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April 15, 2015

Via Overnight Mail
Ms. Terri Lemoine Bordelon
Records and Recording Division
Louisiana Public Service Commission
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Baton Rouge, Louisiana 70802

Re: 2015 Integrated Resource Planning ("IRP") Process for Entergy Louisiana, LLC and Entergy Gulf States Louisiana, L.L.C. Pursuant to the General Order No. R-30021, Dated April 20, 2012
LPSC Docket No. I-33014

Dear Ms. Bordelon:

On behalf of Entergy Louisiana, LLC and Entergy Gulf States Louisiana, L.L.C. (collectively, the "Companies"), enclosed please find Revision 1 of the Companies' 2015 Draft Integrated Resource Plan (the "2015 Draft IRP") and Appendix A, ELL and EGSL Generation Resources. Please retain the original and two copies for your files and return a date-stamped copy to me in the enclosed, self-addressed envelope.

At the Stakeholder Meeting held on February 24, 2015, questions were raised about the inclusion of certain generation resources and their associated capacity in Tables 4 and 19 of the Draft IRP and in Appendix A. In response to those questions, the Companies have reviewed the tables and made the following revisions in order to clarify the information presented:

- Riverbend Station was incorrectly split on Table 19 between "Owned Resources" (389 MW) and "PPA Contracts" (195 MW) in the original filing. Table 19 has been revised so that all 584 MW of the Riverbend Station capacity is included in the "Owned Resources" row, which has resulted in an increase of 195 MW to the "Owned Resources" row and a corresponding reduction of 195 MW to the "PPA Contracts" row. No changes were necessary to Table 4 or Appendix A.
- Little Gypsy 1 was properly excluded from Table 19 in the original filing because it suffered a forced outage and its return to operation is uncertain. However, it was incorrectly included in the capacity totals on Table 4 and in the list of generation resources in Appendix A. It has now been removed from Appendix A with a corresponding reduction of 238 MW in the "ELL-Other Gas" row of Table 4.

- Ninemile 6 was correctly included in Appendix A and the Combined Cycle Gas Turbine (CCGT) row of Table 4 with a total of 448 MW of capacity (308 MW for ELL and 140 MW for EGSL). However, the Combined Total cell of Table 4 erroneously included the remaining 112 MW which has been allocated to ENOI. This 112 MW has now been excluded from the total.
- Montauk was correctly included in the LMR row of Table 19 in the original filing. However, it was incorrectly included in the capacity totals on Table 4 and in the list of Unaffiliated PPAs in Appendix A. It has now been removed from Appendix A with a corresponding reduction of 3 MW in the "ELL-Hydro & Other" row of Table 4.
- Thus, the total of the three changes to Table 4 may be summarized as follows:

  238 MW (Little Gypsy 1)
  112 MW (Ninemile 6)
  + 3 MW (Montauk)
  353 MW Total

  This represents the amount of the change in the Combined Total of Table 4 from 10,915 MW to 10,561 MW.[1] The corrected total of 10,561 MW ties to both Table 19 (sum of Owned Resources and PPA rows for 2015) and Appendix A (Total Capacity for ELL and EGSL). The change in the Combined Total is noted in the paragraph on page 19 and in the first paragraph on page 23.
- Finally, in the first paragraph on page 23, the total net reduction in generating capacity over the planning period was changed from 6,100 MW to 6,859 MW as a result of the changes detailed above.

If you have any questions, please do not hesitate to call me. Thank you for your courtesy and assistance with this matter.

Sincerely,

Edward R. Wicker, Jr.

ERW/ttm
Enclosures

cc: Official Service List (*via electronic and U.S. mail)*

[1] The 1 MW difference between the three changes and the Combined Total is the result of rounding.

CERTIFICATE OF SERVICE
LPSC Docket No. I-33014

I, the undersigned counsel, hereby certify that a copy of the above and foregoing has been served on the persons listed below by facsimile, electronic mail, hand delivery and/or by mailing said copy through the United States Postal Service, postage prepaid, and addressed as follows:

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New Orleans, Louisiana, this 15th day of April, 2015.

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Edward R. Wicker, Jr.

Rev. 1—April 2015

2015 Draft Integrated Resource Plan

Entergy Gulf States Louisiana, L.L.C.

and

Entergy Louisiana, LLC

LPSC Docket No. I-33014

January 30, 2015

Rev. 1—April 2015

Louisiana stands at the center of an industrial renaissance that offers residents an opportunity to change the economic futures of their families and communities for generations to come.

Attracted by low-cost natural gas, low electricity prices, existing infrastructure, and Louisiana's business-friendly climate, energy-intensive industries are investing billions to build new plants or expand existing facilities and creating thousands of jobs for Louisiana residents.

Entergy's Louisiana companies are committed to partnering with the state to capitalize on this tremendous economic opportunity by ensuring Louisiana has an ample supply of clean, affordable and reliable power. We call our plan "Power to Grow, A Blueprint For Louisiana's Bright Future."

This Integrated Resource Plan reflects that commitment to helping our state create needed jobs while also sustaining competitive energy prices and continuing to serve all customers reliably. Through the IRP process, we conducted an extensive study of our customers' needs over the next 20 years. We evaluated different fuels and technologies, including renewable resources and alternative energy programs, and analyzed a variety of economic scenarios to help determine how we can best satisfy those requirements in this rapidly changing environment.

Because of this unprecedented growth, Entergy's Louisiana companies must be prepared to serve up to 1,600 MW of increased industrial load through 2019. Beyond industrial growth, we project a need for at least another 8,000 MW of generating capacity by 2034 to meet growing demand and to continue modernizing our generation fleet.

Adding new, highly efficient generation requires significant capital investment. However, a quickly expanding economy will allow those costs to be spread across a growing volume of sales, which coupled with other factors minimizes the rate effect to customers and helps keeping our rates among the lowest in the country.

The IRP includes a five-year action plan that will allow us to ensure we are able to provide safe, reliable and economic service to all customers, existing and new. The action plan includes:

- Obtaining regulatory approvals for Entergy Gulf States Louisiana to purchase two units of the Union Power Station near El Dorado, Arkansas.
- Adding potential new resources:
  - Completing the Amite South RFP to secure a CCGT resource by 2020.
  - Assessing the need for a new CCGT unit in the Lake Charles area in the 2020-21 timeframe.
  - Determining whether a pair of CT units is needed in the Lake Charles area by 2020 to meet industrial load growth.
  - Continuing to assess development of other CT units in Amite South and WOTAB areas for quick deployment if load growth exceeds projections and/or other supply options are not completed as planned.
- Studying distributed solar and storage pilot projects to determine the viability and performance of the technologies in Louisiana.
- Assessing power contracts as viable alternatives for meeting long-term needs.
- Exploring opportunities for long-term gas supplies to mitigate price volatility and hedge against future price increases.
- Evaluating the results of the Quick Start phase of Entergy Solutions: A Louisiana Program; and
- Working with regulators to develop rules for cost-effective energy efficiency programs beyond the Quick Start phase.

This is an exciting time for Louisiana. Entergy's Louisiana companies have a plan and are committed to meeting the power needs of our customers at a reasonable cost.

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Appendix A	ELL and EGSL Generation Resources
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INTRODUCTION

This draft report, prepared in accordance with the Integrated Resource Planning rules promulgated by the Louisiana Public Service Commission ("LPSC"),[1] describes the long-term integrated resource plan ("IRP") of Entergy Gulf States Louisiana, L.L.C. ("EGSL") and Entergy Louisiana, LLC ("ELL") (collectively referred to as the "Companies") for the period 2015 – 2034. The plan reflects important changes in the Companies' planning and operations and gives consideration to the current and expected economic environment in Louisiana. In addition to the economic outlook for the state, three recently completed or forthcoming initiatives -- the Companies' participation in the Midcontinent Independent System Operator ("MISO") market beginning December 19, 2013, the Companies' Joint Application to combine their respective assets and liabilities into a single operating company, and the proposed termination of the Companies' participation in the Entergy System Agreement on February 14, 2019 -- have implications for the Companies' resource needs and supply strategy. Given the significance of these changes on the Companies' long-term capacity and resource needs, this IRP addresses how the Companies plan to meet their customers' power needs, both economically and reliably.

As discussed in this draft report, residential and industrial load growth, unit deactivations, and purchased power agreement ("PPA") expirations, will require the Companies to add significant generation resources during the planning period, including multiple generators in the 2019-2021 time frame. While additional generation will require substantial capital commitments from the Companies, the Companies do not expect that the generation additions will cause customer rates to increase materially. This is a result of increased consumption (*i.e.,* greater kWh sales over which to spread fixed costs), improved portfolio efficiency, and expiration of other customer charges, among other factors.

Industrial Renaissance in Louisiana

A unique set of circumstances has converged to give Louisiana the opportunity to develop and grow its economy in ways that can benefit its citizens for generations to come. A combination of factors, including low natural gas prices resulting from the development of shale natural gas, low electricity prices, access to world-class energy infrastructure, including deep water ports, an extensive interstate pipeline network and related infrastructure, an experienced workforce, and a pro-business environment have resulted in an industrial renaissance in Louisiana that has seen more than $50 billion in new capital investment and the creation of over 83,000 new direct and indirect jobs since 2008.

[1] *See,* LPSC Corrected General Order No. R-30021, *In re: Development and Implementation of Rule for Integrated Resource Planning for Electric Utilities,* dated April 20, 2012.

This industrial renaissance is resulting in – and is projected to continue to result in – new or expanded industrial facilities concentrated in the Amite South[2] and the West of the Atchafalaya Basin ("WOTAB")[3] planning areas, where there currently are substantial supply requirements that require local generation yet limited available in-region power sources. More specifically, the Companies expect up to 1,600 megawatts ("MW") of industrial load growth in their service areas through 2019, and by 2034, after accounting for the deactivation of existing, older generation the Companies expect to require at least 8,000 MW of additional capacity to meet demand. This industrial load growth is in addition to expected load growth in the residential and commercial sectors. Through the Power to Grow initiative, the Companies are demonstrating their commitment to meeting today's needs and anticipating the power demands of the future so Louisiana has the ample supply of clean, affordable and reliable power needed to capitalize on this tremendous economic opportunity.

MISO Integration

The Companies, along with their affiliate Entergy Operating Companies ("EOC"), became market participants in MISO on December 19, 2013. MISO is a regional transmission organization ("RTO") allowing the Companies access to a large structured market that enhances the resource alternatives available to meet customers' power needs. The availability and price of power in the MISO market affects the Companies' resource strategy and portfolio design. Despite the significance of the move to MISO for the Companies and their customers, the Companies retain responsibility for planning to meet their customers' long-term power needs. MISO considerations are an element of this IRP.

Business Combination of ELL and EGSL

On September 30, 2014, the Companies filed an application[4] with the LPSC seeking approval of a proposal to combine their respective assets and liabilities into a single operating company. This IRP assumes that the proposed combination will be approved and completed; as such, the IRP analysis was conducted, and the results are reported herein, on a combined entity basis. However, because the Companies currently use substantially identical planning criteria to one another and to those used for the combined entity, results of the IRP analysis would not be materially different had the analysis been performed separately for each operating company. A separately performed analysis for EGSL and ELL would result, over the long-term, in two

[2] Amite South is the area generally east of the Baton Rouge, Louisiana, metropolitan area to the Mississippi state line and south to the Gulf of Mexico.

[3] WOTAB is the area generally west of the Baton Rouge, Louisiana, metropolitan area to the western-most portion of EGSL's service territory.

[4] *Ex Parte: Potential Business Combination of Entergy Louisiana, LLC and Entergy Gulf States Louisiana, L.L.C.*, Docket No. U-33244.

portfolios that in combination would include similar elements to the final reference resource plan for the combined entity.

