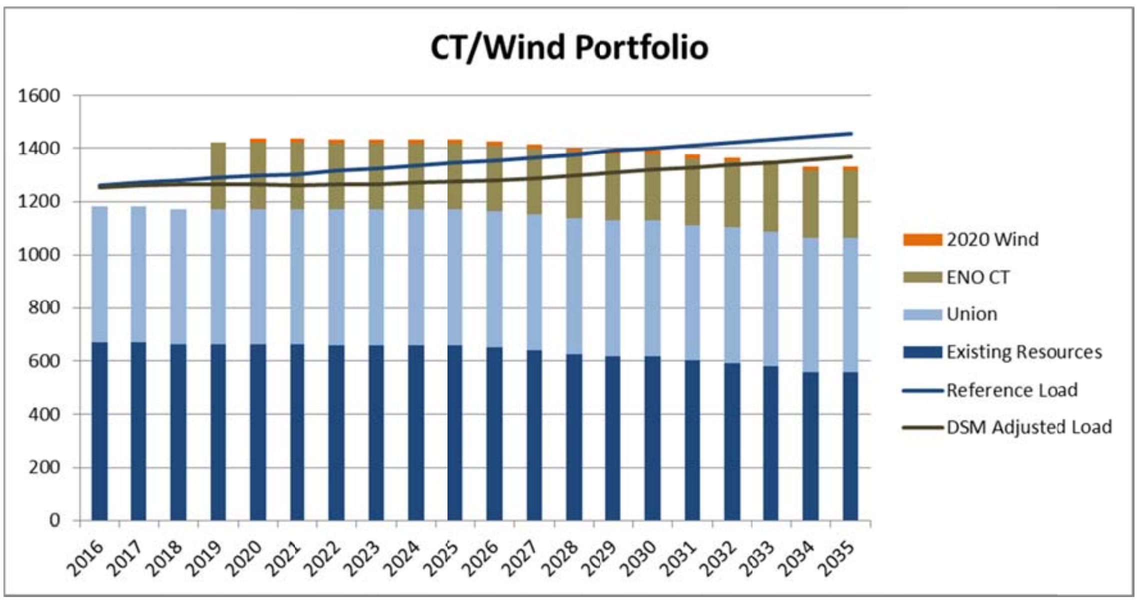


Figure 8: Stakeholder Input Case Scenario CT/Solar Portfolio

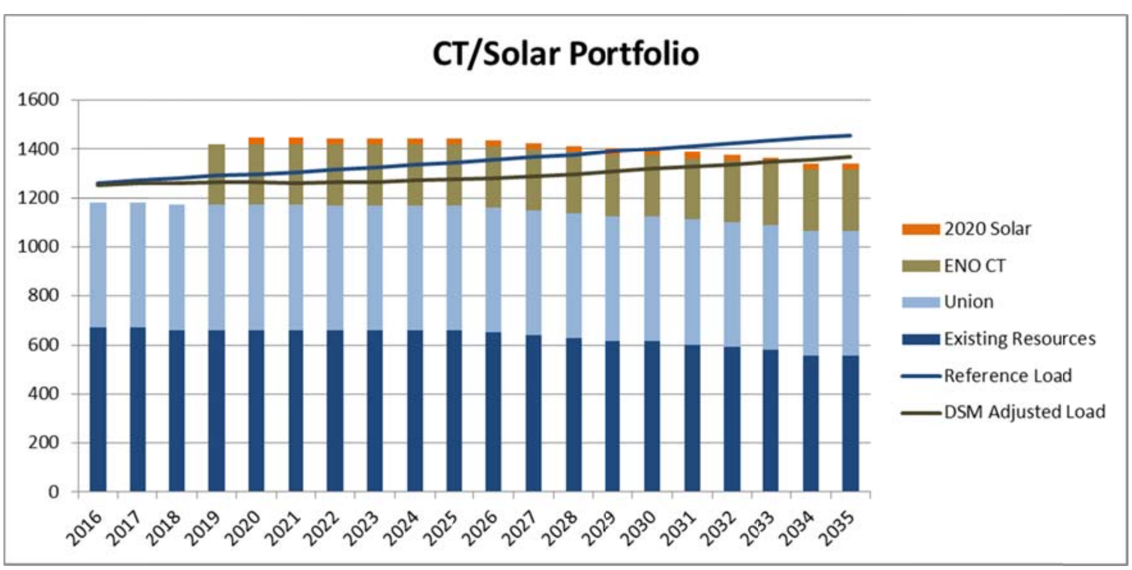