System Agreement

The electric generation and bulk transmission facilities of the EOCs participating in the Entergy System Agreement are operated on an integrated, coordinated basis as a single electric system and are referred to collectively as the "Entergy System."

The EOCs participating today in the System Agreement are EGSL, ELL, Entergy Mississippi, Inc. ("EMI"), Entergy Texas, Inc. ("ETI"), and Entergy New Orleans, Inc. ("ENO").[5] On February 14, 2014, EGSL and ELL provided written notice to the other EOCs of the termination of their participation in the System Agreement.[6] In light of the decision to terminate participation, this IRP was prepared under the assumption that EGSL and ELL will no longer participate in the System Agreement as of February 14, 2019[7]. Although the effective date of the Companies' termination of participation is uncertain, it is appropriate that current resource planning efforts acknowledge that stand-alone operations are on the horizon. This IRP is an assessment of the long-term resource needs of the Companies that may be used to develop strategic direction and guide the development of the future long-term resource portfolio.

PART 1: PLANNING FRAMEWORK

The Companies' planning process seeks to accomplish three broad objectives:

- To serve customers' power needs reliably;
- To reliably provide power at the lowest reasonable supply cost; and
- To mitigate the effects and the risk of production cost volatility resulting from fuel price and purchased power cost uncertainty, RTO-related charges such as congestion costs, and possible supply disruptions.

Objectives are measured from a customer perspective. That is, the Companies' planning process seeks to design a portfolio of resources that reliably meets customer power needs at the lowest reasonable supply cost while considering risk.

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[5] Entergy Arkansas, Inc. ("EAI"), also an EOC, terminated its participation in the System Agreement effective December 18, 2013.

[6] EMI provided notice to the EOCs that it would terminate its participation effective November 7, 2015. ETI has provided notice that it would terminate its participation on October 1, 2018 (subject to the FERC's ruling in Docket No. ER14-75-000 which is the FERC proceeding filed to amend the notice provisions of Section 1.01 of the System Agreement).

[7] EGSL's and ELL's notice would be effective February 14, 2019 or such other date consistent with the FERC's ruling in Docket No. ER14-75-000. However, an earlier termination may be possible if agreed upon by the participating EOCs.

In designing a portfolio to achieve the planning objectives, the process is guided by the following principles:

- Reliability – adequate resources to meet customer peak demands with adequate reliability.

- Base Load Production Costs – low-cost base load resources to serve base load requirements, which are defined as the firm load level that is expected to be exceeded for at least 85% of all hours per year.

- Load-Following Production Cost and Flexible Capability – efficient, dispatchable, load-following resources to serve the time-varying load shape levels that are above the base load supply requirement, and also sufficient flexible capability to respond to factors such as load volatility caused by changes in weather or by inherent characteristics of industrial operations.

- Generation Portfolio Enhancement – a generation portfolio that avoids an over-reliance on aging resources by accounting for factors such as current operating role, unit age, unit condition, historic and projected investment levels, and unit economics, and taking into consideration the manner in which MISO dispatches units.

- Price Stability Risk Mitigation – mitigation of the exposure to price volatility associated with uncertainties in fuel and purchased power costs.

- Supply Diversity Risk Mitigation – mitigation of the exposure to major supply disruptions that could occur from specific risks such as outages at a single generation facility.

Resource Adequacy Requirements

As a load serving entity (”LSE”) within MISO, the Companies are and continue to be responsible for maintaining sufficient generation capacity to meet the minimum reliability requirements of their customers. Under the MISO Open Access Transmission, Energy, and Operating Reserve Markets Tariff (“MISO Tariff”), the Companies meet resource adequacy requirements by providing resources necessary to meet or exceed a minimum planning reserve margin established for the Companies by MISO. Resource Adequacy is the process by which MISO ensures that participating LSEs maintain sufficient reliable and deliverable resources to meet their anticipated peak demand plus an appropriate reserve margin.

Under MISO's Resource Adequacy process, MISO annually determines (by November 1 each year) the planning reserve margin applicable to each Local Resource Zone ("LRZ") for the next planning year (June – May). LSEs are required to provide planning resource credits for generation or demand side capacity resources to meet their forecasted peak load coincident with the MISO peak load plus the planning reserve margin established by MISO. Generation planning resource credits are measured by unforced capacity (installed capacity multiplied by appropriate forced outage rate). The annual planning reserve margin for the LRZ which encompasses ELL and EGSL, as determined by MISO, sets the minimum required planning reserve margin[8] the Companies must provide. For purposes of long-term planning, the Companies have determined that a 12% reserve margin based on installed capacity ratings and forecasted (non-coincident) firm peak load should be adequate to cover MISO's Resource Adequacy requirements and uncertainties such as MISO's future required reserve margins, generator unit forced outage rates, and forecasted peak load coincidence factors. Also, after the business combination, a 12% reserve margin provides enough capacity to cover loss of the Companies' largest generating unit contingency.

Transmission Planning

The Companies' transmission planning ensures that the transmission system (1) remains compliant with applicable NERC Reliability Standards and related SERC and local planning criteria, and (2) is designed to efficiently deliver energy to end-use customers at a reasonable cost. Since joining MISO, the Companies plan their transmission system in accordance with the MISO Tariff. Expansion of, and enhancements to, transmission facilities must be planned well in advance of the need for such improvements given that regulatory permitting processes and construction can take years to complete. Advanced planning requires that computer models be used to evaluate the transmission system in future years taking into account the planned uses of the system, generation and load forecasts, and planned transmission facilities. On an annual basis, the Companies' Transmission Planning Group performs analyses to determine the reliability and economic performance needs of the Companies' portion of the interconnected transmission system. The projects developed are included in the Long Term Transmission Plan[9] ("LTTP") for submission to the MISO Transmission Expansion Planning ("MTEP") process as part of a bottom-up planning process for MISO's consideration and review. The LTTP consists of transmission projects planned to be in-service in an ensuing 10-year planning period. The projects included in the LTTP serve several purposes: to serve specific customer needs, to provide economic benefit to customers, to meet NERC TPL reliability standards, to facilitate

[8] In MISO, Resource Adequacy reserve margin requirements are expressed based on unforced capacity ratings and MISO System coincident peak load. Traditionally, the Companies and other LSEs have stated planning reserve requirements based on installed capacity ratings and forecasted (non-coincident) peak load.

[9] The Companies' most recent LTTP is included in Appendix D.

incremental block load additions, and to enable transmission service to be sold and generators to interconnect to the electric grid.

With regard to transmission planning aimed at providing economic benefit to customers, the Companies have played, and will continue to play, an integral role in MISO's top-down regional economic planning process referred to as the Market Congestion Planning Study ("MCPS"), which is a part of the MTEP process. MISO's MCPS relies on the input of transmission owners and other stakeholders, both with regard to the assumptions and scenarios utilized in the analysis and the proposed projects intended to bring economic value to customers. Based on this stakeholder input, MISO evaluates the economic benefits of the submitted transmission projects, while ensuring continued reliability of the system. The intended result of the MCPS is a project or set of projects determined to be economically beneficial to customers and that is therefore submitted to the MISO Board of Directors for approval.

The Companies' continued involvement in the MCPS began with the 2014 process and the Companies' submission of a collection of projects for MISO's review. The result of the 2014 MCPS included the approval of a portfolio of four projects in southeast Louisiana, called the Louisiana Economic Transmission Project ("LETP").[10] The LETP was identified following a substantial amount of economic analyses performed by the Companies and MISO and is an example of the type of economic planning the Companies anticipate will continue as a part of MISO participation. The LETP, which the Companies will present to the Commission in a certification filing pursuant to LPSC General Order No. R-26018, is anticipated to provide customers with benefits exceeding six times its estimated cost of $56.3 million – benefits that are directly related to the Companies' participation in the MISO market.

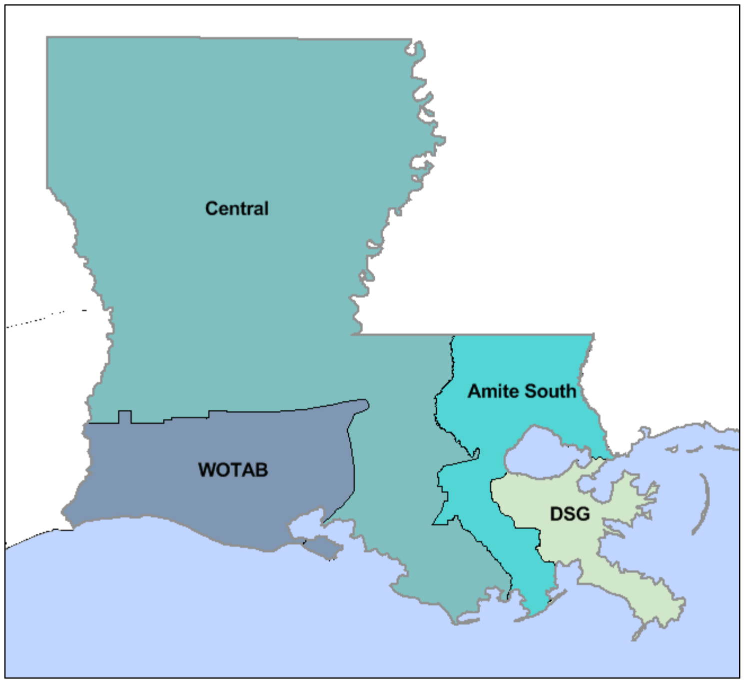
There are approximately 200 projects in the current LTTP, located throughout the four states of the Entergy service footprint, with approximately 80 projects planned for the state of Louisiana.

Area Planning

Although resource planning is performed with the goal of meeting the planning objectives at the overall lowest reasonable supply cost, physical and operational factors dictate that regional reliability needs must be considered when planning for the reliable operation within the area. Thus, one aspect of the planning process is the development of planning studies to identify supply needs within specific geographic areas, and to evaluate supply options to meet those needs.

[10] The MCPS also resulted in the identification of two economically beneficial projects in EAI's service territory, which were approved by the MISO Board of Directors.

Figure 1: Map of Louisiana Planning Areas



For planning purposes, the region served by the Companies is divided into three major planning areas and one sub-area. These areas are determined based on characteristics of the electric system including the ability to transfer power between areas as defined by the available transfer capability, the location and amount of load, and the location and amount of generation. The three major planning areas and sub-area are listed below:

- West of the Atchafalaya Basin ("WOTAB") – the area generally west of the Baton Rouge metropolitan area.

- Amite South – the area generally east of the Baton Rouge metropolitan area to the Mississippi state line, and the area south to the Gulf of Mexico.

    - Downstream of Gypsy ("DSG") – a sub-area encompassing the Southeast portion of Amite South, generally including the area down river of the Little Gypsy plant including metropolitan New Orleans south to the Gulf of Mexico.

- Central – the remainder of Louisiana north of the WOTAB and Amite South areas, including the Baton Rouge metropolitan area.

As described later in this report, separate assessments of the Amite South and WOTAB planning areas indicate a need for additional resources in those planning areas early in the next decade. The near term needs are largely driven by the increase in load resulting from the Louisiana industrial renaissance and expiring PPAs, but resource needs over the planning horizon are also significantly influenced by unit deactivations.

PART 2: ASSUMPTIONS

Technology Assessment

The IRP process considers a range of alternatives available to meet the planning objectives, including the existing fleet of generating units, potential demand-side management alternatives, potential conventional generation resource additions, and potential renewable generation resource additions. As part of this process, a 2014 Technology Assessment was prepared to identify potential supply-side resource alternatives that may be technologically and economically suited to meet customer needs. The initial screening phase of the Technology Assessment reviewed the supply-side generation technology landscape to identify resource alternatives that merited more detailed analysis. During the initial phase, a number of resource alternatives were eliminated from further consideration based on a range of factors including technical maturity, stage of commercial development, and economics. These resource alternatives will continue to be monitored for possible future development. The following resource alternatives were found appropriate for further analysis:

- Pulverized Coal—Supercritical Pulverized Coal with carbon capture ("PC" with "CC")
- Natural Gas Fired alternatives
    - Simple Cycle Combustion Turbines ("CT")
    - Combined Cycle Gas Turbines ("CCGT")
    - Small Scale Aeroderivatives
    - Large Scale Aeroderivatives
- Nuclear – (Generation III Technology)
- Renewables
    - Biomass
    - On shore Wind Power
    - Solar Photovoltaic ("PV")

Upon completion of the screening level analysis, more detailed analysis (including revenue requirements modeling of remaining resource alternatives) was conducted across a range of operating roles and under a range of input assumptions. The analysis resulted in the following conclusions:

- Among conventional generation resource alternatives, CCGT and CT technologies are the most attractive. The gas-fired alternatives are economically attractive across a range of assumptions concerning operations and input costs.
- New nuclear and new coal alternatives are not economically attractive near-term options relative to gas-fired technology. The low price of gas and the uncertainties around emissions regulation make coal technologies unattractive. Nuclear is currently unattractive due to both capital and regulatory requirements.
- Despite recent declines in the capital cost and improvements of renewable generation alternatives, they are still less economically attractive compared to CCGT and CT alternatives due to:
    - Declines in the long-term outlook for natural gas prices brought on by the shale gas boom;
    - Uncertainty about the renewal of production tax credits and investment tax credits that are applicable to resources completed before the end of 2016; and
    - The uncertain near-term outlook for emissions regulation.
- Among renewable generation alternatives, wind and solar are the most likely to become cost competitive. However, uncertainties with respect to various renewable generation tax credit extensions, capacity credits allowed for these resources by MISO, and implementation and timing of CO_2 regulations for fossil fuel resource alternatives likely will affect the competitiveness of renewable resource alternatives. MISO determines the capacity value for wind generation based on a probabilistic analytical approach. The application of this approach resulted in a capacity value of approximately 14.1% for the 2014-15 planning year. Furthermore, the footprint of the Companies is not favorable for wind generation. The transmission cost to serve load with wind power from remote resources will further worsen the economics of wind compared to conventional resources. In MISO, solar resources receive no capacity credit within the first year of operation. Solar-powered resources must submit all operating data for the prior summer with a minimum of 30 consecutive days to have their capacity registered with MISO.

Table 1 summarizes the results of the Technology Assessment for a number of resource alternatives.

Table 1: 2014 Technology Sensitivity Assessment

Based on Generic Cost of Capital[11]		No CO_2 ($/MWh)			CO_2 Beginning 2023 ($/MWh)		
Technology	Capacity Factor[12]	Reference Fuel	High Fuel	Low Fuel	Reference Fuel	High Fuel	Low Fuel
F Frame CT	10%	$198	$224	$179	$204	$230	$184
F Frame CT w/ Selective Catalytic Reduction	20%	$141	$167	$121	$146	$173	$126
E Frame CT	10%	$240	$274	$215	$247	$281	$222
Large Aeroderivative CT	40%	$108	$131	$91	$113	$136	$95
Small Aeroderivative CT	40%	$125	$150	$106	$130	$156	$112
Internal Combustion	40%	$115	$137	$99	$120	$141	$104
2x1 F Frame CCGT	65%	$79	$97	$67	$83	$100	$70
2x1 F Frame CCGT w/ Supplemental	65%	$75	$93	$61	$78	$97	$65
2x1 G Frame CCGT	65%	$76	$93	$63	$79	$96	$67
2x1 G Frame CCGT w/ Supplemental	65%	$72	$90	$59	$76	$94	$63
1x1 F Frame CCGT	65%	$82	$100	$69	$86	$104	$73
1x1 J Frame CCGT	65%	$73	$90	$61	$77	$93	$65
1x1 J Frame CCGT w/ Supplemental	65%	$72	$132	$59	$76	$136	$63
Pulverized Coal w/ Carbon Capturing Sequestration	85%	$163	$230	$94	$165	$232	$96
Biomass	85%	$175	$321	$142	$175	$321	$142
Nuclear	90%	$157	$169	$157	$157	$169	$157
Wind[13]	34%	$109	$109	$109	$109	$109	$109
Wind w/ Production Tax Credit	34%	$102	$102	$102	$102	$102	$102
Solar PV (fixed tilt)[14]	18%	$190	$190	$190	$190	$190	$190
Solar PV (tracking)[15]	21%	$179	$179	$179	$179	$179	$179
Battery Storage[16]	20%	$217	$217	$217	$217	$217	$217

[11] A general discount rate (7.656%) was used in order to accurately model these resources in the Market Modeling stage of the IRP.
[12] Assumption used to calculate life cycle resource cost.
[13] Includes capacity match-up cost of $18.76/MWh due to wind's 14.1% capacity credit in MISO.
[14] Includes capacity match-up cost of $30.93/MWh assuming a 25.0% capacity credit in MISO.
[15] Includes capacity match-up cost of $26.51/MWh assuming a 25.0% capacity credit in MISO.
[16] Includes cost of $25/MWh required to charge batteries.

Demand-Side Alternatives

The Companies engaged the services of ICF International to assess the market-achievable potential for Demand Side Management ("DSM") programs that could be deployed over the planning horizon. In total, 1,097 measures were evaluated, of which 896 were considered cost effective with a Total Resources Cost ("TRC") test result of 1.0 or better. These measures were then collected into 24 DSM programs to be assessed in the IRP process. The Potential Study estimated the peak load, annual energy reduction, and program costs that result from a low, reference, and high level of spending on program incentives. The reference case estimate of DSM potential indicates approximately 673 MW of peak demand reduction could be achieved by 2034 if the Companies' investment in DSM was sustained for a 20 year period.

The methodology of the Potential Study was consistent with a primary objective to identify a wide range of DSM alternatives available to meet customers' needs. In this way, the study results helped ensure that more DSM programs would be identified for further evaluation in the IRP.

DSM program costs utilized in the IRP include incentives paid to participants and program delivery costs such as marketing, training, and program administration. Program delivery costs were estimated to reflect average annual costs over the 20 year planning horizon of the DSM Potential Study. The costs reflect an assumption that over the planning horizon, program efficiencies will be achieved resulting in lower expected costs. That is, as experience is gained with current and future programs, actual cost may decrease over time. As such, actual near-term costs associated with current and future programs may be higher than the assumptions used to determine the optimal cost-effective level identified in the Companies' Final Reference Resource Portfolio Plan. Therefore, future DSM program goals and implementation plans should reflect this uncertainty. The IRP assumptions for the DSM program cost estimates as compared to the cost of typical supply-side alternatives are included in the DSM Technical Supplement to the IRP.

Natural Gas Price Forecast

System Planning and Operations[17] ("SPO") prepared the natural gas price forecast[18] used in the 2015 IRP. The near term portion of the natural gas forecast is based on NYMEX Henry Hub forward prices, which serve as an indicator of market expectations of future prices. Because the NYMEX futures market becomes increasingly illiquid as the time horizon increases, NYMEX forward prices are not a reliable predictor of future prices in the long-term. Due to this uncertainty, SPO prepares a long term point-of-view ("POV") regarding future natural gas prices utilizing a number of expert consultant forecasts to determine an industry consensus regarding long-term prices.

The long-term natural gas forecast used in the IRP includes sensitivities for high and low gas prices to support analysis across a range of future scenarios. In developing high and low gas price POVs, SPO utilizes several consultant forecasts to determine long term price consensus. These forecasts are shown in the Table below.

Table 2: Henry Hub Natural Gas Price Forecasts

Henry Hub Natural Gas Prices						
	Nominal $/MMBtu			Real 2014$/MMBtu		
	Low	Reference	High	Low	Reference	High
Real Levelized[19] (2015-2034)	$4.57	$5.77	$9.72	$3.84	$4.87	$8.17
Average (2015-2034)	$4.82	$6.28	$10.79	$3.66	$5.00	$8.08
20-Year CAGR	2.5%	3.1%	6.2%	0.4%	1.0%	4.1%

[17] System Planning and Operations is a department within Entergy Services, Inc. ("ESI") tasked with: (1) the procurement of fossil fuel and purchased power, and (2) the planning and procuring of additional resources required to provide reliable and economic electric service to the EOCs' customers. SPO also is responsible for carrying out the directives of the Operating Committee and the daily administration of aspects of the Entergy System Agreement not related to transmission.

[18] The forecast was prepared from the July 2014 gas price forecast which is the Companies' latest official forecast and was included in the Companies' November 3, 2014 Updated IRP Inputs filing.

[19] "Real levelized" prices refer to the price in 2014$ 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.

The natural gas forecasts above do not attempt to forecast the effects of the short-term natural gas hedging programs currently employed by the Companies. The current gas hedging program attempts to mitigate short-term gas price volatility. However, given the short term nature of the gas hedging program, there is no effect on the long-term gas prices experienced by the Companies. The Companies have evaluated and continue to evaluate opportunities that would, on a longer term basis, help stabilize gas prices and offer the potential for savings relative to gas prices that may exist in the future. The Companies also note that the Commission has an active rulemaking regarding long-term gas hedging in Docket No. R-32975.

CO2 Assumptions

At this time, it is not possible to predict with any degree of certainty whether national CO_2 legislation will eventually be enacted, and if it is enacted, when it would become effective, or what form it would take. In order to consider the effects of carbon regulation uncertainty on resource choice and portfolio design, the IRP process relied on a range of projected CO_2 cost outcomes. The low case assumes that CO_2 legislation does not occur over the 20-year planning horizon. The reference case assumes that a cap and trade program starts in 2023 with an emission allowance cost of $7.54/U.S. ton and a 2015-2034 levelized cost in 2014$ of $6.83/U.S. ton.[20] The high case assumes that a cap and trade program starts in 2023 at $22.84/U.S. ton with a 2015-2034 levelized cost in 2014$ of $14.61/U.S. ton.

Market Modeling

Aurora Model

The development of the IRP relied on the AURORAxmp Electric Market Model ("AURORA") to simulate market operations and produce a long-term forecast of the revenues and cost of energy procurement for the Companies.[21]

AURORA[22] is a production cost model and resource capacity expansion optimization tool that uses projected market economics to determine the optimal long-term resource portfolio under varying future conditions including fuel prices, available generation technologies, environmental constraints, and future demand forecasts. AURORA estimates price and dispatch using hourly demands and individual resource-operating characteristics in a transmission-constrained, chronological dispatch algorithm. The optimization process within AURORA identifies the set of resources among existing and potential future demand- and

[20] Includes a discount rate of 7.656%.

[21] The AURORA model replaces the PROMOD IV and PROSYM models that the Companies previously used.

[22] The AURORA model was selected for the IRP and other analytic work after an extensive analysis of electricity simulation tools available in the marketplace. AURORA is capable of supporting a variety of resource planning activities and is well suited for scenario modeling and risk assessment modeling. It is widely used by load serving entities, consultants, and independent power producers.

supply-side resources with the highest and lowest market values to produce economically consistent capacity expansion. AURORA chooses from new resource alternatives based on the net real levelized values per MW ("RLV/MW") of hourly market values and compares those values to existing resources in an iterative process to optimize the set of resources.