Figure 9: Stakeholder Input Case Scenario CT/Solar/Wind Portfolio

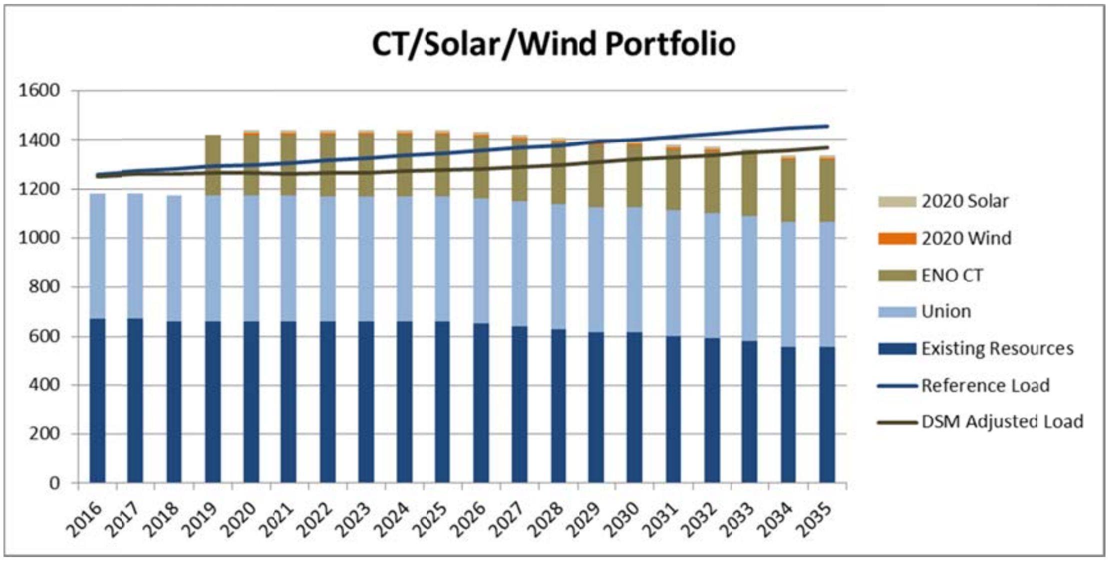


Figure 10: Stakeholder Input Case Scenario CCGT Portfolio

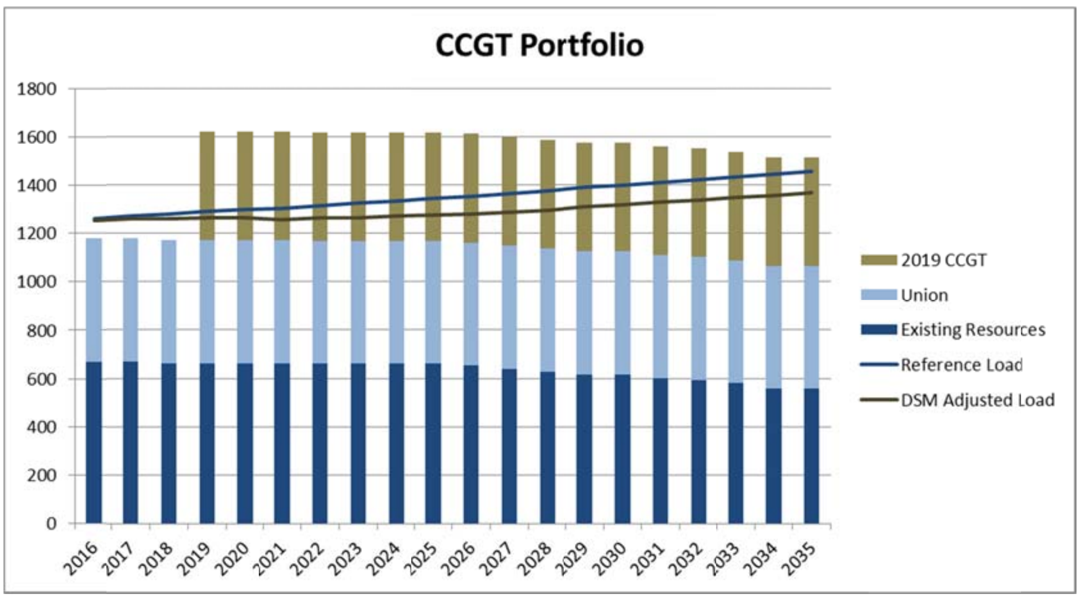
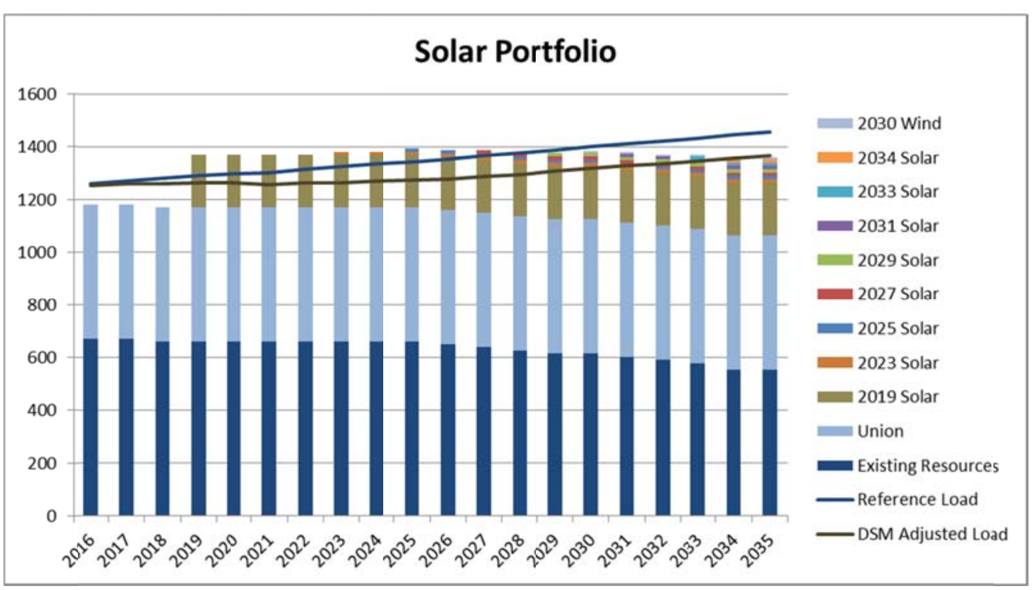