Scenarios

IRP analytics relied on four scenarios designed to assess alternative portfolios across a range of outcomes. The four scenarios are:

- Industrial Renaissance (Reference) – Assumes the U.S. energy market (particularly as it affects the Gulf Coast region and Louisiana) continues with reference fuel prices. Current fuel prices drive considerable load growth and economic opportunity especially in the industrial class. The Industrial Renaissance scenario assumes reference load, reference gas, and no CO_2 costs.

- Business Boom – Assumes the U.S. energy boom continues with low gas and coal prices. Low fuel prices drive high load growth especially in the industrial class, but with residential and commercial class spillover benefits. As a result of the industrial load growth and low fuel prices, power sales increase significantly. A modest CO_2 tax or cap and trade program is implemented and is effective in 2023.

- Distributed Disruption – Assumes states continue to support distributed generation. Consumers and businesses have a greater interest in installing distributed generation, which leads to a decrease in energy demand. Overall economic conditions are steady with moderate GDP growth, which enables investment in energy infrastructure. However, natural gas prices are driven higher by EPA regulation of hydraulic fracturing. Congress or the EPA also implements a moderate CO2 tax or cap and trade program.

- Generation Shift – Assumes government policy and public interest drive support for government subsidies for renewable generation and strict rules on CO_2 emissions. High natural gas exports and more coal exports lead to higher fuel prices.

Each scenario was modeled in Aurora. The resulting market modeling, which included projected power prices, provided a basis for assessing the economics of long-term (here, twenty years) resource portfolio alternatives.

Table 3: Summary of Key Scenario Assumptions

Summary of Key Scenario Assumptions				
	Industrial Renaissance (Ref. Case)	**Business Boom**	**Distributed Disruption**	**Generation Shift**
Electricity CAGR (Energy GWh)[23]	~1.45%	~1.70%	~0.90%	~1.20%
Peak Load Growth CAGR	~1.05%	~1.10%	~0.75%	~0.85%
Henry Hub Natural Gas Price ($/MMBtu)	Reference Case ($4.87 levelized 2014$)	Low Case ($3.84 levelized 2014$)	Reference Case ($4.87 levelized 2014$)	High Case ($8.17 levelized 2014$)
CO_2 Price ($/short ton)	Low Case: None	Reference Case: Cap and trade starts in 2023 $6.83 levelized 2014$	Cap and trade starts in 2023 $6.83 levelized 2014$	Cap and trade starts in 2023 $14.61 levelized 2014$

PART 3: CURRENT FLEET & PROJECTED NEEDS

Current Fleet

Currently, the Companies together control approximately 10,561 MW of generating capacity either through ownership or long-term power purchase contract. Appendix A provides an overview of the Companies' current active generation portfolio. Table 4 shows the supply resources by fuel type measured in installed MW with percentages for ELL and EGSL separately and for the combined company. It is important to note that some of the amounts below represent resources that are not owned by the Companies but instead are under contract through PPAs. As reflected on Table 4 and Appendix A, roughly one-half of the current combined resource portfolios are from legacy gas generation which has been in-service for 40-60 years. While the Companies have made and will continue to make economic investments to extend the service life of these generators, many of these generators are assumed to deactivate over the planning horizon and these unit deactivations are a significant driver of the Companies' need for additional generation regardless of any assumed load growth.

[23] All compound annual growth rates ("CAGRs") in this table: 2015-2034 (20 Years) for the market modeled in AURORA.

Table 4: 2014 EGSL and ELL Combined Resource Portfolio

2014 EGSL and ELL Combined Resource Portfolio						
	ELL		EGSL		Combined	
	MW	%	MW	%	MW	%
Coal	32	1	367	9	399	4
Nuclear	1,609	24	390	9	1,999	19
Combined Cycle Gas Turbine (CCGT)	1,289	20	1,036	26	2,325	22
Other Gas	3,479	53	2,173	54	5,652	54
Hydro & Other	125	2	61	2	186	2
Total	6,534	100%	4,027	100%	10,561 [24]	100%

In addition, the Companies added a new CCGT facility, Ninemile 6, to the portfolio in December 2014. Ninemile 6 is a 561 MW CCGT resource located in Westwego, Louisiana at the Ninemile Point Station in Jefferson Parish. The Companies received Commission approval to construct this new CCGT generating facility, the currently estimated cost of which is $655 million.[25]

Load Forecast

A wide range of factors likely will affect electric load in the long-term, including:

- Levels of economic activity and growth;
- The potential for technological change to affect the efficiency of electric consumption;
- Potential changes in the purposes for which customers use electricity (*e.g.*, the adoption of electric vehicles);
- The potential adoption of end-use (behind-the-meter) self-generation technologies (*e.g.*, rooftop solar panels); and
- The level of energy efficiency, conservation measures, and distributed generation (*e.g.,* rooftop solar panels) adopted by customers.

[24] Total resources include the addition of Ninemile 6.
[25] *Ex Parte: Joint Application of Entergy Louisiana, LLC for Approval to Construct Unit 6 at Ninemile Point Station and of Entergy Gulf States Louisiana, L.L.C. for Approval to Participate in a Related Contract for the Purchase of Capacity and Electric Energy, for Cost Recovery and Request for Timely Relief,* Order No. U-31971 (April 5, 2012).

Such factors may affect both the level and shape of load in the future. Peak loads may be higher or lower than projected levels. Similarly, industrial customer load factors may be higher or lower than currently projected. Uncertainties in load may affect both the amount and type of resources required to efficiently meet customer needs in the future.

In order to consider the potential implications of load uncertainties on long-term resource needs, four load forecast scenarios were prepared for the IRP, which are described below:

Industrial Renaissance – Reference load

Assumes Industrial Renaissance will have a multiplier effect that will spur load growth in residential, commercial, and government classes (referred to as an "economic multiplier") and includes additional industrial growth stemming from the regional Industrial Renaissance.

Business Boom

Assumes higher economic multiplier effect, a lower risk adjustment to future industrial projects, and an increase in the number of industrial projects that are included in forecast.

Distributed Disruption

Decrements the Reference load scenario for Combined Heat and Power ("CHP") impact and distributed solar photovoltaic system ("PV") impact.

Generation Shift

Assumes no economic multiplier effect, no commercial conversions, and fewer industrial projects.

Methodology

SPO used the same load forecasting process as described in previous IRPs developed for the Companies. That process uses computer software from Itron to develop a 20-year, hour-by-hour load forecast. The MetrixND®[26] and the MetrixLT™[27] programs are used widely in the utility industry, to the point where they may be considered an industry standard for energy forecasting, weather normalization, and hourly load and peak load forecasting.

To develop the load forecast, SPO allocates the Retail Energy Forecast (by month) and the Wholesale Energy Forecast (by month) to each hour of a 20-year period based on historical load

[26] MetrixND by ITron is an advanced statistics program for analysis and forecasting of time series data.
[27] MetrixLT™ by ITron is a specialized tool for developing medium and long run load shapes that are consistent with monthly sales and peak forecasts.

shapes developed by ESI's Load Research Department. Fifteen-year "typical weather" is used to convert historic load shapes into "typical load shapes." For example, if the actual sales for an EOC's residential customers occurred during very hot weather conditions, the typical load shape would flatten the historic load shape. If the actual weather were mild, the typical load shape would raise the historic load shape. Each customer class in each EOC responds differently to weather, so each has its own weather response function. MetrixND® is used to adjust the historical load shapes by typical weather, and MetrixLT™ is used to create the 20-year, hourly load forecast.

The load forecast is grossed up to include average transmission and distribution line losses. The Companies have unique loss factors that are applied to each revenue class after the forecast is developed and after accounting for energy efficiency. For example, when line losses are added into the Companies' forecasts ELL's residential class is grossed up by a different amount than EGSL's residential class.

Cogeneration loads are included in the Industrial revenue class and a separate peak is not developed for these customers as their loads can be irregular. Econometric models are used to develop the energy forecast for cogeneration loads which are then combined with both large and small industrial customers to create the Industrial energy forecast. Interruptions are in historical data that the forecast models use, but customer specific interruptions are not forecasted as the interruptions are irregular.

Energy savings from company-sponsored DSM programs are decremented from the Retail energy forecast. The load forecast uses the decremented energy forecast to develop annual peaks that reflect the savings from such programs.

Resource Needs

Over the IRP period, the Companies will need to add resources. The long-term resource needs are primarily driven by load growth expectations, unit deactivation assumptions, and existing PPA contract terminations. For the purpose of developing this IRP, assumptions must be made about the future of generating units currently in the portfolio.

Assumptions made for the IRP are not final decisions regarding the future investment in resources. Unit-specific portfolio decisions, such as sustainability investments, environmental compliance investments, or unit retirements, are based on economic and technical evaluations considering such factors as projected forward costs, anticipated operating roles, and the cost of supply alternatives. These factors are dynamic, and as a result, actual decisions may differ from planning assumptions as greater certainty is gained regarding requirements of legislation, regulation, and relative economics.

Based on current assumptions, a number of the Companies' existing fossil generating units may be deactivated during the IRP planning period. In addition, various PPAs that the Companies have previously entered into will expire. In the years 2015-2034, the total net reduction in the Companies' generating capacity from these assumed unit deactivations and PPA terminations is approximately 6,859 MWrelative to the Companies' current combined resources of approximately 10,561 MW.

Included in this amount is the effect of the termination of the PPAs entered between EGSL and ETI pursuant to the Jurisdictional Separation Plan ("JSP") that led to the separation of Entergy Gulf States, Inc. into EGSL and ETI. Those PPAs are referred to herein as the "JSP PPAs."[28] This IRP assumes that the JSP PPAs will terminate when ETI or EGSL terminates participation in the System Agreement, as provided for in the LPSC's order regarding the JSP.[29] The overall net effect would reduce EGSL's portfolio position by roughly 700 MW in 2018 based on ETI's terminating participation[30] in the System Agreement on October 18, 2018.

Moreover, in the coming years, the Companies will face the need for additional resources to meet load growth. As contemplated by the Industrial Renaissance Scenario (reference case), the areas served by the Companies are experiencing a heightened level of economic development activity stemming from the availability of low-cost natural gas and efforts by the State of Louisiana to add jobs and grow the economy through attracting new and expanded industrial facilities. As such, in the reference case, the Companies' loads are projected to reach approximately 11,200 MW by 2019 (a 15% increase over the current combined level of approximately 9,600 MW), which reflects the addition of approximately 1,600 MW of industrial facilities by 2019. By 2025, the Companies' total reference load is projected to increase approximately 1,760 to 2,200 MW from the present combined level. The following Table

[28] As a result of the implementation of the JSP to separate Entergy Gulf States, Inc. ("EGSI") into separate Texas and Louisiana companies, ETI and EGSL (successors-in-interest to EGSI) currently share certain capacity in Texas and Louisiana. This capacity is shared through cost-based purchases and sales made pursuant to purchased power agreements under Service Schedule MSS-4 of the Entergy System Agreement. Specifically, EGSL sells to ETI 42.5% of the capacity and related energy of the following resources: (1) Willow Glen and Nelson; (2) Calcasieu; (3) Perryville; and (4) River Bend. ETI sells to EGSL: (1) 57.5% of the capacity and related energy associated with its Lewis Creek and Sabine resources; and (2) 50% of the capacity and related energy associated with the Carville resource. A subset of these PPAs, referred to as the "JSP PPAs," will terminate upon ETI's termination of its participation in the System Agreement. These JSP PPAs include the MSS-4 PPAs associated with the Willow Glen, Nelson gas, Lewis Creek, Sabine, and Calcasieu generating units. *See also* LPSC Order Nos. U-21453, U-20925, and U-22092 Subdocket J, *In re: Request for the Approval of the Jurisdictional Separation Plan for Entergy Gulf States, Inc.*, dated January 31, 2007, at 20.

[29] *In re: Request for the Approval of the Jurisdictional Separation Plan for Entergy Gulf States, Inc.,* Order Nos. U-21453, U-20925 and U-22092 (Subdocket J), Order at p. 20 (Jan. 31, 2007).

[30] ETI provided notice to the EOCs of its intent to terminate its participation in the System Agreement effective October 18, 2018.

summarizes the projected peak forecast increase for the Companies over the next 20 years (2015-2034) by scenario.

Table 5: ELL and EGSL Projected Peak Forecast Increase from 2015

	Industrial Renaissance (MWs)	Business Boom (MWs)	Distributed Disruption (MWs)	Generation Shift (MWs)
By 2034	2,226	2,626	1,507	1,751

In both Amite South and WOTAB, current supply needs require local generation, yet there are limited available power sources that exist within each of the regions. Amite South is a supply-constrained region that, based on projected load growth, unit retirements, and PPA expirations, may require new resources every five years in order to continue meeting reliability needs within its load pocket.[31] The industrial load growth in the region further increases this need. In the Industrial Renaissance Scenario, the Amite South region's peak load is expected to grow by approximately 10% (500 MW) to a total of approximately 6,000 MW by 2019. In other words, resources need to be planned and brought on-line in an orderly sequence to maintain adequate capacity and stability and support the region's growing load.

Separate from the Amite South region, the WOTAB region is expected to experience significant industrial load growth under the Industrial Renaissance Scenario. EGSL's load in WOTAB is anticipated to increase by approximately 70% (800 MW) to a total of approximately 1,900 MW by 2019. A substantial portion of the expected growth in load will be centered around Lake Charles. The concentration of load within the Lake Charles area is expected to result in the creation of a load pocket within the planning region, which will require additional resources as load continues to grow.

As discussed later in this report, these increases in residential, commercial, and industrial load, and unit deactivations and PPA expirations will require the Companies to add resources to meet the load and maintain reliability. There is expected to be a limited effect on customer rates, however, because of the increase in customer kWh usage over which the fixed costs of the new resources are spread, portfolio efficiency improvements, and expiration of other customer charges among other factors.

[31] Load pockets are areas of the system where local generation along with transmission import capability is needed to serve the load reliably within the area.

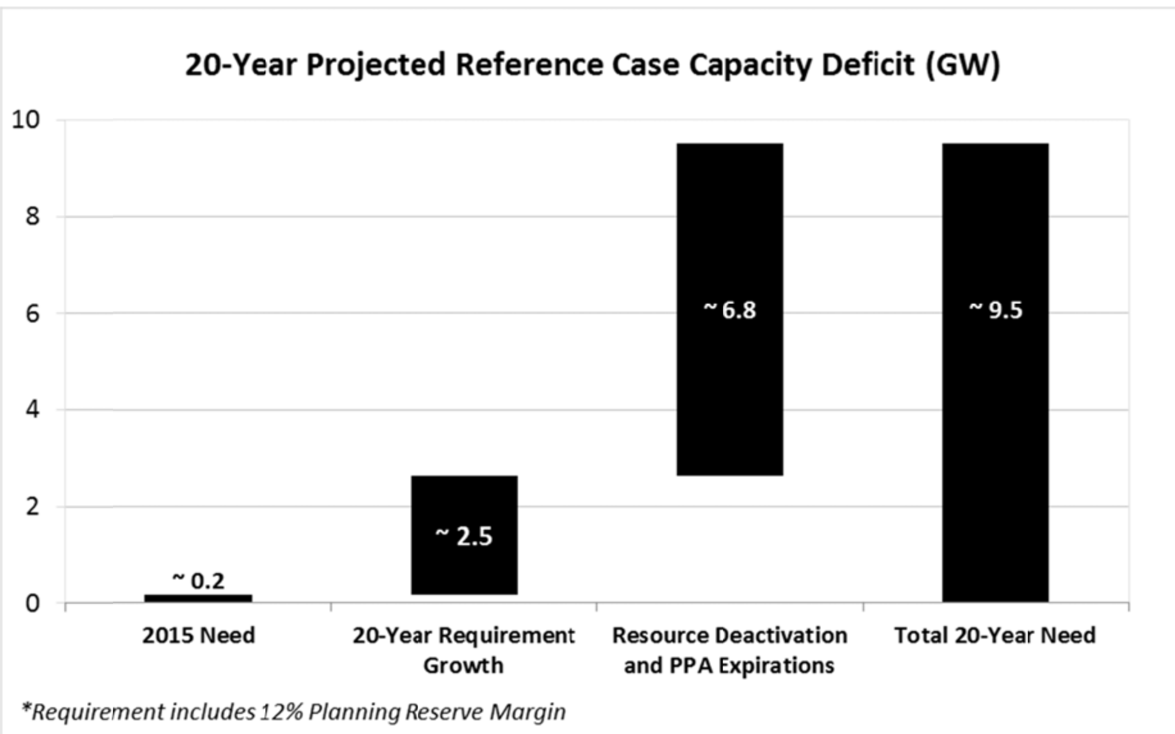
As shown in Tables 6 and 7 below, by 2034, the combination of load growth, resource deactivations and PPA contract expirations may result in approximately 9.5 GW of capacity needed for the Industrial Renaissance Scenario. By 2024, the capacity deficit could be as high as 3.6 GW under the current load forecasts and resource deactivation and expiration assumptions.

Table 6: Resource Needs by Scenario (MWs)

Capacity Surplus/(Need) (Before IRP Additions)				
	Industrial Renaissance	**Business Boom**	**Distributed Disruption**	**Generation Shift**
By 2024	(3,601)	(4,039)	(3,173)	(2,980)
By 2034	(9,536)	(9,999)	(8,695)	(8,913)

**Includes 12% planning reserve margin*

Table 7: Industrial Renaissance 20-Year Projected Capacity Need (GW)



There are a number of alternatives to address the resource needs, including:

- Incremental long-term resource additions including:
    - Self-Supply alternatives

- o Acquisitions
- o Long Term PPAs and renewals

- Demand Side alternatives

- Short-term capacity purchases in MISO Planning Resource Auction or bi-lateral transactions.

Types of Resources Needed

In order to reliably meet the power needs of customers at the lowest reasonable cost, the Companies must maintain a portfolio of generation resources that includes the right amount and types of capacity. With respect to the amount of capacity, the Companies must maintain sufficient generating capacity to meet their peak loads plus a planning reserve margin. As described above, the Companies need to plan for resources to meet the annual reserve margin mandated by MISO, which is assumed to be 12% for long-term planning. In general, the Companies' supply role needs include:

- Base Load—expected to operate in most hours.

- Load-Following—capable of responding to the time-varying needs of customers.

- Peaking and Reserve—expected to operate relatively few hours, if at all.

Table 8: Projected Resource Needs in 2034 by Supply Roles (without Planned Additions) in Industrial Renaissance Scenario

	Need	Resources	Surplus/ (Deficit)
Base Load (MW)	7,948	2,399	(5,549)
Load Following (MW)	2,257	1,270	(987)
Peaking & Reserve (MW)	3,341	341	(3,000)
Totals	13,546	4,010	(9,536)

Table 8 shows that for both Companies, the supply role with the greatest need is base load. Peaking resources will also be needed within the 20 year planning horizon.

PART 4: PORTFOLIO DESIGN ANALYTICS

The IRP utilized a two-step approach to construct and assess alternative resource portfolios to meet the customer needs:

1. Market Modeling
2. Portfolio Design & Risk Assessment

Market Modeling

The first step to develop within the AURORA model is a projection of the future power market for each of the four scenarios. This projection looks at the power market for the entire MISO footprint excluding Louisiana to gain perspective on the broader market outside the state. The purpose of this step was to provide projected power prices to assess potential portfolio strategies within each scenario. In order to achieve this, assumptions were required about the future supply of power. The process for developing those assumptions relied on the AURORA Capacity Expansion Model to identify the optimal set of resource additions in the market to meet reliability and economic constraints. Resulting assumptions regarding new capacity additions in each scenario are summarized in Table 9.

Table 9: Results of MISO Market Modeling

Results of MISO Market Modeling (MISO Footprint, excluding Louisiana) Incremental Capacity Mix by Scenario				
	Industrial Renaissance (Ref. Case)	Business Boom	Distributed Disruption	Generation Shift
CCGT	52%	91%	98%	53%
CT	48%	9%	2%	1%
Wind	0%	0%	0%	31%
Solar	0%	0%	0%	0%
Year of First Addition	2020	2020	2020	2020
Total GWs Added (through 2034)	117	127	73	226

Results of the Capacity Expansion Modeling that supported conclusions from the Technology Assessment, as discussed earlier, were reasonably consistent across scenarios. These results, as summarized below, are the output of the model based on the market conditions that the model analyzed:

- In general, new build capacity is required to meet overall reliability needs.

- Gas-fired, CTs and CCGTs, are the preferred technologies for new build resources in most outcomes.
- The model did not select new nuclear or new coal for any scenario.
- The model did not select solar PV or biomass for any scenario.
- Wind generation has a significant role in only one of the scenarios that involves high gas and carbon prices.

Portfolio Design & Risk Assessment

The AURORA Capacity Expansion Model analyzes least cost portfolios to meet the Companies' resource needs using the screened demand- and supply-side resource alternatives. Through this analysis, the Companies sought to assess the relative performance of the highest ranking resource alternatives from the screening assessments when included with the Companies' existing resources and to test their performance across a range of outcomes as provided by the scenarios. This analysis seeks to identify the portfolio that produces the lowest total supply cost to meet the identified needs, but does not take into account rate design or rate effects.

In total, four portfolios (described below) were constructed and assessed. The AURORA Capacity Expansion Model was used to develop a portfolio for each of the scenarios in a two-step process, which first assessed DSM programs, and then supply-side alternatives. DSM programs were evaluated first without consideration of supply-side alternatives by allowing the AURORA Capacity Expansion Model to determine which of the DSM programs may be able to provide capacity and energy benefits in excess of their costs. All economic DSM programs were included in each portfolio.[32] Once the level of economic DSM was determined within each scenario/portfolio combination, the AURORA Capacity Expansion Model was used to identify the most economic level and type of supply-side resources needed to meet reliability requirements. The result of this process was an optimal portfolio for each scenario consisting of both DSM and supply-side alternatives.

[32] In evaluating the economics of DSM programs, the model evaluates the cost and benefit of the DSM programs, but does not take into consideration ratemaking and policy issues implicated by DSM programs, which must be appropriately addressed as part of DSM implementation.

Table 10: Portfolio Design Mix

Portfolio Design Mix				
	IR Portfolio	**BB Portfolio**	**DD Portfolio**	**GS Portfolio**
DSM Programs	18 Programs	14 Programs	16 Programs	20 Programs
DSM Maximum (MWs)[33]	497	407	539	467
CTs/CCGTs (MWs)	7,348	8,404	6,876	6,512
Wind (MWs)	0	0	0	4,000[34]

Each portfolio was modeled in AURORA and tested in the four scenarios described earlier for a total of 16 cases. The results of the AURORA simulations were combined with the fixed costs of the incremental resource additions to yield the total forward revenue requirements excluding sunk costs of the portfolio. The total forward revenue requirement results and rankings by scenario are provided in the following tables.