Figure 11: Stakeholder Input Case Scenario Solar Portfolio



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

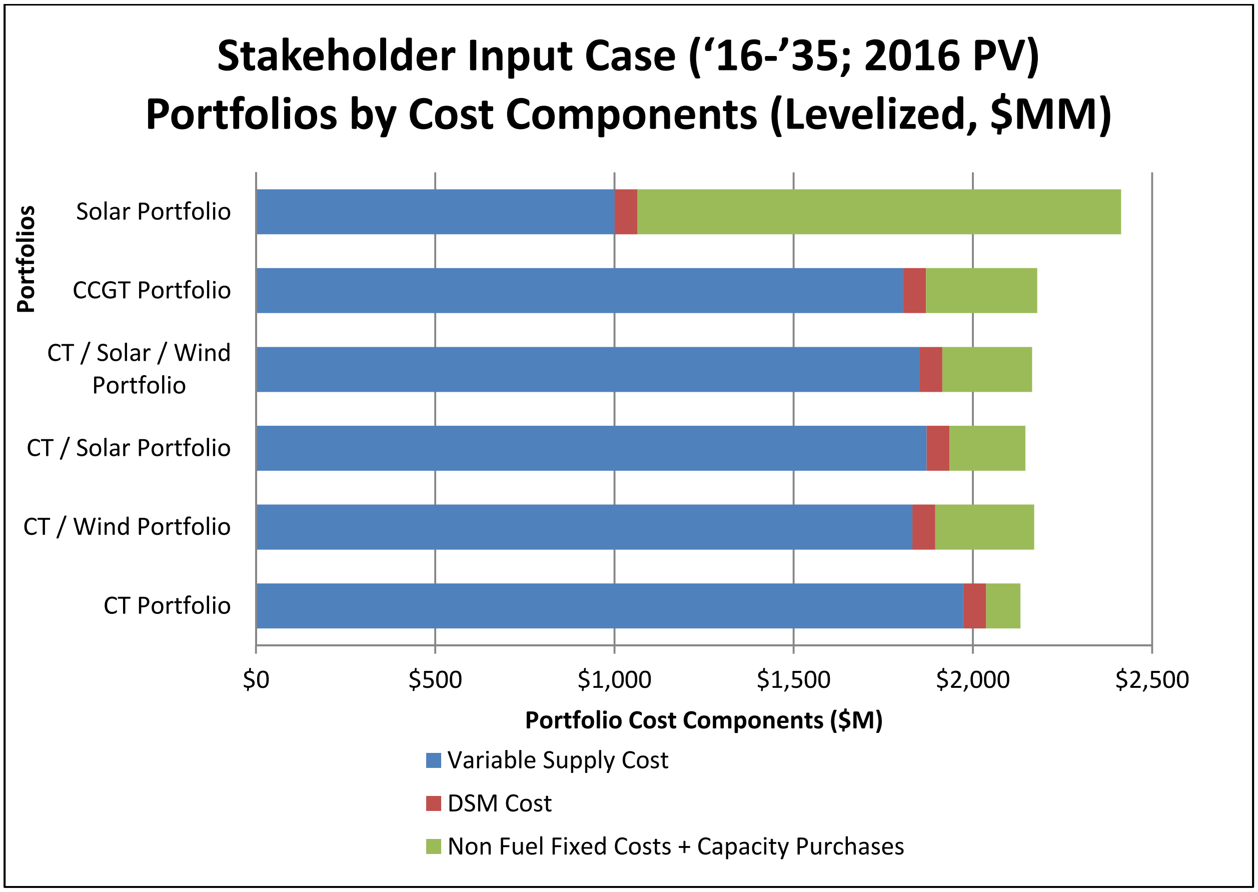


Table 9: Portfolio Ranking by Total Supply Cost

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

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)[23]

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[24]
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%

[23] Includes benefits associated with the optimal (cost-effective) level of DSM identified through the DSM Optimization.

[24] 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)[27]

Load & Capability 2016—2035																				
	2016	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Requirements																				
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
Total Requirements	1,260	1,273	1,280	1,291	1,298	1,303	1,316	1,325	1,336	1,345	1,355	1,366	1,378	1,390	1,401	1,412	1,424	1,435	1,446	1,457
Resources																				
Existing Resources																				
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
Identified Planned Resources																				
Union[25]	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510
Other Planned Resources																				
DSM[26]	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
Total Resources	1,260	1,273	1,280	1,291	1,298	1,303	1,316	1,325	1,336	1,345	1,355	1,366	1,378	1,390	1,401	1,412	1,424	1,435	1,446	1,457

[25]Union plant acquisition is completed pending regulatory approvals.
[26]Demand Side Management (DSM) total is grossed up for Planning Reserve Margin (12%) and transmission losses (2.4%).
[27] Includes Algiers Transfer