Table 11: PV of Forward Revenue Requirements by Scenario

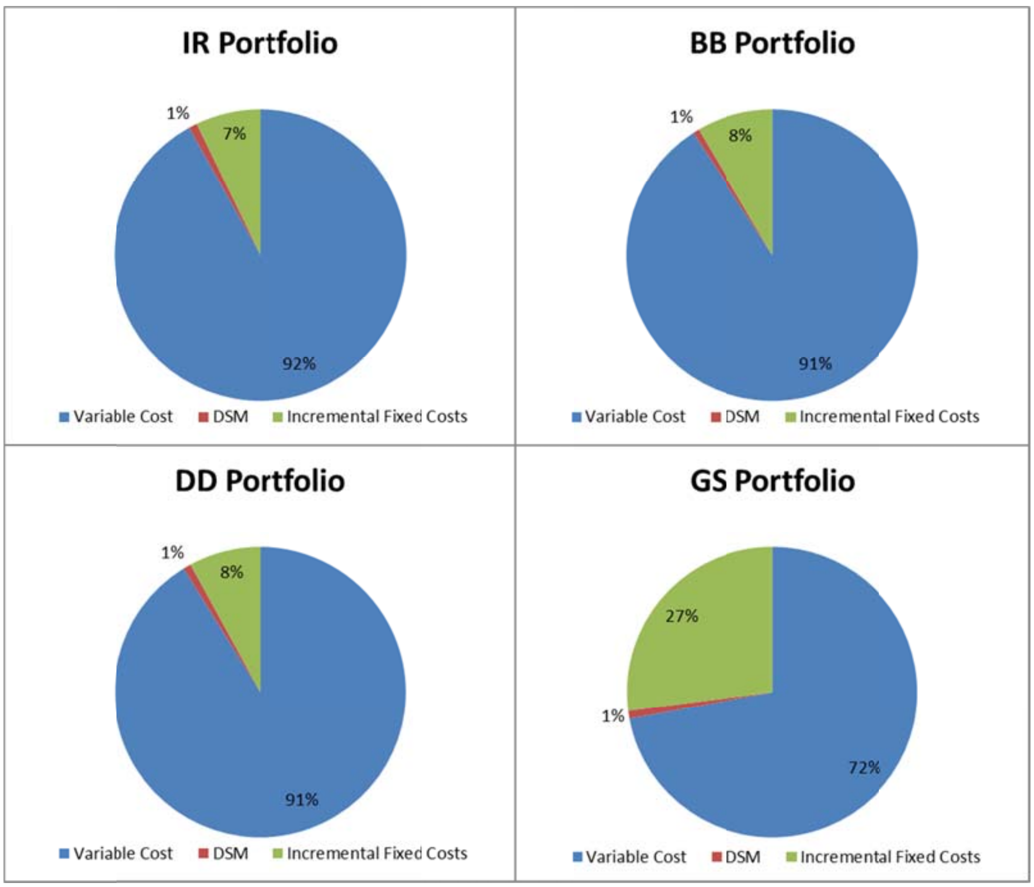
PV of Forward Revenue Requirements ($B) (2015-2034)				
	IR Scenario	**BB Scenario**	**DD Scenario**	**GS Scenario**
Industrial Renaissance Portfolio	35.5	31.9	35.6	45.9
Business Boom Portfolio	35.7	31.7	35.9	45.8
Distributed Disruption Portfolio	35.5	31.7	35.7	45.7
Generation Shift Portfolio	37.3	34.5	36.9	42.5

[33] Demand Side Management (DSM) total is grossed up for Planning Reserve Margin (12%) and transmission losses (2.4%).
[34] Wind was limited to 20 resources annually at 200 MWs each, which provides 564 MW of capacity credit based on MISO-determined wind capacity credit of 14.1%.

The revenue requirements shown above include the total cost to serve total load over the 20 year planning period. It is important to note that the revenue requirements shown are reflective of the total fuel costs and the incremental resource cost to deliver the portfolios under different scenarios and are not reflective of customer rate effects as they do not consider changes in load and other factors affecting rates.

Table 12, below, breaks down the forward revenue requirements for each portfolio in the Industrial Renaissance Scenario (the first column of Table 11) into the component costs. The pie charts show the percentages of incremental fixed, variable, and DSM costs of the total PV forward revenue requirements shown in Table 11.

Table 12: Portfolios by Cost Components in the Industrial Renaissance Scenario (2015-2034)[35] [36]



The columns in Table 13, below, show the rankings of each of the four modeled portfolios in each of the scenarios.

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[35] Variable cost represents the load payment net of generation energy margins.

[36] Incremental fixed cost is the fixed cost revenue requirement of the incremental supply-side resource additions in each portfolio.

Table 13: Portfolio Ranking by Scenario

Portfolio Ranking by Scenario (2015-2034)				
	IR Scenario	BB Scenario	DD Scenario	GS Scenario
Industrial Renaissance Portfolio	1	3	1[37]	4
Business Boom Portfolio	3	2	3	3
Distributed Disruption Portfolio	2	1[38]	2	2
Generation Shift Portfolio	4	4	4	1

The next step was to perform sensitivity analyses on each portfolio by adjusting one variable at a time[39] and computing the PV of forward revenue requirements. Each portfolio was tested across the range of assumptions for:

- Natural Gas Prices
- Coal Prices
- Capital Cost for New Generation
- General Inflation and Resulting Cost of Capital
- CO_2 Costs
- Natural Gas Prices and CO_2 Costs Combinations

The range of total forward revenue requirements results by portfolio in the Industrial Renaissance Scenario is provided in the following five tables.

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[37] Total supply cost for the Industrial Renaissance Portfolio was lower than the Distributed Disruption Portfolio; however, the difference was not significant (0.3%) and the variable supply cost of the Distributed Disruption Portfolio was lower.

[38] Total supply cost for the Distributed Disruption Portfolio was lower than the Business Boom Portfolio; however, the difference was not significant (0.02%) and the variable supply cost of the Business Boom Portfolio was lower.

[39] A combination of natural gas prices and CO_2 costs involved adjustment of two variables at the same time.

Table 14: Natural Gas Sensitivity in the Industrial Renaissance Scenario

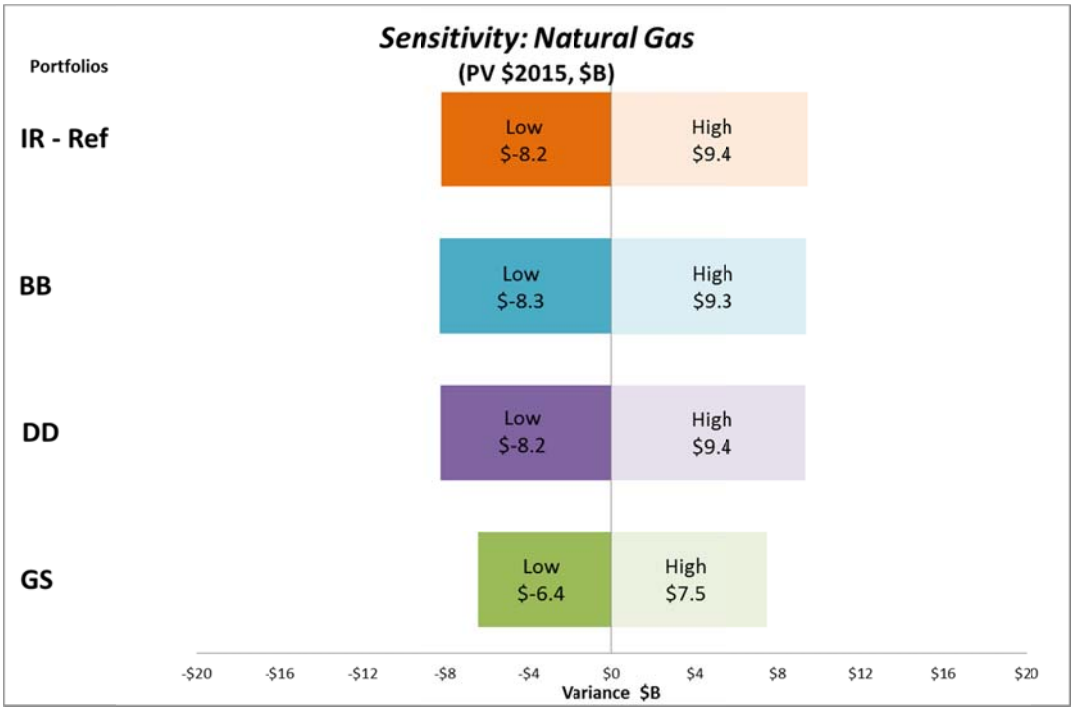


Table 15: CO2 Price Sensitivity in the Industrial Renaissance Scenario

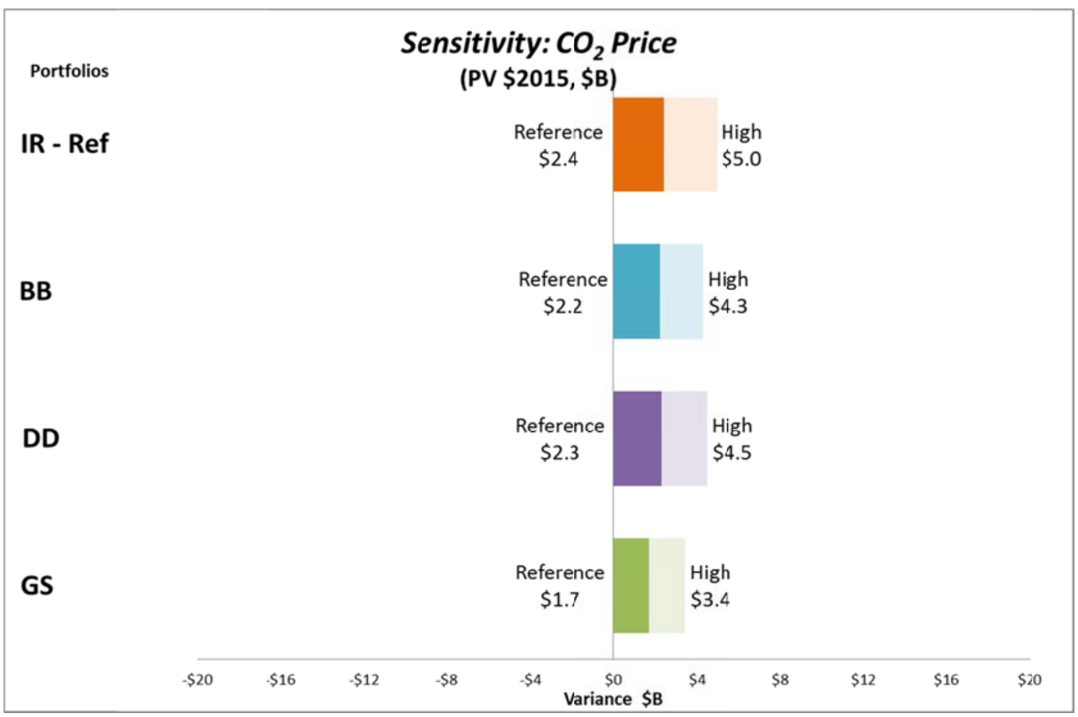


Table 16: Natural Gas and CO_2 Combination Sensitivity in the Industrial Renaissance Scenario

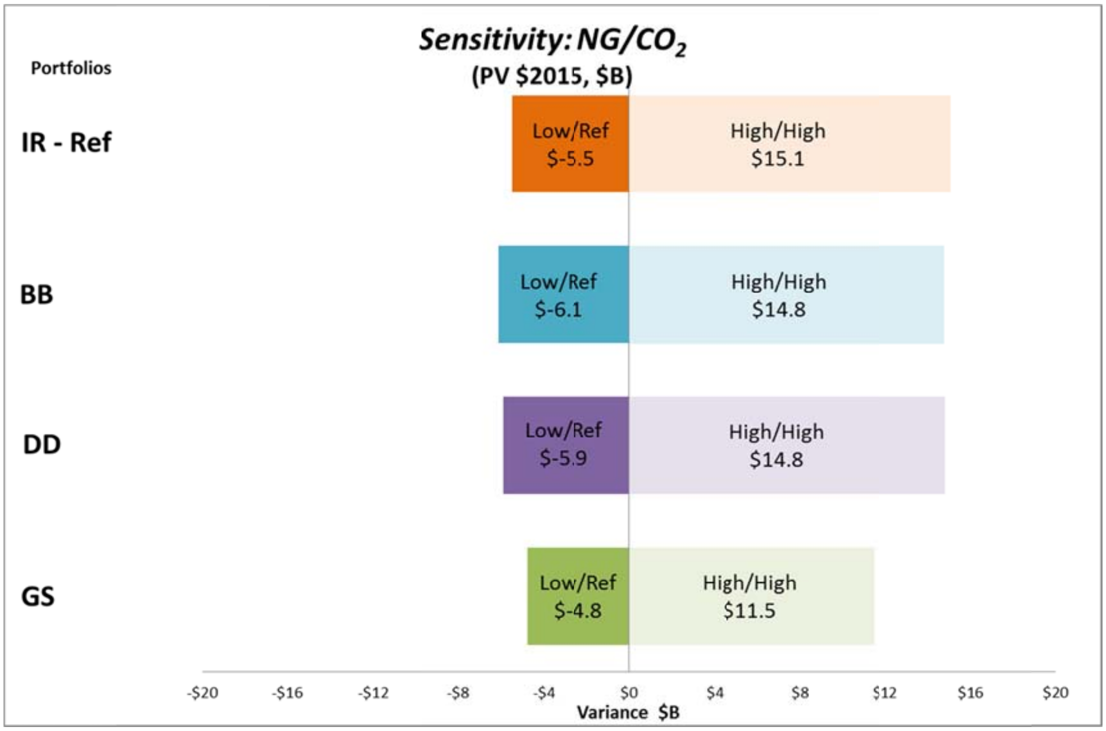


Table 17: Cost of Capital Sensitivity in the Industrial Renaissance Scenario

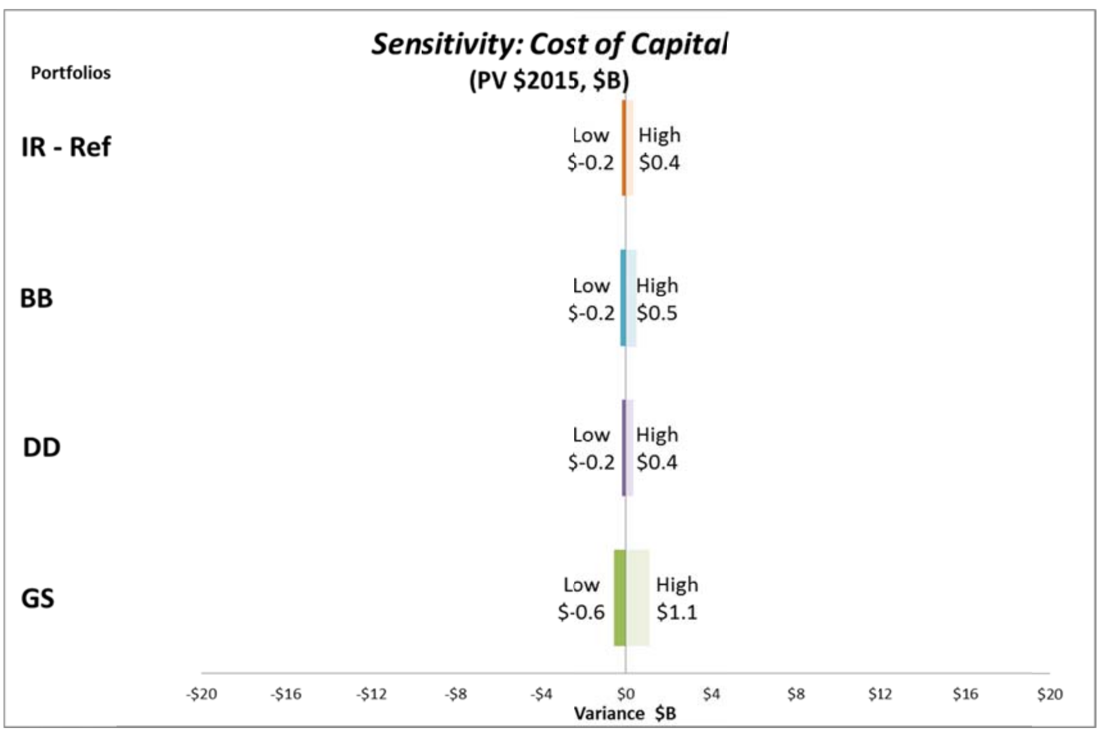
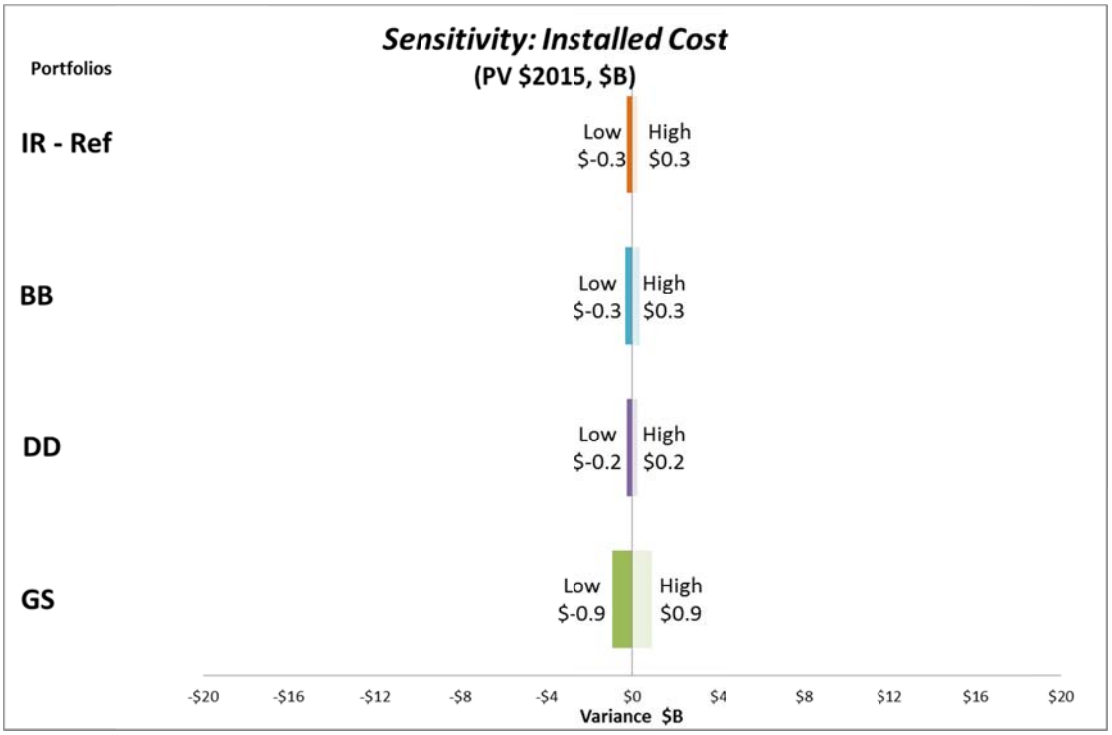


Table 18: Installed Cost Sensitivity in the Industrial Renaissance Scenario



Results of the sensitivity assessments indicate that the installed cost, cost of capital, and coal prices[40] have less of an impact on the variability of total forward revenue requirements results across all portfolios in comparison to natural gas prices, CO_2 prices, and the combination of natural gas price and CO_2 price. The Industrial Renaissance, Business Boom, and Distributed Disruption portfolios are similarly sensitive to natural gas prices, CO_2 prices, and the combination of natural gas and CO_2 prices, whereas the Generation Shift portfolio is relatively less sensitive to these variables. Conversely, the Generation Shift portfolio is more sensitive to installed cost and cost of capital as compared to the Industrial Renaissance, Business Boom, and Distributed Disruption portfolios. This is a result of the Generation Shift portfolio's higher incremental fixed costs relative to the other three portfolios, which is indicated in the accompanying Table. Results of the sensitivity analysis are consistent with the resource type and amount that comprise each of the portfolios.

[40] Coal price sensitivity results are not shown in the sensitivity charts because coal resources are not added as a new resource to any of the portfolios and the existing resource portfolio only has approximately 4% of coal resources.

Summary of Findings and Conclusions

Results of the scenario assessment indicate:

- Supply-side economics were consistent with technology screening analysis.
- Some level of DSM was economic[41] in every scenario.
- Renewables are not economic under most assumptions. Renewable resources depend on high gas and carbon prices to be economic relative to CT and CCGT resources.
- CT and CCGT resources perform well across most scenarios. The choice between CCGT and CT technologies is sensitive to external factors as demonstrated by the narrow range of outcomes for the portfolios comprised primarily of these resources.

PART 5: FINAL REFERENCE RESOURCE PLAN & ACTION PLAN

Final Reference Resource Plan

The IRP process resulted in the identification of a Final Reference Resource Plan that represents the Companies' best available strategy for meeting customers' long-term power needs at the lowest reasonable supply cost, while considering reliability and risk. The Final Reference Resource Plan is based on the following assumptions:

- The industrial renaissance underway in Louisiana, coupled with residential and commercial load growth, is driving significant growth in utility load with up to 1,600 MW of industrial load growth expected in the Companies' service areas through 2019. By 2034, the Companies expect to require at least 8,000 MW of additional capacity to meet demand.
- For purposes of planning capacity, the Companies have assumptions regarding the deactivation of approximately 5,950 MW of older gas fired steam generators over the planning period. This aging fleet is increasingly susceptible to accelerated deactivation as decisions are made regarding unit economics associated with unexpected maintenance costs and ongoing evaluation of unit availability. Actual decisions to continue to invest in and operate these units have not been made and will be subject to on-going assessments of economics and technical feasibility.

[41] *See* note 32, *supra.*

- In order to reliably meet the power needs of their respective customers at the lowest reasonable cost, the Companies will maintain a portfolio of generation resources that includes the right amount and types of capacity.

    - With respect to the amount of capacity, the Companies must maintain sufficient generating capacity to meet their peak loads plus a planning reserve margin. The Companies will plan resources to a 12% reserve margin. The Companies will need to add capacity for three reasons: 1) to meet load growth; 2) to replace existing resources that will reach the end of their useful lives (unit deactivations); and 3) to replace PPAs that will expire.

    - With respect to the type of capacity, the Companies seek to add modern, efficient generating capacity, which will predominantly be CCGTS and CTs.

- The Companies will continue to meet the bulk of their reliability requirements with either owned assets or long-term PPAs. The emphasis on long-term resources mitigates exposure to capacity price volatility and ensures the availability of resources sufficient to meet long-term reliability needs.

- A portion of reliability requirements may be met through a reasonable reliance on limited-term power purchase products including zonal resource credits, to the extent these are economically available when considering risk.

- Some level of DSM is considered economically attractive but presents ratemaking and policy issues that must be addressed in connection with adoptions of such programs. A variety of factors, many of which are highly uncertain, will affect the amount of DSM that can and will be achieved over the planning horizon.

- All existing coal and nuclear units will continue operating throughout the planning horizon. All nuclear units are assumed to receive license extensions from the Nuclear Regulatory Commission ("NRC") to operate up to 60 years.

- New build capacity, when needed in 2020 and beyond, comes from a combination of CT and CCGT resources. New build capacity may be obtained through owned resources or long-term power purchase contracts. For the purpose of preparing the IRP, the economics were assumed to be equivalent.

- No new solid fuel capacity is added, and new nuclear development remains in the monitoring phase.

- Renewable resources are not economically attractive relative to conventional gas turbine technology (whether in simple or combined cycle) as solely a capacity resource. However, renewable cost and performance – in particular, solar – continues to improve as a source of zero emission generation. Due to potential state and federal incentives, potential environmental requirements, and as general cost and technology performance improve, it is conceivable that the Companies and their customers could incorporate solar or other intermittent, renewable resources at distributed or utility scale magnitude. These possibilities warrant further analysis.

The Final Reference Resource Plan shown in Table 19 includes assumptions regarding future major resource additions, such as the Union Power acquisition, the 2020 Amite South CCGT, 2020 WOTAB CTs, and the 2020-21 WOTAB CCGT, as well as assumptions regarding implementation of cost-effective DSM programs. The actual resources deployed (including the amount and timing of technology and power purchase products) and DSM implemented, will depend on factors which may differ from assumptions used in the development of the IRP. Such long term uncertainties include, but are not limited to:

- Load growth (magnitude and timing), which will determine actual resource needs

- The relative economics of alternative technologies, which may change over time

- Environmental compliance requirements

- Practical considerations that may constrain the ability to deploy resource alternatives such as the availability of adequate sources of capital at reasonable cost

- Condition of existing units and ongoing assessments of those units

There are two important points to consider when reviewing the Final Reference Resource Plan. First, the decision to procure a given resource will be contingent upon a review of available alternatives at that time, including the economics of any viable transmission alternatives available that would be coupled with a purchase of capacity and/or energy. In addition, the decision to procure a specific resource in a specific location must reflect the specific lead time for that type of resource, which will vary by resource type, and the time required for obtaining regulatory approvals. By deferring specific resource decisions until deployment is needed, the Companies retain the flexibility to respond to changes in circumstance up to the time that a commitment is made.

Second, a variety of factors, many of which are highly uncertain, will affect the amount of DSM that can and will be implemented over the planning horizon. DSM assumptions, including the level of cost-effective DSM identified through the IRP process, are not intended as definitive commitments to particular programs, program levels or program timing. The implementation of cost-effective DSM requires consistent, sustained regulatory support and approval. The Companies' 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. It is important that appropriate mechanisms be put into place to ensure the DSM potential actually accrues to the benefit of customers and that utility investors are adequately compensated for their investment through opportunity to earn performance-based incentives.

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Table 19: Final Reference Resource Plan--Load & Capability 2015-2034 (All values in MW)

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	9,869	10,081	10,495	10,896	11,172	11,090	11,162	11,231	11,303	11,376	11,452	11,526	11,599	11,672	11,743	11,811	11,882	11,952	12,024	12,095
Reserve Margin (12%)	1,184	1,210	1,259	1,307	1,341	1,331	1,339	1,348	1,356	1,365	1,374	1,383	1,392	1,401	1,409	1,417	1,426	1,434	1,443	1,451
Total Requirements[42]	11,053	11,290	11,754	12,203	12,513	12,421	12,502	12,578	12,659	12,741	12,826	12,909	12,991	13,073	13,152	13,229	13,308	13,387	13,466	13,546
Resources																				
Existing Resources																				
Owned Resources[43]	9652	9549	9549	8826	8826	8814	8814	8688	8688	8688	8688	8277	7616	7616	7095	6528	5571	4419	3702	3702
PPA Contracts	909	909	866	386	386	386	386	144	144	144	144	144	144	144	144	144	39	9	-	-
LMRs	308	308	308	308	308	308	308	308	308	308	308	308	308	308	308	308	308	308	308	308
Identified Planned Resources																				
Union[44]	-	816	816	816	816	816	816	816	816	816	816	816	816	816	816	816	816	816	816	816
Amite South CCGT[45]	-	-	-	-	-	560	560	560	560	560	560	560	560	560	560	560	560	560	560	560
Other Planned Resources																				
DSM[46]	19	44	77	105	151	220	266	299	329	334	403	413	414	471	457	532	539	423	456	538
CTs (2)	-	-	-	-	-	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388
CCGT 1	-	-	-	-	-	764	764	764	764	764	764	764	764	764	764	764	764	764	764	764
CCGT 2	-	-	-	-	-	-	-	-	-	-	-	-	764	764	764	764	764	764	764	764
CCGT 3	-	-	-	-	-	-	-	-	-	-	-	-	-	764	764	764	764	764	764	764
CCGT 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	764	764	764	764	764	764
CCGT 5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	764	764	764	764	764
CCGT 6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	764	764	764	764
CCGT 7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	764	764
CCGT 8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	764
Market Purchase	165	-	138	1,762	2,026	165	200	611	663	739	755	1,239	1,218	478	328	133	503	1,881	1,889	1,122
Total Resources	11,053	11,625	11,754	12,203	12,513	12,421	12,502	12,578	12,659	12,741	12,826	12,909	12,991	13,073	13,152	13,229	13,308	13,387	13,466	13,546

42 Total load requirement adjusts for the peak load diversity between the two companies.

43 The JSP PPAs are included in the Owned Resources row.

44 Union plant acquisition is completed pending regulatory approvals. 816 MW is two trains of the facility less 20% allocation to ENO.

45 ELL/EGSL share of Amite South RFP is presently estimated at 560 MW. RFP responses are currently being evaluated; actual capacity of selected resource could range between 650 to 1,000 MW and a portion of that capacity may be shared with another Entergy operating company. As a result, actual capacity may exceed 560 MW.

46 Demand Side Management (DSM) total is grossed up for Planning Reserve Margin (12%) and transmission losses (2.4%).

Action Plan

The Companies have developed the following Action Plan for pursuing the Final Reference Resource Plan described above over the first five years of the planning period. The Action Plan recognizes that there are numerous uncertainties that will be encountered over the 20-year IRP period, the outcome of which will significantly influence the resulting supply portfolio.

Table 20: Action Plan

Category	Item	Action to be taken
Supply-Side Alternatives	Union Acquisition	- Obtain regulatory approval and complete the acquisition of Power Blocks 3 and 4 of the Union Plant near El Dorado, Arkansas. Net of a 20% PPA to ENO, Union Plant would add approximately 816 MWs to the Companies' current capacity in 2016.
	Renewables	- The energy and capacity performance of utility scale intermittent resources and locational impacts on distribution feeders of distributed renewables at the residential or small utility scale will need to be determined to reliably and economically incorporate these resources over time. Long term investments in the system operations and utility distribution infrastructure might be required to reliably interconnect these technologies at a large scale. The Companies will evaluate distributed pilot projects (<5MW) for solar and storage technology in order to assess energy and capacity based plant performance, verify forecast integration of intermittent renewables for system reliability, and evaluate distributed solar PV locational impacts and economics on distribution feeders.
	Legacy Fleet	- Evaluate costs and benefits of investing in existing resources in order to support safe, reliable operation beyond the currently assumed deactivation dates.
	PPAs	- Evaluate costs and benefits of PPAs as viable alternatives to meet long-term needs.

	New Resources	- Continue to assess the development of a CT option (approximately 380 MWs) that could be deployed in the Lake Charles area in 2020 to meet the industrial load growth expected in that area; however, the timing of this resource is uncertain and subject to change based on changes in load additions, implementation of other supply additions, and changes in transmission topography. - Complete the Amite South RFP currently underway to obtain new CCGT capacity by 2020. - Pursue the addition of a new CCGT facility (approximately 800-1000 MWs) in the Lake Charles area by 2020-21 to maintain reliable and economic service to customers given the industrial load growth, PPA terminations, and anticipated unit deactivations expected in that area. - Continue to assess development of additional options for CT additions in the Amite South and WOTAB areas that could be deployed quickly if load growth is higher than expected and/or supply alternatives are not completed as planned.
	Gas Supply	- Explore opportunities for long-term gas supplies that could mitigate price volatility and/or reduce the cost of gas relative to future market conditions.
Demand-Side Alternatives	DSM and Energy Efficiency Programs	- Evaluate the results of the Quick Start Energy Efficiency programs in Louisiana. - Work with regulators to develop rules that would provide a framework for implementing cost effective DSM programs beyond the Quick Start phase and provide appropriate cost recovery.

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APPENDIX A: ELL & EGSL GENERATION RESOURCES

Generating Assets Owned or Controlled by ELL as of 1/1/15					
Plant	**Unit**	**Megawatt Capability**	**Fuel**	**COD**	**Region**
ANO	1	23	Nuclear	12/19/1974	North
ANO	2	27	Nuclear	3/25/1980	North
Acadia	2	367	Gas	7/3/2002	WOTAB
Buras	8	12	Gas	1/30/1971	DSG
Grand Gulf		209	Nuclear	7/1/1985	Central
Independence 1		7	Coal	1/18/1983	North
Little Gypsy	2	411	Gas	4/18/1966	Amite South
Little Gypsy	3	520	Gas	3/21/1969	Amite South
Ninemile Point	3	103	Gas	11/5/1955	DSG
Ninemile Point	4	699	Gas	5/1/1971	DSG
Ninemile Point	5	717	Gas	6/12/1973	DSG
Ninemile Point	6	308	Gas	12/24/2014	DSG
Perryville	1	133	Gas	7/1/2002	Central
Perryville	2	36	Gas	7/1/2001	Central
Sterlington	7	126	Gas	1/1/1986	Central
Riverbend	1	195	Nuclear	1/1/1986	Central
Waterford	1	411	Gas	6/27/1974	Amite South
Waterford	2	411	Gas	9/13/1975	Amite South
Waterford	3	1,156	Nuclear	9/24/1985	Amite South
Waterford	4	33	Oil	9/24/1985	Amite South
White Bluff	1	13	Coal	8/22/1980	North
White Bluff	2	12	Coal	7/23/1981	North
Total Owned		**5,929**			
Unaffiliated PPAs		**605**			
Total Capacity		**6,534**			

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Generating Assets Owned or Controlled by EGSL as of 1/1/15					
Plant	**Unit**	**Megawatt Capability**	**Fuel**	**COD**	**Region**
Acadia	2	184	Gas	7/3/2002	WOTAB
Big Cajun 2	3	146	Coal	1/1/1983	Central
Calcasieu	1	82	Gas	5/30/2000	WOTAB
Calcasieu	2	91	Gas	5/1/2001	WOTAB
Lewis Creek	1	133	Gas	12/1/1970	WOTAB
Lewis Creek	2	132	Gas	5/1/1971	WOTAB
Ninemile Point	6	140	Gas	12/24/2014	DSG
Ouachita	3	241	Gas	8/1/2002	Central
Perryville	1	228	Gas	7/1/2002	Central
Perryville	2	63	Gas	7/1/2001	Central
Roy Nelson	4	244	Gas	7/1/1970	WOTAB
Roy Nelson	6	222	Coal	5/1/1982	WOTAB
Riverbend	1	389	Nuclear	1/1/1986	Central
Sabine	1	122	Gas	3/1/1962	WOTAB
Sabine	2	122	Gas	12/1/1962	WOTAB
Sabine	3	228	Gas	11/1/1964	WOTAB
Sabine	4	306	Gas	8/1/1974	WOTAB
Sabine	5	270	Gas	12/1/1979	WOTAB
Willow Glen	2	104	Gas	1/1/1962	Central
Willow Glen	4	276	Gas	7/1/1973	Central
Total Owned		**3,723**			
Unaffiliated PPAs		**304**			
Total Capacity		**4,027**			